Australian Energy Market Commission

RULE DETERMINATION

NATIONAL ELECTRICITY AMENDMENT (PRIMARY FREQUENCY RESPONSE INCENTIVE ARRANGEMENTS) RULE 2022

AEMO

8 SEPTEMBER 2022

DETERMINATION

INQUIRIES

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ABOUT THE AEMC

The AEMC reports to the Energy Ministers' Meeting (formerly the Council of Australian Governments Energy Council). We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the Energy Ministers' Meeting.

SUMMARY

1 As we move towards a lower emissions energy future, the provision of essential system services is one of the key priority areas of policy reform in the National Electricity Market (NEM) and for the Australian Energy Market Commission (AEMC). Lower cost, variable, inverter connected generation such as batteries, wind and solar are displacing synchronous and dispatchable thermal generation and this is creating challenges for how the security of the power system is managed.

2 One aspect of system security is the control of power system frequency within a narrow range around 50Hz. This is achieved by dynamically balancing electricity generation and consumption under both normal system conditions and in response to contingency events, which can cause larger deviations in frequency.

3 The Commission has decided to make a more preferable final rule on *Primary frequency response incentive arrangements* in response to a rule change request received from the Australian Energy Market Operator (AEMO). The final rule comprises three core elements to support system security and deliver reduced costs for frequency control over the long term, as compared with the continuation of the current arrangements and the solution proposed in the rule change request.

The core elements of the final rule are largely the same as the draft rule, but the details have been refined following further analysis and stakeholder feedback

4 The core elements of the final rule, which are similar to the draft rule, are:

- **Confirmation that the mandatory primary frequency response (PFR) arrangements will endure** beyond 4 June 2023. This will mean that all scheduled and semi-scheduled generators will continue to be required to support the secure operation of the power system by responding automatically to changes in power system frequency.
- **Introduction of a new double-sided frequency performance payments process** to encourage plant behaviour that helps to control power system frequency. These arrangements will value helpful frequency response provided in accordance with the mandatory PFR requirement and also incentivise provision of additional PFR to support the effective control of system frequency into the future. In other words, it will encourage the PFR service to be provided to the system when it is most valued.
- **New reporting obligations for AEMO and the AER** in relation to the levels of aggregate frequency responsiveness in the power system and the costs of frequency performance payments. This change supports the principle of transparency and would provide relevant information to market participants and stakeholders to assess the effectiveness and efficiency of the frequency control frameworks over time.

5 The Commission considers that these reforms will provide AEMO with the tools it needs to manage the secure operation of the power system in accordance with the technical limits specified in the Frequency operating standard (FOS). At the same time, the final rule will

deliver more efficient operation of power system plant and encourage innovation and investment in new capability to help control power system frequency, thereby lowering costs for consumers over the long term.

6 In response to stakeholder feedback on the draft rule, the final rule includes a number of minor changes and refinements with respect to the draft rule. These changes include:

- Clarification that the Mandatory PFR obligation under clause 4.4.2(c1) of the NER applies to each Scheduled Generator and Semi-Scheduled Generator that has received a dispatch instruction in accordance with clause 4.9.2 to generate a volume greater than zero MW.
- Changes and refinements to simplify the transactions for the frequency performance payments process.
- Changes and additional inclusions in relation to the requirement for AEMO to determine the frequency contribution factor procedure. The final rule includes clear principles and requirements to guide AEMO in its development of the procedure as well as a clear set of requirements for the publication of related data.

7 A summary of the final rule, and changes from the draft rule, is included in appendix F.

Acknowledgement of market body and industry contributions

8 Along with input provided by AEMO and the AER, the Commission also acknowledges the contribution provided by ARENA and the AEC to the development of the frequency performance payments process. The *Australian Energy Council double-sided causer pays* study, completed on 30 April 2022, progressed the theoretical design for performance-based frequency incentives in the NEM through the application of double-sided causer pays.[1] This project helped to progress the conceptual development for the frequency performance payments process and educate industry participants on how such a process could work to support the efficient provision of frequency control services.

Implementation will occur in successive stages

9 The key implementation milestones include:

8 September 2022:	Publication of final rule and commencement of obligation for AEMO to report on aggregate frequency responsiveness on a quarterly basis.
by 8 May 2023:	AEMO to consult on and publish the *Primary frequency response requirements.*
by 8 June 2023:	AEMO to consult on and publish the *Frequency contribution factor procedure.*
8 June 2025:	Commencement of the new frequency performance payments process and the obligation for the AER to report on the costs of frequency performance payments.

1 ARENA knowledge sharing reports available at: https://arena.gov.au/projects/australian-energy-council-double-sided-causer-pays-study/

10 Further detail on the implementation timeline and next steps following this determination are set out in section 1.1.4.

Further detail on the key elements of the final rule

11 The key elements of the final rule are the confirmation of mandatory PFR, supported by new PFR incentive arrangements, and additional reporting requirements for AEMO and the AER. Each of these elements is summarised below.

Confirmation that generators must be responsive to power system frequency

12 The final rule confirms that all scheduled and semi-scheduled generators will continue to be required to support the secure operation of the power system by responding automatically to changes in power system frequency.

13 In order to maintain the power system in a secure operating state and avoid unplanned system or plant outages, power system frequency must be controlled within a narrow range around 50Hz. This is achieved by dynamically balancing electricity generation and consumption under both normal system conditions and in response to sudden larger changes in frequency caused by the sudden unexpected failure of generation or transmission elements. In this way, continuous PFR helps to control power system frequency in a similar way to how cruise control maintains the desired speed in a passenger vehicle.

14 In March 2020, the Commission introduced an obligation for all scheduled and semi-scheduled generators in the NEM to support the secure operation of the power system by responding automatically to small changes in power system frequency (the Mandatory PFR rule).[2] The Commission considered that mandatory PFR was required to address an immediate need to restore effective frequency control in the NEM but, at the same time, noted that it was not a complete solution for the long term. The Commission considered that further work was needed to better understand the power system requirements for maintaining good frequency control and that it would be preferable to introduce alternative or complementary arrangements that incentivise and reward the provision of PFR.

15 The Commission considers that a continuation of the mandatory arrangements is warranted as a complement to the new frequency performance payment arrangements. The implementation of Mandatory PFR has been particularly effective in improving the control of power system frequency in the NEM, given the current generation mix. This has been evidenced through data showing improvements in frequency performance since the implementation of control system changes on large-scale centralised generation in accordance with the Mandatory PFR rule. Expert advice received from AEMO and independent advice received from GHD also supports the continuation of mandatory PFR as necessary to support the secure operation of the power system.

16 The Commission acknowledges concerns from some stakeholders in relation to a continuation of the mandatory PFR requirement and in particular the settings under the requirement which require generators to be sensitive to small changes in frequency outside of the range

2 The rule and final determination are available at: https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response

50 ±0.015Hz. However, as set out above expert advice across the course of this process - as well as the noticeable difference in frequency distribution since the introduction of this requirement - has demonstrated the value in mandatory PFR.

17 Some stakeholders asked for the Commission to commit to a future review of these arrangements. The Commission does not consider such a commitment is necessary. This is because the Reliability Panel is in the process of reviewing the FOS, including the specification of the primary frequency control band (PFCB) that sets the sensitivity for mandatory PFR. The Commission expects that the Reliability Panel will also recommend the timing for a subsequent future review of the FOS which will allow for settings in the FOS for normal operation, including the PFCB, to be further reviewed following a sufficient period of operational experience with the new frequency performance payments in effect. This will have the same outcome as the Commission reviewing this, and is already occurring under existing arrangements reducing duplication of process.

New double-sided frequency performance payments

18 The final rule introduces double-sided frequency performance payments for all eligible units of generation and load. These new arrangements build on the existing 'causer pays' arrangements for the allocation of regulation FCAS costs. They are designed to deliver improved valuation and pricing of plant behaviour that impacts on power system frequency. They will provide financial incentives to encourage innovation and investment in new capability to support the effective control of system frequency into the future.

19 The key elements of the new frequency payments process in the final rule include that:

- **transactions to support frequency performance payments** will be made to market participants who obtain positive contribution factors in a trading interval. Contribution factors reflect the impact of power system equipment (generation and load) on system frequency. A positive contribution factor represents plant behaviour that helps to control system frequency and reduce a frequency deviation (from 50Hz). The costs of frequency performance payments will be allocated to market participants who obtain negative contribution factors for that trading interval. A negative contribution factor represents plant behaviour that contributes to the deviation of system frequency.
- **the arrangements for the allocation of costs for the enablement of regulation services** will be modified to be more transparent and to be more reflective of the real time use of regulation services.
- AEMO must prepare **a new frequency contribution factors procedure** that describes the process for determining contribution factors which will be used in the transactions for frequency performance payments and for the allocation of costs for the enablement of regulation services. AEMO must develop and publish, in accordance with the Rules consultation procedure, the first Frequency contribution factors procedure by **8 June 2023.**

20 These changes are expected to better align the economic incentives for plant active power performance, with the impact of that behaviour on the need for corrective action through the deployment of regulation services to rebalance supply and demand and restore power system

frequency to 50Hz. By incentivising the provision of primary frequency response this is expected to lead to more efficient outcomes in relation to the operation of the power system by encouraging all market participants to operate their plant in a way that reduces the need for regulation services and helps to control power system frequency.

21 The new frequency performance payments transactions as set out in the final rule will commence on **8 June 2025**.

Additional reporting requirements for AEMO and AER

22 The final rule includes new reporting obligations for AEMO and the AER in relation to the levels of aggregate frequency responsiveness in the power system and the costs of frequency performance payments.

23 The final rule:

- introduces a new reporting obligation on the AER in its quarterly report in respect of market ancillary services to report on the total amounts of frequency performance payments made. This will help market participants understand the cost of the incentives required to encourage market participants to behave in a manner which supports power system frequency control. This requirement will commence from **8 June 2025**.
- introduces new reporting obligations on AEMO in its quarterly report on the power system to report on its assessment of the level of aggregate responsiveness in the power system provided by frequency responsive plant in each region. This will enable the effectiveness of these arrangements to be monitored and provide early indications of emerging needs for further actions which may arise in the future. This requirement will commence from **8 September 2022**.

24 These reporting obligations provide transparency through the provision of relevant information to market participants and stakeholders to assess the effectiveness and efficiency of the frequency control frameworks over time. They will inform further consideration by the market bodies as to whether there is any need for changes to the nature of these arrangements in the future.

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APPENDICES

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1 FINAL RULE DETERMINATION

This final determination is to make a more preferable final rule (final rule) to improve the incentives that relate to the provision of primary frequency response in the NER to help control power system frequency.

This chapter provides:

- An overview of the final rule and how the related reforms will work — see section 1.1.
- A summary of how stakeholder feedback has shaped the final rule — see section 1.2.
- An overview of the interactions between this rule determination and other current and upcoming market reforms — see section 1.3.

Further detail on the final rule can be found in chapter 3 below.

The Commission's assessment of this final rule determination against the national electricity objective is set out in chapter 2.

Further information on the legal requirements for making this final rule determination is set out in appendix D.

1.1 Overview of the final rule

The final rule made by the Commission is attached to and published with this final rule determination. The key features of the final rule are:

- confirmation that the mandatory primary frequency response (PFR) arrangements — that require scheduled and semi-scheduled plant to provide active power response to changes in power system frequency — will endure beyond 4 June 2023; accompanied by
- the introduction of financial incentives, through frequency performance payments, for market participants to operate their plant in a way that helps to control power system frequency; supported by
- new reporting requirements for AEMO and the AER related to frequency responsiveness and the costs of frequency performance payments.

The following sections provide a brief overview of each of these elements of the final rule along with the process and timing for implementation of the new arrangements.

Further detail on the elements of the final rule is included in chapter 3.

1.1.1 Confirmation of the existing mandatory PFR arrangements

The final rule confirms that the mandatory PFR arrangements will endure beyond 4 June 2023 by removing the existing sunset provision for these arrangements.[3] This means that all scheduled and semi-scheduled generators will continue to be required to support the secure operation of the power system by responding automatically to changes in power system frequency. However, this requirement will be supplemented by new arrangements that will

3 This is achieved by the final rule revoking Schedule 2 of the National Electricity Amendment (Mandatory primary frequency response) Rule 2020, which would have ended the existing mandatory PFR arrangement on 4 June 2023.

reward and incentivise plant to provide this service in such a way that adds value to the system.

The Commission notes stakeholder views that consider that the sensitivity of the mandatory PFR arrangements should be reviewed at a future date, following a suitable period of operational experience with the new frequency performance payments arrangements in place. This potential future will be further considered by the Reliability Panel which is currently reviewing the FOS, including the PFCB that sets the sensitivity for mandatory PFR.[4] The Commission expects that the Reliability Panel will also recommend the timing for a subsequent future review of the FOS to allow the settings in the FOS for normal operation, including the PFCB, to be further reviewed at a later date. A summary of the Reliability Panel Review of the FOS is provided in section 1.3.1.

In addition to the confirmation that the existing mandatory PFR arrangements will continue, in response to stakeholder feedback, the final rule also includes revised drafting for NER clause 4.4.2(c1). This clarifies that the mandatory PFR requirement applies to "each *Scheduled Generator* and *Semi-Scheduled Generator* that has received a *dispatch instruction* in accordance with clause 4.9.2 to generate a volume greater than zero MW". While this drafting is consistent with the Commission's final determination for the Mandatory primary frequency response rule, it clarifies that generators which are not dispatched in the energy market to generate electricity are not required to operate in a frequency response mode in accordance with the *Primary frequency response requirements (PFRR)*, determined by AEMO.

This element of the final rule is described in further detail in section 3.1.

1.1.2 New arrangements for double-sided frequency performance payments for all generation and load

The final rule introduces double-sided frequency performance payments for all generation and load to deliver improved valuation and pricing of plant behaviour that impacts on power system frequency. This provides a financial incentive to plant to be rewarded for providing PFR to the system. This is achieved through reforms to the existing requirements in the NER that relate to the allocation of costs for regulation FCAS.[5]

The frequency payments process in the final rule maintains the key elements set out in the draft rule, including that:

- **transactions to support Frequency performance payments** will be made to market participants who obtain positive contribution factors in a trading interval. Contribution factors reflect the impact of power system equipment (generation and load) on system frequency. A positive contribution factor represents plant behaviour that helps to control system frequency and reduce a frequency deviation (from 50Hz). The costs of frequency performance payments will be allocated to market participants who obtain negative

4 Refer to the project webpage for further information: https://www.aemc.gov.au/market-reviews-advice/review-frequency-operating-standard-2022

5 The existing arrangements are set out in NER Cl clause 3.15.6A(i) to (nb)(k). The final rule replaces these arrangements in clause 3.15.6AA.

contribution factors for that trading interval. A negative contribution factor represents plant behaviour that contributes to the deviation of system frequency.

- **the arrangements for the allocation of costs for the enablement of regulation services** will be modified to be more transparent and to be more reflective of the real time use of regulation services.
- AEMO must prepare **a new frequency contribution factors procedure** that describes the process for determining contribution factors which will be used in the transactions for frequency performance payments and for the allocation of costs for the enablement of regulation services.

These changes are expected to better align the economic incentives for plant active power performance, with the impact of that behaviour on the need for corrective action through the deployment of regulation services to rebalance supply and demand and restore power system frequency to 50Hz. By incentivising the provision of primary frequency response this is expected to lead to more efficient outcomes in relation to the operation of the power system by encouraging all market participants to operate their plant in a way that reduces the need for regulation services and helps to control power system frequency.

Further detail on the three elements of the new frequency performance payments process is set out below.

Transactions for frequency performance payments

The final rule includes frequency performance payment transactions that apply for plant behaviour that contributes to the need to raise or lower the frequency of the power system. These transactions are based on the product of three key elements for each trading interval:

- the valuation of active power deviations based on the price for the regulation raise or regulation lower service.
- the scaling of payments by the aggregate system requirement for corrective response (RCR) — this is equivalent to the enablement volume for a market ancillary service.
- a contribution factor determined for each eligible unit of generation and load — this allocates payments and costs based on the proportional contribution of each plant to the need to raise or lower the frequency of the power system.

Analysis undertaken by IES estimated that the scale of gross payments (and cost allocations) under the frequency performance payments transactions would be expected to be similar in size to the total costs for regulation services. The IES analysis also demonstrated that net payments, taking into account payments and cost allocations that cancel out over the relevant period, would be expected to be in the order of one third of the costs of regulation services.[6] The estimated financial impact as a result of the new frequency performance payments transactions is described further in appendix E.

These transactions build on the existing 'causer pays' process for the allocation of costs for the enablement of regulation services. The existing causer pays process determines a

6 IES, Frequency performance payments analysis, 19 May 2022, p.6.

contribution factor for each market participant, which reflects the degree to which that market participant contributed to the need for regulation services. Participant contribution factors can be positive, for those participants that reduced the need for regulation services, or negative, for those participants that increased the need for regulation services. The current framework recovers the costs of regulation services from participants with net negative contribution factors but does not support any payments being made to market participants with net positive contribution factors. The final rule creates a 'double-sided causer pays' framework where payments are made to participants whose plant obtain positive contribution factors and the costs of these payments are allocated to participants whose plant obtain negative contribution factors. The existing 'causer pays' process is described further in appendix B.2.

The transactions in the final rule reflect changes and refinements that were made in response to stakeholder feedback on the draft rule and are set out in detail in the second directions paper. One such change, in response to feedback from AEMO, that affects the general application of the frequency performance payments, relates to the consideration of how the transactions will apply throughout the NEM, given different global or regional requirements for regulation services. In response to feedback from AEMO on the revised rule, the final rule clarifies that the elements of the frequency performance payments transactions (contribution factors, regulation price and RCR) will apply to the region or regions relevant to the global or local requirement for regulation services.[7] This will allow for AEMO to determine contribution factors for local or global regulation requirements, as applicable.

Modified arrangements for the allocation of costs for the enablement of regulation services

The costs of regulation services that are <u>used</u> within each trading interval will be allocated to market participants who obtain negative contribution factors and therefore cause the need for these services. This is consistent with the draft rule.

The costs of regulation services <u>not used</u> in a trading interval will be allocated based on negative default contribution factors. This is a change from the draft rule which proposed that these costs be distributed across all market participants in proportion to the energy consumed or generated by that market participant in that trading interval.

A new frequency contribution factor procedure

The final rule requires AEMO to develop and consult on a new frequency contribution factor procedure to set out how contribution factors will be calculated for generation and load. The frequency contribution factors procedure will replace the existing regulation FCAS contribution factors 'causer pays' procedure from the date of commencement for the new frequency performance payments process, 8 June 2025.

While much of the practical application of the final rule will be set out in AEMO's procedure, the final rule includes a set of principles to guide AEMO in the development of the frequency contribution factor procedure, including:

7 AEMO, Submission to the second directions paper, 16 June 2022, pp.9 -14.

- that the objective for a contribution factor is related to the measured impact on the frequency of the power system, which differs from the draft rule which was related to the need for regulation services.
- that a contribution factor is determined for each eligible unit, rather than for a market participant's portfolio as in the draft rule. This will avoid distortions due to participant portfolios.
- that the residual contribution factor for all eligible units that do not have appropriate metering must be equal across and within all classes of Cost Recovery Market Participants. This is consistent with the current causer pays process and the draft rule.
- that separate contribution factors must be determined with respect to the need to raise or lower the frequency of the power system. This allows for 'raise' contributions to be valued based on the price for regulating raise service and 'lower' contributions based on the price for the regulation lower service.
- that a contribution factor for each eligible unit must be determined by AEMO for every trading interval unless in AEMO's reasonable opinion it is impractical to do so, in which AEMO must determine a default contribution factor.
- that a contribution factor for each eligible unit applies for the region or regions relevant to the global market ancillary service requirement or local market ancillary service requirement for the regulating raise service or regulating lower service.
- a default contribution factor should be determined based on historical data, where practical. AEMO may develop an alternative methodology for use where it is impractical to use historical data.
- a default contribution factor may only be used for the allocation of costs for frequency performance payments. Positive frequency performance payments may not be made based on default contribution factors. The approach to this element in the final rule differs from the revised rule, which would have allowed for payments to be made based on default contribution factors.

The final rule also specifies that the frequency contribution factor procedure includes:

- the criteria for determining whether an eligible unit has appropriate metering.
- a formula that *AEMO* will use to calculate the measure of the need to raise or lower the *frequency* of the *power system* (the system frequency metric), which is used by AEMO to determine unit contribution factors.
- the methodology *AEMO* will use to determine a default contribution factor.
- the data *AEMO* will use to calculate the contribution factor for an eligible unit with appropriate metering.
- the methodology *AEMO* will use to determine the requirement for corrective response (RCR) used to scale the frequency performance payments, including any related parameters. Additional provisions in the final rule clarify that AEMO may include parameters to determine RCR. These parameters will allow for the scaling of the frequency performance payments to be adjusted subject to operational frequency control

requirements. AEMO must publish any such parameter 5 days in advance of its application.

