Frequency Contribution Factors Procedure

Draft Report – Standard consultation for the National Electricity Market

Published: 7 February 2023

Executive summary and consultation notice

The publication of this draft report commences the second stage of the standard consultation procedure conducted by AEMO to develop and publish a new Frequency Contribution Factors Procedure (**FCFP**) (the **proposal**) under the National Electricity Rules (**NER**).

This consultation is undertaken as required by NER 11.152.3 following the procedure in NER 8.9.2.

The FCFP will have effect under NER 3.15.6AA, which commences on 8 June 2025 under the National Electricity Amendment (Primary Frequency Response incentive arrangements) Rule 2022 (**PFR incentives rule**)[1].

The standard rules consultation procedure is described in NER 8.9.2.

The detailed sections of this draft report include more information on the proposal and AEMO's reasons for making it. A draft of the FCFP reflecting the proposal is published with this draft report.

Consultation notice

AEMO invites written submissions from interested persons on the proposal, including the draft FCFP and issues identified in this draft report to FPPconsultation@aemo.com.au by 5:00pm (Melbourne time) on 15 March 2023.

Submissions may make alternative or additional proposals you consider may better meet the objectives of this consultation and the national electricity objective in section 7 of the National Electricity Law. Please include supporting reasons.

Please note the following important information about submissions:

- All submissions will be published on AEMO's website, other than confidential content.
- Please identify any parts of your submission that you wish to remain confidential, and explain why. AEMO may still publish that information if it does not consider it to be confidential, but will consult with you before doing so. Material identified as confidential may be given less weight in the decision-making process than material that is published.
- Submissions received after the closing date and time will not be valid, and AEMO is not obliged to consider them. Any late submissions should explain the reason for lateness and the detriment to you if AEMO does not consider your submission.

Interested persons can request a meeting with AEMO to discuss any particularly complex, sensitive or confidential matters relating to the proposal. Please refer to NER 8.9.1(k). Meeting requests must be received by the end of the submission period and include reasons for the request. AEMO will try to accommodate reasonable meeting requests but, where appropriate, we may hold joint meetings with other stakeholders or convene a meeting with a broader industry group. Subject to confidentiality restrictions, AEMO will publish a summary of matters discussed at stakeholder meetings.

[1] Final determination and amending rule available on the Australian Energy Market Commission's website at: https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

Contents

Tables

Figures

1. Stakeholder consultation process

As required by NER 11.152.3, AEMO is consulting on the initial FCFP in accordance with the standard rules consultation procedure in NER 8.9.2.

Note that this document uses terms defined in the NER, which are intended to have the same meanings. There is a glossary of additional terms and abbreviations in Appendix A.

AEMO's process and expected timeline for this consultation are outlined below. Future dates may be adjusted and additional steps may be included as needed, as the consultation progresses.

Table 1 Consultation process and timeline

Consultation steps	Dates
Information workshop	19 September 2022
Consultation paper published	31 October 2022
Consultation briefing	4 November 2022
Submissions due on consultation paper	6 December 2022
Draft report published	7 February 2023
Submissions due on draft report	15 March 2023
Final report published	8 June 2023

AEMO's consultation webpage for the proposal is at https://aemo.com.au/consultations/current-and-closed-consultations/frequency-contribution-factors-procedure, containing all previous published papers and reports, written submissions, and other consultation documents or reference material (other than material identified as confidential).

In response to its consultation paper on the proposal, AEMO received four written submissions.

AEMO also held three briefings, one hosted by AEMO open to all interested parties, one with the Australian Energy Council and one with the Clean Energy Council, on 4/11/22, 7/11/22 and 5/12/22 respectively.

AEMO thanks all stakeholders for their feedback on the proposal to date, which has been considered in preparing this draft report, and looks forward to further constructive engagement.

2. Background

2.1. Context for this consultation

On 8 September 2022, the Australian Energy Market Commission (**AEMC**) published its final determination of the PFR incentives rule. The rule provides enduring arrangements to support the control of power system frequency and incentivise plant behaviour that reduces the overall cost of frequency regulation during normal operation. In order to allow participants to have sufficient certainty around the implementation of this new framework for the optimisation and development of their systems, the PFR incentives rule requires AEMO to develop and publish the FCFP by 8 June 2023, to take effect from 8 June 2025 when the main provisions of the rule will commence.

The FCFP will replace the existing Regulation FCAS Contribution Factor Procedure (made under NER 3.15.6A(k)), which currently determines how AEMO calculates the contribution factors for recovering the cost of regulating raise and regulating lower market ancillary services (**regulation FCAS**) in the national electricity market (**NEM**). These factors are intended to reflect the extent to which a market participant can be taken to have 'caused' the need for regulation FCAS based on the negative performance of its facilities relevant to target frequency (where this can be measured), with the residual being allocated to market customers based on energy consumption.

The FCFP will reflect significant changes to be introduced by the PFR incentives rule for the recovery of regulation FCAS costs, including the introduction of frequency performance payments (**FPP**) for market participants' eligible facilities where their primary frequency response (**PFR**) helps to reduce the frequency deviations which would otherwise require the use of regulation FCAS.

2.2. NER requirements

AEMO is required to publish the initial FCFP under NER 11.152.3, under the transitional provisions of the PFR incentives rule. The FCFP must include the content and be consistent with the principles in NER 3.15.6AA. Stakeholders should note that all references to NER 3.15.6AA are to that clause as introduced by the PFR incentives rule.

2.2.1. Content requirements

NER 3.15.6AA(g) requires the FCFP to include seven mandatory items, described below:

(1) The criteria for determining whether an eligible unit has 'appropriate metering' – that is, metering to allow its individual contribution to the deviation in power system frequency to be assessed.

(2) A formula to calculate the measure of the need to raise or lower the frequency of the power system in each trading interval, which:

(i) must be based on the frequency of the power system in the relevant region(s);

(ii) must contain sufficient detail for a relevant participant to estimate the need to raise or lower the frequency of the power system during a trading interval; and

(iii) may include parameters to be determined by AEMO from time to time for different elements of the formula.

(3) The methodology for determining a contribution factor for an eligible unit which reflects its contribution to the deviation in frequency of the power system. This methodology must be consistent with the principles in NER 3.15.6AA(f), summarised in section 2.2.2 below.

(4) The methodology for determining default contribution factors to apply to an eligible unit:

(i) where it is impractical for AEMO to determine a contribution factor for that unit in a trading interval; and

(ii) for use in calculating trading amounts to recover the cost of regulation FCAS enabled but not used.

(5) The data AEMO will use to calculate the contribution factor for an eligible unit with appropriate metering. The data must include the unit's active power output or consumption and a measure of frequency, and may include frequency measured at the connection point or other data AEMO considers relevant.

(6) The methodology for determining the requirement for corrective response as a measure of the total megawatts (MW) volume that contributed to reducing the deviation in frequency of the power system, and the proportion of enabled regulation FCAS that was used. The requirement for corrective response methodology may include parameters to be determined by AEMO from time to time.

(7) The methodology for determining a reference trajectory in each trading interval for each eligible unit with appropriate metering. This must consider the relevant dispatch target or level, and any information provided by the relevant participant relating to the expected trajectory of non-scheduled units. Other relevant matters may also inform the methodology.

2.2.2. Principles for determining contribution factors

In determining the contribution factors to apply to eligible units in a trading interval for the purpose of determining frequency performance payments and cost recovery amounts for regulation FCAS determined to have been used, the FCFP should give effect to the principles listed in NER 3.15.6AA(f), summarised below:

(1) A negative contribution factor for an eligible unit should reflect the extent to which the unit contributed to increasing the deviation in frequency of the power system.

(2) A positive contribution factor for an eligible unit should reflect the extent to which the unit contributed to reducing the deviation in frequency of the power system.

(3) A contribution factor is a number between -1 and 1.

(4) The residual contribution factor for all eligible units without appropriate metering must be equal across and within all market participant classes involved in the cost recovery process.

(5) Separate contribution factors must be determined for the contribution to the need to raise or lower the frequency of the power system.

(6) AEMO must determine a contribution factor for each eligible unit unless in AEMO's reasonable opinion it is impractical to do so, in which case AEMO must determine a default contribution factor.

(7) A contribution factor for each eligible unit applies for the region(s) relevant to a global market ancillary service requirement or local market ancillary service requirement for each regulation FCAS (raise or lower).

(8) A default contribution factor for an eligible unit must be determined based on historical data for that unit unless in AEMO's reasonable opinion it is impractical to do so.

A default contribution factor must only be used in the frequency performance payments calculation to determine a trading amount payable by (not to) a relevant market participant.

2.3. The national electricity objective

Within the specific requirements of the NER applicable to this proposal, AEMO will seek to make a determination that is consistent with the national electricity objective (**NEO**) and, where considering options, to select the one best aligned with the NEO.

The NEO is expressed in section 7 of the National Electricity Law as:

> *to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *(b) the reliability, safety, and security of the national electricity system.*

3. List of material issues

The key material issues arising from the proposal or raised in submissions or consultation meetings are listed in the following table.

Table 2 List of material issues

No.	Issue	Raised by
1.	Measurement of power system frequency	AEMO (initial consultation)
2.	Determination of the frequency measure	AEMO (initial consultation)
3.	Formulation of performance and contribution factors	AEMO (initial consultation)
4.	Formulation of default contribution factors	AEMO (initial consultation)
5.	Application of default contribution factors	AEMO (initial consultation)
6.	Formulation of requirement for corrective response	AEMO (initial consultation)
7.	Formulation of usage	AEMO (initial consultation)
8.	Impact of delays to dispatch instructions	AEMO (initial consultation)
9.	Determination of reference trajectories	AEMO (initial consultation)
10.	Formulation of the Residual	AEMO (initial consultation)
11.	Publication of data additional to rule requirement	AEMO (initial consultation)
12.	Aggregated dispatch conformance	AEMO (new issue)
13.	Where AEMO is unable to calculate and publish contribution factors within a 'reasonable' timeframe	AEMO (new issue)

A detailed table of stakeholder feedback in written submissions to the consultation paper, together with AEMO's responses, is contained in Appendix B.

Each of the material issues in Table 2 is discussed in Section 4.

4. Discussion of material issues

4.1. Measurement of power system frequency

4.1.1. Issue summary and submissions

NER 3.15.6AA(g)(2)(i) requires AEMO to measure power system frequency. In the consultation paper, AEMO proposed to measure power system frequency uniquely for each region. Such regional measurement was generally supported.

Delta Electricity noted that there may be some benefit in certain regions with network challenges to have multiple points of measurement. IES noted that local measurement could allow for potentially increased resolution of frequency readings at the connection point which would lead to more accurate factors.

4.1.2. AEMO's assessment

Based on AEMO's original proposed formulation of the frequency measure and analysis of the impact of reasonable levels of communications latency, measurement of frequency at the connection point would have minimal impact on contribution factors compared to a regional frequency framework. Given that the measured frequencies of a steady-state AC-connected power system at different connection points are almost equal at each specific 4-second interval, the only benefit of a local measurement is the similarity between the likely delay in the SCADA readings of power output and the frequency deviations used to determine the frequency measure. Assuming that a unit's SCADA readings have a maximum communication delay of 6 seconds, using the connection point frequency can make the 4-second performance values more accurate in one or two 4-second intervals (affected by the delay). This is less than 4% of a trading interval for which AEMO calculates the contribution factors. More importantly, as the performance of the unit is calculated based on the frequency measure, which is a much smoother signal than the raw frequency deviations, the difference between the real-time frequency measure and the 4- or 8-second delayed frequency measure is minimal (the average differences are 0.002Hz and 0.004Hz, significantly smaller than those of raw frequency deviations). Thus, due to the minimal impact of using local frequency measurements on the accuracy of performance values, AEMO holds the view that the cost and complexity of installing frequency measurement devices at all connection points (or even just installing the requisite systems to accommodate such new data feeds) outweigh the benefits.

With regard to the IES submission, note that AEMO intends to use an exponential weighted moving average filter with a span of 28 seconds to determine regional frequency measures. Frequency measures will be significantly smoothed such that any increase in the accuracy of a frequency measure due to an increase in the rate of local frequency sampling below 4 seconds would not be material. If a strong case arises for such local metering in the future, AEMO will consider the necessary amendments to the system at that time.

Regional frequency measurement, however, is expected to deliver significant benefits over a single measure for each automatic generation control system (**AGC**) area (for synchronously connected regions – normally all mainland NEM regions – and Tasmania). Regional measurement means that, when there is a separation event at or near the region boundary, calculated performance will still be based on an accurate frequency measure. In addition, regional frequencies readings should, in general, be more closely aligned with local frequencies that individual units may be responding to.

Note that if power system frequency is measured regionally, the frequency measure will also be regional and a solution is needed in order to calculate requirements for corrective response (**RCRs**) for requirements that span multiple regions (such as for a global requirement). This will be discussed further in section 4.6 below.

4.1.3. AEMO's conclusion

AEMO remains of the view that power system frequency should be determined regionally, and this is provided in section 1 of the draft FCFP. Compared with AGC area measurement, this will provide a frequency measure that is more closely aligned with what most local units are responding to and requires no adjustment when regional separation occurs. Compared with local measurement, the cost and complexity of implementation will be significantly lower.

4.2. Determination of the frequency measure

4.2.1. Issue summary and submissions

The 'frequency measure' is a metric used to calculate the 'need to raise or lower the frequency of the power system…'. This measure (referred to in the IES analysis as the 'performance Metric') must be based on power system frequency, and its product with each eligible unit's 4-second deviations gives a performance value that is summed for each 5-minute trading interval and used to create contribution factors. No preferred formulation of frequency measure was described in the consultation paper.

The consultation paper indicated that the frequency measure could be comprised of multiple parameters. Delta Electricity suggested that the frequency measure should be smoothed to avoid periodic frequency variation that occurs in the 25-30 second time frame. IES supported a combined frequency metric with a slower moving component approximating the 'AGC value' and suggested that a time constant of 30 seconds would be appropriate.

4.2.2. AEMO's assessment

To select the most suitable formulation for the frequency measure, AEMO evaluated numerous possibilities, ranging from the raw 4-second frequency deviations and the smoothed frequency deviations (which can be obtained by applying various low-pass filters) to a combination of both. Each candidate was tested on one-year's worth of historical data and assessed against a particular set of criteria. These criteria and the reasoning for them are as follows:

A. The frequency measure must be highly correlated with the real-time frequency deviations. **Reasoning**: The frequency measure should reflect the need to raise or lower the frequency of the power system.
B. The frequency measure must have a similar strong correlation with the frequency deviations of the past 10 seconds. **Reasoning**: AEMO acknowledges that not all types of eligible units can provide PFR within a couple of seconds. Given the interim PFR requirements[2], we aim to value a response within 10 seconds of a frequency deviation more highly compared to a more delayed response. We are not seeking to discriminate

[2] Page 7 of the interim Primary Frequency Response Requirements - https://www.aemo.com.au/-/media/files/initiatives/primary-frequency-response/2020/interim-pfrr.pdf

materially amongst responses that occur within 10 seconds. Changes to PFR requirements in the future that impact this can be addressed via alterations to the frequency measure parameters.

C. The frequency measure should be highly correlated with the frequency deviations of up to 16 past seconds. **Reasoning**: AEMO recognises that there might be communication delays in the SCADA power measurements of generators compared to the frequency measurements. To minimise the impact of such delays and properly incentivise all frequency responses, the frequency measure should be correlated with the past frequency deviations of up to 16 seconds, which is the sum of 10 (i.e., the ideal response time for PFR as mentioned in the previous criterion) and 6 seconds (i.e., the requirement for end-to-end data transmission time to AEMO[3]).
D. The frequency measure's correlation with frequency deviations should be decreasing with respect to the amount of time lag. **Reasoning**: The frequency measure must incentivise a faster response more than a delayed one and it should be more strongly correlated with more recent power system frequency data.
E. The frequency measure should be predictable and have minimal erratic changes. **Reasoning**: As the performance of the participating units is determined based on a product of the frequency measure and their deviation, erratic or unpredictable changes in the frequency measure can lead to incorrectly quantifying the helpful responses as unhelpful, or vice versa. Additionally, a predictable frequency measure would mean units can react to the frequency deviations with higher confidence and less risk of being penalised for a 'helpful' response. A predictable frequency measure can also promote a sustained PFR.

Here, AEMO reports a summary of the comparison among the selected frequency measure options based on these criteria. Each of the selected candidates below was chosen from a larger group of similar formulations (categorised by two types of low-pass filters and potential combinations of them) based on how they performed. The two types of chosen low-pass filters are a causal moving average (**MA**) and an exponential weighted moving average (**EMA**). In AEMO's assessments, these showed better results against the mentioned criteria compared to other filters, such as Butterworth and Savitzky-Golay. In the context of 4-second frequency data as input, the MA and EMA filtered time series can be determined using the following equations:

$$MA_t(T) = \left(x_{t-\frac{T}{4}} + x_{t-\frac{T}{4}+1} + \cdots + x_t\right) \Big/ \left(\frac{T}{4} + 1\right)$$

$$EMA_t(\alpha) = [1-\alpha]EMA_{t-1}(\alpha) + \alpha x_t$$

where t is the 4-second interval index, x_t is the input time series (i.e., the negative of frequency deviations with the temporal resolution of 4 seconds) at 4-second interval t, T is the length of the MA filter in seconds, and α (alpha) is the smoothing factor decided by AEMO.

The selected frequency measure options are as follows:

1) Raw frequency deviations
2) An MA with $T = 16$ seconds

[3] Page 12 of the Power System Data Communications Standard - https://www.aemo.com.au/-/media/Files/Electricity/NEM/Network_Connections/Transmission-and-Distribution/AEMO-Standard-for-Power-System-Data-Communications.pdf

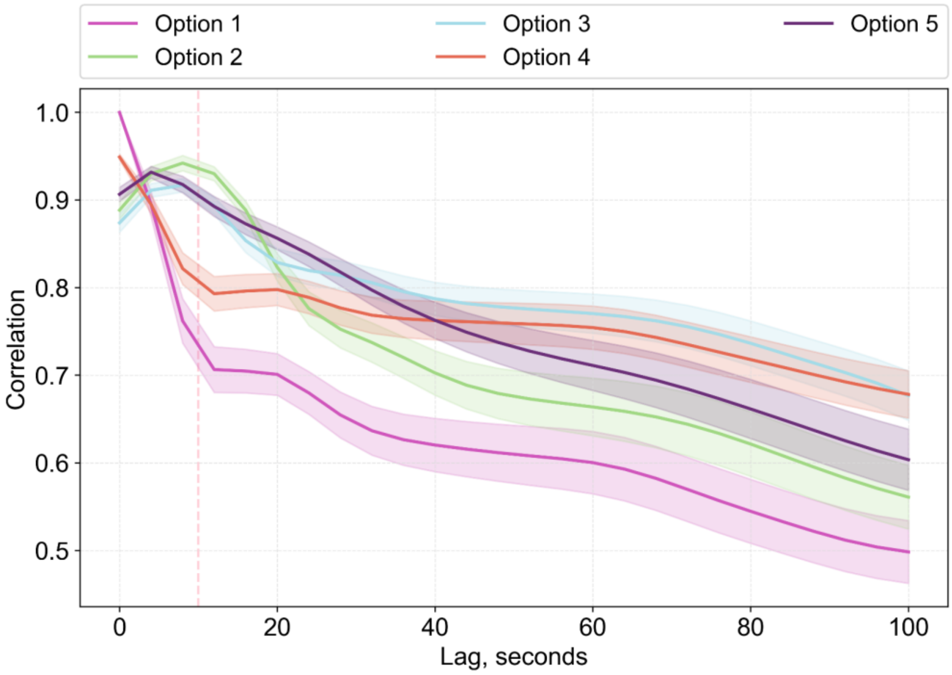
3) A combination of an MA with $T = 12$ seconds and one with $T = 100$ seconds, i.e., $0.5MA_t(12) + 0.5MA_t(100)$
4) A combination of raw frequency deviations and an MA with $T = 120$ seconds, i.e., $0.5x_t + 0.5MA_t(120)$
5) EMA with $\alpha = 2/9$ (i.e., a time constant of roughly 16 seconds or a span of 28 seconds).

Given the first four criteria, AEMO compared the correlation between different frequency measure options and the raw frequency deviations, both present and past. In this regard, there are seasonal changes in generation and demand in the NEM, which can impact the system frequency dynamics. Thus, the study considered the potential uncertainty between the correlation of frequency measure options and past frequency deviations. This was done by calculating the correlations between the two parameters using data from 26 different fortnights across a year.

Figure 1 illustrates the correlation between different frequency measure options and the frequency deviations of the real-time and the past with respect to the frequency deviation lag. Given the uncertainty modelling, each line shows the mean correlation between a candidate frequency measure and the frequency deviation of up to 100 seconds. Also, each line's shaded area highlights the determined correlations' standard deviation.

As can be seen in Figure 1, option 5, which is the EMA with $\alpha = 2/9$, has a strong correlation with minimal changes with the real-time frequency deviations and those of up to the past 10 seconds (the pink horizontal line marks the 10-second lag). While it is also highly correlated with the past frequency deviations of up to 16 seconds, the correlation decreases with respect to the lag. Additionally, the strictly decreasing trend of correlation with respect to the lag holds for almost all the past frequency deviations up to 100 seconds, ensuring that a faster response is more incentivised. That notwithstanding, the correlation is still relatively high up to 60 seconds, meaning that even a delayed PFR would still be rewarded on average. Yet, the earlier the response, the higher the reward. Based on the assessment criteria, this option is the best choice among the candidates.

Figure 1 The correlation of frequency measure options with real-time and past frequency deviations



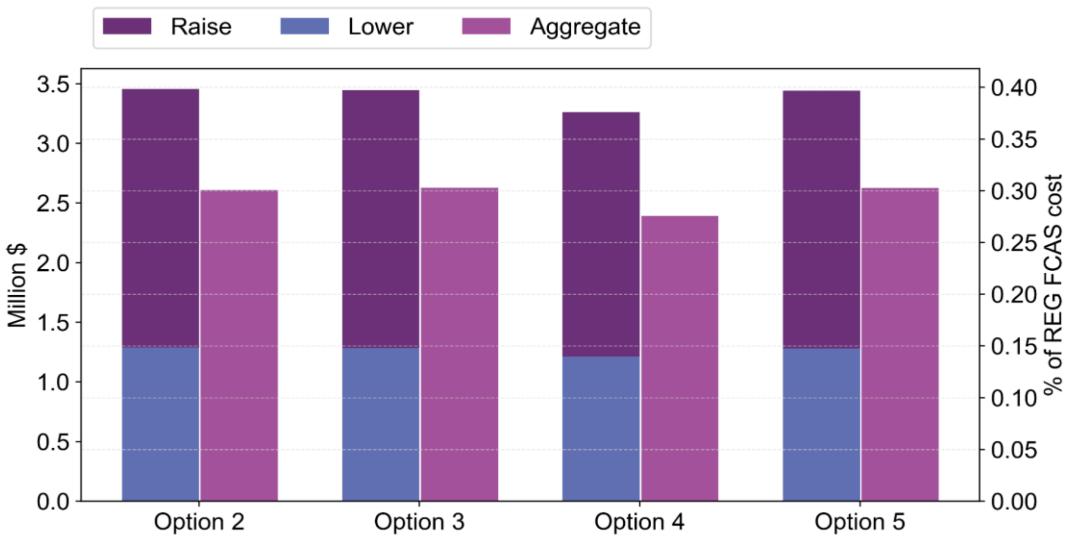
Finally, to compare these five options in terms of predictability (criterion E), AEMO used a complexity metric called permutation entropy. This metric shows the complexity of a signal, which means the lower it is, the more predictable the signal will be. Thus, a White noise, an utterly unpredictable signal, would have a complexity of close to 1. In this context, options 1 to 5 respectively have a complexity of 0.82, 0.47,0.52, 0.81, and 0.53. While the EMA option is better in this sense compared to options 1 and 4, there is not a meaningful difference among options 2, 3, and 5. This confirms the suitability of option 5 as the frequency measure from a predictability point of view.

Additionally, based on these results, one can also see that adding a 'slow' moving component to the frequency measure formulation, such as an MA with $T = 100$ seconds, would lead to quantifying the value of delayed frequency responses higher than faster responses, which should be avoided.

Despite the identified differences, AEMO's analysis of the FPP settlements shows that the net settlements of units over the period of a few months are in fact not significantly different when different frequency measure options are used.

Figure 2 shows the sum of net settlements of the units that receive net incentives in the FPP over a 3-month period for different frequency measure options. The summations of net settlements are almost equal for options 2, 3, and 5, and slightly lower for option 4. This is mainly because option 4 includes the raw frequency deviations as a component, which makes the frequency measure erratic; thus, the FPP transactions are more random compared to other cases, and 'helpful' units have lower net settlements on average.

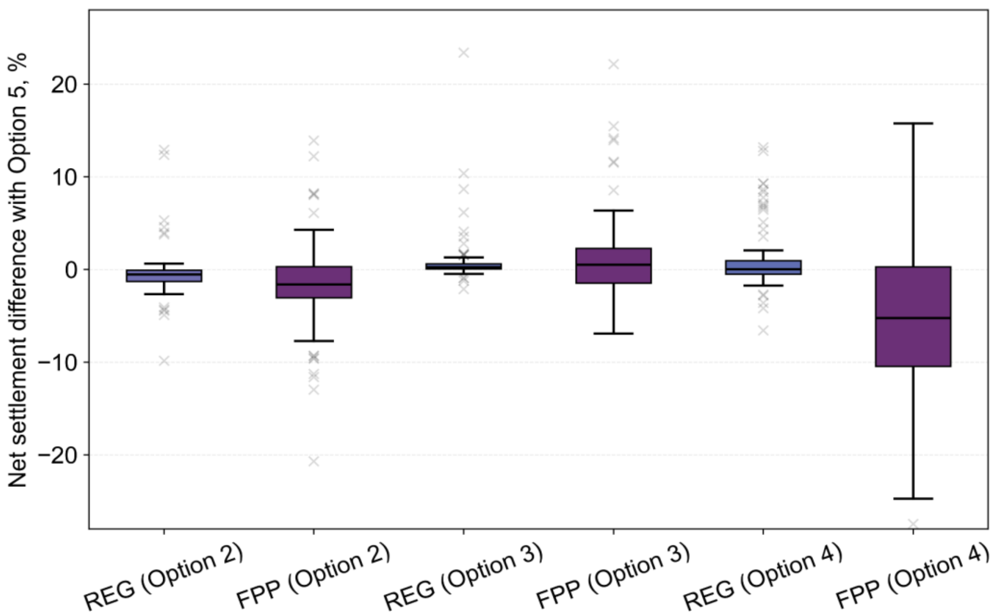
Figure 2 Sum of net settlements of units that receive positive net incentives over time



Even on a unit level, this analysis shows that the differences between the net settlements of units are not significant when different frequency measures are chosen. To be specific, AEMO analysed how much a different frequency measure option would change the net settlement of a unit compared to option 5.