- the methodology AEMO will use to determine the usage (U) of regulation services for the allocation of costs of regulation services by used and not-used.
- the methodology *AEMO* will use to determine a reference trajectory which provides an active power baseline against which unit performance is measured.

The final rule also clarifies the data publication requirements related to the calculation of contribution factors. This includes:

- data used to determine contribution factors and default contribution factors
- any parameters related to the system frequency metric or the requirement for corrective response
- data related to the system frequency metric, RCR and the usage or regulation services.

This element of the final rule is described in further detail in section 3.2.3.

1.1.3 New reporting obligations for AEMO and the AER

The final rule includes new reporting obligations for AEMO and the AER in relation to the levels of aggregate frequency responsiveness in the power system and the costs of frequency performance payments. As per the draft rule, the final rule:

- introduces a new reporting obligation on the AER in its quarterly report in respect of market ancillary services to report on the total amounts of frequency performance payments made. This will help market participants understand the cost of the incentives required to encourage market participants to behave in a manner which supports power system frequency control. This requirement will commence from 8 June 2025.
- introduces new reporting obligations on AEMO in its quarterly report on power system to report on AEMO's assessment of the level of aggregate responsiveness in the power system provided by frequency responsive plant in each region. This will enable the effectiveness of these arrangements to be monitored and provide early indications of emerging needs for further actions which may arise in the future. This requirement will commence from 8 September 2022.

These reporting obligations provide transparency through the provision of relevant information to market participants and stakeholders to assess the effectiveness and efficiency of the frequency control frameworks over time.

This element of the final rule is described in further detail in section 3.3.

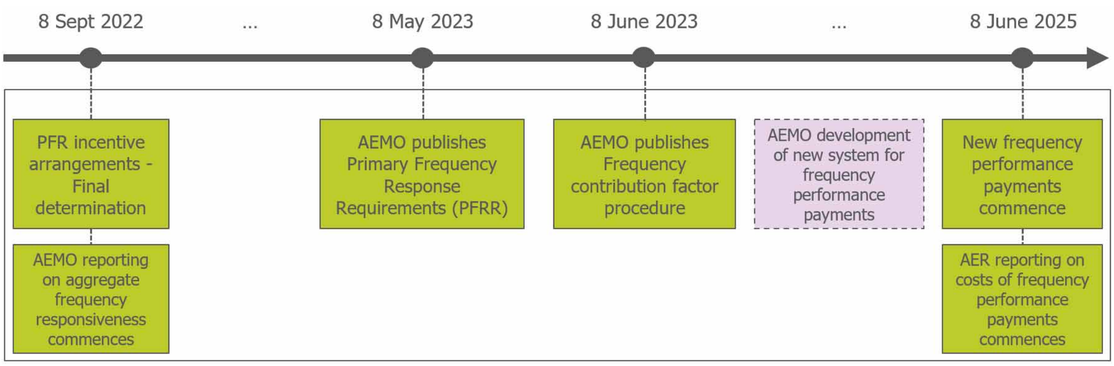
1.1.4 Implementation and transitional arrangements

The final rule sets out the process and timing for AEMO to consult on the related procedures and make the related changes to its internal processes and systems. The specific timings for implementation, which have been informed by engagement with AEMO's Reform delivery committee, are:

- AEMO must develop and publish — in accordance with the Rules consultation procedure — the Primary Frequency Response Requirements (PFRR) referred to under clause 4.4.2(a) by **8 May 2023.** This date is eight months from the date of the final rule. The Commission has increased the time available for the preparation of the PFRR by two months, from that proposed in the draft determination, to account for resourcing constraints over the 2022/23 Christmas/New Year period.
- AEMO must develop and publish — in accordance with the Rules consultation procedure — the first Frequency contribution factors procedure by **8 June 2023.** This date is nine months from the date of the final rule, as per timing proposed in the draft determination.
- The new frequency performance payments transactions as set out in the final rule will commence on **8 June 2025**. This date which is two years and nine months from the date of the final rule.

The implementation timing for the key elements of the final rule is shown in Figure 1.1.

Figure 1.1: Implementation timeline — PFR incentive arrangements



Source: AEMC

The Commission notes AEMO's intention to undertake a non-financial industry trial of the new frequency performance payments and frequency contribution factor processes for a period of three to six months prior to the formal commencement of the relevant provisions on 8 June 2025. AEMO has indicated that such a trial will allow participants to understand and adapt to the new arrangements and also allow AEMO to calibrate the many related operational parameters.[8] The details of any industry trial will be managed by AEMO.

8 AEMO, Submission to the second directions paper, 16 June 2022, p.16.

1.2 How did stakeholder feedback shape the Commission's determination?

The Commission commenced consultation on this rule change on 19 September 2019 and has invited formal stakeholder submissions through the publication of two consultation papers, two direction papers and a draft determination.[9] The rule making process has also been informed by collaboration with AEMO and input from industry representatives through the AEMC's frequency control technical working group. Further detail on the rule making process is included in appendix A.

The consultation on this rule change request can be divided into two phases, each focused on different reform objectives.

Phase one — Initial consultation alongside the Mandatory PFR rule change request(s)

Initially this rule change request was considered in parallel to two other rule change requests relating to *Mandatory primary frequency response* (PFR), one from AEMO and the other from Dr Peter Sokolowski. In their rule change requests, AEMO and Dr Sokolowski expressed the view that the absence of a requirement in the NER for scheduled and semi-scheduled generators to be responsive to small changes in system frequency contributed to a degradation in frequency control over the period 2014 to 2018. The proponents stated that this led to reduced the security and resilience of the power system. Informed by the findings from its investigation of the power system separation event that occurred on 25 August 2018 and expert advice provided by Dr John Undrill, AEMO urged the AEMC to urgently introduce a mandatory PFR obligation for scheduled and semi-scheduled generators.[10]

In March 2020 the Commission made a rule in relation to AEMO and Dr Sokolowski's rule change requests to introduce an obligation for all scheduled and semi-scheduled generators in the NEM to support the secure operation of the power system by responding automatically to small changes in power system frequency (the Mandatory PFR rule). The mandatory provision of narrow-band PFR was supported by power system engineers, transmission networks, Hydro Tasmania and AEMO.[11] However many stakeholders expressed concern that the mandatory PFR was unlikely to be the most efficient option for valuing primary frequency response in the long-term. These stakeholders reasoned that incentive or market-based arrangements to provide PFR would likely be more efficient and effective over the longer term.[12]

9 This rule change request was initiated under the project name: *Removal of disincentives to primary frequency response*. In July 2020, the project name was changed to *Primary frequency response incentive arrangements* to reflect the revised scope and objectives following on from the final determination for the *Mandatory primary frequency response rule*.

10 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, pp.26-28.

11 Submissions on the Directions paper - Frequency control rule changes, 17 December 2020: AEMO, p.2.; UNSW, p.19.; Hydro Tasmania, p.5. Submissions on the Consultation paper - PFR rule changes, 19 September 2019: AEMO, p.1.; Ergon Energy and Energex, p1; Kate Summers, p.2; TasNetworks, p.3.

12 Submissions on the directions paper - Frequency control rule changes, 17 December 2020: Alinta Energy, p.5.; AGL, p.8.; CEC, p.2.; Delta Electricity, p.13.; Infigen, p.7.; Neon, p.1.; Origin, p.5.; Snowy Hydro, p.8. Submissions to the consultation paper – PFR rule changes, 19 September 2019: CS Energy, p. 2, Delta Electricity, p. 6, Neoen p.1, Enel X, p. 8, IES, p.2, Enel Green Power, p. 2, ARENA, p.3

At the time of making the Mandatory PFR rule, and in response to stakeholder concerns, the Commission acknowledged that mandatory PFR on its own is not a complete solution and may not be sufficient to deliver effective economic signals to meet the operational needs of the power system now and into the future. The Commission recognised that the mandatory approach would ideally be replaced or complemented by market or incentive based arrangements for PFR. However, given the time needed to develop such arrangements, the Commission considered that it was not possible to implement incentive or market based arrangements at the same time as addressing the immediate system security needs identified by AEMO. To reflect the interim nature of the mandatory arrangement on its own, the final rule included provisions for the mandatory PFR requirement to sunset after three years on 4 June 2023.

On 2 July 2020 through the publication of consultation paper relating to seven Systems services rule changes the Commission confirmed that it would use the *Primary frequency response incentive arrangements* rule change to investigate the appropriateness of the existing incentives for PFR during normal operation, including the mandatory PFR arrangements, and amend these arrangements as required to meet the future needs of the power system.

Phase two — Consultation on enduring PFR arrangements

On 17 December 2020, the Commission published a directions paper in relation to two frequency control rule changes: the *PFR incentive arrangements* rule change and another rule change request concerning a proposal to introduce new fast frequency response market ancillary services into the NEM. The directions paper sought stakeholder views on pathways towards enduring PFR arrangements, informed by related proposals submitted by the AEC and CS Energy.[13] At that time, the Commission set out its plan to:

- consider the role of mandatory PFR and confirm whether or not it would endure beyond the sunset date of 4 June 2023.
- Develop arrangements to procure, price and allocate costs for the provision of narrow-band PFR to meet the long-term needs of the power system.
- Consider revisions to the frequency operating standard in relation to how the required frequency performance for the power system during normal operation is specified.

Consideration of whether mandatory PFR should be an enduring arrangement

In recognition of the range of stakeholder views in relation to PFR, the Commission requested advice from AEMO in relation to the power system requirement for PFR and the potential for new incentive arrangements to support the long-term provision of this essential system service. The Commission also engaged GHD to provide independent advice on the feasibility of different policy options to deliver on the long-term requirements for PFR. The related advice from GHD and AEMO was published alongside the Commissions draft

13 AEC, Supplementary submission to the Primary frequency response incentive arrangements rule change, 22 September 2020, p.2. CS Energy/IES, Submission to the Primary frequency response incentive arrangements rule change, 30 June 2020, p.v.

determination on 16 September 2021.[14] Supported by AEMO and GHD advice, the key elements of the draft rule were:

- confirmation of the mandatory PFR arrangements, as enduring beyond the sunset date on 4 June 2023.
- introduction of incentives, through frequency performance payments, for market participants to operate their plant in a way that helps to control power system frequency.
- improvements to the cost recovery for regulation FCAS by making them more transparent and better aligning incentives with the real time need for frequency control.
- additional reporting requirements for AEMO and the AER in relation to frequency performance and the costs of frequency performance payments.

Refinement of the Frequency performance payments arrangements

In response to the draft determination, many stakeholders were concerned by what they considered to be a lack of detail on the proposal for frequency performance payments set out in the draft rule and described in the draft determination.[15] These stakeholders were concerned that arrangements set out in the draft rule were ill-defined and would not adequately value helpful active power response to encourage efficient operational and investment outcomes for PFR over the long-term. Stakeholders requested that the Commission extend the rule change to allow for further development and consultation on the design of the frequency performance payment arrangements. The Commission acknowledged this feedback and extended the time for making a final determination to allow for additional analysis and consultation on the proposed new frequency performance payments process.

In December 2021, the Commission engaged Intelligent Energy Systems (IES) to undertake detailed analysis to inform the refinement of the frequency performance payments process. The IES analysis built on previous work by IES in the area of frequency deviation pricing, including the Australian Energy Council's double sided causer pays study, supported by ARENA which concluded in February 2022.[16]

Supported by a detailed analysis undertaken by IES, the Commission published a second directions paper and revised rule drafting on 19 May 2022. The second directions paper include a revised rule and set out simplified frequency performance payments transactions accompanied by a *Frequency performance payments analysis* report prepared by IES. The IES report provided detailed analysis on a range of issues related to the application of double-sided frequency performance payments in the NEM. This analysis, directions paper, and stakeholder responses have been key inputs to shaping and informing this final rule.

Section 1.1 provides an overview of the elements of the final rule and the changes made between the draft rule and the revised rule and then between the revised rule and the final

14 See project page for more detail: https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

15 For example, Submissions to the draft determination: Clean energy council, p.3; Energy Australia, p.3.; ENGIE, p.2.; Iberdrola, pp.15-16.; Snowy Hydro, pp.4-5.

16 AEC Double sided Causer pays study reports are available at: https://arena.gov.au/projects/australian-energy-council-doublesided-causer-pays-study/

rule. Further detail on each of the elements of the final rule, including discussion of relevant stakeholder views is included in chapter 3.

Future consideration of key settings for mandatory PFR by the Reliability Panel

The Commission notes that stakeholder feedback in relation to the confirmation of mandatory PFR continues to be mixed, with a number of stakeholders advocating for the Mandatory PFR arrangements to be abolished, or for the sunset to be extended and reviewed at a later date following a sufficient period of operation with the new incentive arrangements in place. [17] The Commission understands that a key point of contention with mandatory PFR is the sensitivity of the arrangements as specified by the Primary frequency control band (PFCB). While most generator representatives object to mandatory PFR with a very narrow response setting, many generators support a mandatory PFR arrangement with a wide setting for the PFCB.[18] The final rule confirms the existing arrangements under the NER that allow the Reliability Panel to specify the PFCB through the frequency operating standard.[19] As discussed further in section 1.3.1, the Panel is currently undertaking a Review of the Frequency operating standard (FOS) which includes consideration of the settings in the FOS that apply for normal operation and the PFCB.[20] The Commission has also suggested that the Panel provide a recommendation on when an appropriate time may be to review the FOS in future. The Commission considers that the existing arrangements under the NER, which are confirmed in the final rule, provide sufficient provision for the PFCB to be reviewed by the Reliability Panel following sufficient operational experience with the new incentive arrangements in place.

1.3 Interactions with future reforms

The final rule is part of an ongoing program of reforms to adapt the market and regulatory arrangements to meet the needs of the future power system. There are a number of ongoing and upcoming reform processes that directly relate or overlap to some degree with the changes made by the final rule. These include:

- The Reliability Panel's *Review of the Frequency operating standard*.
- The Commissions' assessment of the *Flexible trading relationships* rule change request-received 6 May 2022.
- The future assessment of a rule change related to the introduction of a new 'Scheduled lite' participant category.

The interactions between the final rule and each of these areas of reform are described below.

17 For example, Submissions to the second directions paper: AEC, p.3.; Alinta Energy, p.2.; Iberdrola, p.2.; Shell Energy, p.2.

18 For example, AEC submission to the second directions paper, pp.2,5.

19 NER cl 4.4.2A and chapter 10 definition for Primary frequency control band.

20 Refer to the project webpage for further information: https://www.aemc.gov.au/market-reviews-advice/review-frequency-operating-standard-2022

1.3.1 The Review of the Frequency operating standard

The Reliability Panel commenced its current *Review of the Frequency operating standard* on 28 April 2022 and this review is scheduled for completion by April 2023 with a draft determination planned for publication in November 2022. [21]

Through the review of the FOS the Panel is considering the appropriateness of settings in the standard in light of the ongoing energy market transformation. The specific issues identified for review include:

- The settings in the FOS for normal operation
- The potential inclusion of standards for the rate of change of frequency (RoCoF) following contingency events
- The settings in the FOS for contingency events, including the contingency containment bands and limits on maximum credible events sizes.
- The limit on accumulated time error.

The main interaction between the final rule and the Review of the FOS relates to the consideration of the settings in the FOS for normal operation. This element of the FOS review is considering how the FOS specification of acceptable frequency performance during normal operation and the setting for the Primary frequency control band (PFCB) that relates to the Mandatory PFR obligation.[22]

The Commission understands that the Reliability Panel intends to investigate the costs and benefits of a range of different settings for the PFCB and the interaction of this setting and the target bands for frequency performance during normal operation. As noted above, the Commission also expects the Panel to recommend the timing for a subsequent future review of the FOS which allows for settings in the FOS for normal operation, including the PFCB, to be further reviewed following a sufficient period of operational experience with the new frequency performance payments in effect.

1.3.2 The Flexible trading relationships for consumer energy resources rule change

On 6 May 2022 the AEMC received a rule change request from AEMO to establish flexible trading arrangements that would enable end users to separate their controllable electrical resources and have them managed independently from their passive load without needing to establish a second connection point to the distribution network. As identified through the Energy Security Board's (ESB) post 2025 reform program, this reform is expected to support the transition towards a two-sided market and more efficient integration of consumer energy resources (CER) into the electricity system.[23]

Through consultation on the PFR incentive arrangements rule change, a number of stakeholders queried how the frequency performance payment could incentive helpful

21 Refer to the project webpage for further information: https://www.aemc.gov.au/market-reviews-advice/review-frequency-operating-standard-2022

22 NER cl. 4.4.2 & cl. 4.4.2A

23 Refer to the project webpage for further information: https://www.aemc.gov.au/rule-changes/flexible-trading-arrangements-consumer-energy-resources

frequency performance from CER such as potentially through aggregated virtual power plant (VPP) arrangements.[24] The consideration of the *Flexible trading arrangements for consumer energy resources* rule change is one of the next steps of regulatory reform towards more active participation of distribution connected equipment in the electricity market and the provision of essential system services.

Future considerations with respect to CER may consider the potential to schedule and dispatch these resources and the degree to which such equipment could be assessed as contributing towards the control of power system frequency.

1.3.3 Proposed Scheduled lite reforms

Another element of the ESB's post 2025 reforms relating to demand-side participation, is the development of new arrangements to encourage the integration of generation and demand into the energy market dispatch process through proposed 'Scheduled Lite' reforms.[25] In June 2022, AEMO published a consultation paper to seek feedback on a draft high-level design for a scheduled lite mechanism to inform a subsequent rule change request.[26]

As a concept, the scheduled lite reforms would be targeted at smaller generators between 5 and 30 MW and demand side resources such as C&I loads and aggregations of DER. Scheduled Lite would use a mix of lower barriers and incentives to encourage these resources to 'opt-in' to either:

- provide greater visibility to the market operator about intentions in the market, or
- to participate in dispatch with lighter telemetry.

There is a close interaction between the new frequency performance payments arrangements and the potential future scheduled lite arrangements. The frequency performance payments will provide an incentive for non-scheduled plant to opt to obtain appropriate metering to allow for the individual contribution to the aggregate deviation in frequency of the power system to be assessed. Market participants who opt to do this would not be part of the residual component of plant that does not have appropriate metering. Instead, they will receive an individual contribution factor that reflects their individual plant behaviour. The frequency performance payments process will also incentivise the provision of self-forecast information from these market participants. Together, these two reforms will support the improvement in the accuracy of the information provided as an input to market dispatch and the integration of CER to encourage active and beneficial participation of these resources in the electricity market.

24 For example, ARENA submission to the second directions paper.

25 Energy Security Board, Post-2025 Market Design - Final advice to Energy Ministers - Part B, 27 July 2021, pp.87 - 89.

26 Refer to AEMO's project page for further information: https://aemo.com.au/initiatives/trials-and-initiatives/scheduled-lite

2 THE FINAL RULE WILL CONTRIBUTE TO THE NATIONAL ELECTRICITY OBJECTIVE

This chapter explains why the Commission has made its final determination and the accompanying more preferable final rule. It outlines:

- the problem identified in the rule change request and how the final rule will address it to promote the long-term interests of consumers. This includes an overview of the costs and benefits and how these will be managed.
- how the final rule meets the assessment criteria set out in the consultation paper.

Under the National Electricity Law (NEL), the Commission can only make a rule if it is satisfied it will or is likely to contribute to the achievement of the relevant energy objective, which in this case is the National Electricity Objective (NEO).[27] The NEO is set out in the NEL as being:[28]

> 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.

See appendix D for more detail on the legal requirements that relate to the Commission's decision.

The question to be answered in assessing any rule change proposal is, therefore, would the proposed change promote more efficient decisions relating to investment, operation and use of electricity services in a way that would ultimately promote the long-term interests of consumers?

The Commission is satisfied that the confirmation of the mandatory PFR obligation for scheduled and semi-scheduled generators, combined with double-sided incentive arrangements to value helpful active power deviations and new reporting obligations will, or is likely to, contribute to the achievement of the NEO. This will support system security and deliver reduced costs for frequency control over the long term by encouraging innovation and investment in new capability to provide primary frequency response. The Commission has made a final rule to achieve this. This final rule is published alongside this final rule determination.

Under s.91A of the NEL, the Commission may make a rule that is different (including materially different) to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issues raised in the rule change request, the more preferable rule will, or is likely to, better contribute to the achievement of the NEO. In this instance, the Commission has made a more preferable rule as it will better meet the NEO by establishing an incentive

27 Section 88 of the NEL.

28 Section 7 of the NEL.

framework to encourage the efficient provision of PFR and investment in frequency responsive plant, compared to the solution proposed in the rule change request. The reasons are set outlined below.