Figure 3 illustrates a box plot showing the result of the comparison. In this figure, the y axis shows the percentage of change in the net settlement compared to the base case (option 5). Also, each box is associated with an option and either FPP or regulation FCAS net settlements. This once again shows that the net settlement of the large majority of units does not change significantly when different frequency measure options are chosen. Note that option 4 is an outlier as it includes raw frequency deviations, leading to random FPP transactions and lower net settlements for the majority of the units.

Figure 3 The difference in units' net settlements in the FPP and regulation FCAS when different frequency measure options are chosen



Finally, choosing the EMA option would also allow for relatively straightforward revision of the frequency measure in the future through the smoothing factor, alpha, if it is considered necessary to change the relative value of a fast or slow frequency response.

Regarding frequency measure conditions: While the frequency measure is formulated to indicate the need to raise or lower the frequency, AEMO acknowledges that in some instances it may not reliably reflect such need. AEMO aims to detect those instances through a set of conditions for the frequency measure such that if the conditions were not met, the measure would be considered unreliable for indicating the need to raise or lower the frequency. It is also important that the conditions are not too strict in order to avoid unnecessarily disregarding good data.

The first condition is to have at least 7 four-second intervals or more in a trading interval, where the frequency measure is positive (negative) to indicate the need to raise (lower) the frequency. The specific number of intervals was chosen in order to balance the above considerations.

The second condition is to have at least one 4-second interval in a trading interval where the frequency measure is above 0.01 Hz (below -0.01 Hz) to indicate the need to raise (lower) the frequency. In determining the appropriate deadband, our primary consideration was that it should be within the PFR deadband specified in the interim PFR requirements[4] in order to ensure that all primary frequency response is appropriately recognised and rewarded.

Figures 4 and 5 below show that the total performance (i.e., the sum of all positive and negative performance – in absolute amounts – in a trading interval divided by 2) and the RCR multiplied by the regulation FCAS price (i.e., the scaling factor of FPPs). The figures illustrate that the proposed frequency measure conditions set the RCR to zero (leading to no FPP transactions in that trading interval) when the total performance is very low. This is despite the fact that, in the trading intervals that do not meet the conditions, the scaling factor that depends on the RCR might be high. This means that without these conditions, some units might receive a large payment or penalty even though their performance was small, making FPPs more random. This observation supports the use of the frequency measure conditions, which are aimed to ensure that FPP transactions occur only when there is a genuine need to raise or lower the frequency.

[4] Page 8 of the interim Primary Frequency Response Requirements - https://www.aemo.com.au/-/media/files/initiatives/primary-frequency-response/2020/interim-pfrr.pdf

Figure 4 The total performance against the scaling factor of payments for the global raise regulation FCAS requirement in the trading intervals over three months

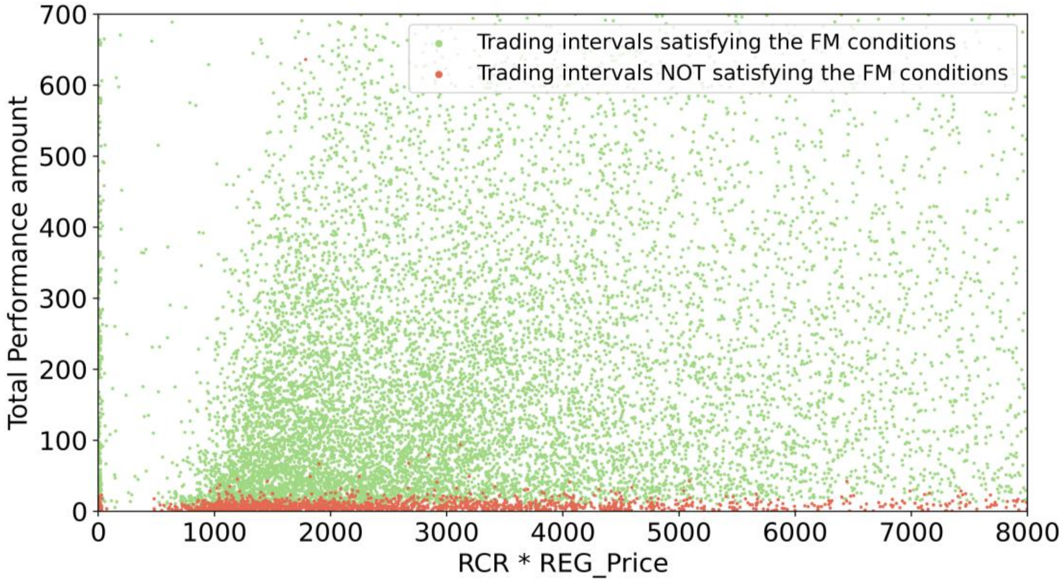
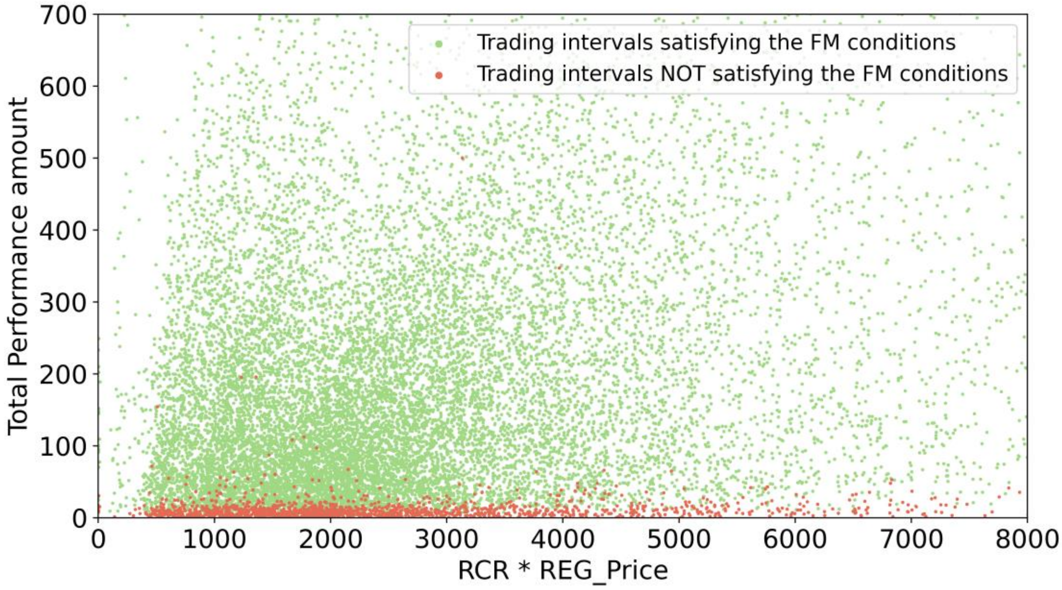


Figure 5 The total performance against the scaling factor of payments for the global lower regulation FCAS requirement in the trading intervals over three months



4.2.3. AEMO's conclusion

The frequency measure as described in the draft FCFP appears to be fit for purpose. Additional conditions have been identified where the frequency measure is considered not a reliable measure of the need to raise or lower the frequency of the power system. In these cases, there would be no frequency performance payments (for either raise or lower) and all regulation FCAS costs would be recovered on the basis of default contribution factors.

4.3. Formulation of performance and contribution factors

4.3.1. Issue summary and submissions

Contribution factors are normalised numbers based on unit performance that are used to apportion payments and receipts of frequency performance payments as well as allocate the costs of the 'used' component of regulation FCAS costs. AEMO proposed a draft formulation of performance and contribution factors in the initial FCFP. The high-level formulation was supported by IES. Delta Electricity noted some concerns about the interaction between AGC and reference trajectories.

4.3.2. AEMO's assessment

The formulations of performance and contribution factors set out in the proposal is fit for purpose and meets the requirements of the NER.

AEMO notes that changes to AGC are not within the scope of the FPP project. There is further analysis around the relationship between AGC and the FPP framework in section 4.9 below.

4.3.3. AEMO's conclusion

The formulation of performance and contribution factors should remain as described in the original proposal, and are described in section 6 of the draft FCFP.

4.4. Formulation of default contribution factors

4.4.1. Issue summary and submissions

Default contribution factors are used primarily to allocate the costs of the 'unused' component of regulation FCAS costs. They are also used as a substitute for contribution factors for frequency performance payments and the 'used' component of regulation FCAS costs in circumstances where the calculation of a contribution factor is impractical.

Where practical, default contribution factors must be based on historical performance. Therefore, AEMO must determine how to cap historical performance since default contribution factors can only be used to determine liability under this framework – FPPs cannot be determined using default contribution factors. AEMO must also determine the relevant time frame over which to assess performance.

AEMO must decide whether to exempt offline units from contributing to regulation FCAS costs when historical performance factors are applied.

In their submissions, in respect of the historical performance period, both Origin and IES suggested that the settlement period of a week would be a sufficient sample for determining historical performance. Delta Electricity suggested using a four-week period. Delta Electricity and IES also noted that capping performance for averaged historical performance values would lead to generally good performing units contributing trivial amounts towards regulation FCAS costs.

In respect of the question of whether to exclude good performance across trading intervals from default contribution factor formulation, Delta Electricity raised concerns regarding errors arising from 'the generation of the next target from a last actual read 20 seconds before the end of the previous TI' while IES noted that capping could raise questions around the arbitrariness of doing so at a five-minute resolution.

In respect of whether offline units should continue to contribute to the cost of regulation FCAS, Delta Electricity, Origin and IES all generally supported the idea of giving such units a zero default contribution factor, while IES noted a caveat that doing so would unfortunately influence a unit's decision on whether to commit.

4.4.2. AEMO's assessment

Capping historical performance for 'used' and 'unused' regulation FCAS cost recovery: AEMO considers that it is appropriate to ignore historical trading intervals with positive performance by capping performance at zero for each trading interval that makes up the historical performance period. This aligns the basis for cost recovery for unused and used regulation FCAS, since the unused component will be recovered based on a historical average of trading intervals capped at zero, while the 'used' component will be based on either:

- the performance for the applicable trading interval, capped at zero, or,
- where performance is null for that interval, the historical average of trading intervals capped at zero (same basis as the unused component).

In other words, good performance for a trading interval, while rewarded through FPP, cannot wash out the bad performance of previous trading intervals that has led to the need for regulating services when calculating historical performance for the purposes of regulation FCAS cost recovery.

Capping historical performance to be used as a substitute when contribution factors cannot be determined for FPPs: Where historical performance will be substituted for actual performance within a trading interval (for example if a single unit has bad SCADA) for FPP calculations, it is more appropriate to take a simple average of historical performance, *including good performance*. The draft FCFP proposes to cap the resulting average at zero rather than capping each trading interval that makes up the historical performance period, since this is more aligned with contribution factors used for FPP allocation that can be greater than zero. In effect, unlike for regulation FCAS cost recovery, this means that generally good performing units will not be liable for any costs related to FPPs when a default contribution factor is applied.

Historical performance period: AEMO has identified that it is important to ignore previous trading intervals where RCR was deemed equal to zero. These are intervals in which, for one reason or another, the frequency measure was not deemed a good indicator of the need to raise or lower frequency and therefore performance in that trading interval should not contribute to default contribution factor calculation. Considering the above, a period of 28 days is a reasonable timeframe over which to consider past performance for the purpose of calculating default contribution factors. AEMO considers this preferable to the period of a week as there is a greater likelihood of avoiding a scenario where there is no data that can be used to determine historical performance.

Offline units: AEMO does not propose to exclude offline units from contributing to the unused component of regulation FCAS costs. This approach is based on:

- There is additional solution complexity for AEMO to determine a reliable and consistent criteria for unit status for the purposes of FPP.
- At the moment AEMO does not vary the amount of regulation FCAS that is required based on either time of day or the mix of generation that is online.

A consequence of this is that a peaking or intermittent unit will be assessed for frequency performance at all times, with its factor averaged over the sample period including times where it is offline. This is consistent with the current calculation of contribution factors used for the recovery of regulation FCAS.

4.4.3. AEMO's conclusion

The updated formulation of default contribution factors as described in the draft FCFP in section 6 incorporates the following features:

- Capping historical performance as described in Table 3 below.
- A rolling 28-day average for assessment of past performance.
- No distinction between units that are 'offline' or otherwise.