2.1 The final rule provides an enduring framework to support the provision of PFR and effective control of power system frequency

The Commission's determination is to make a more preferable final rule. This final rule continues the mandatory PFR arrangements, develops incentives to encourage provision of PFR, and improves transparency through increased publication of data, reporting obligations, and related requirements for AEMO's frequency contribution factors procedure.

AEMO's rule change request identified that a degradation of frequency performance in the NEM was undermining power system security and resilience.[29] AEMO identified a deficiency of primary frequency response from scheduled and semi-scheduled generators as the primary cause of this degradation and proposed a number of minor changes to the NER to remove disincentives to the provision of PFR by scheduled and semi-scheduled generators. The rule change request is further described in appendix A.1.

The final rule is consistent with AEMO's proposed solution to change the NER to remove disincentives to the voluntary provision of PFR. The final rule is more preferable as it also confirms the mandatory PFR arrangements as enduring and introduces frequency performance payments to reward the provision of PFR and other behaviour to support power system frequency, weighting these payments by the need for this support. Additionally, the final rule introduces reporting obligations on AEMO and the AER to improve transparency around the objectives and efficacy of the enduring PFR arrangements, both for individual market participant behaviour and power system frequency performance. The inclusion of these additional components in the final rule more holistically addresses the problem identified in the rule change request — the deficiency of PFR — than the solution identified in the rule change request and does so in a way that is likely to be more effective and efficient over the long-term. Therefore, the final rule better meets the NEO, when compared to the solution proposed in the rule change request.

The final rule recognises, based on advice from AEMO and GHD, that widespread narrow-band PFR is required to effectively control power system frequency. Therefore, the final rule revokes the schedule in the *National Electricity Amendment (Mandatory primary frequency response)* rule that would have ended the existing Mandatory PFR arrangements on 4 June 2023. Those arrangements are therefore enduring.

At the same time, the Commission recognises that the mandatory PFR arrangements are not a complete solution on their own and that there is an opportunity to improve the incentive arrangements for plant behaviour that impacts on the control of power system frequency. Incentive arrangements in relation to provision of frequency control services are likely to be efficient and effective where:

29 AEMO, *Primary frequency response incentive arrangements - Electricity rule change proposal*, 3 July 2019, p.14.

- helpful contributions are valued and rewarded with costs allocated to those who contribute to the deviation in system frequency
- there is an alignment in relation to the timing for the measurement of participants' impacts on system frequency and the financial implications they incur
- the incentive process is transparent and allows participants to understand the financial implications associated with the operational performance of their plant.

In making its determination, the Commission has taken into account the proponent's views, stakeholder views, engagement with the technical working group, and expert technical advice provided by AEMO, Greenview Strategic Consulting (Greenview), GHD and IES. To support the rule change process, AEMO prepared formal advice on the technical requirements for PFR as well as a discussion paper on the feasibility of market and incentive arrangements for frequency control services during normal operation, including potential reforms to causer pays. The Commission also commissioned analysis from Greenview on the impacts of mandatory PFR on the power system and affected plant, and independent advice from GHD on the relative benefits, risks and costs of each of the pathways for enduring PFR arrangements. Finally, in response to stakeholder feedback on the frequency performance payments process set out in the draft rule, the Commission engaged IES to investigate and report on the frequency performance payments process.[30]

Advice received from AEMO, Greenview and GHD, and our analysis outlined in chapter 3, have informed the Commission's decision to make the more preferable final rule. The key elements of advice include that:

- widespread PFR is required within a tight frequency control band to support power system security and resilience, and to give AEMO greater confidence that it is maintaining the power system in a secure operating state. The current mandatory requirements for scheduled and semi-scheduled generators to automatically respond to changes in system frequency has improved frequency performance in the power system. Greenview's survey of a range of generators in the NEM noted that some early adopters of the mandatory arrangements initially noticed some more significant plant movements but that, once reasonable aggregate frequency responsiveness was achieved with more plant providing PFR, the implementation of the mandatory PFR arrangements has not had a significant adverse impact on affected generation plant.[31] AEMO's advice also highlights the costs and risks that arise without these arrangements.[32]
- the continuation of the current mandatory arrangements is not a complete solution and, on its own, will not incentivise the provision of sufficient or efficient levels of primary frequency response, nor will the existing arrangements support investment in additional capability to efficiently meet future requirements. While mandatory PFR has been delivering improved frequency performance, affected participants are concerned with the potential for losses due to foregone energy market revenue and increased wear and tear

30 These reports are available on the PFR incentive arrangements rule change page: https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

31 Greenview Strategic Consulting presentation to the Frequency Control Technical Working Group, Understanding the impacts of mandatory PFR on generation plant, 23 July 2021.

32 AEMO, Enduring primary frequency response requirements for the NEM, 31 August 2021

on plant.[33] In the future, as the generation technology mix continues to evolve, further measures may be required to ensure sufficient aggregate frequency responsiveness (MW/Hz) in the power system to deliver effective frequency control.[34]

- there are improvements that can be made to the current causer pays arrangements to better allocate costs to those causing the need for the management of system frequency, as well as to incentivise and reward better performance.[35] Improved transparency in relation to the causer pays process will help generators better understand and respond to the economic signals through the causer pays arrangements promoting system security in the most efficient manner.

The Commission considers that the benefits of addressing these issues through the final rule outweighs the expected costs. These benefits include optimised frequency control, more efficient use of regulation FCAS, and efficient investment, operation and use of PFR from a diverse set of technologies.

2.2 Considering the more preferable final rule against the assessment criteria

In assessing AEMO's rule change request, and potential alternative solutions, the Commission must consider how changes to the NER to support the provision of PFR are likely to promote the NEO. The Commission identified the following assessment criteria to support that objective:

- **Promoting power system security —** The operational security of the power system relates to the maintenance of the system within predefined limits for technical parameters such as voltage and frequency. System security, including frequency, underpins the operation of the energy market and the supply of electricity to consumers.
- **Appropriate risk allocation —** The allocation of risks and the accountability for investment and operational decisions should rest with those parties best placed to manage them. The arrangements that relate to frequency control should recognise the technical and economic characteristics and capabilities of different types of market participants to engage with the system services planning, procurement, pricing and payment. Where practical, operational and investment risks should be borne by market participants, such as businesses, who are better able to manage them.
- **Technology neutral —** Regulatory arrangements should be designed to take into account the full range of potential market and network solutions. They should not be targeted at a particular technology, or be designed with a particular set of technologies in mind. Technologies are changing rapidly, and, to the extent possible, a change in technology should not require a change in regulatory arrangements.

33 GHD, *Enduring Primary Frequency Response - CT2 - power system operation and strategic regulatory advice*, 16 September 2021, p.31

34 GHD, *Enduring Primary Frequency Response - CT2 - power system operation and strategic regulatory advice*, 16 September 2021, p.ii.

35 AEMO, *Primary Frequency Response incentive arrangements- Discussion paper*, August 2021

- **Flexibility —** Regulatory arrangements must be flexible to changing market and external conditions. They must be able to remain effective in achieving security outcomes over the long-term in a changing market environment. Where practical, regulatory or policy changes should not be implemented to address issues that arise at a specific point in time.
- **Transparent, predictability and simplicity —** The market and regulatory arrangements for frequency control should promote transparency and be predictable, so that market participants can make informed and efficient investment and operational decisions. Simple frameworks tend to result in more predictable outcomes and are lower cost to administer and participate in.
- **Implementation costs —** Regulatory change typically comes with some implementation costs for regulators, the market operator and/or market participants. These costs are ultimately borne by consumers. The cost of implementation should be factored into the overall assessment of any change.

These criteria are set out in further detail in section 3.3 of the draft determination.[36]

The rest of this section explains why the final rule better promotes the long-term interests of consumers than the solution proposed in the rule change request, when assessed against the above criteria.

2.2.1 The final rule promotes power system security

The final rule promotes power system security through the combined action of the enduring mandatory PFR requirement supported by new frequency performance payments arrangements to reward active power deviations that help to control power system frequency. The mandatory PFR obligation has been shown to deliver much improved control of power system frequency, which provides a solid operational foundation in the midst of increasing operational variability and uncertainty associated with the technological transition underway in the power system. The benefits of mandatory PFR are described further in section 3.1.

The new frequency performance payments arrangements are expected to reinforce the impact of the mandatory PFR requirement, by not only valuing PFR provided in accordance with the mandatory obligation but also encouraging frequency response over and above the mandatory requirement. This additional response could be delivered as a consequence of scheduled and semi-scheduled generators maintaining additional stored energy to provide PFR (which is not required under clause 4.4.2(c1) of the NER), or through PFR being provided by other market participants, such as non-scheduled generators and loads.

In its technical advice to the AEMC, AEMO advised there is a need for narrow band PFR to be widespread and tightly controlled around 50 Hz. AEMO considers that this can be best achieved through a continuation of the mandatory narrow-band obligation.[37] This view is supported by independent advice provided by GHD, summarised in section 2.5.2 of the draft

36 Available on the project web page: https://www.aemc.gov.au/rule-changes/fast-frequency-responsemarketancillary-service

37 AEMO, *Enduring Primary frequency response requirements for the NEM*, August 2021, p.16.

determination, which also concludes that mandatory, narrow-band PFR should be continued for promoting power system security.[38] AEMO identified that near universal narrow band frequency response improves the effectiveness of other elements of the broader frequency control framework and increases the predictability of generating system response to disturbances. This provides a sound control base for system operation and supports AEMO's analysis and modelling of power system performance which feeds the design of system, control, and protection arrangements. [39]

Effective, tight control of frequency is a necessity today and will be more so in the transition towards a power system that is increasingly dependent on variable and inverter-based generation. AEMO acknowledges that there are expected to be future operating conditions where large scale centralised generation is increasingly displaced by variable renewable generation and distributed roof top solar power, which provide limited or no PFR. During these future operating conditions, the level of PFR provided by generating resources under the mandatory arrangements may reduce. Additional arrangements may be required to deliver sufficient levels of aggregate frequency responsiveness.[40] Such additional arrangements could include:

- changes to the mandatory PFR arrangement and the related settings, including the PFCB
- changes to the frequency performance payments arrangements
- additional measures to procure frequency responsive plant to provide continuous narrow band PFR.

The requirement for AEMO to report on the level of aggregate frequency responsiveness in the power system will help to identify the role it plays in delivering effective frequency control and whether any further remedial actions are required at a future date.

Potential future procurement arrangements

The Commission recognises that an alternative to introducing incentive arrangements would be to have a specific procurement arrangement to deliver the required levels of frequency responsiveness to control power system frequency. However, the Commission does not consider that this is preferred at the current time. Not only would this have higher implementation costs than the arrangements set out under the final rule, but it also has significant risks and competition concerns that would need to be worked through.

However, the Commission recognises that the effectiveness of the combination of the mandatory arrangements and incentives will need to be monitored on an ongoing basis through the additional reporting arrangements. The Commission considers that the arrangements in the final rule can be enduring and provide what the market needs to maintain effective primary control of power system frequency. Nevertheless, the Commission notes GHD's advice that additional procurement arrangements may be required to deliver sufficient levels of frequency responsiveness to control power system frequency in the future.

38 GHD, *Enduring Primary Frequency Response - CT2 – Power system operation and strategic regulatory advice*, 16 September 2021, p.18.

39 AEMO, *Enduring Primary frequency response requirements for the NEM*, August 2021, p.18.

40 Ibid., pp.32-34.

Further discussion of potential future procurement arrangements is set out in section 5.2 of the draft determination.

2.2.2 Risk and cost allocation under the final rule

The final rule clarifies, through a continuation of the mandatory arrangements, that all scheduled and semi-scheduled generators have a responsibility to help control power system frequency. It also includes a double-sided frequency performance payments process that values the provision of PFR and allocates the costs for this service to market participants that have caused the need for corrective response. The new frequency performance payments process builds on the existing 'causer pays' process for the allocation of costs associated with the enablement of regulation services.[41]

The double-side frequency performance payments process creates a broad-based incentive framework that encourages any market participant to help to control power system frequency, where it is in their interests to do so, taking into account the expected economic costs and benefits. For example, a market participant that is not subject to the mandatory PFR provision, such as a non-scheduled generator may opt to be unresponsive to system frequency if it considers that the potential frequency performance payments do not outweigh the costs of being responsive to system frequency. In this case, the participant is choosing to be a consumer of frequency response services. Alternatively, market participants that are not subject to the mandatory PFR provision, may opt to be responsive to system frequency and obtain an individual contribution factor through installation of appropriate metering to measure their unit's active power response to system frequency. In this case, the participant is choosing to be a provider of frequency response services and the frequency performance payments process is designed to value and reward such contributions.

In this way, the final rule clarifies that scheduled and semi-scheduled generators have the primary responsibility for control of power system frequency, as these generators are well-placed to manage this responsibility through the active power control capability in their plant. At the same time, the incentive arrangements spread the financial burden of frequency response amongst all market participants that cause the need for corrective response, in a way that incentivises operation that reduces the need for this service.

2.2.3 The final rule is technology neutral

The final rule applies equally to all technologies both through the mandatory PFR provision and through the frequency performance payments arrangements. More specifically, the broad-based and open nature of the incentive arrangements is designed to encourage provision of PFR by whichever technology can most cost effectively provide the service. This approach encourages open competition for the provision of PFR that is expected to lead to lower costs for frequency control than would be the case through alternative approaches.

41 The existing causer pays process is described in appendix B.2.

2.2.4 Provisions in the final rule to support flexibility

The final rule is intended to be adaptive as power system needs change over time. This is achieved through specific elements of the frequency performance payments arrangements, including the financial weighting of payments by the price for regulation services and the scaling of payments by the aggregate requirement for corrective response (RCR) in each trading interval. Each of these values is expected to dynamically represent the need for frequency response and the associated value over time. The final rule sets out that AEMO may include parameters in relation to RCR that enable this element of the frequency performance payments transaction to be tuned based on the operational needs of the power system and AEMO's responsibility to manage power system frequency in accordance with the frequency operating standard.

Further flexibility is embedded in the final rule through the requirement that AEMO consult on and develop the relevant procedures, both the *Primary frequency response requirements* for PFR and the *Frequency contribution factors procedure* for the incentive arrangements. The principles and requirements in relation to the *Frequency contribution factors procedure* establish a framework to support AEMO in developing a process that meets the present power system needs and can be adapted as required in the future. These requirements are described further in section 3.2.3.

2.2.5 Provisions in the final rule to deliver transparency, predictability and simplicity

The final rule is intended to deliver improved transparency and therefore better meets the NEO, as compared to the current causer pays arrangements and the proposed rule included in AEMO's rule change request. The lack of transparency with the current causer pays process was a key criticism identified by the Commission both through the consultation on this rule change and through the previous frequency control frameworks review.[42]

There are a number of aspects of the current causer pays process that undermine transparency and lead to confusion amongst market participants. The final rule makes a number of changes to improve on the current process including in relation to the definition of the system frequency metric, the approach to defining a reference trajectory, and the publication of data and other information related to the frequency contribution factors procedure. The final rule also includes additional reporting obligations for AEMO in relation to aggregate frequency responsiveness and the AER in relation to the costs of frequency performance payments. The elements of the contribution factors procedure are described in section 3.2.3. The new reporting requirements are set out in section 3.3.

2.2.6 Consideration of implementation process and costs

The Commission considers that the implementation costs associated with the final rule primarily relate to AEMO's development and implementation of the revised Frequency contribution factors procedure.

42 AEMC , Frequency control frameworks review - Final report, 26 July 2018, p.76.

The development and implementation of the PFR incentive arrangements will be a regulatory obligation imposed on AEMO which will result in expenditure to undertake technical studies, consultation on the *Frequency contribution factor procedure*, and changes to AEMO systems. AEMO has advised that the cost of implementing new causer pays arrangements is likely to be in the order of $9.6 million.[43] However, prior to this rule change, AEMO had already identified potential changes to the rules and improvements to its procedures. For example, addressing calculations when regulation FCAS requirements apply, differing treatment of contingency events, and reviewing the reference trajectory.[44] This means some of these costs would likely be incurred irrespective of the implementation of the final rule, albeit with potentially less impetus. These additional costs will be recovered from market participants through AEMO's market fees.[45]

The Commission has also considered the potential for further implementation costs that would be borne directly by market participants or consumers. The nature of any such costs is expected to be minor, as the new frequency performance payments process builds on the existing 'causer pays' process for the allocation of regulation costs. Most eligible units, for example scheduled and semi-scheduled generators, that require metering to measure their impact on system frequency will already have this metering in place. Other market participants, such as non-scheduled generators and loads, may opt to install additional metering to obtain individual contribution factors, however this would be on a voluntary basis in response to their individual assessment of the costs and benefits of doing so. Direct implementation costs for market participants are therefore expected to be confined to costs associated with engaging with AEMO's consultation on the new *Frequency contribution factors procedure* and so are considered to be relatively modest.

43 Further information on the timing for the implementation of changes related to the Primary frequency response incentive arrangements is available via AEMO's Regulatory Implementation roadmap. Refer to https://aemo.com.au/en/initiatives/major-programs/regulatory-implementation-roadmap

44 See section 5.2 Subsequent work program in AEMO's consultation document available at: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2018/causer-pays/final-determination—-causer-pays-consultation.pdf?

45 AEMO's recovery of its budgeted revenue requirements through participant fees (including its expenditure requirements relating to power system operation activities and expenditure relating to the electricity industry generally) is addressed in rule 2.11 of the NER, and which sets out that AEMO can recover development and implementation costs through electricity participant fees.

3 ELEMENTS OF THE FINAL RULE

This chapter describes the final rule. It includes the following key elements:

- **Confirmation that the mandatory PFR arrangements that require scheduled and semi-scheduled plant to provide PFR will endure beyond 4 June 2023.**

  This is achieved by the final rule revoking Schedule 2 of the National Electricity Amendment (Mandatory primary frequency response) rule which would have ended the existing mandatory PFR arrangement on 4 June 2023. This means that all scheduled and semi-scheduled generators will continue to be required to support the secure operation of the power system by responding automatically to changes in power system frequency. Further detail on this element of the final rule is included in section 3.1.
- **Reforms to the existing 'causer pays' process for the allocation of regulation FCAS costs to deliver improved valuation and pricing of plant behaviour that impacts on power system frequency, in other words, rewarding plant for providing primary frequency response in such a way that adds value to the system.** These changes include the introduction of frequency performance payments to value positive contributions, the shortening and alignment of the sample and application periods for the determination of participant contribution factors, and further changes to improve the transparency of the causer pays process. These changes are expected to better align the economic incentives for plant active power performance, with the impact of that behaviour on the need for corrective action through the deployment of regulation services to rebalance supply and demand and restore power system frequency to 50Hz. By incentivising the provision of PFR this is expected to lead to more efficient outcomes in relation to the operation of the power system by encouraging all market participants to operate their plant in a way that reduces the need for regulation services and helps to control power system frequency. Further detail on this element of the final rule is included in section 3.2.
- **New reporting obligations for AEMO and the AER in relation to the levels of aggregate frequency responsiveness in the power system and the costs of frequency performance payments to promote transparency and improve information flows to result in more efficient operational and investment decisions**. This change supports the principle of transparency and will provide relevant information to market participants and stakeholders to assess the effectiveness and efficiency of the frequency control frameworks over time. Further detail on this element of the final rule is included in section 3.3.

A summary table describing each of the elements of the final rule and the changes from the draft rule is included for reference in appendix F.

3.1 Confirmation of mandatory PFR as enduring

The final rule confirms that the mandatory PFR arrangements which took effect from 4 June 2020 will be enduring beyond 4 June 2023. This determination is supported by expert advice that a near-universal requirement for scheduled and semi-scheduled generators is necessary to support the secure and resilient operation of the power system now and into the future. An overview of the benefits of mandatory PFR is provided in section 3.1.1.

In response to stakeholder feedback, the final rule includes a minor amendment to clarify the application of the mandatory PFR obligation, in line with the final determination for the Mandatory PFR rule. These amendments and the related reasoning, are described further in section 3.1.2.

The Commission recognises that some stakeholders continue to hold concerns in relation to the appropriateness of the mandatory PFR arrangements as enduring and the potential for the sensitivity of the mandatory PFR arrangements to be reviewed and relaxed at a future date, following a suitable period of operational experience with the new frequency performance payments arrangements in place. This potential future will be further considered by the Reliability Panel which is currently reviewing the FOS, including the PFCB that sets the sensitivity for mandatory PFR.[46] The Commission expects that the Reliability Panel will also recommend the timing for a subsequent future review of the FOS to allow the settings in the FOS for normal operation, including the PFCB, to be further reviewed at a later date. A summary of the Reliability Panel Review of the FOS is provided in section 1.2.

3.1.1 Mandatory PFR supports power system security and resilience

As set out in section 4.1 of the draft determination, the confirmation of mandatory PFR is based on expert technical advice received from AEMO and the independent advice provided by GHD that widespread (mandatory) PFR within a tight (narrow) band around 50Hz is required to provide a secure and resilient power system. This advice is consistent with international power system operating practice where almost all generation plant are required to provide narrow-band PFR.[47] AEMO has consistently advised this level of PFR is a priority for secure and stable power system operation.[48]

Independent advice from GHD also supports the continuation of mandatory narrow-band PFR arrangements as the preferred method of delivering effective frequency control in the NEM over the short to medium term.[49] The Commission considers that the risks of a substantial impact to the system from removing the requirement for generators to provide PFR would be significant given the importance of effective frequency control in maintaining power system security.[50]

AEMO's expert advice is that PFR is an important part of an integrated chain of control actions that also includes secondary (regulation) control, contingency reserves and emergency frequency control schemes. Tight control of system frequency complements and improves the effectiveness of each of the other elements of this integrated frequency control

46 Refer to the project webpage for further information: https://www.aemc.gov.au/market-reviews-advice/review-frequency-operating-standard-2022

47 AEMO, Enduring PFR requirements for the NEM, August 2021, pp.3-4, 58.

48 AEMO, Mandatory Primary Frequency Response - Electricity rule change proposal, 16 August 2019, pp.55-56

49 GHD, Enduring Primary Frequency Response - CT2 - power system operation and strategic regulatory advice, 16 September 2021, p. i-iii.

50 The Commission understands that PFR will play a particularly important role in the future with higher variability of generation and demand and lower levels of synchronous inertia.

framework. Near universal narrow band frequency response also increases the predictability of generating system response to disturbances which supports AEMO's analysis and modelling of power system performance which feeds into the design of system control and protection arrangements.[51]

Stakeholder views

The Commission is aware of a wide range of stakeholder views in relation to the arrangements for PFR in the NEM. Representatives from transmission networks along with power system engineers and AEMO have advocated for mandatory PFR and the associated benefits from broad based active power control.[52] At the same time, generator representatives have expressed concern that the mandatory PFR requirement is unlikely to be the most efficient option for valuing primary frequency response in the long-term. These stakeholders reasoned that incentive or market-based arrangements to provide PFR would likely be more efficient and effective over the longer term. [53]

While there are a wide range of views in relation to the general concept of mandatory PFR, the Commission notes that there is a degree of consensus in relation to a mandatory requirement for generators to provide active power response following significant contingency events that cause large changes in power system frequency. For example, the AEC proposes a pathway that would transition the current narrow band PFR requirement to a wide-band requirement. [54]

> After an initial period of operation [of the new frequency performance payments arrangements], the market will be confident to move the Primary Frequency Control Band (PFCB) out to wide control, e.g. ±0.5Hz where it would act as a last-resort protection to extreme events but not greatly interfere with voluntary provision for normal operation nor the FCAS contingency markets.

A number of stakeholders, including the AEC, propose that the Commission should not remove the sunset for mandatory PFR, but rather should extend it and confirm a future process to review this requirement in the NER at a future date.[55]

The Commission acknowledges this view and note that the governance arrangements in the NER, and final rule, allow for the sensitivity of the PFR requirement to be adjusted through the review of the Primary frequency control band (PFCB) by the Reliability Panel.[56] As discussed in section 1.3.1, the Reliability Panel is in the process of reviewing the Frequency

51 AEMO, Enduring primary frequency response requirements for the NEM, August 2021, p.4-5.

52 Submissions on the draft determination: AEMO, p.1.; Hydro Tasmania, p.1-2.; SA Dept. of Energy and mining, pp.1-2 .; Tesla, p.1.; Submissions on the directions paper - Frequency control rule changes, 17 December 2020: AEMO, p.2.; UNSW, p.19.; Hydro Tasmania, p.5. Submissions on the Consultation paper - PFR rule changes, 19 September 2019: AEMO, p.1.; Ergon Energy and Energex, p1; Kate Summers, p.2; TasNetworks, p.3.

53 Submissions to the draft determination: AEC, p.1.; AGL, pp.1-2.; Alinta Energy, p.2.; Delta Electricity, p.1.; Fluence,p.2.; Iberdrola,pp.1-2; Shell Energy, p.3.; Snowy Hydro, p.1.; Stanwell Corporation, pp.2-3; Submissions on the directions paper - Frequency control rule changes, 17 December 2020: Alinta Energy, p.5.; AGL, p.8.; CEC, p.2.; Delta Electricity, p.13.; Infigen, p.7.; Neon, p.1.; Origin, p.5.; Snowy Hydro, p.8. Submissions to the consultation paper – PFR rule changes, 19 September 2019: CS Energy, p. 2, Delta Electricity, p. 6, Neoen p.1, Enel X, p. 8, IES, p.2, Enel Green Power, p. 2, ARENA, p.3.

54 AEC, Submission to the second directions paper, p.2.

55 For example, submissions to the second directions paper: AEC, p.2.; Alinta Energy, p.2.; Iberdrola, p.2.

56 Chapter 10 of the NER - Definition of *Primary frequency control band*.

operating standard, including the PFCB. The Commission expects that the Panel will also consider the timing for a subsequent future review of the FOS which would allow for the PFCB to be further reviewed following a sufficient period of operational experience with the new frequency performance payments in effect.

Commissions commentary and analysis

As described in section 4.1 of the draft determination, the Commission considers that there is sufficient justification for the continuation of the mandatory requirement for narrow-band frequency response from scheduled and semi-scheduled generation plant.

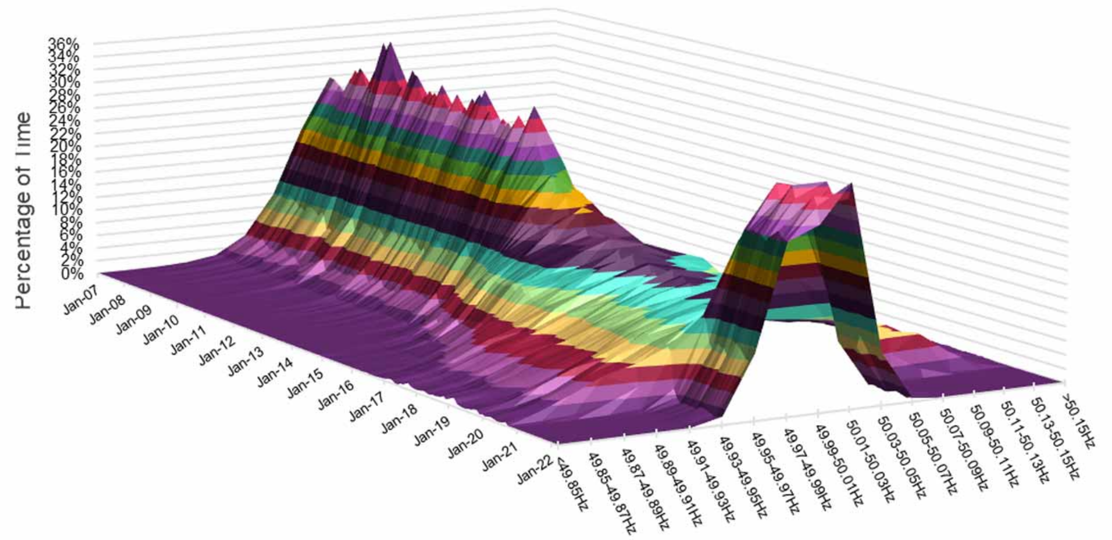
The key basis for this position is that effective control of power system frequency requires a high ratio of proportional active power response to changes in power system frequency. High aggregate system levels of frequency responsiveness lead to frequency being well controlled close to 50Hz.[57] The aggregate level of frequency responsiveness is directly related to the distribution and variation of power system frequency during normal operation and, as such, this active power response is best delivered by a large proportion of generation plant.

The Commission recognises that a numerous subset of generator stakeholders do not support the mandatory arrangements; however, the analysis and expert advice throughout this rule change process has shown that the mandatory narrow-band PFR arrangements are a particularly effective mechanism given the current generation mix at delivering high levels of aggregate active power response. This has been evidenced through frequency data and reporting showing improvements in frequency performance as a result of the implementation of changes to generator control settings from June 2020 onwards.[58] The improved frequency performance in the NEM from January 2021 is shown in Figure 3.1 as compared to the degraded frequency distribution during the period January 2015 through to January 2020. A simplified comparison of the frequency distribution for two days in September 2020 versus two days in June 2022 is shown in Figure 3.2 which clearly demonstrates the improvement in frequency control.

57 This concept of frequency responsiveness is also referred to as "droop control" for individual generators and "frequency bias" for power system operation. The concept and its implications are described further in the Appendix F of the draft determination.

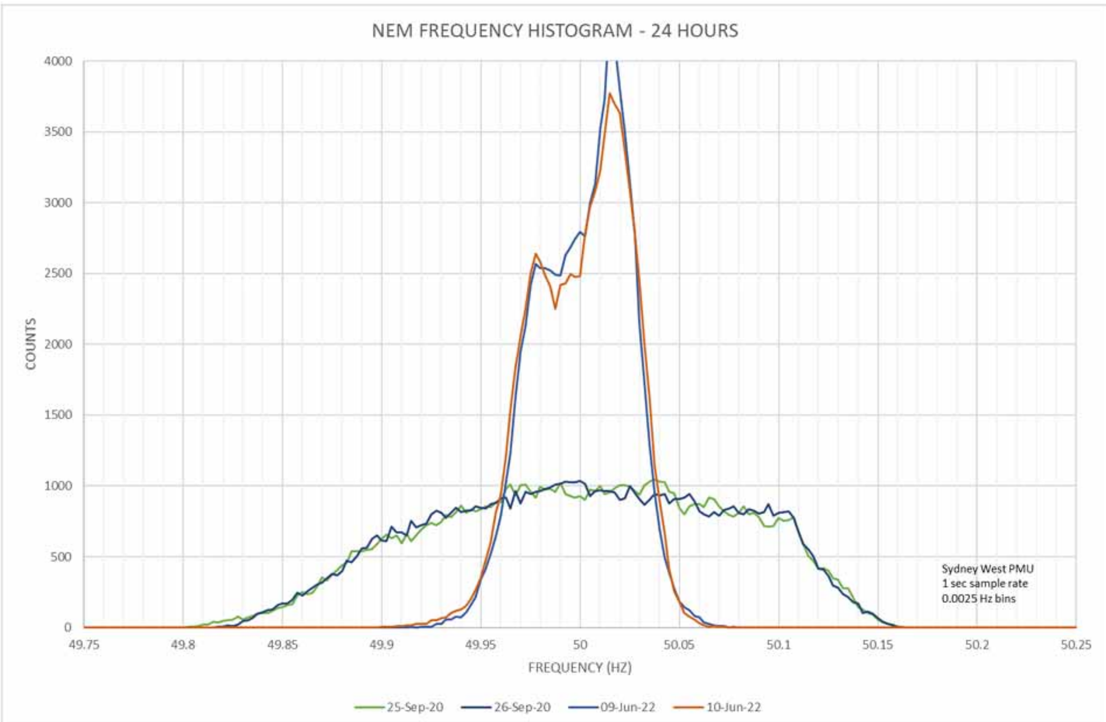
58 As at 10 June 2022, AEMO reported Mandatory PFR settings had been implemented for approximately 40GW or 70% of the 58GW of eligible generation plant in the NEM. AEMO, Implementation of the National Electricity Amendment (Mandatory Primary Frequency Response) Rule 2020, 14 June 2022.

Figure 3.1: Monthly frequency distribution - January 2007 to January 2022



Source: AEMO, Frequency and Time Error Monitoring – Quarter 1 2022, 17 May 2022, Figure 2, p.8.

Figure 3.2: Comparison of 24hr NEM frequency distributions - September 2020 vs June 2022



Source: AEMO, Implementation of the National Electricity Amendment (Mandatory Primary Frequency Response) Rule 2020, 14 June 2022, Figure 3, p.23.

The mandatory PFR arrangements provide a clear signal to those parties who are entering the market that they are expected and required to provide primary frequency response. This effectively sets an operational standard for the provision of PFR by registered generators in the NEM.

While the Commission considers that continuing the mandatory arrangements is important for the effective operation of the power system, the Commission does not consider that the mandatory arrangements, on their own, provide a complete and enduring solution. This is because the changing nature of technologies on the power system are likely to present challenges to the effectiveness of the mandatory arrangements on their own. As the generation mix changes from large, centralised units to inverter-based generation such as wind, solar & batteries, the prevailing operational conditions of the new resources (despite having a requirement) may impact on their ability to provide PFR, which may reduce the effectiveness of the arrangements over time.

The Commission considers that there needs to be accompanying arrangements to incentivise provision of PFR going forward. These are important in order to provide participants with effective information and signals to make efficient investment and operational decisions. The final rule therefore includes a new frequency performance payments process to incentivise plant behaviour that helps to control power system frequency. The improved incentive arrangements are expected to deliver more efficient operation of power system plant along with investment in new capability to help control power system frequency. Over time, the importance of arrangements to value plant behaviour that helps to control power system frequency is expected to increase.

The combination of mandatory primary frequency response and the new frequency performance payments arrangements will together provide the outcomes of a secure system, while minimising costs to consumers. The two elements will work together to promote efficient outcomes and make sure that primary frequency response arrangements can be enduring, effective and adaptive to both changes in the power sector and related technology.

The Commission recognises that an alternative to introducing incentive arrangements would be to have a specific procurement arrangement to deliver the required levels of frequency responsiveness to control power system frequency. However, as discussed in section 5.2 of the draft determination, the Commission does not consider that this is preferred at the current time. Not only would this have higher implementation costs than the option set out under the final rule, but it also has significant risks and competition concerns that would need to be worked through. For these reasons, the Commission's final rule for enduring PFR arrangements comprises the two elements discussed above.

However, the Commission recognises that the effectiveness of the combination of the mandatory arrangements and incentives will need to be monitored on an ongoing basis. The Commission considers that the arrangements in the final rule can be enduring and provide what the market needs to maintain effective primary control of power system frequency. Nevertheless, the Commission notes GHD's advice that additional procurement arrangements may be required to deliver sufficient levels of frequency responsiveness to control power system frequency in the future.[59] To support this task, the final rule includes additional requirements for AEMO to report on aggregate frequency responsiveness in the power system. This reporting, described in section 3.3.1, will inform further consideration by the market bodies of any future need for changes to the PFR arrangements.

3.1.2 The final rule includes a minor amendment in response to stakeholder feedback

The final rule includes a minor amendment to NER clause 4.4.2(c1) to clarify that the mandatory PFR requirement applies to "each *Scheduled Generator* and *Semi-Scheduled Generator* that has received a *dispatch instruction* in accordance with clause 4.9.2 to generate a volume greater than zero MW". The reference to a dispatch instruction in accordance with clause 4.9.2 has been included in the final rule in response to stakeholder feedback that there was some ambiguity as to the application of the mandatory PFR obligation to battery energy storage systems that have a zero dispatch target in the energy market but are dispatched to provide contingency (or regulation) FCAS.[60]

The amendment to clause 4.4.2(c1) is consistent with the Commission's final determination for the Mandatory primary frequency response rule. It clarifies that generators which are not dispatched in the energy market to generate electricity are not required to operate in a frequency response mode in accordance with the *Primary frequency response requirements (PFRR)*, determined by AEMO. As noted in the final determination for the *Mandatory Primary frequency response rule*:[61]

> unlike other generation technologies, battery energy storage systems are capable of providing a frequency response when they are neither charging nor discharging, ie neither supplying nor consuming energy from the grid. Under the final rule, generators that are not dispatched in the energy market to generate electricity are not required to operate in a frequency response mode in accordance with the PFRR. As such, the final rule includes a provision that generators are only required to provide PFR when they have received a dispatch instruction to generate at a volume greater than 0 MW. The Commission considers that the application of the mandatory PFR requirement to battery energy storage systems that are not dispatched to generate electricity would be discriminatory, as other generation technologies cannot provide PFR unless they are online and generating.

The Commission notes that a generator that receives a zero generation target in the energy market may be dispatched to provide a market ancillary service such as contingency or regulation FCAS. In such cases the generator must comply with the requirements for the relevant ancillary service set out by AEMO in the *Market ancillary service specification* (MASS).[62]

59 GHD, Enduring Primary Frequency Response - CT2 - power system operation and strategic regulatory advice, 16 September 2021, p.ii-iii.

60 For example, Submissions to the second directions paper: Iberdrola, p.6.; Shell Energy, pp.2-3.

61 AEMC, Mandatory Primary frequency response - Final determination, 26 March 2020, p.46.

62 NER cl. 3.8.7A(k)

3.2 New Frequency performance payments arrangements

The final rule introduces new frequency performance payments arrangements that incentivise market participants to operate their plant in a way that helps to control power system frequency. The key elements of the final rule are consistent with those set out in the draft rule. Some changes and refinements have been made that were set out in the second directions paper and revised rule and in response to stakeholder feedback on the revised rule.

The key elements of the new frequency performance payments arrangement are:

- Transactions to provide for **frequency performance payments** to be made to market participants who obtain positive contribution factors in a trading interval. The costs of frequency performance payments will be allocated to market participants who obtain negative contribution factors for that trading interval. This element of the final rule is described further in section 3.2.1.
- Modified arrangements for the allocation of **costs for regulation services** including that:
  - the costs for regulation services <u>used</u> within a trading interval would be allocated based on negative contribution factors determined for the trading interval (as per the draft rule)
  - the costs of regulation services <u>not used within a trading interval</u> would be allocated based on negative default contribution factors. These default contribution factors would be determined by AEMO based on historical plant performance.

  This element of the final rule is described further in section 3.2.2.
- AEMO will prepare a **frequency contribution factors procedure** that describes the process for determining contribution factors. The contribution factors reflect the impact of power system equipment (generation and load) on system frequency. This element of the final rule is described further in section 3.2.3.

3.2.1 Transactions for frequency performance payments

A core element of the final rule is new transactions for frequency performance payments.[63] These transactions establish double-sided incentive arrangements for eligible units of generation or load to provide active power response that helps control power system frequency. Under the final rule, all generation and load are exposed to new incentive arrangements in some way, with the specific application of this depending on whether a unit has "appropriate metering", which allows for individual contributions to the deviation in the frequency of the power system to be assessed.

This section describes how the frequency performance payments process under the final rule will work, including:

- The definitions for an "eligible unit" and "appropriate metering".

63 Final rule clause 3.15.6AA(b)

- An overview of the transactions for frequency performance payments.
- How each unit is allocated a share of positive payments or negative charges.
- Frequency performance payments will be valued based on the relevant price for regulation services.
- Frequency performance payments will be scaled by the aggregate requirement for corrective response (RCR) - and AEMO may include parameters in relation to RCR.

In response to stakeholder feedback on the frequency performance payments process set out in the draft rule, the Commission published a second directions paper to consult on a revised frequency performance payments process, supported by analysis by IES. Stakeholders were generally supportive of the revised frequency performance payments process, specific issues are discussed in detail below.

New local definitions

The final rule includes new local definitions under cl 3.15.6AA for terms related to the Frequency performance payments arrangements. These were introduced in the revised rule which was published as part of the second directions paper to more clearly describe which market participants the new arrangements will apply to, and the important role of "appropriate metering" in relation to the frequency performance payment transactions. These definitions are described below.

An eligible unit

Under the final rule an **eligible unit** means:[64]

- a scheduled generating unit,
- a semi-scheduled generating unit,
- a scheduled bidirectional unit,
- a scheduled load, an
- ancillary service unit,
- a non-scheduled generating unit,
- a non-scheduled bidirectional unit, or
- a market connection point for a non-scheduled (customer) load.

The set of eligible units differs from the draft rule which applied the frequency performance payments transaction to all market participants. The final rule, which is consistent with the revised rule, deletes any reference to plant operated by a Demand response service provider (DRSP) or Market network service provider (MNSP).

The removal of the reference to plant operated by a DRSP is consistent with feedback provided by EnelX in response to the draft determination. EnelX argued that DRSP's should not be included in the frequency performance payments process, as the allocation of non-

64 Further detail explanation of the unit based approach to the frequency performance payments process is included in section 4.1.1 of the second directions paper.

energy costs to DRSP's should ideally be considered through a future review of the wholesale demand response mechanism.[65]

The exclusion of MNSPs was informed by feedback from AEMO and Hydro Tasmania. Their submissions suggested that Basslink, which is currently the only registered MNSP in the NEM, should be excluded from the frequency performance payments transactions. This is because the objective for the Basslink frequency controller is to limit the difference between frequency in Tasmania and the mainland, and it is not set up to independently control frequency to 50Hz in either Tasmania or the mainland NEM.[66]

Further commentary on the reasoning behind the included and excluded market participants is available in section 4.1.1 of the second directions paper.