Table 3 Default contribution factors – historical data and capping

Relevant settlement equation rule reference	When default contribution factors are used	Method of capping default contribution factors
3.15.6AA(b)	Default contribution factors are only used in the calculation of FPPs when performance is null (e.g. SCADA outage)	Since the FPP calculation utilises both positive and negative contribution factors, AEMO will simply average all performance across the historical period (including positive performance) and cap the end result at zero to determine a default contribution factor.
3.15.6AA(c)	Default contribution factors are only used in the allocation of used regulation FCAS costs when performance is null (e.g. SCADA outage)	Since contribution factors are effectively capped at zero when used to determine regulation FCAS cost recovery, AEMO will cap performance of each trading interval across the historical period at zero, then average them to determine the default contribution factor.
3.15.6AA(d)	Default contribution factors are always used in allocating unused regulation FCAS costs.	As above.

4.5. Application of default contribution factors

4.5.1. Issue summary and submissions

AEMO must determine when, under NER 3.15.6AA(f)(6), it is impractical to calculate contribution factors for an eligible unit and then to substitute historical performance for actual performance and determine a default contribution factor for trading amounts calculated under NER 3.15.6AA(b) or (c).

Delta Electricity suggested that AEMO could apply default contribution factors where power system frequency was significantly out of alignment with the frequency measure, or seek to address this circumstance in the formulation of the frequency measure itself. IES supported AEMO's proposal and agreed that the use of default contribution factors should be kept to a minimum and would not necessarily be justified in the event of a contingency.

4.5.2. AEMO's assessment

Where there is an incomplete set of data for an eligible unit for the current trading interval, a default contribution factor should be applied for the purpose of determining that unit's liability under either NER 3.15.6AA(b) or (c).

In relation to the concerns raised by Delta Electricity regarding alignment of the frequency measure and system frequency, please refer to the discussion in section 4.2 of this report, noting that the primary criterion for selection of the frequency measure was a high correlation with raw frequency. In addition, AEMO has proposed a number of conditions (described in section 4.2 of the draft FCFP) that demonstrate a weak signal from the frequency measure and therefore indicate that FPPs should not occur for the trading interval. These conditions are:

1. where there are less than 7 four-second intervals within a *trading interval* where the Frequency Measure is positive (in respect of *regulating raise services*) or negative (in respect of *regulating lower services*);
2. where there are no four-second intervals within a *trading interval* where Frequency Measure is above 0.01 Hz (in respect of *regulating raise services*) or below -0.01 Hz (in respect of *regulating lower services*);
3. where a system separation occurs and the AGC area does not align with the dispatched regulation FCAS Requirement in NEMDE; or
4. where there is global bad SCADA.

AEMO's analysis shows that, even without considering these conditions, the sign of frequency deviation and frequency measure aligns in 88% of four-second intervals over a one-year period.

4.5.3. AEMO's conclusion

Default contribution factors will be applied to an eligible unit to calculate liability for FPPs and 'used' regulation FCAS where there is an incomplete set of performance data for the relevant trading interval. Where any of the conditions in section 4.2 of the draft FCFP apply, RCR will be zero, so no FPPs will exist and all regulation FCAS costs will be recovered on the basis of default contribution factors.

4.6. Formulation of requirement for corrective response

4.6.1. Issue summary and submissions

The RCR is 'a measure of the total volume in MW that contributed to reducing the deviation in frequency of the power system' which is used to scale the total amount of frequency performance payments. In the original proposal, the RCR for raise and lower requirements is determined by the 'peak' of helpful deviations in each direction.

AEMO asked participants in the initial consultation paper to consider the following additional matters:

1. Whether minimum thresholds should be applied to the determination of RCR (this is addressed now via the frequency measure filters in section 4.2 above).
2. Whether RCR should be capped.
3. Whether some types of units should be aggregated for the purpose of calculating RCR.
4. How to calculate RCR for global requirements where there are two or more AGC areas.

In respect of the high-level formulation, Delta Electricity supported the proposal, while Hydro Tasmania suggested that AEMO should consider the sum of a generator's performance across an interval rather than the peak.

In respect of RCR capping, Delta Electricity suggested that with an appropriately smoothed frequency measure, capping would be unnecessary, while Origin noted that it would be prudent to cap RCR in limited circumstances to provide participants with some certainty around FPP exposures. IES submitted a formulation that is addressed in more detail in Appendix B.

In respect of unit aggregation, IES submitted that any such aggregation would be arbitrary.

In respect of calculating RCR for global requirements that span two or more AGC areas, IES stated their understanding that Basslink and Marinus would be treated as pseudo generators and loads and the RCR would be calculated for each AGC area independently.

4.6.2. AEMO's assessment

High level formulation: Regarding the Hydro Tasmania submission, AEMO notes that $P_{regulation}$ is a 'capacity' price and not an 'energy/volume' price. While NER 3.15.6AA(g)(6) provides the opportunity to determine parameters for calculating RCR, it must be referable to the relevant requirement for raise or lower. At this stage AEMO intends to use maximum and minimum, (subject to sample thresholds for inclusion) rather than averaging techniques. This is to derive a real time capacity value, and to pay for all good deviations that occurred in the trading interval.

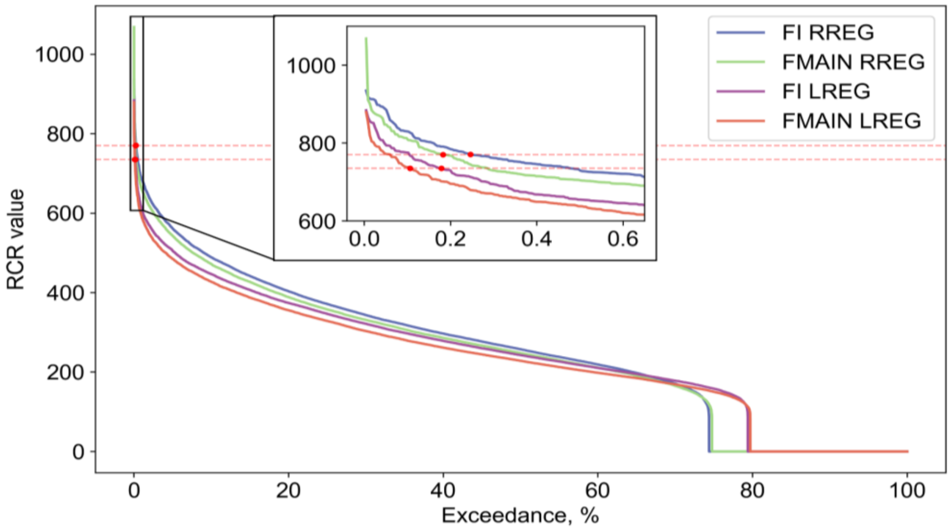
RCR capping: AEMO agrees with Origin's submission that capping RCR in limited circumstances is sensible and considers that setting the cap at a very high level would protect against potential errors or unforeseen circumstances while ensuring that the incentive to provide PFR remains strong and proportionate to the work done.

AEMO proposes to set the RCR cap relating to a Regulation FCAS requirement at a level equal to a multiple of the relevant constraint's left-hand-side (LHS) term that relate to the regulating services, and a coefficient bigger than 2. This way, if the requirement is relevant to a small region, the cap would be proportionally smaller. Similarly, the cap will change dynamically if the amount of enabled regulation FCAS changes.

The constant that is multiplied by the LHS regulation term is a parameter that can be updated when appropriate (we propose that AEMO review it annually) to ensure that the RCR capping remains limited and appropriate as market conditions in the NEM change over time.

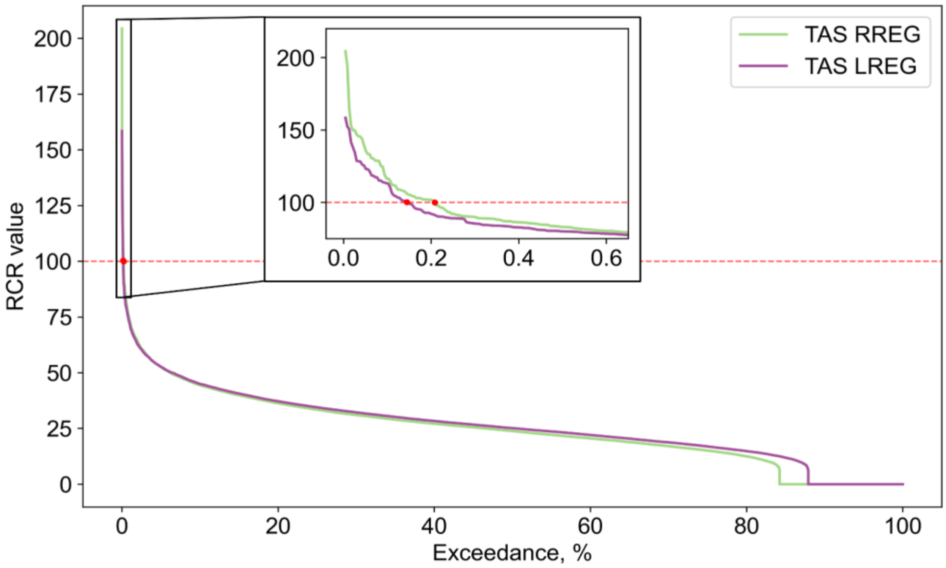
AEMO proposes an initial coefficient of 3.5 for the global and Mainland requirements and 2 for the Tasmania requirement. Figure 6 shows the exceedance curves of RCR values for global (FI) and mainland (FMAIN) requirements, as well as the proposed caps. In this respect, the LHS relevant to raise regulation (RREG) and lower regulation (LREG) of these requirements are at minimum 220 and 210, respectively. Thus, the minimum RCR cap (i.e., 3.5*LHS) for them would be 770 and 735, respectively. Note that the exceedance percentages of relevant RCR caps shown in the figure are higher than the actual percentage of times that the RCR will be capped. In other words, because the LHS is likely to be higher when the deviations are larger, the RCR cap would be higher too; hence, the times that RCR is capped would be lower than what showed in the figure.

Figure 6 RCR exceedance curves for global and mainland requirements with the proposed caps



Similarly, Figure 7 shows the exceedance curves of RCR values for Tasmania, as well as the proposed RCR caps.

Figure 7 RCR exceedance curves for Tasmania requirements with the proposed caps



AEMO proposes that the coefficients would be reviewed to ensure that that the percentage of times that RCR is capped in most requirements would be between 0.1% to 0.4%.

Unit aggregation: AEMO agrees with the IES submission that unit aggregation would be arbitrary and is undesirable for that reason.

RCR across two AGC areas: For a global requirement, the sum of the gross values of all deviations at each 4-second interval will be considered in the RCR calculation only when the Frequency Measure relevant to the Mainland NEM and Tasmania are aligned (i.e., have the same sign) during the trading interval.

4.6.3. AEMO's conclusion

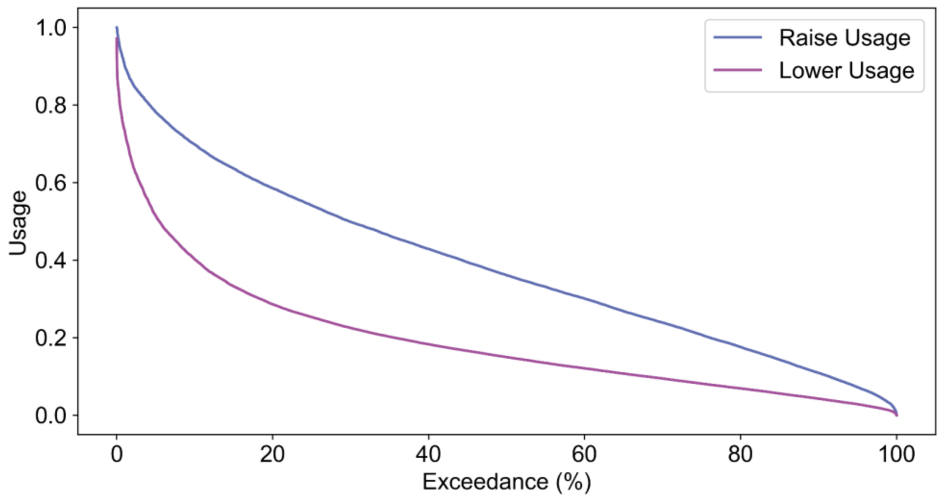
The formulation of RCR in the original proposal appears to be fit for purpose. In section 7 of the draft FCFP, RCR is based on the peak of aggregate gross deviations in each direction when aligned with the frequency measure. AEMO would particularly welcome further feedback around the level of the proposed RCR cap. Units will not be aggregated for the purpose of determining RCR. RCR will only be determined for global requirements where the frequency measure for Tasmania and Mainland regions is aligned.

4.7. Formulation of usage

4.7.1. Issue summary and submissions

Usage is the factor that determines what percentage of regulation FCAS costs are recovered on the basis of contribution factors (based on measured performance within a trading interval) and what percentage are recovered on the basis of historical default contribution factors. The concept of Usage is designed to represent how much of the total amount of a regulation FCAS requirement was utilised during a trading interval. Figure 8 shows the exceedance curves for raise and lower usage of the global requirement over three months.

Figure 8 Raise and lower usage exceedance curves



In the original proposal, AEMO proposed to calculate usage as the maximum (at any point during the trading interval) of the sum of positive deviations for all eligible units with appropriate metering that are enabled to provide the relevant service (capped at the level each unit is enabled).

Hydro Tasmania suggested that AEMO should use the total of all positive deviations across the trading interval, rather than the peak level, in determining usage.