Appropriate metering

The final rule defines **appropriate metering** as metering to allow an eligible unit's individual contribution to the deviation in the frequency of the power system to be assessed, in accordance with the requirements set out in the frequency contribution factors procedure. This definition was included in the revised rule to clarify the important role that "appropriate metering " plays in supporting the calculation of individual frequency contribution factors. This phrase is also used in AEMO's regulation FCAS contribution factor procedure.[67]

Section 3.2.3 describes the provisions in the final rule that relate to the calculation of contribution factors and residual contribution factors.

Transactions for frequency performance payments

The transactions for eligible units with appropriate metering are based on individual contribution factors which in turn are based on each unit's active power performance over the trading interval.[68] The transactions for all other eligible units are based on the aggregate performance of all non-metered units, referred to as the "residual". As described in section 3.2.3, AEMO will set out the specification for appropriate metering in the frequency contribution factors procedure.

A summary of frequency performance payment transactions in the final rule are:[69]

For eligible units with appropriate metering — Final rule clause 3.15.6AA(b)(1):

$$TA = CF \ x \ \frac{Price_{regulation}}{12} \ x \ RCR$$

where:

65 EnelX, Submission to the draft determination, 1 November 2021.

66 Submissions to the draft determination: AEMO, p.8., Hydro Tasmania, pp.2-4.

67 AEMO, Regulation FCAS contribution factor procedure - V6.0, 9 November 2018, p.4.

68 A default contribution factor may be applied if, in AEMO's reasonable opinion, it is impractical to determine a contribution factor based on data from the relevant trading interval. The concept of default contribution factors is described further in section 3.2.3.

69 As defined in the final rule, clause 3.15.6AA(a).

TA (in $)	- the *trading amount* payable or receivable by the *Cost Recovery Market Participant*;
CF (a number)	- the contribution factor for the eligible unit determined by AEMO under paragraph (e) for the relevant trading interval and relevant to the global market ancillary service requirement or local market ancillary service requirement for regulating raise service or regulating lower service;
$Price_{regulation}$ (in $ per MW per hour)	- the marginal price of meeting the global market ancillary service requirement or local market ancillary service requirement for the regulating raise service or regulating lower service in that trading interval;
RCR (in MW)	- the requirement for corrective response determined by AEMO in accordance with the methodology set out in the frequency contribution factors procedure.

For all other eligible units — Final rule clause 3.15.6AA(b)(2):

$$TA = RCF\ x\ \frac{Price_{regulation}}{12}\ x\ RCR\ x\ \frac{TE}{ATE}$$

where, in addition to the definitions above:

RCF (a number)	- the residual contribution factor for eligible units that do not have appropriate metering, for the relevant trading interval and relevant to the global market ancillary service requirement or local market ancillary service requirement for the regulating raise service or regulating lower service
TE (in MWh)	- the sum of the absolute value of any adjusted gross energy amount, for the Cost Recovery Market Participant for an eligible unit that does not have appropriate metering, for the trading interval.
ATE (in MWh)	- the aggregate of the absolute value of adjusted gross energy amounts for all Cost Recovery Market Participants, for eligible units that do not have appropriate metering, for the trading interval

Allocation of positive payments and negative costs based on contribution factors

The allocation of frequency performance payments and the costs of these payments under the final rule are based on contribution factors determined for each eligible unit, including both generation and load. This contribution factor approach is consistent with the draft rule and the revised rule included in the second directions paper. The fundamental element that remains unchanged from the draft rule, is that positive payments are made based on positive contribution factors and the costs are allocated based on negative contribution factors.

However, some changes were made from the draft rule to the final rule in response to stakeholder feedback that the transactions under the draft rule did not provide sufficient clarity as to how the new arrangements would effectively incentives helpful frequency response.[70] Informed by stakeholder feedback and guided by the analysis and investigation provided by IES, the final rule set out a balanced and independent process to measure and value active power behaviour that impacts power system frequency.

The principal change in the final rule, is that the contribution factor term in the transactions for the frequency performance payments is not divided by the aggregate of all negative contributions. Instead, the final rule clarifies that contribution factors must be between -1 and 1 which provides for contribution factors that are normalised and balanced.[71]

The normalised contribution factors reflect the relative deviations of eligible units relative to the aggregate (positive or negative) deviations of all units. The IES analysis showed that a top down energy balance approach could be used to account for the impact of the power system plant that do not have appropriate metering, referred to as 'the residual'. This energy balance approach is used to derive a contribution factor for the residual component and leads to a result where the positive contributions are balanced by equal and opposite negative contributions.

Stakeholder responses to the directions paper were generally supportive of the revised frequency performance payments arrangements, noting considerable improvement in clarity and function from the arrangements set out in the draft rule.[72]

Further explanation of this balanced approach to frequency performance payments is included in section 4.2.1 of the second directions paper.

The process and principles related to the determination of contribution factors are described in section 3.2.3.

Payments will be valued by the relevant price for the regulation raise or lower service

As for the revised rule, the transactions in the final rule value active power behaviour that impacts power system frequency using the relevant price for the regulation raise or regulation lower service for the respective trading interval. The regulation price ($/MW/hr) is divided by 12 to give a price in $/MW per five minute trading interval. This valuation approach is different to that in the draft rule which valued frequency performance payments based on the total costs of the relevant regulation service. The valuation by the regulation price allows for the total value of frequency performance payments to be decoupled from the volume of regulation services procured in each trading interval. This approach recognises that the regulation price provides a fair valuation for active power deviations that support power system frequency while allowing for the total value of frequency performance payments to be greater or less than the total cost of regulation services.

70 For example, Submissions to the draft determination: Clean energy council, p.3; Energy Australia, p.3.; ENGIE, p.2.; Iberdrola, pp.15-16.; Snowy Hydro, pp.4-5.

71 Final rule, clause 3.15.6AA(f)(3)

72 For example, Submissions to the second directions paper: AEC, p.3.; AEMO, p.1.; Alinta Energy, p.1.; ARENA, p.1.; Iberdrola, pp.1-2.; Snowy Hydro, p.1.; Tilt Renewables, p.1.;

As described in section 3.2.3, AEMO will determine separate contribution factors with respect to the need to raise or lower the frequency of the power system. [73] As such:

- Frequency performance payments that relate to contributions to the need to raise the frequency of the power system will be valued by the price for the regulation raise service.
- Frequency performance payments that relate to contributions to the need to lower the frequency of the power system will be valued by the price for the regulation lower service.

Further explanation of the rationale for weighting the frequency performance payments by the respective prices for the raise and lower regulation services is included in section 4.2.2 of the second directions paper.

In addition to the general support for the revised approach set out in the revised rule, a number of stakeholders expressed support for the use of the regulation price to value frequency performance payments.[74]

Payments will be scaled by the aggregate requirement for corrective response (RCR)

The final rule maintains the scaling approach set out in the revised rule and second directions paper, where the frequency performance payments are scaled based on the aggregate requirement for corrective response (RCR). This approach is different from the approach proposed in the draft rule where frequency performance payments would have been scaled by the requirement for the regulation service during the trading interval as a proportion of the regulation amount enabled at the start of the trading interval (RR/EA).

Stakeholders responses to the draft determination requested that this scaling amount be more clearly defined to support a robust and transparent frequency performance payments process.[75]

Informed by significant analysis provided by IES, the revised rule introduced the RCR scaling term to provide a simple representation of the ‘volume’ of corrective response required in each trading interval to raise or lower the frequency of the power system. When combined with a price in $/MW, this volume creates a total sum for the cost/value of helpful active power response (PFR) for the relevant trading interval. The concept of RCR is envisaged to include and account for the total of all helpful active power deviations across the power system. This recognises that there may be a significant quantity of active power deviations for metered plant that are balancing out harmful deviations without translating into a significant frequency error or a significant requirement for regulation services. The IES analysis developed a method for determining RCR, based on the aggregate dispatch error of all eligible units with appropriate metering. It reflects the cumulative ‘work’ done by all units acting to correct frequency deviations in the power system.

The process developed with IES aggregated all deviations for metered plant (typically generation) and then presented these deviations as either above target or below target

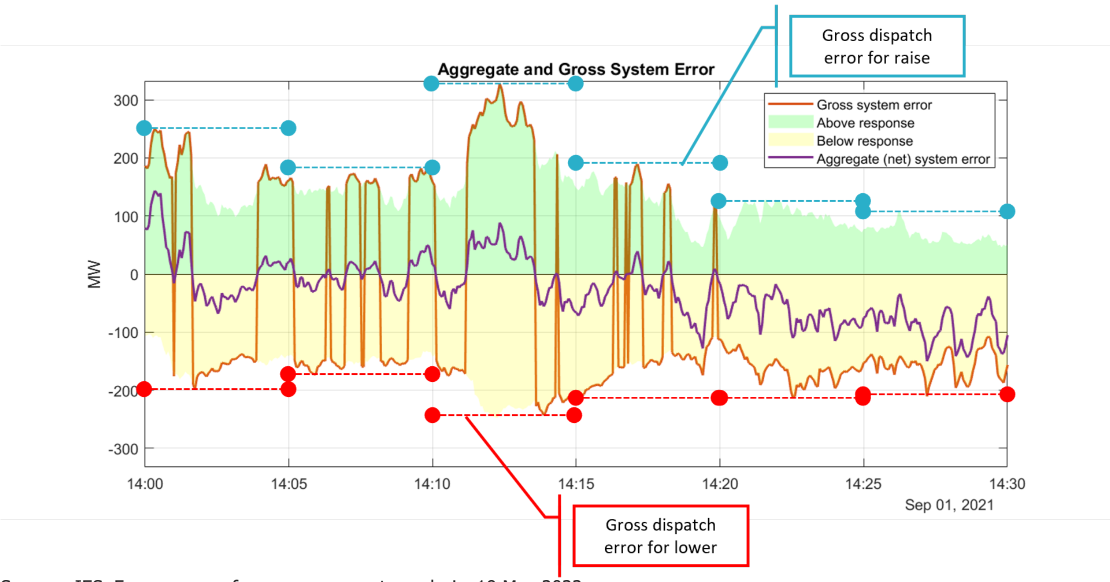
73 Final rule, cl. 3.15.6AA(f)(4)

74 For example, submissions to the second directions paper: AEC, p.3.; Alinta Energy, p.1.; Iberdrola, p.4.; Snowy Hydro, p.1.;

75 For example, Submission to the draft rule determination: Iberdrola, p.12.

deviations. The above target deviations contributed to raising the frequency of the power system while the below target deviations contributed to reducing the frequency of the power system. An example of this is provided in Figure 3.3 based on IES analysis of historical causer pays data.

Figure 3.3: RCR — Aggregate (net) and gross dispatch error



Source: IES, Frequency performance payments analysis, 19 May 2022.
Note: Above response is the sum of all positive deviations for plant with appropriated (SCADA) metering.
Note: Below response is the sum of all negative deviations for plant with appropriated (SCADA) metering.
Note: Aggregate (net) dispatch error is the net sum of above and below response
Note: Gross dispatch error tracks the maximum of the above and below response and is a measure of the total or gross positive deviations

Following consideration of a number of alternative scaling methods, the IES analysis landed on the use of gross dispatch error as its preferred measure of the requirement for corrective response in the frequency performance payments transactions.[76] The benefits of this value include:

- It is a readily quantifiable value that is based on the measurement of all active power deviations for plant with appropriate metering.
- It is independent of AGC and the requirement or use of regulation services.
- By accounting for all deviations, it would (subject to the effectiveness of the performance metric) include primary and secondary response.

Further discussion of the investigations and analysis relating to RCR is included in section 4.2.3 of the second directions paper.

76 IES, Frequency performance payments analysis, 19 May 2022, pp.10,36.

The value for RCR will be determined by AEMO after the end of each trading interval based on a methodology set out in the frequency contribution factors procedure, as described in section 3.2.3.

In responses to the second directions paper, Iberdrola noted that while the RCR term is an improvement on the scaling approach in the draft rule, there was still room for the scaling factor to allow for some degree of operational flexibility to tune the frequency performance payments to deliver a desired frequency performance outcome in accordance with the power system frequency operating standard. Iberdrola suggested that additional "levers" could be included in the frequency performance payments transactions to allow AEMO to adjust the strength of the frequency performance payments to provide confidence that the incentive arrangements can meet the system frequency control requirements.[77]

On the other hand, the AEC expressed support for the frequency performance payments transactions in the revised rule, noting that one benefit of the revised approach was that it was not reliant on a parameter or 'operator constant' determined based on AEMO's judgement.[78]

The transactions in the final rule are scaled by RCR, as set out in the revised rule. However, as described in section 3.2.3, the final rule does clarify that AEMO may include 'parameters' in the methodology it will use to determine RCR. This approach maintains the core transactions set out in the revised rule, while also clarifying that AEMO has a degree of operational flexibility to tune the scaling amount. These parameters would perform a similar function to the 'levers' proposed by Iberdrola, albeit within the methodology used to determine RCR. The final rule also clarifies that AEMO must notify market participants of any such parameter at least 5 business days prior to their application, this provides a transparent process for the application of parameters relating to RCR.[79]

3.2.2 Modified arrangements for the allocation of costs for regulation services

The final rule includes modified arrangements for the allocation of costs for regulation services based on the separation of the costs for regulation services used and not-used during each trading interval. This change from the draft rule is intended to more accurately allocate the costs for regulation services to market participants that have caused the need for those services.

Under the final rule:

- the costs for regulation services <u>used</u> in a trading interval will be allocated based on negative contribution factors determined for the trading interval.
- the costs for regulation services <u>not used</u> in a trading interval will be allocated based on default contribution factors — which are intended to reflect the longer-term historical performance of eligible units of generation or load.

77 Iberdrola, Submission to the second directions paper, p.5.

78 AEC, Submission to the second directions paper, p.5.

79 Final rule cl.3.15.6AA (j)

The final rule maintains the same approach as the draft rule for the allocation of costs for regulation services used in a trading interval. This approach recognises that a negative contribution factor for a trading interval provides a good indication of those who cause the need for regulation services. Stakeholder responses to the draft determination and second directions paper were generally supportive of this change.[80]

However, in response to stakeholder feedback on the draft rule, the final rule takes a different approach to the allocation of costs for regulation services not used in a trading interval. Stakeholders responses to the draft determination opposed the approach taken in the draft rule which would have allocated these costs based on energy consumed or generated in the trading interval. The intent of the approach in the draft rule was to spread these costs as broadly as possible, given that the unit performance during the trading interval does not provide a good indication of those who have caused the need for these services. However, stakeholders expressed concern that this broad allocation of costs could deliver perverse incentives, as positive performing units would be penalised through the allocation of a share of costs for regulation services not-used.[81]

The final adopts the same approach that was set out in the revised rule and second directions paper, which allocates the costs of regulation services not used based on negative default contribution factors, rather than being based on energy consumed or generated in the trading interval. This approach recognises that it is not possible to identify specific plant behaviour during a trading interval as causing the need for regulation services that were not used during that trading interval.

At the same time, it is appropriate for the long-term behaviour of eligible plant to be used as the basis for the allocation of these costs, similar to the current causer pays process. It also provides an incentive to encourage consistently helpful frequency response from eligible plant, which will complement the sharp incentives provided through the frequency performance payments and the allocation of costs for regulation service used in each trading interval. Stakeholder responses to the second directions paper were supportive of this revised approach.[82]

Further commentary on the process for the allocation of costs for the enablement of regulation services is included in section 4.3 of the second directions paper and section 3.10 of the IES report, *Frequency performance payments analysis*. [83]

3.2.3 A new frequency contribution factors procedure

The final rule requires AEMO to consult on a new *frequency contribution factors procedure* which will set out the detailed process for the calculation of frequency contribution factors for each eligible unit for the frequency performance payments transactions and for the allocation of costs for regulation services.[84] The *Frequency contribution factors procedure* will replace

80 For example, Submissions to the second directions paper: AEC, p.4.; Alinta Energy, p.1.

81 For example, Submissions to the draft determination: CEC, p.1.; Iberdrola pp.13-14.

82 For example, Submissions to the second directions paper: AEC, p.4.; Alinta Energy, p.1.; Iberdrola, p.1.;

83 Available on the project page https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangement

84 Final rule cl. 3.15.6AA (e)

the existing procedure used to determine contribution factors for the allocation of costs of regulation services, known as 'causer pays'. This general approach is consistent with the draft rule, although the final rule includes a number of refinements and additions in response to stakeholder feedback.

In response to the draft rule, stakeholders requested that the Commission undertake further work to clarify the frequency performance payments process, including the requirements for the development of frequency contribution factors. [85] Stakeholders acknowledged that the process set out in the revised rule and second directions paper was significantly improved from the draft rule, and therefore were generally supportive of the frequency contribution factor process in the revised rule.[86]

The final rule includes the following elements in relation to the *frequency contribution factors procedure:*

- A set of principles that guide AEMO in its development of the procedure — clause 3.15.6AA (f).
- Requirements for issues that must be included or addressed in the procedure — clause 3.15.6AA (g).
- Requirements for the publication of data related to the frequency contribution factors — clause 3.15.6AA (i), (j), (k) & (l).

Each of these elements of the final rule are described further below.

Principles for the frequency contribution factors procedure

Table 3.1 sets out the principles included in the final rule in relation to the *frequency contribution factors procedure*. This sub-section describes these principles based on the sub-heading groupings included in the table.

Table 3.1: Principles for the frequency contribution factors procedure — final rule clause 3.15.6AA(f)

NO.	PRINCIPLE	COMMENTARY AND RATIONALE
Frequency contribution factor objective		
(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;	As per the revised rule, the final rule clarifies that the objective for a contribution factor is related to the measured impact on the frequency of the power system, which differs from the draft rule which was related to the need for regulation services. Also, the revised rule and final rule set out that a
(2)	a positive contribution factor for	

85 For example, Submissions to the draft determination: Clean energy council, p.3; Energy Australia, p.3.; ENGIE, p.2.; Iberdrola, pp.15-16.; Snowy Hydro, pp.4-5.

86 For example, Submissions to the second directions paper: AEC, p.3.; AEMO, p.1.; Alinta Energy, p.1.; ARENA, p.1.; Iberdrola, pp.1-2.; Snowy Hydro, p.1.; Tilt Renewables, p.1.;

NO.	PRINCIPLE	COMMENTARY AND RATIONALE
	an eligible unit should reflect the extent to which the unit contributed to reducing the deviation in frequency of the power system;	contribution factor is determined for each eligible unit, rather than for a market participants portfolio. This avoids distortions due to portfolio aggregation.
(3)	a contribution factor is a number between -1 and 1.	This principle in the final rule maintains the approach introduced in the revised rule, which clarifies that the contribution factors are normalised and balanced.
Residual contribution factors		
(4)	the residual contribution factor for all eligible units that do not have appropriate metering must be equal across and within all classes of Cost Recovery Market Participants;	The revised rule and final rule introduced the term 'residual contribution factor' to refer to the contribution factor for eligible units that do not have appropriate metering. This approach is consistent with existing clause 3.15.6A(k)(2) of the NER and AEMO's 'causer pays' methodology.
Raise/lower categorisation		
(5)	separate contribution factors must be determined with respect to the contribution to the need to raise or lower the frequency of the power system;	The calculation of separate contribution factors for raise and lower response is consistent with the draft rule and aligns with financial weighting of payments by the price for the raise or lower regulation service.
Timing of sample and application periods		
(6)	a contribution factor for each eligible unit must be determined by AEMO for every trading interval unless in AEMO's reasonable opinion it is impractical to do so, in which AEMO must determine a default contribution factor;	This principle maintains the approach set out in the draft rule, which included the alignment of the sample and application periods and the determination of contribution factor for each trading interval. The final rule includes additional text to clarify that a default contribution factor will be determined where it is impractical to determine a real-time contribution factor.
Geographical and regional considerations		
(7)	a contribution factor for each eligible unit applies for the region or regions relevant to the global market ancillary service requirement or local market ancillary service requirement for the regulating raise service or regulating lower service; and	This principle clarifies the relationship between the contribution factors and the requirements for regulation services at the global (NEM-wide) and local (regional) level. This principle has been revised from the draft rule in response to operational feedback from AEMO. It replaces the provisions of the draft rule and the revised rule that referred respectively to asynchronous operation and the frequency measured for each

NO.	PRINCIPLE	COMMENTARY AND RATIONALE
		NEM region.
Default contribution factors		
(8)	a default contribution factor for an eligible unit must be determined based on historical data for that eligible unit unless in AEMO's reasonable opinion it is impractical to do so;	The concept of default contribution factors was introduced in the revised rule to clarify the approach to determining contribution factors where it was not practical to use data measured for a given trading interval, for example where there is a lack of quality data available. The principles for default contribution factors build on the provisions included in clause 3.15.6AA(g)(4) of the revised rule to clarify that: • A default contribution factor should be determined based on historical data, where practical. AEMO may develop an alternative methodology for use where it is impractical to use historical data. • A default contribution factor may only be used for the allocation of costs for frequency performance payments. Positive frequency performance payments may not be made based on default contribution factors.
(9)	a default contribution factor must only be used under clause 3.15.6AA(b) to determine the trading amount payable by a Cost Recovery Market Participant	

Frequency contribution factor objective

Clause 3.15.6AA(f)(1), (2) & (3) of the final rule provide a set of principles that describe the high-level objective for frequency contribution factors. These principles are unchanged from those included in the revised rule.

The following attributes of the contribution factors, included in the draft rule, are maintained in the final rule:

- Contribution factors would be determined for a trading interval, based on measurement of plant and system performance during the same trading interval — where it is practical to do so.

The final rule differs from the draft rule in the following ways:

- The objective for a contribution factor is linked to the impact on system frequency, not the need for regulation services as per the draft rule. This change supports the calculation of frequency contribution factors that have a degree of separation from the enablement and operational objectives for regulation FCAS, while maintaining a link to the objective for the control of power system frequency.
- Contribution factors would be determined for each eligible unit of generation or load, not for an entire portfolio of plant operated by a market participant as allowed for in the draft

rule. This change avoids the outcome whereby market participants with large portfolios would receive a lower allocation of regulation costs through portfolio netting effects. Under the final rule, the contribution factors that apply for frequency performance payments and regulation cost allocation are determined and apply for each eligible unit, which creates a consistent valuation for the plant performance that impacts power system frequency, regardless of administrative arrangements that relate to its market participant registration.

The frequency contribution factor objective is described further in section 4.1.1 of the second directions paper.

Residual contribution factors

Clause 3.15.6AA(f)(4) of the final rule maintains the approach under the draft rule - and the current 'causer pays' methodology - where there is a single contribution factor calculated for all eligible units that do not have appropriate metering. As in the revised rule, the final rule introduces the term 'residual' contribution factor to refer to the aggregate of these eligible units. The term, ' residual', is consistent with the terminology used by AEMO in the *Regulation FCAS contribution factor procedure.*

Raise/lower categorisation

Clause 3.15.6AA(f)(5) of the final rule sets out that separate contribution factors must be determined with respect to the need to raise or lower the frequency of the power system. This approach, which is unchanged from the draft rule, aligns weighting of the frequency performance payments by the relevant market prices for the regulating raise and regulating lower services determined in each trading interval. It recognises that contributions to the need to raise the frequency of the power system should be valued based on the price for the regulating raise service and contributions to the need to lower the frequency of the power system should be valued based on the price for the regulating lower service.

Investigations into this element of the contribution factor procedure are set out in section B.6. of the IES *Frequency performance payments analysis* report.

Timing of sample and application periods

A key element of the final rule, as set out in clause 3.15.6AA(f)(6), is the alignment of the sample and application period for the measurement of plant performance that impacts on power system frequency and the application of contribution factors that drive the incentive arrangements. This change is consistent with the draft rule and creates real-time incentives to encourage market participants to operate their plant in a way that helps to control power system frequency, subject to the needs of the power system and the real-time cost of active power response.

The Commission recognises that there may be situations where data quality issues mean that it is not practical to determine a real-time contribution factor based on data measured for a trading interval. In such situations the final rule allows AEMO to determine and apply a default contribution factor, as discussed further below.

This element of the new frequency performance payments process is described further in section 4.2.2 of the draft determination.

Geographical and regional considerations

Clause 3.15.6AA(f)(7) of the final rule sets how contribution factors shall be determined with respect to the global and/or regional requirement for regulation services. This principle recognises that unit active power response may contribute to control of frequency within the whole power system (globally) or within a local region, depending on the system configuration and enablement of regulation services at the time.

This approach in the final rule differs from the approach set out in the draft and revised rules. The changes are intended to clarify how each of the elements of the frequency performance payments transactions should account for regional considerations.

In the draft rule, it was proposed that AEMO would determine contribution factors separately for a region that is operated asynchronously.[87] This approach was based on the current approach where AEMO is required to publish estimated contribution factors for application to NEM regions that are operated asynchronously as a result of network separation.[88] Submissions from AEMO and Hydro Tasmania noted that while the Tasmanian region is operated asynchronously to the mainland NEM, active power response from Tasmanian units plays a role in controlling frequency both in Tasmania and in the mainland, due to the frequency control transfer capability provided by Basslink. As such, Hydro Tasmania expressed the view that Tasmania units should continue to receive both global and local contribution factors.[89] In response to this feedback, the revised rule removed reference to asynchronous operation and instead proposed that AEMO be required to determine contribution factors based on local power system frequency measured in each region.[90]

AEMO's feedback to the revised rule was that it did not provide sufficient clarity as to whether the elements of the frequency performance payments transactions should be determined for each region of the NEM or based on the requirement for regulation services, which may be regional or global. AEMO's view was that each of these elements, including the contribution factors, RCR and the regulation price, would need to be determined based on the same geographical grouping and that the rule drafting should provide clarity on this.[91] In response to AEMO's feedback, and consistent with the current 'causer pays' process for the allocation of costs for regulation services, the final rule clarifies that contribution factors must be calculated with respect to the region or regions relevant to the global or local requirement for the regulating raise or regulating lower service.

87 Draft rule cl. 3.15.6A(j)(2)
88 NER Cl. 3.15.6A(nb)
89 For example, submissions to the drat determination: AEMO, pp.7-8.; Hydro Tasmania p.4.
90 Second directions paper - revised rule cl.3.15.6AA(f)(6)
91 AEMO, Submission to the second directions paper, p.9-14.

Default contribution factors

Clause 3.15.6AA(f)(8) and (9) of the final rule provide direction to AEMO in relation to the determination and application of default contribution factors for use when it is not practical to determine contribution factors based on real-time data measured during a trading interval.

The concept of default contribution factors was introduced in the revised rule to provide clarity as to how the frequency performance payments process would work when it was not practical for AEMO to determine real-time contribution factors, due for example to a lack of good quality data. As described further below, the revised rule required AEMO to set out the methodology it would use to determine a default contribution factor, but it did not include any related guiding principles.

In response to the revised rule and second directions paper, AEMO requested further clarification on the determination and application of default contribution factors. In particular, AEMO queried whether it should be appropriate for positive payments to be made on the basis of default contribution factors.[92] On further consideration, the Commission acknowledges that inconsistencies and perverse incentives could arise if payments were made to market participants based on default contribution factors. Therefore, the final rule clarifies that default contribution factors may only be used for allocation of costs under the frequency performance payments.

Matters that must be addressed in the frequency contribution factors procedure

In addition to the methodology that AEMO will use to determine a contribution factor, clause 3.15.6AA(g) of the final rule also requires that the following issues be addressed and included in *frequency contribution factors procedure*:

- The criteria for determining whether an eligible unit has appropriate metering.
- A formula that *AEMO* will use to calculate the measure of the need to raise or lower the *frequency* of the *power system* (the system frequency metric).
- The methodology *AEMO* will use to determine a default contribution factor.
- The data *AEMO* will use to calculate the contribution factor for an eligible unit with appropriate metering.
- The methodology *AEMO* will use to determine the requirement for corrective response (RCR) used to scale the frequency performance payments, including any related parameters.
- The methodology AEMO will use to determine the usage (U) of regulation services for the allocation of costs of regulation services by used and not-used.
- The methodology *AEMO* will use to determine a reference trajectory which provides an active power baseline against which unit performance is measured.

Each of these inclusions are described further below.

92 Ibid. p.15.

Appropriate metering requirements

Clause 3.15.6AA(g)(1) of the final rule requires that AEMO include in the frequency contribution factors procedure, the criteria for determining whether an eligible unit has appropriate metering. This requirement is intended to provide transparency to market participants in terms of the metering requirements that are required to support the determination of individual contribution factors.

A formula for the system frequency metric

The final rule requires that AEMO include in the frequency contribution factors procedure, a formula that *AEMO* will use in each *trading interval* to calculate the measure of the need to raise or lower the *frequency* of the *power system* or the 'system frequency metric'. Active power deviation for eligible units of generation or load will be compared against the output of this formula to determine a contribution factor. Clause 3.15.6AA(g)(2) of the final rule requires that this formula:

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

(ii) must contain sufficient detail so that a *Cost Recovery Market Participant* can use it to estimate the need to raise or lower the *frequency* of the *power system* during each *trading interval*; and

(iii) may include parameters to be determined by *AEMO* from time to time to be applied to the different elements of the formula;

In simple terms, the deviation of power system frequency from the target of 50Hz is a measure of the need to raise or lower the frequency of the power system. The most direct form of a 'system frequency metric' is the real-time measure of the deviation of system frequency from 50Hz. A frequency deviation below 50Hz would signal the need for additional generation output (or reduction in energy consumed) to raise the frequency of the power system, whereas a frequency deviation above 50Hz would signal the need for a decrease in generation output (or increase in energy consumed) to lower power system frequency. Raw frequency measurement was considered as a potential metric for use in determining contribution factors for the frequency performance payments, however the Commission recognised that it may be appropriate for the process to allow for additional elements to be incorporated into the determination of the system frequency metric.

The Commission notes feedback from Iberdrola, that further work may be required to clarify the detailed approach to the determination of the formula for the system frequency metric.[93] The Commission acknowledges this point, and notes that the approach developed by IES through the Frequency performance payments analysis is intended as an example and to guide AEMO in the detailed design of the system frequency metric through the development and consultation on the frequency contribution factors procedure. The approach under the

93 Iberdrola, Submission to the second directions paper, p.3.

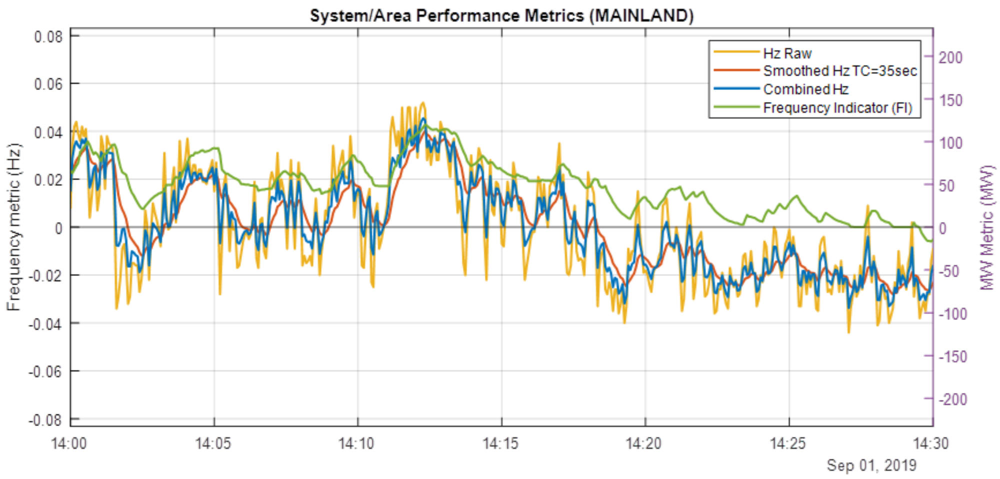
final rule, which is consistent with the draft rule, is intended to provide for a transparent system frequency metric — based on system frequency — while also allowing AEMO flexibility to determine a metric that aligned with its operational frequency control objectives.

The system frequency metric was a key focus of the IES analysis, which investigated a number of potential approaches for this element of the frequency performance payments process. The goal of these investigations was to identify a system frequency metric that provided a transparent and consistent measure of the need to raise or lower the frequency of the power system.[94]

Figure 4.1 shows the following frequency-based metrics investigated by IES:

- raw frequency deviation (Hz) — this is a measure of the real-time, unfiltered deviation of system frequency with respect to 50Hz.
- smoothed Frequency (Hz) — this smoothed version of real-time frequency deviation. For the IES analysis, a time constant of 35 seconds was used.
- combined frequency — 1:1 combination of raw and smoothed frequency (Hz)

Figure 3.4: Comparison of potential system frequency metrics



Source: IES, Frequency performance payments analysis, 19 May 2022.

The preferred metric used to determine settlement amounts from the IES analysis was the combined frequency metric. This metric was selected by IES as it is based on system frequency and provides a combination of raw Hz and smoothed Hz, recognising the combined role of proportional PFR and sustained active power response to help control power system frequency.

The final rule provides for the development of a formula for a transparent frequency metric available in real-time to all market participants. AEMO will be responsible for developing the

94 For further detail refer to section 3.3 of the IES report, *Frequency performance payments analysis*, available on the project web page.

detail for this metric, including any associated parameters, through its consultation on the *frequency contribution factors procedure*.

The methodology to be used to determine a default contribution factor

Clause 3.15.6AA(g)(4) of the final rule requires that AEMO include in the frequency contribution factors procedure, the methodology to be used to determine a default contribution factor. These default contribution factors would apply:

- for the allocation of costs for frequency performance payments, where it is not practical to determine a real-time contribution factor based on data measured for the relevant trading interval.[95]
- for the allocation of costs for enablement of regulation services that are not used by AEMO within a trading interval — as described in section 3.2.2.[96]

The draft rule did not include a specific requirement in relation to default contribution factors. This requirement was included in the revised rule in response to AEMO's submission to the draft determination which suggested that there was an opportunity clarify the arrangements for "back-up" factors and the allocation of costs for regulation services not-used.[97]

This requirement in the final rule is consistent with the revised rule with the exception that the final rule clarifies that default contribution factors may only be used for the allocation of costs associated with frequency performance payments. As described above, in response to AEMO's feedback on the revised rule, positive frequency performance payments may not be made based on default contribution factors.

Specification of the data AEMO will use to determine contribution factors

Clause 3.15.6AA(g)(5) of the final rule requires that AEMO include in the frequency contribution factors procedure the data it will use to calculate a contribution factor for an eligible unit with appropriate metering. This data must include the unit's active power output or consumption and a measure of frequency. It may also include the frequency measured at the connection point for the eligible unit and any other data that AEMO considers relevant.

The draft rule did not include any requirements in relation to the specification of data to be used to calculate contribution factors. This requirement was included in the revised rule in response to concerns expressed through the stakeholder technical working group around data quality issues. In particular, working group participants noted that the quality of data used to determine contribution factors can be affected by communication delays in the order of tens of seconds. These data quality issues can affect the alignment of the unit active power measurements (measured locally) with the frequency measurement (measured centrally by AEMO).

The final rule maintains the data specification requirements from the revised rule with the exclusion of the reference to "electronic signals from AEMO via the AGC with respect to the

95 Final rule cl. 3.15.6AA(4)(i)

96 Final rule cl. 3.15.6AA(4)(ii)

97 AEMO, Submission to the draft determination, 2 November 2021, pp.7-

provision of a market ancillary service". This provision is removed in the final rule in response to feedback from AEMO that it was impractical and unnecessary to refer to these electronic signals in relation to unit performance measurement. AEMO notes the discussion in the second directions paper in relation to the potential adjustment of the reference trajectory by the electronic signals relating to the regulation requirement, however it notes that the rule requirements in relation to the reference trajectory are dealt with under a separate paragraph — clause 3.15.6AA(g)(7) in the final rule.[98]

The methodology to be used to determine the requirement for corrective response (RCR)

Clause 3.15.6AA(g)(6(i)) of the final rule requires that AEMO include in the frequency contribution factors procedure, the methodology *it* will use to determine the requirement for corrective response (RCR) used to scale the frequency performance payments, including any related parameters. RCR is described in the final rule as a measure of the total volume in MW that contributed to reducing the deviation in frequency of the power system.

The draft rule did not include any requirements in relation to a methodology for RCR. This element of the final rule was introduced in the revised rule to reflect the Frequency performance payments process informed by the IES *Frequency performance payments analysis.* The concept of RCR and the related investigations by IES are described further in section 3.2.1.

The methodology to be used to determine the usage(U) for regulation services

Clause 3.15.6AA(g)(6(ii)) requires that AEMO include in the frequency contribution factors procedure, the methodology it will use to determine the usage (U) for the regulating raise service and the regulating lower service in each trading interval. As described in section 3.2.2, this term — U — is used to split the allocation of costs for the enablement of regulation services by 'used' and 'not-used'.

The concept of splitting the allocation of regulation enablement costs be used and not-used was proposed in the draft rule and carried through to the revised rule, however neither the draft rule nor revised rule set out a requirement for a method for determining usage to be specified by AEMO. Rather, the term 'U' was defined under clause 3.15.6AA(c)(1) of the revised rule as:

U (a number)	-	the maximum proportion of the dispatched regulating raise service or regulating lower service used by AEMO in that trading interval (which is a number between 0 and 1)

AEMO's feedback to the second directions paper was that there may be benefit in allowing it to consider alternative methods to determine U, including approaches that were not directly linked to the Automatic generation control system (AGC) that coordinates the electronic signals sent to generators enabled to provide regulation services. As and example, AEMO

98 AEMO, Submission to the second directions paper, p.14.

proposed an alternative approach to determining U, based on the aggregate deviations of units enabled to provide regulation services.[99]

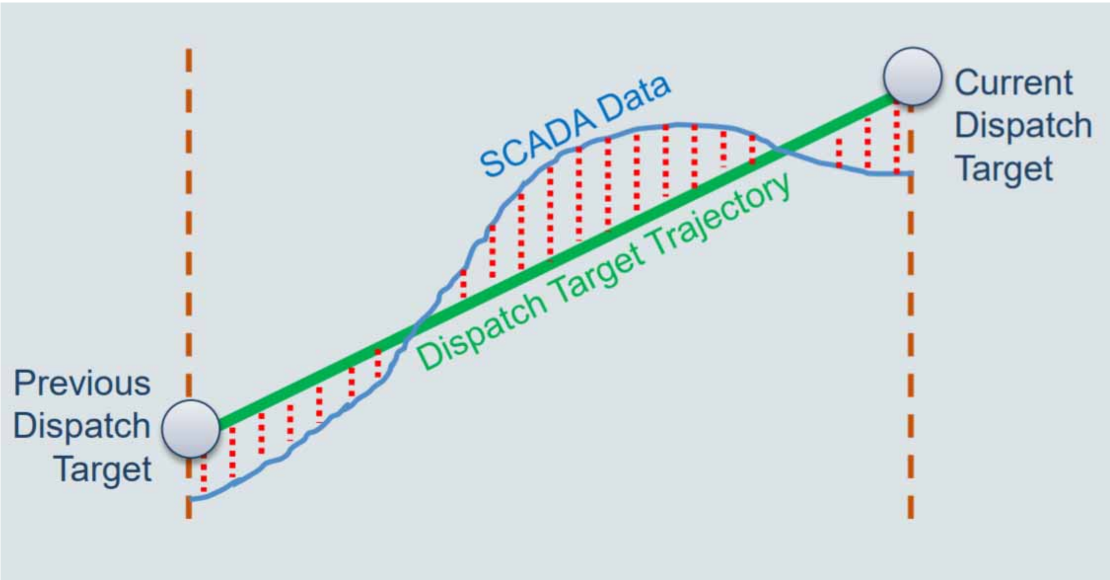
In response to AEMO's feedback on the revised rule, the final rule includes additional provisions to enable AEMO flexibility as to how it specifies the methodology for determining the usage of regulation services.

The methodology to be used to determine a unit reference trajectory

Clause 3.15.6AA(g)(7) of the final rule requires that AEMO include in the frequency contribution factors procedure, the methodology it will use to determine a reference trajectory for each eligible unit that has appropriate metering.

The 'reference trajectory' describes the expected — baseline — performance for the relevant plant over the trading interval. Unit active power deviations are measured with reference to this baseline. If a unit's active power behaviour matches this baseline, then it would receive a neutral or zero contribution factor and would not be allocated any payments or costs through the frequency performance payments process. Measured deviations from the reference trajectory determine the degree to which an eligible unit is considered to have contributed to causing or reducing the aggregate deviation of power system frequency. The current approach to determining a reference trajectory for a scheduled or semi-scheduled generator is shown in Figure 3.5.

Figure 3.5: Reference trajectory for scheduled and semi-scheduled plant



Source: AEMO, Regulation FCAS contribution factor procedure – Determination of contribution factors for regulation FCAS cost recovery, 9 November 2018, p.12.

Note: A description of the current approach for determining a reference trajectory through the Causer pays procedure is included in section 4.2.3 of the draft determination.