4.7.2. AEMO's assessment

If AEMO was to use the sum of positive deviations across the entire trading interval (rather than taking a snapshot of it at its peak), it would also need to be compared with the total amount of regulation FCAS that could have been provided across the trading interval, which would essentially give the lower value of the average utilisation rather than the peak. AEMO does not think this was intended by the PFR incentives rule and it is inconsistent with the regulation FCAS framework being capacity based.

4.7.3. AEMO's conclusion

The formulation of usage described in the original proposal, and included in section 8 of the draft FCFP, is considered fit for purpose.

4.8. Impact of delays to dispatch instructions

4.8.1. Issue summary and submissions

It is possible that communication lags between the start of a trading interval and receipt of dispatch instructions from AEMO could lead to a unit deviating from its target trajectory. In the initial consultation paper, AEMO undertook to assess the impact of such a delay, noting some anecdotal reports of delays in receiving to dispatch instructions up to 20 seconds from the start of the trading interval.

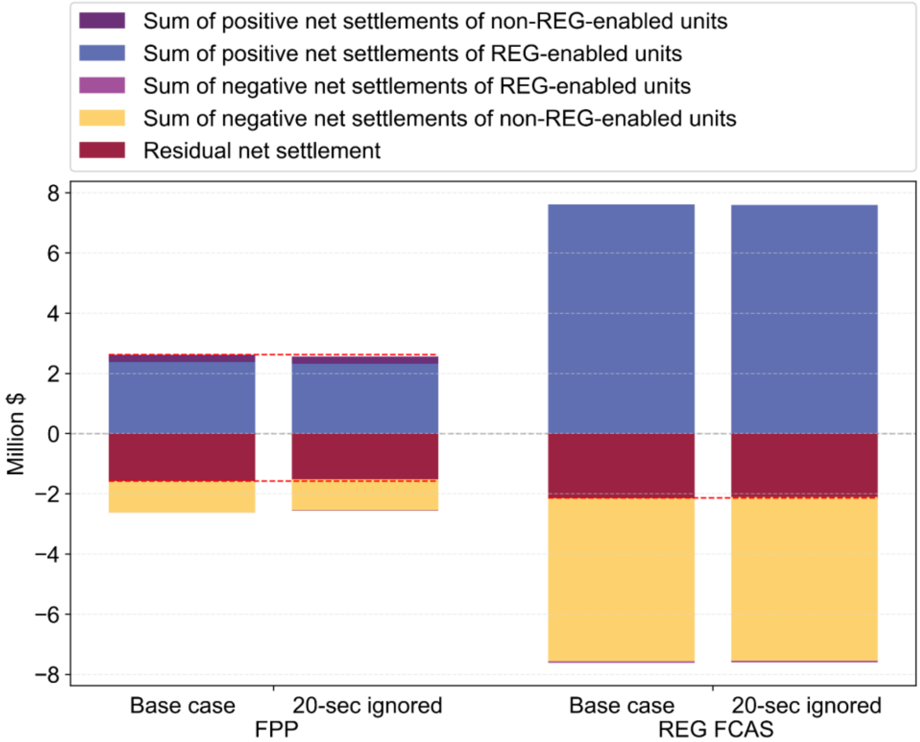
4.8.2. AEMO's assessment

The recently reviewed Power System Data Communications Standard[5] requires a maximum end to end time interval of six seconds for dispatch data. Where delays exceed this standard, the delay itself should be addressed directly rather than through indirect means such as adapting the design of the FPP framework. Setting this aside, however, AEMO has analysed the impact of ignoring the first 20 seconds of a trading interval on units' performance and net settlements.

Figure 9 illustrates the sum of positive and negative net settlements for regulation FCAS-enabled units, other eligible units with appropriate metering, and the Residual over a three-month period. Regulation-enabled units are compared against others as they are generally good performing units under the proposed framework. The figure shows ignoring the first 20 seconds of data in calculating performance has almost no impact on the net settlements of each category of units. It just marginally decreases the net cost of residual and the net incentive of regulation enabled units over three months.

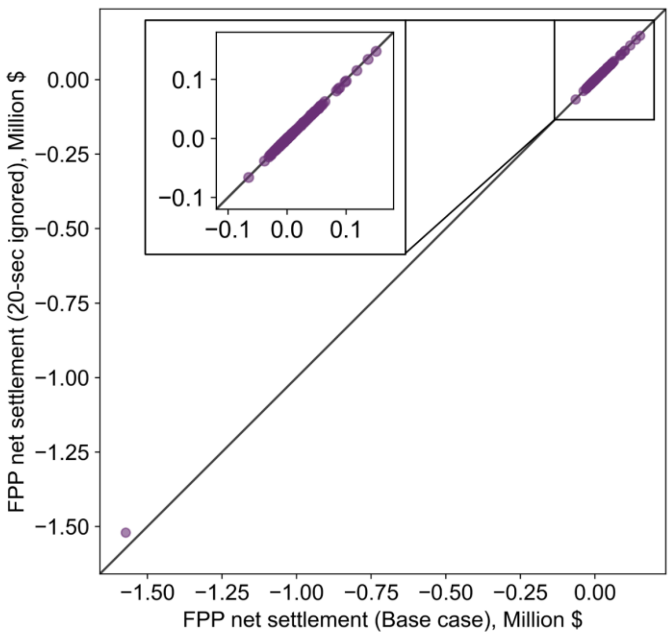
[5] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Network_Connections/Transmission-and-Distribution/AEMO-Standard-for-Power-System-Data-Communications.pdf

Figure 9 System-level analysis of the impact of ignoring the first 20 seconds in trading intervals



AEMO's analysis on a unit level also confirms the above finding. Figure 10 shows the variance in the FPP net settlements of each unit in the base case in comparison with the case of ignoring the first 20 seconds. The underlying data shows that ignoring the first 20 seconds has a small positive impact on the residual's penalty and a negative impact on the net settlement of 'helpful' units that receive a net incentive.

Figure 10 Unit-level analysis of the impact of ignoring the first 20 seconds in trading intervals



Given the analysis results and the basic principle that, where possible, valid data should be considered, AEMO has found no substantive reason to ignore the first 20 seconds of trading intervals in the units' performance calculation.

4.8.3. AEMO's conclusion

No changes are required to the proposal in respect of communication delays to dispatch instructions.

4.9. Determination of reference trajectories

4.9.1. Issue summary and submissions

AEMO must determine an appropriate reference trajectory for all eligible units in order to determine deviations and, ultimately, contribution factors. The PFR incentives rule requires AEMO to determine a reference trajectory based on successive dispatch targets. AEMO originally proposed that the reference trajectory would be a simple linear ramp between dispatch targets, with non-scheduled units being given a notional target at the same level as their generation or load at the start of the interval. AEMO specifically sought input on whether units enabled to provide regulation FCAS should be treated differently in this respect.

IES noted that treating regulation FCAS enabled units the same as other units "*removes any issues of determining a boundary between what is provided under enablement and what is provided as an "extra"*". IES also noted that where the incentive arrangement was aligned with the AGC performance requirement that such units should earn a fair return and that this would then factor into bidding for regulation services, mitigating concerns around double payment.

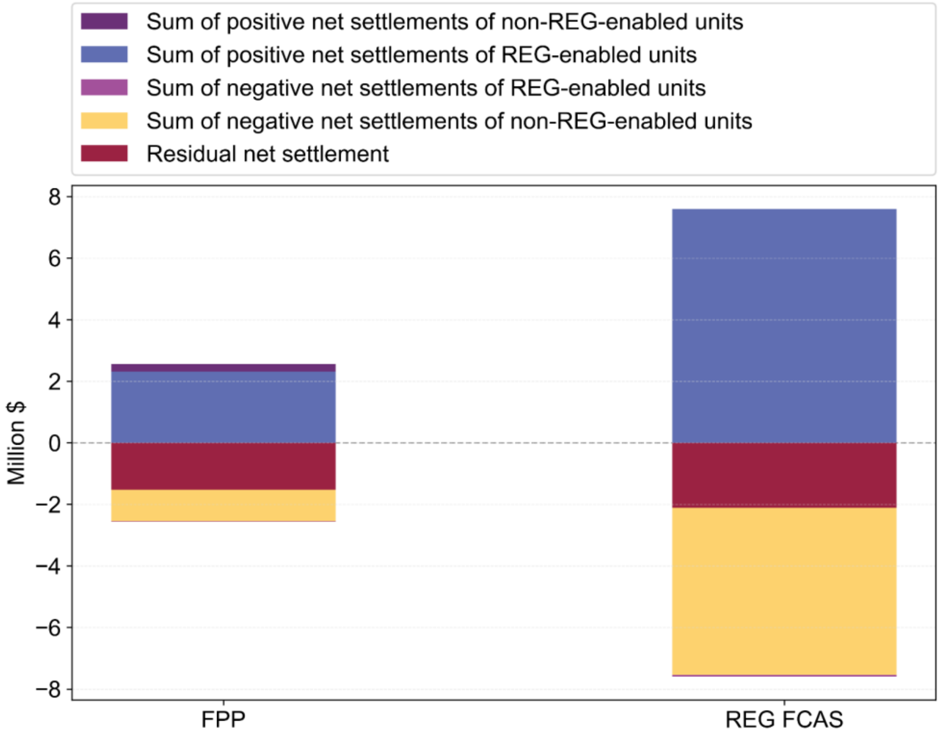
Delta Electricity stated that "*a compliant regulation FCAS provider should not incur an overall net financial loss from PFR causation in a TI. It would be better if the procedure is designed so that the PFR performance cannot produce a causation outcome for a Unit correctly observing FCAS regulation dispatch*".

4.9.2. AEMO's assessment

AEMO generally agrees with the IES submission on this point. AEMO expects market participants will factor in the likely impact of FPPs when bidding to provide regulation FCAS services. Where regulation FCAS and FPPs are generally aligned, a commensurate reduction in the total cost of providing regulation FCAS would normally be expected, as enabled units would be paid FPPs due to having positive contribution factors as a result. In the event that they are not aligned, the opposite would be true, and would be an acceptable outcome regardless. Incidentally, AEMO's analysis confirms that generally, the two incentives are aligned and that responsive units that are enabled to provide regulation FCAS should expect to receive positive contribution factors as a result.

Figure 11 shows the sum of positive and negative net settlements for regulation-enabled units, other eligible units, and the residual over a three-month period. Regulation-enabled units are compared against others, as they are generally good performing units that respond to the frequency deviations. As can be seen in the figure, almost all regulation-enabled units (that receive all payments in regulation FCAS market) also have a positive net settlement over the three-month period and receive most of the FPP incentives. Similarly, there is no regulation-enabled unit that has a negative net settlement in the FPP.

Figure 11 Net settlements of regulation-enabled units compared to other units and residual



AEMO has considered whether to implement Delta Electricity's suggestion, but it introduces several complexities regarding the balancing of payments. For example, it might require multiple iterations of contribution factor calculation to determine whether the net receipts from being enabled for regulation FCAS offset a negative net impact from FPPs and 'used' regulation FCAS cost recovery, and, where they do not, artificially capping that unit's contribution factor and recalculating contribution factors across the rest of the market. It is not clear whether this would be consistent with the intent of the rule, and ultimately AEMO thinks it is not necessary given the above analysis.

4.9.3. AEMO's conclusion

Reference trajectories will be determined as described in section 5 of the draft FCFP, consistent with the original proposal.

4.10. Formulation of the residual

4.10.1. Issue summary and submissions

AEMO must determine how to calculate residual performance for each regulation FCAS requirement. Key considerations in formulating a residual specific to each requirement include:

- How to manage interconnector deviations for local residual calculation.
- Whether to cap residual performance at zero (noting that default contribution factors for eligible units that are appropriately metered are capped at zero).
- How to calculate residual performance for requirements that span multiple regions.

Delta Electricity submitted that it was not reasonable for a local residual to bear the impact of interconnector variations that can have many different causes (unrelated to the performance of the Residual). Delta Electricity also suggested that it would be appropriate to cap residual performance "*at zero because without more elaborate metering from which to generally determine good PFR is occurring positive factors seem random and would [be] erroneous in the objectives for incentivisation of those participants that can adequately demonstrate performance*."

IES suggested that the residual could be regarded as any other metered unit and so contribution factors could be treated similarly – there being no particular merit in capping them at zero for the residual.

4.10.2. AEMO's assessment

Treatment of interconnectors: In following the general approach to determining a regional residual as the offset of all relevant metered units for a region, AEMO agrees with Delta Electricity that it is important not to ignore the impact of interconnectors at the boundary of the region. If interconnector performance is ignored and not subtracted from the net offset calculation of all the appropriately metered units in the region, it would have the effect of skewing residual performance and therefore the distribution of costs between the residual and the appropriately metered units for said region.

On whether to cap residual performance at zero: In weighing up the respective arguments for and against, encapsulated by the Delta Electricity and IES submissions, AEMO finds them to be evenly balanced and notes that capping at zero will not have a significant impact in most cases since residual performance is generally negative. AEMO notes that the rules have specifically called out default contribution factors as being effectively capped at zero, but have not done the same in respect of the residual contribution factor. With these considerations in mind, there does not appear to be a compelling case to impose a cap.