99 AEMO, Submission to the second directions paper, pp.6-7.

As for the draft rule and the revised rule, the final rule requires that the reference trajectory must be informed by:

- the dispatch target for scheduled generation, scheduled load, scheduled bidirectional unit and ancillary service unit
- the dispatch level for semi-scheduled generation
- where practical, information provided by a registered participant for a non-scheduled generating unit or non-scheduled bidirectional unit, that relates to its expected trajectory over the trading interval.

The reference trajectory may also be informed by any other factors that AEMO considers relevant.

While not included in the final rule, the draft rule and revised rule also noted that the reference trajectory may be informed by the requirement for an eligible unit enabled to provide a market ancillary service to respond to electronic signals from AEMO with respect to the provision of a market ancillary service. However, AEMO provided feedback on the revised rule that this optional reference to electronic signals was unnecessary, as it may include such matters through the more general reference to "any other factors that AEMO considers relevant".[100] This matter relates to the issue of whether or not the reference trajectory should include the regulation component which is communicated to units enabled to provide regulation services via AEMO's AGC system.

The inclusion of the regulation component in the reference trajectory has been extensively investigated by the Commission including through the IES *Frequency performance payments analysis* and related discussions with the technical working group. The Commission provided a detailed breakdown of the potential advantages and challenges associated with this approach in section 4.2.3 of the draft determination and section 4.1.3 of the second directions paper. The key points of this commentary were:

- There are a number of practical challenges associated with the inclusion of the regulation component that relate to the operation of AEMO's AGC system. The impact of this is expected to be that the performance of units enabled to provide regulation services would be assessed more harshly than other units. Including the regulation component in the reference trajectory would result in less favourable performance measurement for enabled plant and a smaller share of frequency performance payments being provided to enabled plant as compared to the alternative. Under this approach the delivery of regulation services would be relatively separate to the measurement of plant performance with respect to frequency performance payments. Therefore, the introduction of frequency performance payments would have less impact on the market outcomes for regulation FCAS, where the regulation component is included in the reference trajectory.
- Conversely, excluding the regulation component from the reference trajectory would result in more favourable performance measurement for enabled plant with the result being that enabled plant would receive a larger share of the frequency performance

100 AEMO, Submission to the second directions paper, p.14.

payments as compared to the alternative. The provision of these payments to enabled plant would be expected to reduce the marginal cost of providing regulation services and put downward pressure on the market prices for regulation FCAS.

- In this case the regulation price would be expected to more closely match the true price for the provision of PFR, as the economic signals for regulation services and PFR would be linked through the frequency performance payments. Rather than being undesirable, this outcome may lead to more accurate pricing of helpful continuous frequency response in the absence of new market arrangement to reveal the price for PFR on its own.
- In either case, the long run combined costs for regulation enablement and frequency performance payments would be expected to be relatively similar. This outcome is expected as a result of the dynamic economic forces which would be expected to play out through market competition, noting that the fundamental costs for provision of frequency control services are unchanged.

The inclusion of the regulation component in the reference trajectory was investigated through the IES analysis.[101] The results of the IES analysis for this scenario confirmed that the inclusion of the regulation component in the reference trajectory would divert frequency performance payments away from plant enabled to provide regulation services, in favour of non-enabled plant. The results showed that the overall scale of frequency performance payments was in the order of fifteen percent smaller, compared to the reference scenario (3.8). This result showed that the scaling approach has a more dominant impact on the scale of frequency performance payments than the approach to the regulation component.

In the second directions paper, the Commission concluded that it is not appropriate for the rule to require that the regulation component be included in the reference trajectory. Rather, AEMO is better placed to consider the potential inclusion of the regulation component through its consultation on and determination of the *frequency contribution factors procedure*.

The Commission notes that stakeholders have a range of views in relation to the inclusion of the regulation component ion the reference trajectory. AEMO's view is that there are challenges associated with this approach and that it may not be appropriate.[102] The AEC expressed appreciation for the Commission's investigation of this issue and indicated its support for the rule to not require AEMO to include the regulation component in the reference trajectory:[103]

> On balance, the AEC prefers the AEMC's recommended design, but also supports excluding this choice from the rules and permitting AEMO the freedom to adjust the design as more experience comes to light.

On the other hand a number of stakeholders continue to support the inclusion of the regulation component in the reference trajectory.[104]

101 Refer to section 3.4.2 of the IES report, Frequency performance payments analysis, 19 May 2022.

102 Ibid.

103 AEC, Submission to the second directions paper, p.4.

104 For example: Iberdrola's submission to the second directions paper, p.3.

While recognising the range of views on this issue, the Commission has determined not to require that AEMO include the regulation component in the reference trajectory as we consider that there is not a strong economic justification to require its inclusion. As such AEMO is best placed to determine whether it is practical to include this information in the reference trajectory. We note that AEMO may do so under the provision in the final rule that the reference trajectory "may be informed by any other factors *AEMO* considers relevant."[105]

Data publication requirements

The final rule provides a consolidated list of data publication requirements relating to the determination of frequency contribution factors. These requirements build on the existing requirements in the NER for AEMO to publish data related to the determination of contribution factors and the requirements set out in the draft rule and the revised rule.

Under the final rule, AEMO must publish:

- any data that will be used to determine default contribution factors at least 5 days before the billing period in which the contributions factor will apply.
- any parameters it determines in relation to the system frequency metric or the requirement for corrective response, at least 5 business days prior to applying those parameters.
- as soon as practicable after the relevant trading interval:
    - the contribution factors determined for each eligible unit
    - the data calculated from applying the formula for the system frequency metric
    - the requirement for corrective response
    - the usage of the enabled regulating raise service or regulating lower service
- the data used to determine the contribution factors including the measured data for each eligible unit which has appropriate metering, in accordance with the Spot market operations timetable.

The list of publication requirements in the final rule includes the following changes and additions with respect to the revised rule. The final rule includes an additional requirement for AEMO to publish the usage for regulation services. This reflects the additional provisions in the final rule that require AEMO to set out the methodology for determining U, as described above. The final rule does not require AEMO to publish default contribution factors in advance of their application, instead it must publish any related data that it will use to calculate default contribution factors at least 5 days before the billing period in which it would be applied. The Commission acknowledges AEMO's feedback on the revised rule, that it may not be meaningful for it to publish default contribution factors in advance of their application, as they would need to be adjusted through a process of re-normalisation when they are applied in a given trading interval.[106] The final rule also reflects a change to the drafting approach to clarify each publication requirement and the specified timeframe.

105 Final rule cl.3.15.6AA(g)(7)

106 AEMO, Submission to the second directions paper, p.15.

3.3 New reporting requirements for AEMO and the AER

The final rule includes new reporting obligations for AEMO and the AER that will provide transparency in relation to the operational availability of PFR and the value of financial transactions related to the new frequency performance payments process. The final rule requires that:

- AEMO must report, on a quarterly basis, on its assessment of aggregate frequency responsiveness in the power system provided by frequency responsive plant.[107]
- The AER must report, on a quarterly basis, on the total costs of frequency performance payments.[108]

3.3.1 AEMO reporting on aggregate frequency responsiveness

The final rule requires AEMO to report on the level of aggregate frequency responsiveness on a quarterly basis as part of its existing obligation to report on quarterly frequency performance.[109] This new reporting requirement will provide a transparent record of how the PFR arrangements are performing and is expected to show the impact of aggregate frequency responsiveness on system frequency.

Aggregate frequency responsiveness, also referred to as system frequency bias or aggregate droop, is a system-wide characteristic measured in MW/Hz. It is based on:

- the amount (in MW) of plant that are operating in a frequency responsive mode and
- the aggregate plant responsiveness to changes in system frequency, as expressed by frequency droop (the change in plant output as a proportion of its rated capacity, relative to a change in system frequency);

The concept of aggregate frequency responsiveness is described further in appendix B.3.

Greater clarity will help those developing new generation projects to form clearer expectations of system requirements, as well as help to identify potential shortages in headroom/footroom which may limit aggregate system responsiveness. Consumers will have better information on the effectiveness of these services which they will ultimately pay for. This should be accompanied by simple, transparent reporting on the costs of providing the frequency performance payments to deliver these outcomes, akin to reporting on market ancillary services.

This new reporting obligation aligns with the expert technical advice provided to the AEMC by AEMO and GHD in advance of the draft determination. AEMO's advice noted that it will be increasingly important to track frequency performance under normal operating conditions.[110] GHD noted that there are future risks in relation to the provision of sufficient PFR to support power system security. These risks are associated with uncertainty in relation to the

107 Final rule, clause 4.8.16(b)(1A).

108 Final rule, clause 3.11.2A(b)(1)(v). The final rule more specifically describes this as being the total amounts paid to a Cost Recovery Market Participant in accordance with clause 3.15.6AA(b).

109 NER Cl 4.8.16(b)

110 AEMO, *Enduring primary frequency response requirements for the NEM*, August 2021, p.5.

sufficiency of frequency responsive headroom due to the exit of synchronous generation and increasing penetration of VRE over the coming decades.[111] Monitoring the aggregate frequency responsiveness in the power system, along with the performance of system frequency, will therefore play an important role in identifying any emerging challenges associated with frequency control in the NEM.

Stakeholders were generally supportive of the proposal to require AEMO to report on aggregate frequency responsiveness.[112]

The Commission's final rule is to include the new reporting requirement on AEMO as new clause 4.8.16(b)(1A), which commences on 8 September 2022. Schedule 1, item 8 of the *National Electricity Amendment (Fast frequency response market ancillary service) Rule 2021* (fast frequency response rule) also inserts new clause 4.8.16(b)(1A) which will commence on 9 October 2023. To avoid duplication in this paragraph reference, the Commission's final rule makes a necessary or consequential amendment to the fast frequency response rule to insert that item as new clause 4.8.16(b)(1B).

The Commission acknowledges GHD's advice that incentive arrangements may be appropriate for the current system needs, but there may be a need to procure or schedule necessary responsive plant and reserves post 2030 to ensure sufficient PFR. AEMO's expert technical advice also notes a perceived risk that insufficient PFR could be obtained during periods of little to no synchronous generation, with supply entirely provided by inverter based VRE, storage and DER. Reporting on the levels of aggregate frequency responsiveness and the impact of PFR on system frequency over time will provide a forewarning of the need for additional remedial action to support effective frequency control.

3.3.2 The AER to report on the costs of frequency performance payments

The final rule requires the AER to report on the costs of frequency performance payments as part of its existing obligation to report on costs of market ancillary services for each calendar quarter.[113] The drafting of this requirement in the final rule has been refined from that in the draft rule, due to the drafting approach taken to the frequency performance payment transactions. The Commission notes that reporting on the costs of the new frequency performance payments will be of equivalent importance to reporting on FCAS costs. This new reporting requirement will provide more complete information in relation to the costs associated with frequency control without significantly adding to the administrative burden for the AER.

Stakeholders were generally supportive of the proposal to require the AER to report on the costs of frequency performance payments.[114]

111 GHD, *Enduring Primary Frequency Response - CT2 – Power system operation and strategic regulatory advice*, 16 September 2021, p.59.

112 For example, submission to the second directions paper: AEC, p.5.; Snowy Hydro, p.2.

113 NER Cl. 3.11.2A.

114 For example, submission to the second directions paper: AEC, p.5.; Snowy Hydro, p.2.

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGC	Automatic generation control system
CF	Contribution factor
CER	Consumer energy resource
Commission	See AEMC
DCF	Default contribution factor
DER	Distributed energy resource
DSCP	Double-sided causer-pays
EA	Enablement amount
ESB	Energy Security Board
ESS	Essential system services
FCAS	Frequency control ancillary service
FFR	Fast frequency response
FI	Frequency indicator
FOS	Frequency operating standard
FPP	Frequency performance payment
GW	Gigawatt
ISP	Integrated System Plan
Hz	Hertz
MASS	Market ancillary service specification
MCE	Ministerial Council on Energy
MNSP	Market network service provider
MW	Megawatt
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	National Electricity Market dispatch engine
NEO	National Electricity Objective
NOFB	Normal operating frequency band
OSM	Operational security mechanism
PFCB	Primary frequency control band
PFR	Primary frequency response
PFRR	Primary frequency response requirements
PV	Photo-voltaic (solar power)
RCF	Residual contribution factor
RCR	Requirement for corrective response

RoCoF	Rate of change of frequency
RR	Regulation requirement
TA	Trading amount
TNSP	Transmission network service provider
U	Usage — of the relevant regulation service(raise or lower)
VPP	Virtual power plant
VRE	Variable renewable energy (generation)

A RULE MAKING PROCESS

This appendix outlines the rule change request and the related consultation process undertaken by the Commission.

A.1 AEMO's rule change request

On 3 July 2019, AEMO submitted a rule change request to the AEMC seeking changes to the NER to address perceived disincentives to the voluntary provision of PFR by participants in the NEM.[115] This rule change request was initiated under the project name: *Removal of disincentives to primary frequency response*. In July 2020, the project name was changed to *Primary frequency response incentive arrangements* to reflect the scope and objectives for this rule change request following on from the final determination for the *Mandatory primary frequency response rule* (Mandatory PFR).

The rule change request included a proposed rule.

A.1.1 Rationale for the rule change request

In the rule change request, AEMO sought to improve the performance of system frequency control through the removal of disincentives to the provision of PFR from generators.

The fundamental problem identified in AEMO's rule change request was the degradation of frequency performance in the NEM under normal operating conditions over the five-year period from 2015 to 2019.[116] AEMO claimed that the degradation of frequency performance during normal operation had resulted in the power system frequency spending more time further away from the target frequency of 50Hz than had historically been the case. This was evidenced as a flattening of the frequency distribution in the power system during normal operation.

AEMO also reported an increased incidence of exceedance events, where the power system frequency falls outside the normal operating frequency band (NOFB).[117] Many of these excursions occurred under normal operating conditions in the absence of a contingency event.

AEMO identified the degradation of frequency performance during normal operation as being caused by:

- a decline in the provision of PFR by generators, exacerbated by elements of the NER
- an increase in the variability of generation and load in the power system

115 Rule change request available on project web page: https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

116 AEMO, *Primary frequency response incentive arrangements - Electricity rule change proposal*, 3 July 2019, p.14.

117 The frequency operating standard requires that, in the absence of contingency events, the power system frequency is maintained within the normal operating frequency band (49.85 Hz - 50.15Hz) for 99% of the time. The frequency may exceed the normal operating frequency band for 1% of the time, but, in the absence of a contingency event, it must not exceed the normal operating frequency excursion band (49.75 – 50.25Hz).

- the inappropriateness of secondary regulation services to effectively control system frequency in the absence of PFR.[118]

A.1.2 Proposed solution

AEMO sought to resolve the issues discussed above by proposing a rule (proposed rule) to remove disincentives to the voluntary provision of PFR.

Through consultation with market participants, AEMO identified the following aspects of the NER as being perceived to provide disincentives to the voluntary provision of PFR:

1. Certain aspects of the arrangements for the allocation of costs associated with regulation services, known as 'causer pays' (NER Clause 3.15.6A).
2. A focus by generators on prioritising strict compliance with dispatch instructions over operating their plant in a frequency response mode and providing PFR (NER Clause 4.9.8).
3. A perception that the NER requires generators to provide PFR only when they are enabled to provide a Frequency control ancillary service (FCAS) (NER Clause 4.9.4 & Clause S5.2.5.11).

AEMO's proposed rule sought to address these perceived disincentives in the NER to remove barriers to the provision of voluntary PFR during normal operation and thereby halt the decline of frequency performance during normal operation.

Issues addressed in the Mandatory PFR rule

The Mandatory PFR rule 2020 included changes to NER clause 3.15.6A, cl 4.9.4, cl 4.9.8 and cl S5.2.5.11 to clearly acknowledge that it is expected and acceptable for generation output to vary from dispatch targets when providing PFR. These changes to the NER were made to address the latter two of the three disincentives set out above (items 2 and 3).

To address the disincentives created through item 1, AEMO's rule change proposed further changes to clause 3.15.6A such that providers of PFR, in accordance with parameters defined by AEMO, would not be allocated any share of regulation costs.[119] This proposal was not addressed by the Mandatory PFR rule. Rather, the Commission noted that further changes to the NER in relation to the causer pays arrangements would be considered through the assessment of the *Primary frequency response incentive arrangements* rule change request.[120]

In particular, the Commission recognised that a mandatory requirement for narrow-band PFR was not a complete solution for the long term and, on its own, will not incentivise the provision of primary frequency response. Further work needed to be done to understand the power system requirements for maintaining good frequency control, which would occur through the rule change that is the subject of this paper.

118 AEMO, *Primary frequency response incentive arrangements — Electricity rule change proposal*, 1 July 2019, p.16.

119 AEMO, *Primary frequency response incentive arrangements — Electricity rule change proposal*, 1 July 2019, p.27.

120 AEMC, *Mandatory primary frequency response — Rule determination*, 26 March 2020, p.127.

A.2 Consultation process

A standard rule change request includes the following formal stages:

- a proponent submits a rule change request
- the Commission commences the rule change process by publishing a consultation paper and seeking stakeholder feedback
- stakeholders lodge submissions on the consultation paper and engage through other channels to make their views known to the AEMC project team
- the Commission publishes a draft determination and draft rule (if relevant)
- stakeholders lodge submissions on the draft determination and engage through other channels to make their views known to the AEMC project team
- the Commission publishes a final determination and final rule (if relevant).

You can find more information on the rule change process in *The Rule change process – a guide for stakeholders.*[121]

For this rule change, the Commission discussed and sought stakeholder input on the relevant issues through an additional consultation paper and two additional directions papers, as set out below.[122]

A.2.1 Consultation papers

On 19 September 2019, the Commission published a consultation paper to commence the rule making process and consultation in respect of this rule change request, *Primary frequency response incentive arrangements*.[123] The Commission received 33 submissions in response to this consultation paper, which have informed the final determination and which have been responded throughout this process.

On 2 July 2020, the Commission published another consultation paper seeking further stakeholder input on this rule change request and how it should be assessed in the context of six other rule change requests that relate to the provision of system security services in the NEM.[124] The Commission received 43 submissions as part of this consultation, which have informed the final determination and which have been responded throughout this process.

A.2.2 First directions paper

On 17 December 2020, the Commission published a directions paper for both rule change requests that relate to the arrangements for frequency control in the NEM, *Fast frequency response market ancillary service* and *Primary frequency response incentive arrangements*.[125] The directions paper set out the Commission's initial views and high-level policy directions on

121 *The rule change process: a guide for stakeholders, June 2017, available here: https://www.aemc.gov.au/sites/default/files/2018-09/A-guide-to-the-rule-change-process-200617.PDF*

122 The relevant project documents are available on the AEMC project webpage: https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

123 This notice was published under s.95 of the National Electricity Law (NEL).

124 AEMC, *System services rule changes - consultation paper*, 2 July 2020.

125 AEMC, *Frequency control rule changes - directions paper*, 17 December 2020.

key issues in relation to the arrangements for fast frequency response and primary frequency response in the NEM. The Commission received 29 submissions , which have informed the final determination and which have been responded throughout this process.

A.2.3 Draft determination

On 16 September 2021, the Commission published a draft determination and draft rule, *Primary frequency response incentive arrangements. T*he Commission also published the following related documents alongside its draft determination:

- AEMO's technical white paper — *Enduring primary frequency response requirements for the NEM*
- AEMO's *Primary Frequency Response Incentive arrangements — discussion Paper*
- GHD's advice — *Enduring Primary Frequency Response*

Informed by AEMO and GHD advice, along with stakeholder submissions and the Commission's own analysis, the draft rule proposed to:

- confirm the mandatory primary frequency response arrangements that were established in March 2020 as enduring beyond the sunset date on 4 June 2023.
- introduce incentives, through frequency performance payments, for market participants to operate their plant in a way that helps to control power system frequency.
- improve the efficiency and effectiveness of the arrangements that exist to recover the costs of regulation FCAS by making them more transparent and by better aligning incentives to participant behaviour.
- include additional reporting requirements for AEMO and the AER in relation to frequency performance and the costs of frequency performance payments.

The Commission received 22 submissions in response to its draft rule determination, which have informed the final determination and which have been responded throughout this process.

A.2.4 Second directions paper

In response to stakeholder feedback on the draft determination and draft rule, the Commission published a second directions paper on 19 May 2022 which described a revised frequency performance payments process. The revised process was informed by detailed analysis provided by IES. The IES report, *Frequency performance payments analysis,* was published alongside the second directions paper.

The Commission received 8 submissions in response to the second directions paper, which have informed the final determination and which have been responded throughout this process.

B BACKGROUND AND CONTEXT

This appendix provides:

- a summary of related work by the market bodies and others
- an overview of the current 'causer pays' process for the allocation of costs for enablement of regulation services
- an explanation of the concept of aggregate frequency responsiveness.