Calculating the residual's performance for multiple regions subject to a regulation FCAS requirement: The performance values of residuals for all regions that are RELEVANT to a regulation FCAS requirement should be aggregated before determining the Residual performance and contribution factor for the requirement. This ensures that interconnector flows within an area subject to the regulation FCAS requirement (which are not relevant) are netted out and do not impact the calculation of residual performance within the relevant requirement.

4.10.3. AEMO's conclusion

As described in section 5.3 of the draft FCFP, interconnector performance will not be ignored in the calculation of a local residual and a residual performance value relevant to a requirement that spans multiple regions will be calculated by aggregating each region's individual residual deviations.

AEMO's considers that residual performance should not be capped at zero.

4.11. Publication of data additional to rule requirement

4.11.1. Issue summary and submissions

AEMO's consultation paper sought input about what additional data AEMO could publish that would be helpful for participants (other than that which is required under the PFR incentives rule).

Delta Electricity proposed the following additional reports:

1. The reasoning for the 'weighting factors'

2. The reasoning behind the dispatch quantities for regulation and contingency FCAS.

3. Any AEMO estimates for the minimum quantity of PFR required to maintain the expected histogram shape for frequency control in the NEM.

4. AEMO targets for frequency performance over and above that required by, or those not include within, the FOS, and routine performance of real conditions measured against those targets.

4.11.2. AEMO's assessment

The NER require the following to be published five business days before the relevant settlement period:

1. Data used to determine contribution factors (five days before settlement period)
2. Parameters used in the calculation of the frequency measure, RCR and usage.

The NER require the following to be published after the relevant trading interval:

1. Contribution factors
2. Data calculated from determining the frequency measure
3. RCR
4. Usage
5. Raw input data used to calculate contribution factors.

In addition to the above, AEMO proposes to publish the following:

- Predispatch estimates of recovery amounts of regulation FCAS costs based on default contribution factors (AEMO currently publishes estimated recovery amounts for the existing regulation FCAS cost recovery process, and expects that participants will similarly seek this information to help them manage their portfolio exposure as an input to bidding).

- Reasoning for any change to the "Frequency Contribution Factor Tuning Parameters and Input Sources" document.

- Summary data and visualisations (to be determined with input from participants in a workshop to follow this draft report).

Regarding the feedback received from Delta Electricity on this point, we note the following:

1. Rationale will be provided in respect of any changes to any parameters that impact FPP calculations.

2. Dispatch quantities for regulation and contingency FCAS are determined for AEMO to meet the NER obligations for managing power system security and the Frequency Operating

Standard. Information on how these constraints are determined is provided in the Constraint Formulation Guidelines.

3. AEMO does not specify a minimum quantity of PFR required to maintain frequency control. In accordance with the NER, AEMO defines the Primary Frequency Response Requirements (PFRR) which specifies how generators will support the secure operation of the power system by providing PFR. Details of the roll-out of PFR is published on the website[6]

4. AEMO provides quarterly and weekly reporting of frequency and time deviation on its website[7]

4.11.3. AEMO's conclusion

While not required by the NER, AEMO intends to publish pre-dispatch estimates as described in section 9 of the draft FCFP, and will conduct a public workshop with participants following the publication of this draft report to seek further feedback on the format of summary data and visualisations.

4.12. Aggregated dispatch conformance

4.12.1. Issue summary and submissions

Aggregated Dispatch Conformance (**ADC**) is being implemented as part of the Integrated Energy Storage Systems (IESS) reform, commencing from March 2023. ADC will be in operation when the FPP framework goes live in 2025. ADC allows eligible units in certain circumstances to aggregate for the purpose of dispatch conformance. The impact of ADC on the FPP framework should therefore be considered as part of this consultation.

4.12.2. AEMO's assessment

AEMO considers it important that the FPP framework is aligned with dispatch conformance wherever practical, and consequently aggregated units are not penalised under FPP for utilising ADC. AEMO considered treating such units in a dynamic manner under the FCFP as they are treated for dispatch conformance for each trading interval. However this gives rise a number of complications in determining appropriate default contribution factors, including:

- Determining individual default contribution factors (based on historic performance) when the unit can change aggregation status every interval
- If historical performance was only calculated using data from trading intervals where units in an integrated resource system are in the same configuration (aggregated or not) as they are in the current trading interval, there may be insufficient data for reliable factors to be determined
- The impact of bad SCADA for an individual unit within an aggregate.

An alternative approach is to always treat the units as an aggregate, even during periods when one or more units are subject to individual conformance. This would effectively allow individual units to offset performance at all times. AEMO considers this to be a reasonable approach, as the units are located at the same connection point and so any offsetting of

[6] https://aemo.com.au/en/initiatives/major-programs/primary-frequency-response

[7] https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/frequency-and-time-deviation-monitoring

performance would not give rise to issues with frequency control. This approach also reduces the complexity of AEMO's implementation, as it involves treatment of the aggregate as a single eligible unit.

4.12.3. AEMO's conclusion

AEMO proposes that where two or more eligible units in an integrated resource system register to participate in aggregated dispatch conformance under NER 4.9, for the purposes of the FCFP, they will be assessed as a single *eligible unit*, regardless of the status of their compliance mode in dispatch for a specific *trading interval*

4.13. Where AEMO is unable to calculate and publish contribution factors within a 'reasonable' timeframe.

4.13.1. Issue summary and submissions

A scenario in which AEMO is unable to publish contribution factors within the expected timeframe (anticipated to be within five minutes of the end of a trading interval) may occur as a result of technology system issues. It will be necessary to determine what the appropriate course of action is to take in such cases.

4.13.2. AEMO's assessment

There are at least two possible courses of action:

1. AEMO publishes the contribution factors at a later time – whenever they become available – and the associated settlement outcomes related to the contribution factors that were the subject of delayed publication take place as normal; or
2. AEMO does not calculate contribution factors relating to the trading intervals that were the subject of delayed publication and calculates no FPPs for the period, with all regulation FCAS costs being recovered on the basis of default contribution factors.

The benefit of the first approach is that the correct incentives for the provision of primary frequency response continue to apply; however AEMO considers that the timely publication of contribution factors is a critical aspect of this framework as it enables participants to monitor their own performance and potentially respond based on the published factors.

4.13.3. AEMO's conclusion

On balance, AEMO's preference is for option 2 – not to calculate contribution factors at a later time where there is an outage in the calculation system. AEMO seeks input from participants in respect of what deadline should be applied for the publication of contribution factors.

5. Draft determination on proposal

Having considered the matters raised in submissions to the consultation paper, AEMO's draft determination is to make the Frequency Contribution Factors Procedure in the form published with this draft report, in accordance with NER 8.9.2(b).

Effective date

AEMO's proposed effective date for the determination is 8 June 2025, in accordance with the requirements of NER 11.152.3(b).

AEMO's existing Regulation FCAS Contribution Factor Procedure (version 6.0 - 2 December 2018) will be revoked with effect from the same date.

Appendix A. Glossary

Term or acronym	Meaning
ADC	Aggregated dispatch conformance
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator Limited
AGC	Automatic generation control system
Contribution Factor	A factor calculated in accordance with section 6 of the draft FCFP and applied to an eligible unit (and includes a Default Contribution Factor unless otherwise specified).
Default Contribution Factor	A Contribution Factor determined in accordance with section 6.2 of the draft FCFP and applied to an eligible unit in the circumstances described in NER 3.15.6AA(g)(4)
FCFP	Frequency Contribution Factors Procedure
FDP	Frequency deviation pricing
FPP	Frequency performance payments
Frequency Measure	The indication of need to raise or lower *frequency* calculated in accordance with section 4 of the draft FCFP
Frequency Performance Payments	*Trading amounts* payable by or to a *Cost Recovery Market Participant* determined under NER 3.15.6AA(b)
Historical Performance Period	The 28 days immediately prior to the Historical Performance Period cut-off
Historical Performance Period cut-off	5 business days prior to the date that AEMO is required to publish the data used to determine Default Contribution Factors under NER 3.15.6AA(i)
Lower Performance	The performance in MWHz of the residual or an eligible unit with appropriate metering in respect of trading intervals where the Frequency Measure is negative
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules, and NER followed by a number refers to that numbered rule or clause of the NER
Performance	Collectively refers to Raise Performance and Lower Performance
PFR	Primary frequency response
PFR incentives rule	National Electricity Amendment (Primary Frequency Response incentive arrangements) Rule 2022
Raise Performance	The Performance in MWHz of the Residual or an *eligible unit* with appropriate metering in respect of *trading intervals* where the Frequency Measure is positive
RCR	Requirement for corrective response
Reference Trajectory	The expected *active power* output or consumption of an *eligible unit* or the Residual, calculated in accordance with section 5 of the draft FCFP
Regulation FCAS	*Regulating lower service* and *regulating raise service*
Regulation FCAS Requirement	A binding constraint for Regulation FCAS
Residual	The aggregate of all relevant *eligible unit*s without *appropriate metering*
Usage	The proportion of Regulation FCAS that is deemed Used Regulation FCAS, calculated in accordance with section 8 of the draft FCFP
Unused Regulation FCAS	Regulation FCAS that is deemed unused and for which costs are recovered in accordance with NER3.15.6AA(d)
Used Regulation FCAS	Regulation FCAS that is deemed used and for which costs are recovered in accordance with NER3.15.6AA(c)

Appendix B. List of submissions and AEMO responses

Are there any alternatives to the proposal that would provide demonstrably greater net benefit to the market than regional measurement?

No.	Stakeholder	Issue	AEMO response
1	Delta Electricity	Regional is probably better than global but some possible regions e.g., the entire state of Queensland, may benefit from having more than one region (which may be what AEMO is intending) particularly if there are known network challenges from long transmission or distribution corridors between Generation and Loads.	Noted, however splitting regions into sub-regions has complex impacts on other aspects of this framework such as RCR calculations. AEMO thinks that calculating frequency regionally will be sufficient for most conditions within the NEM. Should intraregional islanding occur, AEMO will not calculate FPPs for the impacted intervals.
2	Origin	We support AEMO's proposal to measure frequency regionally rather than at every connection point.	Noted.
3	IES	The default metering available to AEMO is that available through the SCADA system. However, there is some scope to use local measurements which the consultation paper dismisses as likely too complex to implement and probably not necessary. However, this possibility is worth exploring. It is possible and commonplace to measure frequency and load or generation at different resolutions, for example to as little as 50ms for high resolution instruments, ranging to around a second or fraction of a second for local control, to 4 or 8 seconds used for mainland and Tasmanian SCADA, respectively. The local measurement would likely lead to more accurate factor, and a higher factor in the case of a provider. Of course reducing such effects is a key motivation for making local measurements. We have suggested above that local measurement and initial processing could be advantageous to specific sites and provision should be made to support the option in the design of AEMO's software system. However, development of a complete protocol need not be a current priority.	Based on AEMO's proposed formulation of the frequency measure and analysis of the impact of reasonable levels of communications latency, local measurement of frequency should have minimum impact on contribution factors and AEMO therefore does not think that the added complexity of accommodating local frequency readings at variable resolutions passes the cost/benefit test. A regional measurement of frequency strikes a good balance.

What process should AEMO follow to change the weighting of parameters for the frequency measure?

No.	Stakeholder	Issue	AEMO response
1	Delta Electricity	The weighting of parameters could be listed within the procedure and determined via consultation. However, if such parameters will define or limit the outcomes of the incentives that the procedure will offer and different options produce great variability, a more independent check via the Reliability Panel, for example, to confirm the resulting incentives are what the market prefers might be worth considering. AEMO unilaterally determining the weighting is another possible method, but such a path probably then determines that AEMO will be independently responsible for the result.	The intent of the rule regarding these parameters is that they can be tuned without the need to conduct a lengthy consultation. The parameters will represent potential incremental change to the formulation of the frequency measure. As per the draft FCFP, AEMO will provide prior notice of such changes.
2	IES	Broadly, the process should work as follows:	AEMO agrees that short-term changes with no or little notice should be avoided. For changes that are simply tuning the existing formulation,

		• AEMO assesses the likely need for one or more parameter changes and publishes the proposal for consultation • When a determination is made it sets a date to implement the proposed change. Typically, this would be a month or two ahead • Short term, emergency changes should be avoided if the parameter settings are "near enough"	AEMO thinks that five days' notice is sufficient and notes that a consultation would be undertaken for a more substantial change.

How should AEMO assess the efficacy of the frequency measure and weightings?

No.	Stakeholder	Issue	AEMO response
1	Delta Electricity	The statistical condition of system frequency itself presents the best guide. However, it is considered that PFR incentives alone will not necessarily produce the steadiest frequency possible. Better overall coordination is considered to require central coordination by AEMO and scrutiny of interactions between the AGC and each participant and between various participants e.g., A single unit of one participant closely connected to a large capacity of MWs from a group of Units from another participant may develop poor performance in reaction to a poor frequency control design from the larger group of Units. PFR incentivisation will not be able to fix these problems. AEMO should focus on what sort of improvements to system frequency they are hoping for and develop reasonable monitoring targets and include these in the reporting metrics.	PFR incentives are just one piece of the puzzle and need to be adjusted in a coordinated manner considering interactions with other related aspects of the NEM.
2	IES	This may be difficult. However, the thinking on this could be along the following lines: • The objective is to maintain frequency control to within the required standard • The parameters should be set to give the desired technical performance, bearing in mind that the short-term outcome must be stable and the long term outcome should tend to encourage the maintenance of PFR capability.	AEMO thinks its solution in the draft FCFP will meet this requirement (with tuning).

Feedback is sought on the proposed formulation for determining contribution factors in the FCFP. Do you see any issues with the proposal?

No.	Stakeholder	Issue	AEMO response
1	Delta Electricity	The target trajectory should be determined with limitations to ensure that the assigned target for the Trading Interval, is achievable by the Unit. There are many intervals where the NEMDE and the AGC targets are inadequate and whilst it may be AEMOs preference to fix this in the AGC (outside of this project), the targeting trajectory used in the Frequency Contribution Factors Procedure could also be built to overcome this inadequacy. It may be better to either correct the targeting process before this procedure takes effect or, if not possible, ensuring the target-to-target trajectories used in the procedure adjust each TI target to that achievable by a Unit. Applying trajectories that are not achievable by units will not incentivise and will be reason for complaint and confusion in particular Trading Interval results.	See the response in section 4.9. AEMO notes that changes to the AGC may be made independently from this project and are out of scope.
2	IES	The broad description in the consultation paper makes sense, although it will need more detail at some point. With more than one component and with a requirement for separated Raise and Lower, how does the procedure then look? Bearing in mind the issues discussed in Section 2.4, there will be more steps involved.	See the response to the IES submission in the 'other comments' section.

AEMO is assessing possible timeframes for determining average performance for historical default contribution factors. This could be, for example, an eligible unit's average raise or lower performance for a period of a week, or as in the draft FCFP, a certain number of trading intervals for which there is valid raise or lower performance values. What principles should AEMO have regard to in determining this?

No.	Stakeholder	Issue	AEMO response
1	Delta Electricity	performance could be the result of seasonal and time of day conditions. There may be a benefit in having schedule of performance factors for each Unit drawn from historical conditions but if the intention is to keep it simple, a schedule produced from historical four-week sub-factors (LEF, LNEF, REF, RNEF) for each unit from the current system would be a starting point. This history has some advantage in that at least the factors are already normalised, averaged and relative between Units to overall conditions.	AEMO agrees and has decided to implement a four-week historical performance period.
2	Origin	The FCFP consultation paper asks what timeframe should be used to determine average performance for historical default contribution factors. In our view, a weekly sample period close to the actual settlement period would be appropriate.	See (1) above.
3	IES	There are likely to be different views on this, but we see merit in defining a sufficiently long period, say a full settlement period over which to average a performance factor. In this way the long term performance would be used to allocate this cost, rather than a potentially more volatile shorter-term measure.	See (1) above.

In determining default contribution factors should AEMO exclude good performance or, as in the draft FCFP, should it be a simple average of all performance?

No.	Stakeholder	Issue	AEMO response
1	Delta Electricity	Unless the trajectory will be mindful of the errors that can occur in the generation of the next target from a last actual read 20s before the end of the previous TI, there will be many periods where good performance and bad performance will be adjacent through no fault of the operating unit so, if the trajectory is not going to prevent inappropriate trajectories being used, it will be necessary to consider both good and bad performance to work towards default contribution factors. If the targeting trajectory can eliminate the potential for utilising impossible targets, it may then be possible to concentrate only on the poor performing periods.	Noting that good performance will offset bad performance within an interval, AEMO does not think this would significantly change the average historical performance of a unit. AEMO considers the proposed basic trajectory is sufficiently 'accurate' to find the good and bad performing units in each trading interval.
2	IES	If only negative values are used, one might ask about the arbitrariness of setting 5-minute boundaries. Using only negative values bring in generally good performers or often trivial amounts, for little benefit. Our suggestion would be to choose a relatively long measurement period, say a settlement cycle and use the performance factors (price weighted?) summed over that period. Such an approach will clearly delineate the good and the bad.	See the assessment in section 4.4.

What specific circumstances are there where default contribution factors should apply automatically that should be explicitly captured in section 5.3 of the draft FCFP? Where should AEMO have discretion to apply default contribution factors?

No.	Stakeholder	Issue	AEMO response
1	Delta Electricity	If the frequency measure utilised is significantly out of alignment with local frequency conditions, in a similar way to how the existing procedure checks for FI being opposite in sense to reactions expected from local frequency, this is one circumstance. However, the determination of the frequency measure will hopefully reduce the occurrences of this in any set of 4s samples in any Trading Interval.	This is partly addressed in the formulation of the frequency measure itself (based on our analysis, the sign of chosen frequency measure is aligned with that of frequency deviations in 88% of four-second intervals). Furthermore, AEMO has introduced a number of filters to mitigate the possibility of giving negative factors to good performing units when that response slightly overshoots. AEMO will continue to internally monitor and review the performance of the frequency measure in this respect.
2	IES	Default factors will need to be used where there is some data failure and a calculation cannot otherwise be done. However, we agree with the comment in the draft procedure that such exceptions should be minimised or eliminated. Specifically, there is no basis replacing measured factors with defaults where there has been a contingency. The (modest) negative spike that the failed generator would incur is not an unreasonable outcome, and the positive incentive provided over the one or two dispatch intervals would assist the recovery.	AEMO agrees – its proposal is consistent with this.

How should offline units contribute to the cost of regulation FCAS? Are there circumstances (such as being offline for an extended period of time) in which a unit should cease being liable and be given a default contribution factor of zero? If so, how should AEMO determine a unit to be offline?

No.	Stakeholder	Issue	AEMO response
1	Delta Electricity	If a Unit goes off-line but has not yet rebid for this condition the system should continue to be consider such a unit on-line as the market will consider them available until the bid is adjusted. Off-line Units should continue to contribute towards costs of regulation FCAS until the rebids are processed. However, from a control perspective, when units go off-line suddenly it is true that in the immediate aftermath there is probably a benefit to the NEM from faster reassignment of frequency control drivers to enable other sources to replace that lost from the unit that is suddenly off-line. Other status indicators may exist for some Units upon which to base a faster reaction for more advance reassignment of Contingency and Regulation FCAS and energy dispatch. In specific cases, such signalling may come from the participant but in others may come from the TNSP which the Generator is connected to.	AEMO has considered the possibility of giving offline units a default contribution factor of zero. The idea of giving participants some limited ability to hedge against regulation FCAS costs by turning off may have some merit, however AEMO has been unable to devise either a consistent definition or means of automatically determining what is 'offline' that is practicable and does not create inconsistencies with the rest of the FPP framework. See section 4.4.2 for further discussion.
2	Origin	We do not consider offline units should be liable for regulation FCAS costs as they are not contributing to any poor frequency performance.	See above.
3	IES	It would seem unreasonable to charge units that are not online by giving them default factors. Unfortunately, if they pay when online, it will influence their decision on whether to commit or not. This is one of several unfortunate by-products of the approach taken to regulation FCAS cost recovery.	See above.

Should the requirement for corrective response be capped in certain circumstances? What should those circumstances be?

No.	Stakeholder	Issue	AEMO response
1	Delta Electricity	No capping is required but it is important that the frequency measure be smoothed so that the procedure and resultant performance/causation is only relative to controllable PFR. The present frequency conditions contain movements that are not controllable by PFR and these movements should be removed from the frequency measure.	See section 4.6.2.
2	Origin	It would be prudent to ensure the RCR is capped in certain circumstances to provide participants with a level of certainty around FPP exposures. This would be particularly important where a region is islanded or at risk of islanding and there are only a limited number of resources available for service provision, given the potential for extreme outcomes to occur.	See section 4.6.2.
3	IES	As noted above, the following formula, derived from the approach in Appendix A of the IES report to the AEMC, resolves the problem posed by small or zero frequency excursions in either Raise or Lower. This could be capped at some value but there would seem little point in doing so as it would dilute incentives, especially after a contingency. $$Settlement\_amount = Contributon\_factor \times Price \times \left(\left(\frac{Measured\_frequency_{rms}}{Target\_frequency_{rms}}\right) \times Gross\_deviation_{rms}\right)$$	AEMO assumes IES consider it to be problematic that there could be a small FM values during an interval, and yet relatively large RCR values, possibly on both sides, indicating deviations that are largely netting off. AEMO considers these settlement amounts may largely “net off” during, and over multiple trading intervals and will investigate empirical data to see if this is so. After reading the IES Report to the AEMC, AEMO understands that IES prefers a RCR that is more of a static constant and can be used known in advance and incentivise generators to provide a level of control – this is Frequency Deviation Pricing (**FDP**). Unlike FDP the philosophy behind FPP is to specify the required control and frequency performance (mandatory PFR), institute a method to pay for all good deviations that result from this at the real-time rate of deviations (the Reg price),and let the amount that is paid “float”. This contrasts with the idea of FDP, which sets or “caps” the amount that will be paid in advance, incentivizing a level of control from that, and letting frequency performance “float”. The IES proposal to use the RMS avg approach (over which timeframe is unclear), rather than a straight mean, seems to increase the RCR to a higher value, but the Hz ratio may have the opposite effect. Yet more importantly, the proposal would suggest far lower RCRs than maximum and minimum of good deviations should be used. While AEMO considers the idea of using a RMS average as possibly useful, because it focuses the avg on the larger values, it is difficult to move from using a maximum and minimum for the following reasons: $P_{regulation}$ is a ‘capacity’ price and not an ‘energy/volume’ price; and, as discussed in point 9 above, RCR is inherently associated with the deviations, and CFs, that occurred in that trading interval. The IES suggestion may under or overpay for deviations in any one interval. While NER 3.15.6AA(g)(6) allows the FCFP to specify parameters for calculating RCR, it must still be referable to the relevant requirement for raise or lower. At this stage AEMO intends to use a maximum and minimum in the trading interval, [subject to sample thresholds for inclusion] rather than averaging techniques. This is to

			derive a real time capacity value, and to pay for all good deviations that occurred in the trading interval.

Is the use of a simple maximum value in MW for a 4-second period within a trading interval ideal? What other options are there that meet the rule requirement, and how should AEMO evaluate them?

No.	Stakeholder	Issue	AEMO response
1	Delta Electricity	A simple maximum is probably best in the first instance of this new system. With the benefit of experience and real-data assessments, an alternative may evolve.	See section 4.6.2
2	Hydro Tasmania	Hydro Tasmania considers that performance of a generator should be the total (summed) MW dispatch occurring at each of the 4 second frequency recording intervals (as proposed in Section 2.2.1(6)), and not the peak MW produced to reduce the largest deviation (as proposed in Section 3.4.3).	See section 4.6.2.

Should minimum thresholds apply to the calculation (for example, a minimum number of consecutive raise or lower 4-second intervals before a 4-second interval can be used to potentially determine RCR, or a minimum frequency deviation required to set RCR?)

No.	Stakeholder	Issue	AEMO response
1	Delta Electricity	Designing the frequency measure to be smooth enough to avoid the more rapid movements not being controlled by PFR will probably overcome the need for minimum thresholds and would determine the minimum frequency deviation.	AEMO thinks that a smoothed frequency measure may still not provide a strong indication of whether a deviation is helpful or not and have decided to both implement a smoothed frequency measure alongside certain thresholds described in section 4.2 of the draft FCFP.
2	Origin	We support the introduction of minimum thresholds for the RCR (e.g. a minimum number of consecutive raise or lower 4-second intervals as suggested by AEMO), to reduce the risk that a single 4-second interval can be used to determine the RCR for the whole 5-minute trading interval.	AEMO has implemented a number of filters in respect of the frequency measure that implement this indirectly.

Should some types of variable generation be aggregated for the purpose of calculating RCR?

No.	Stakeholder	Issue	AEMO response
1	IES	Choice of the gross deviation measure inevitably leads to some arbitrariness in dispatch interval outcome depending on how units are grouped, but such differences should wash out over a settlement period. Excepting some type of plant would seem to increase that level of arbitrariness. Measurement at the connection point is the simplest approach. Other ways of calculating the RCR (e.g. some extended form of rms calculation operating at the unit as well as time level) might sidestep this issue.	AEMO agrees – its proposal does not seek to discriminate between different sources of deviation.

How should RCR be calculated for global requirements when there are two AGC areas (e.g. Tasmania and Mainland)?

No.	Stakeholder	Issue	AEMO response
1	IES	We understand that Basslink and Marinus when operating will have their own frequency management arrangements between AGC areas. Inflows and outputs to and from these	AEMO's preference is to consider the sum of the gross values of all deviations in the RCR calculation only when the Frequency

		areas should be treated as pseudo generators and loads and the RCR in each AGC area calculated independently.	Measure relevant to the Mainland NEM and Tasmania are aligned (i.e., have the same sign) during the trading interval.

Are there any preferable alternatives to the draft FCFP formulation of usage?

No.	Stakeholder	Issue	AEMO response
1	Hydro Tasmania	AEMO proposes that regulation FCAS usage is defined as "the maximum (at any point during the trading interval) of the sum of positive deviations for all eligible units with appropriate metering that are enabled to provide the relevant service (capped at the level each unit is enabled)". Similar to the issues outlined above in relation to RCR, the inclusion of 'maximum' rather than 'total' will lead to situations where the positive contribution from 'good' generators in reducing frequency deviations across a dispatch interval are not appropriately recognised.	The regulation FCAS market is about capacity (enablement volume) rather than the total used. In AEMO's view, it does not make sense to use a total figure in this scenario.

Referring to section 7.3 of the draft FCFP, are there any circumstances in which usage should be defined as being equal to zero, for which the requirement for corrective response should not also be zero? In other words, are there any scenarios in which frequency performance payments would not be made, but for which regulation FCAS costs should still be allocated in part to eligible units on the basis of measured frequency performance during that trading interval?

No.	Stakeholder	Issue	AEMO response
1	Delta Electricity	Delta Electricity cannot think of any. Theoretically, proportional systems will be trying to provide support based on detected conditions. It is likely, and demonstrable from evidence of mandatory PFR delivery, that performance payments are warranted in all periods even if FCAS regulation is not at very high dispatch levels. The quantity of PFR is considered to be typically ten-fold that of regulation FCAS and so it is actually possible the reverse applies that there could be some times when no or very minimal regulation costs may be allocated but the PFR reaction is large. performance should always be respected and acknowledged in the procedure.	Noted

There is a lag between the start of the trading interval and when AEMO sends out a dispatch instruction. If this impact is deemed to have a material impact on contribution factors, what are the options to address it?

No.	Stakeholder	Issue	AEMO response
1	Delta Electricity	The statistical condition of system frequency itself presents the best guide. However, it is considered that PFR incentives alone will not necessarily produce the steadiest frequency possible. Better overall coordination is considered to require central coordination by AEMO and scrutiny of interactions between the AGC and each participant and between various participants e.g., A single unit of one participant closely connected to a large capacity of MWs from a group of Units from another participant may develop poor performance in reaction to a poor frequency control design from the larger group of Units. PFR incentivisation will not be able to fix these problems. AEMO should focus on what sort of improvements to system frequency they are hoping for and develop reasonable monitoring targets and include these in the reporting metrics.	See section 4.8.
2	IES	This may be difficult. However, the thinking on this could be along the following lines	See section 4.8

		• The objective is to maintain frequency control to within the required standard • The parameters should be set to give the desired technical performance, bearing in mind that the short-term outcome must be stable and the long term outcome should tend to encourage the maintenance of PFR capability.	

Should units that are enabled to provide Regulation FCAS be treated differently? If so, how?

No.	Stakeholder	Issue	AEMO response
1	Delta Electricity	A unit correctly responding to Regulation FCAS should also not result in poor performance under this procedure… Regulation FCAS Units should be paid for Regulation FCAS and be included for PFR performance payments and causation costs but should not have a resultant transaction for both that represents an overall expense unless demonstrably failing in the regulation FCAS dispatch. The design of the frequency measure and the way the frequency input is smoothed will be critical in this consideration because evidence exists that regulation FCAS dispatch is generally slower in application on a Unit than PFR reactions. System frequency might require a reaction opposite to that driven by a Unit observing regulation FCAS dispatch particularly when dispatched on a steady energy target. A procedure considering performance against a target-to-target trajectory may need to consider the regulation FCAS performance with the PFR performance/causation payments/costs for a trading interval and ensure it does not produce a negative result. It is suggested that the FCAS/PFR Net result should consider a comparison something like: Maximum(0, (PFR performance - PFR costs) + FCAS Regulation Income). In other words, a compliant regulation FCAS provider should not incur an overall net financial loss from PFR causation in a TI. It would be better if the procedure is designed so that the PFR performance cannot produce a causation outcome for a Unit correctly observing FCAS regulation dispatch.	AEMC in its rule change recognises that FCAS providers are able to adjust their offers to consider the net impact of FPPs. In addition to this, AEMO's analysis shows that in the vast majority of scenarios, AGC enabled units are incentivised by FPP, not disincentivised.
2	IES	Including regulation FCAS-enabled units in the performance incentive arrangements is the simplest approach which removes any issues of determining a boundary between what is provided under enablement and what is provided as an “extra”. If the incentive arrangement is substantially (not necessarily completely) aligned with the AGC performance requirement, enabled units should earn a fair return for good performance. The perceived risk of “double payment” should be reduced as the extra incentive to get paid for both enablement and performance makes bidding for regulation enablement more attractive.	Agreed, AEMO's analysis confirms that the incentive arrangement is substantially aligned with the AGC performance requirement.

Are there any complications with this approach that have not been raised?

No.	Stakeholder	Issue	AEMO response
1	IES	The proposed approach is simple and robust. The concept of a scheduled and physical energy balance applies around any close boundary around all or part of the system, s drawing a boundary at an interconnector is valid.	Noted

Would it be preferable for the impact of interconnector deviations to be borne entirely by the local residual for local requirements? This would enable the framework to have good and bad performance for appropriately metered units to offset (since the link between deviations and cost would remain intact).

No.	Stakeholder	Issue	AEMO response

1	Delta Electricity	Interconnector variations present conditions to either region that are similar to that of a load or generator but the cause for the variation on the interconnector are many and varied so it does not seem reasonable to have the local residual bear the impact exclusively unless it is expected that the opposite impact occurs on the adjacent region and its local residual.	AEMO agrees with this and has decided to calculate each region's residual accordingly.
2	IES	This option is unclear. An interconnector is essentially just another metered unit and should be treated as such.	See our discussion in section 4.10

Should contribution factors for the residual be capped at zero? (noting that default contribution factors for eligible units that are appropriately metered are capped at zero)

No.	Stakeholder	Issue	AEMO response
1	Delta Electricity	As the residual is unmetered it seems appropriate to cap it at zero because without more elaborate metering from which to generally determine good PFR is occurring positive factors seem random and would erroneous in the objectives for incentivisation of those participants that can adequately demonstrate performance.	See discussion in section 4.10.2.
2	IES	The residual can be regarded as just another metered unit (with many meters) and so contribution factors should be treated the same way. For normal factors, there is no merit in any capping, the residual factor can be positive or negative although it is usually negative. For default factors, choice of a suitably long reference period (say a full settlement period) should clearly delineate good and bad performers, so no capping should be required.	See discussion in section 4.10.2.

Decision: allow residual to be positive – on basis that AEMO has estimated performance for that interval in respect of the residual.

Do you see value in AEMO publishing estimated aggregate values in the Pre-dispatch timeframe?

No.	Stakeholder	Issue	AEMO response
1	Delta Electricity	Any data that can assist participants improve understanding of exposure to PFR local requirements is considered valuable.	Noted

What other data do you consider worthwhile for AEMO to publish?

No.	Stakeholder	Issue	AEMO response
1	Delta Electricity	• The frequency measure. • The x and y weighting factors and reasons for them. • The reasoning behind the dispatch quantities for Regulation and contingency FCAS. • Any AEMO estimates for the minimum quantity of PFR required to maintain the expected histogram shape for frequency control in the NEM. • AEMO targets for frequency performance over and above that required by, or those not include within, the FOS, and routine performance of real conditions measured against those targets.	See discussion in 4.11
2	IES	• 4-second data each 5 minutes, at least for individual units • Draft performance factors each 5 minutes	See discussion in 4.11

Other comments

No.	Stakeholder	Issue	AEMO response
1	Delta Electricity	AEMO are advised to ensure that the adopted frequency measure aims to track larger changes in frequency over longer time intervals (than 4s) than attempt to have addressed smaller changes occurring	AEMO agrees with this and has implemented a frequency measure that balances these needs against the underlying principle that the frequency

		in a 4s timeframe. Frequency smoothed to avoid the regular 50mHz peak to peak changes that occur over a period of 25 to 30s is also recommended	measure should be generally well correlated with raw frequency. AEMO notes that a PFR that counteracts the regular 'peak to peak' changes is still valuable and worth incentivising.
2	Delta Electricity	For this procedure, if possible, AEMO should consider making some use of Unit setpoints, data that is also being returned to AEMOs AGC every 4 seconds, to confirm the assigned target-to-target trajectories are achievable by automatic control. Concerned that the target trajectory proposed for the procedure will produce variations in performance results between trading intervals not always related to frequency and/or the PFR from individual units. It is considered that either the AEMO NEMDE/AGC targeting process needs modification or the procedure's target-to-target trajectory designed from targets adjusted to be always achievable by units subject to automatic control. If not done, there will often be trading intervals where performance results are actually reflective of the inadequacy in the unit dispatch expectation rather than inadequate PFR from a unit.	AEMO has decided to avoid linking reference trajectories to AGC. The additional complexity involved would be substantial and AEMO does not think there is a strong design case for doing so, particularly since changes may be made to AGC independently of this project. Changing the operation of the dispatch engines is out of scope for this project.
3	Delta Electricity	Delta Electricity considers that the NEMDE/AGC basepoint assignment and the dependence on a snapshot SCADA reading taken of the unit actual MW output 20-30sec before start of the interval regularly results in inadequate targets (for numerous 5-minute TIs per day). Target-to-target trajectories based upon this inadequate targeting is a source of concern for the effectiveness of this new procedure.	See the response to (2) above.
4	Origin	We understand AEMO intends to conduct a non-financial industry trial of the new FPP and frequency contribution factor processes for a period of three to six months prior to the formal commencement of the rule on 8 June 2025. We support this approach, but strongly encourage AEMO to revisit the FCFP and undertake an abridged stakeholder consultation process following the trial so that any lessons learned can be incorporated in the FCFP. The earlier AEMO can commence this trial, the greater the opportunity to improve industry understanding of the highly complex new process and enhance the FCFP.	The intention is that the FCFP will be completed (and fit for purpose) by 8 June 2023 as required by the rule. If material errors or issues are discovered during the implementation of the project, then AEMO may elect to conduct a further consultation, but none are currently planned.
5	Origin	We support AEMO applying a moving average approach to determining frequency deviations that will smooth the impact of any instantaneous deviations that could not be reasonably controlled / responded to by generators.	See the response to (1) above.
6	IES	The IES report to AEMC suggested an incentive based on a combined [frequency] metric with fast and slow-moving components. There is merit in setting the slow-moving component as closely as possible to the AGC value to ensure the enabled and non-enabled units operate reasonably consistently. A time constant of 30 seconds seems to give a good fit.	Refer to the discussion regarding formulation of the frequency measure. AEMO believes that the frequency measure proposed balances the need to be strongly correlated with raw power system frequency with the need to have a more stable metric that indicates good and bad performance.
7	IES	We note that it would be possible to define additional components [in frequency measure] such as: 1) a 5-minute (300 second) time constant component to assist with ramping; 2) an internal time correction element, similar to but simpler and not directly linked to the AGC correction (to minimise incentives that may work against each other). 3) with improved metering and at some time in the future, shorter time constants to reward good PFR performance, for example. These different components would reflect the different dynamic elements at play in the system and their	See AEMO's analysis in section 4.2.

		weightings will change over time as the draft procedure anticipates.	
8	IES	IES discuss the effect of calculating RCR as the maximum (or minimum) gross deviation when the performance measure is on the Raise (or Lower) side has the effect of creating a relatively stable value. IES state that this amount remains the same regardless of whether the service (Raise or Lower) is used a lot, a little or not at all (hence the need for default factors in the last case).	A minor clarification needs to be made with respect to this observation. RCR is expected to be calculated for each side (raise or lower) by the maximum value of the sum of positive deviations for raise, and minimum value of the sum of negative deviations for lower. Because deviations balance, the maximum positive will equal the minimum negative value. This does not mean RCR will be the same for raise and lower, because the maximum value for raise is taken only on the condition that FM is positive. Similarly, the minimum value for lower is on the condition FM is negative. What this means is the RCR for raise and lower are selected at different points in the trading interval, with the extreme being zero RCR on one side. This ensures, for example when FM stays positive for the trading interval, and there is no performance data for lower, RCR for lower is zero too. For clarification, this means default factors are not required to recover RCR because RCR is zero. This confusion may have arisen because the AEMC/IES project prepared for the Second Directions Paper calculated what was the equivalent of RCR independent of the FM, because the same 'RCR' (or scaling factor as known then) in that modelling exercise was applied to contribution factors calculated using different FMs – this was simply more expedient at the time.
9	IES	The FM measure defines whether deviation data is used to calculate a CF for raise (FM positive), or lower (FM negative). Rather than use a single combined FM, IES suggest two separate FMs be used to represent fast governor action and slow AGC response. These FMs would be used then to split performance to calculate two sets of performance data, where the need for raise or lower may be different. To be clear this would mean a 4-sec deviation may be raise in one set of data, say for the fast FM, and lower, say for the slow FM. AEMO assumes these would not be recombined, but used to calculate separate factors for each FM, which could then be multiplied by alternative RCR values for each FM. This would duplicate the Trading Amounts and would create separate payments for fast and slow response.	AEMO considers this recommendation to be out of scope. The drafting of 3.15.6AA clearly envisages contribution factors, RCR and trading amounts be calculated based on a single, combined frequency measure that indicates a need for raise or lower services, and for this to be performed for each global or local requirement. The reason for having a single combined frequency measure that indicates a need for raise and lower by being positive or negative is because there is only one price (being the marginal value of the relevant requirement) for the trading interval. This then extends to FM, RCR and CFs. If there was a different underlying price available to value fast or slow response then it could be more feasible be sensible to effectively develop two settlement systems, rather than as proposed in 3.15.6AA. Further, the comment reflects a more general misunderstanding of the purpose of the scheme, which is not to incentivize a level of control or frequency performance through a price, but rather settle deviations at the prevailing rate of regulation services.

			Instead, control is specified in the Primary Frequency Response Requirements (PFRR), and through AGC-Regulation dispatch.