B.1 Related work

This final rule determination is made in the context of a broad and ongoing program of reform that is being pursued by the market bodies and the Energy Security Board (ESB), comprising AEMO, the AER and the AEMC. This program encompasses the ESB's work on essential system services as part of its post-2025 market design along with a range of other related projects.[126]

Relevant work being undertaken by AEMO includes the consultation and publication of:

- The **Integrated System Plan** which is a whole-of-system plan that provides an integrated roadmap for the efficient development of the National Electricity Market (NEM) over the next 20 years and beyond.[127]
- The **Engineering framework** which aims to define the full range of operational, technical and engineering requirements needed to prepare the NEM power system for six identified future operational conditions, including preparation for 100% instantaneous penetration of renewable generation.[128]
- The **Market ancillary service specification** which defines the operational specifications for the various market ancillary services, including contingency and regulation FCAS.[129]
- The **Regulation FCAS Contribution Factor Procedure - Causer Pays**, which defines the process AEMO uses to determine contribution factors which are used for the allocation of costs for regulation services.[130]
- **Frequency and time deviation monitoring**, which provides weekly and quarterly monitoring reports of system frequency performance with respect to the requirement set out in the Frequency operating standard.[131]

126 Energy Security Board, Post 2025 market design - final advice to energy ministers, 26 August 2021. Available at https://esb-post2025-market-design.aemc.gov.au/

127 Refer to https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp

128 Refer to https://aemo.com.au/en/initiatives/major-programs/engineering-framework

129 Refer to https://aemo.com.au/consultations/current-and-closed-consultations/amendment-of-the-mass-very-fast-fcas

130 Refer to https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/ancillary-services-causer-pays-contribution-factors

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

- **Primary frequency response requirements** and related implementation monitoring reports for Mandatory PFR.[132]

The final determination builds on previous related work by the AEMC, including:

- The 2018 **Frequency control frameworks review**, which investigated whether the frequency control frameworks in the NEM were fit for purpose in the context of the ongoing transformation of the electricity system.[133] The review provided a series of recommendations and a frequency control work plan that sought to:
  - address the recent deterioration of frequency performance under normal operating conditions
  - promote transparency of NEM frequency control performance and the competitiveness of the frequency control ancillary service markets
  - remove inefficient barriers to the provision of essential frequency control services by new technologies.
- The **Monitoring and reporting on frequency control framework rule 2019**. Following on from one of the recommendations in the *Frequency control frameworks review*, this rule revised the requirements in the NER to clarify the obligations for AEMO to report on key frequency performance metrics on a weekly and quarterly basis and for the AER to report quarterly on the market outcomes related to the various FCAS products.[134]
- The **Mandatory primary frequency response rule 2020**, which introduced an interim requirement for all scheduled and semi-scheduled generators in the NEM to support the secure operation of the power system by responding automatically to changes in power system frequency.[135]
- The **Fast frequency response market ancillary service rule 2021**, which made changes to the NER to introduce new market ancillary service arrangements for very fast raise and very fast lower FCAS to help efficiently manage power system security during periods of low inertia operation.[136]

The Commission also notes the following active projects that are also part of the AEMC's system services work program:

- The Reliability Panel **Review of the Frequency operating standard**, which is discussed in section 1.3.1.[137]
- The **Operational security mechanism rule change**, which is considering solutions to better procure schedule and price essential system security services that aren't otherwise provided through the market.[138] The Commission plans to publish a draft determination for this rule change on 22 September 2022.

132 Refer to https://aemo.com.au/en/initiatives/major-programs/primary-frequency-response
133 Refer to https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review
134 Refer to https://www.aemc.gov.au/rule-changes/monitoring-and-reporting-frequency-control-framework
135 Refer to https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response
136 Refer to https://www.aemc.gov.au/rule-changes/fast-frequency-response-market-ancillary-service
137 Refer to https://www.aemc.gov.au/market-reviews-advice/review-frequency-operating-standard-2022
138 Refer to https://www.aemc.gov.au/rule-changes/operational-security-mechanism

- The **Efficient provision of inertia rule change**. This rule change, submitted on 15 December 2021 by the AEC, proposes the development of new market ancillary service arrangements for the provision of inertia in the NEM.[139] On 6 June 2022, the AEMC and AEMO published a joint paper to update stakeholders on the progress of the ESB's essential system services (ESS) reform initiatives, including those related to inertia and the AEC's rule change request, and seeking stakeholder feedback on the matters contained within.
- The **Operating reserve market rule change**, which is considering whether explicitly unbundling procuring and pricing operating reserves - rather than the current implicit approach - would promote the NEO. [140]

B.2 The current 'causer pays' process for allocation of regulation enablement costs

The NER sets out a process for the allocation of the costs of regulation services based on the measurement of plant performance and the degree to which a market participant contributes to, or 'causes', the need for regulation services. This procedure is commonly referred to as the 'causer pays' procedure. Allocating costs to those causing the need for frequency control aims to incentivise market participants to act to minimise the need for frequency control services.

This allocation is calculated using contribution factors that reflect the extent to which a market participant contributed to the need for the regulation services (i.e. contributes negatively). A negative contribution factor reflects plant behaviour that causes the need for regulation services, while a positive contribution factor reflects plant behaviour that reduces the need for regulation services. A market participant will not be considered to have contributed to the deviation in the frequency of the power system if they:[141]

- are a scheduled or semi-scheduled participant who is providing PFR in accordance with the *Primary frequency response requirements*,
- respond to a control signal for a market ancillary service to AEMO's satisfaction
- behave in a way that reduces the need for regulating services.

The current arrangements allow for positive contributions to offset negative contributions within a market participant's portfolio of plant with appropriate metering. However, any net positive contribution factor is zeroed out and therefore positive contributions are not fully valued under the existing arrangements. The methodology for determining contribution factors for each market participant is set out by AEMO in its causer pays procedure.[142] At a high level the process is based on two key elements:

139 Refer to https://www.aemc.gov.au/rule-changes/efficient-provision-inertia

140 Refer to https://www.aemc.gov.au/rule-changes/operating-reserve-market

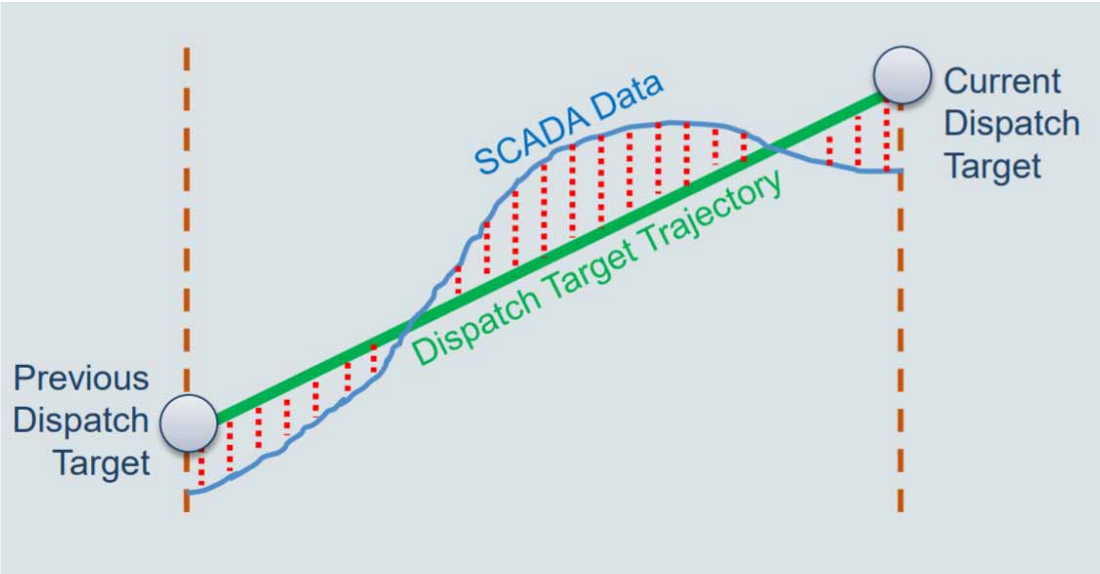
141 NER Cl. 3.5.6A(k)

142 This is referred to as the procedure for determining contribution factors in the NER. The current version is available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Regulation-FCASContribution-Factors-Procedure.pdff

- plant active power deviation, which is the difference between expected and actual plant behaviour; and
- a measure of the need for regulation services, frequency indicator (FI).

Plant active power deviation can be illustrated using the figure below which shows the plant initially providing less than the dispatch target trajectory (equivalent to regulation lower) and then above (regulation raise). Whether these are good or bad contributions depends on the frequency performance during this dispatch interval.

Figure B.1: Generation deviations for scheduled and semi-scheduled plant



Source: AEMO, Regulation FCAS contribution factor procedure - Determination of contribution factors for regulation FCAS cost recovery, 9 November 2018

The frequency indicator (FI) indicates whether more or less generation is required to adjust the frequency towards 50 Hz. This is not a direct measure of system frequency, but rather AEMO's estimate of the correction required to return power system frequency during normal operation to 50 Hz. Currently, AEMO makes this variable (FI) available to market participants at a slight delay (typically 15-30 minutes) through AEMO's data subscription service. [143]

Not all market participants have appropriate metering to determine individual contribution factors for the allocation of regulation costs. Under the current arrangements, market customers that do not have appropriate metering are allocated a share of regulation costs based on the total energy consumed in a period in proportion to the total customer energy for a period. These participants, which are typically not controlled through central dispatch or able to respond to correct power system frequency deviations, are referred to collectively as the 'residual'. The current framework limits the residual component to market customers only.

143 The data is also available publicly at http://www.nemweb.com.au/Reports/Current/Causer_Pays_Scada/

As such, non-scheduled generators that do not have appropriate metering are not allocated a share of the costs for regulation services. [144]

B.3 Explanation of aggregate frequency responsiveness

AEMO's technical advice makes the case that the objective for broad based universal narrow band PFR is for a high level of aggregate frequency responsiveness to be provided, to deliver stable frequency that is controlled close to 50Hz. [145] Aggregate frequency responsiveness, also referred to as system frequency bias or aggregate droop, is based on:

- the amount (in MW) of plant that are operating in a frequency responsive mode and
- the aggregate plant responsiveness to changes in system frequency, as expressed by frequency droop (the change in plant output as a proportion of its rated capacity, relative to a change in system frequency);

Figure B.2: Droop equation - proportional active power response to change in frequency

$$droop = \frac{df}{f_0}\ x\ \frac{P_{max}}{dP}$$

Where:

- df is the change in system frequency
- f_0 is the nominal system frequency – 50Hz
- P_{max} is the maximum rated power output for a generator
- dP is the change in active power for a generator

This relationship can be rearranged to describe the active power response to a change in frequency:

Figure B.3: Droop equation - rearranged for change in active power

$$dP = \frac{df}{f_0}\ x\ \frac{P_{max}}{droop}$$

Where:

- df is the change in system frequency
- f_0 is the nominal system frequency – 50Hz
- P_{max} is the maximum rated power output for a generator
- dP is the change in active power for a generator

144 Frequency control frameworks review final report Pages 10 - 11. Available at: https://www.aemc.gov.au/sites/default/files/201807/Final%20report.pdf

145 AEMO, Enduring primary frequency response requirements for the NEM, August 2021, pp. 16-17, 55.

Aggregated across the entire fleet of generation plant gives:

Figure B.4: Aggregate system droop equation

$$\sum_{i=1}^{n} dP_i = \frac{df}{f_0} \times \sum_{i=1}^{n} \frac{P_{max,i}}{Droop_i}$$

Where:

- df is the change in system frequency
- f_0 is the nominal system frequency – 50Hz
- P_{max} is the maximum rated power output for each generator
- dP is the change in active power for a generator
- droop is the % change in system frequency to drive power output to 100%
- i is the identifier for each generator
- n is the number of generators providing frequency response.

Note that any active power response will be limited by available headroom and footroom capacity. **Headroom** refers to the ability for a generator to increase its delivered generation in response to a change in system frequency. It is supported by available stored energy within the generation system that can be rapidly converted into electricity in a short time period, typically within a matter of seconds. Similarly, **footroom** refers to the ability for a generator to reduce its delivered generation.

The following table provides a comparison of different droop settings as they relate to generation capacity and the expected active power response to frequency variations within the Normal operating frequency band, 49.85 – 50.15Hz. For simplicity of calculation, this table assumes no control deadband, active power response commences for any deviation of frequency away from 50Hz.

Table B.1: Equivalent arrangements to deliver similar levels of aggregate frequency response (PFR)

	ACTIVE POWER 'DROOP' RESPONSE						
System frequency: *f*	49.85 Hz	49.90 Hz	49.95 Hz	50.00 Hz	50.05 Hz	50.10 Hz	50.15 Hz
Frequency error: df_{Hz} = f - 50	-0.15 Hz	-0.10 Hz	-0.05 Hz	0 Hz	0.05 Hz	0.10 Hz	0.15 Hz
Frequency error: $df_{\%}$ = df/50 x 100%	-0.3%	-0.2%	-0.1%	0	0.1%	0.2%	0.3%
5% droop active power response: $dP_{\%} = e_f$ / -5%	6%	4%	2%	0	-2%	-4%	-6%
Active power response from 1 x 250MW unit at 5% droop: $dP_{MW} = P_{max} \times dP_{\%}$	15 MW	10 MW	5 MW	0	-5 MW	-10 MW	-15 MW
a) Aggregate active power response from 35GW of plant at 5% droop	2100 MW	1400 MW	700 MW	0	-700 MW	-1400 MW	-2100MW
b) Aggregate active power response from 17.5GW of plant at 2.5% droop	2100 MW	1400 MW	700 MW	0	-700 MW	-1400 MW	-2100MW
c) Aggregate active power response from 7GW of plant at 1% droop	2100 MW	1400 MW	700 MW	0	-700 MW	-1400 MW	-2100MW

Source: AEMC

Note: As at 27 August 2021,As at 10 June 2022, AEMO reported Mandatory PFR settings had been implemented for approximately 40GW or 70% of the 58GW of eligible generation plant in the NEM. AEMO, Implementation of the National Electricity Amendment (Mandatory Primary Frequency Response) Rule 2020, 14 June 2022

Note: The *Interim primary frequency response requirements* includes a specification for affected plant to provide a minimum of 5% droop response outside of a frequency response deadband of ± 0.015Hz either side of 50Hz.

In each of the examples a), b) and c) above, the overall frequency bias MW/Hz is the same, but it is being delivered in different ways i.e. with less plant providing more aggressive response.

For example, a unit operating at 1% droop will deliver its maximum active power response for a 0.5Hz change in frequency compared to at 2.5Hz when operating at 5%. Therefore, each of the units in the 7GW of responsive plant in example c) will have to carry five times the reserve, per unit, to achieve the same outcome.[146]

The Commission makes the following observations based on this analysis:

- The expected maximum delivery of active power response for frequency variations within the normal operating frequency band is approximately three times greater than typical maximum contingency FCAS volumes in the order of 700MW for fast raise services.
- 7GW of plant operating at 1% droop can theoretically provide the same aggregate active power response as 35GW of plant operating at 5% droop.
- The above analysis shows that a small quantity of plant operating with more aggressive droop settings can theoretically provide the same aggregate active power response as a large quantity of plant operating with a more relaxed droop.

146 Note that if thermal plant were to provide such aggressive droop response, they may need to operate at levels near minimum dispatch to provide the required level of raise response. When operating near minimum load, thermal plant may have limited ability to provide frequency lower services by reducing active power output.

C SUMMARY OF OTHER ISSUES RAISED IN SUBMISSIONS TO THE SECOND DIRECTIONS PAPER

This appendix sets out the issues raised in response to the second directions paper on this rule change request and the AEMC's response to each issue. Responses to previous submissions were discussed in the draft determination and second directions paper. If an issue raised in a submission has been discussed in the main body of this document, it has not been included in this table.

Table C.1: Summary of other issues raised in submissions

STAKEHOLDER	ISSUE	AEMC RESPONSE
Shell Energy, Submission to the second directions paper, p.2.	Shell considers that the current target to target approach to determining a reference trajectory is flawed. They consider that this approach does not replicate the market dispatch process and the reference trajectory should instead be based on an initial to target approach.	This issue was investigated through the IES Frequency performance payment analysis, which demonstrated that the target to target reference trajectory approach was appropriate as it provided a linear and continuous basis against which to measure unit performance. The Commission notes that the decision on the specific approach to a reference trajectory is best managed by AEMO through the determination of the frequency contribution factors procedure, taking into account stakeholder views and operational matters.
Shell Energy - Submission to the second directions paper, p.3.	Shell energy sought clarification on the compliance implications relating to the interaction between Mandatory PFR and the provision of contingency FCAS.	The AEMC acknowledges this concern and notes that AEMO is actively considering this issue through its current review of the Market ancillary service specification.
Iberdrola - Submission to the second directions paper, p.5.	Iberdrola requested further clarification in relation to the treatment of contingency events or large deviations under the frequency performance payments process.	The frequency performance payments process is intended to operate for contingency events, as well as during normal operation. This approach is supported by IES through its frequency performance payments analysis (p.12). We note that

STAKEHOLDER	ISSUE	AEMC RESPONSE
		the frequency performance payments process requires unit data for each trading interval to be available and for AGC and NEMDE to be aligned with the system configuration. As a result, following some types of contingency events, such as separation events, it may not be practical to calculate contribution factors for a period of time. Also, given that the frequency performance payments are calculated for every five minute trading interval, the financial risk associated with being a causer of frequency deviation following a contingency event is expected to be muted. The Commission acknowledges the potential for extreme results to occur through the frequency performance payments process. It is expected that AEMO will further investigate these issues through the development of the frequency contribution factor procedure and incorporate appropriate control measures to avoid and limit unintended consequences.

D LEGAL REQUIREMENTS UNDER THE NATIONAL ELECTRICITY LAW

This appendix sets out the relevant legal requirements under the National Electricity Law (NEL) for the AEMC to make this final rule determination.

D.1 Final rule determination

In accordance with s.102 and 102A of the NEL the Commission has made this final rule determination in relation to the rule proposed by AEMO.

The Commission's reasons for making this final rule determination are set out in chapter 2.

A copy of the more preferable final rule is attached to and published with this final rule determination. Its key features are described in chapter 3.

D.2 Power to make the rule

The Commission is satisfied that the more preferable final rule falls within the subject matter about which the Commission may make rules. The more preferable final rule falls within s.34 of the NEL as it relates to the operation of the national electricity market, and the operation of the national electricity system for the purposes of the safety, security and reliability of that system.

Under s.91A of the NEL, the Commission may make a rule that is different (including materially different) to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule will or is likely to better contribute to the achievement of the NEO.

In this instance, the Commission has made a more preferable rule. The reasons are summarised in chapter 2.

D.3 Commission's considerations

In assessing the rule change request the Commission considered:

- it's powers under the NEL to make the rule
- the rule change request
- submissions received to the consultation paper, the second consultation paper, the directions paper, the draft rule determination and the second directions paper
- the Commission's analysis as to the ways in which the proposed rule will or is likely to, contribute to the NEO.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.[147]

The Commission may only make a rule that has effect with respect to an adoptive jurisdiction if satisfied that the proposed rule is compatible with the proper performance of AEMO's declared network functions.[148] The more preferable final rule is compatible with AEMO's declared network functions because it leaves those functions unchanged.

D.4 Making electricity rules in the Northern Territory

Test for scope of "national electricity system" in the NEO

Under the NT Act, the Commission must regard the reference in the NEO to the "national electricity system" as a reference to whichever of the following the Commission considers appropriate in the circumstances having regard to the nature, scope or operation of the proposed rule:[149]

(a) the national electricity system

(b) one or more, or all, of the local electricity systems[150]

(c) all of the electricity systems referred to above.

Test for differential rule

Under the NT Act, the Commission may make a differential rule if it is satisfied that, having regard to any relevant MCE statement of policy principles, a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.[151] A differential rule is a rule that:

- varies in its term as between:
  - the national electricity systems, and
  - one or more, or all, of the local electricity systems, or
- does not have effect with respect to one or more of those systems

but is not a jurisdictional derogation, participant derogation or rule that has effect with respect to an adoptive jurisdiction for the purpose of s. 91(8) of the NEL.

147 Under s.33 of the NEL the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for energy. On 1 July 2011, the MCE was amalgamated with the Ministerial Council on Mineral and Petroleum Resources. In December 2013, it became known as the Council of Australian Government (COAG) Energy Council. In May 2020, the Energy National Cabinet Reform Committee and the Energy Ministers' Meeting were established to replace the former COAG Energy Council.

148 Section 91(8) of the NEL.

149 Clause 14A of Schedule 1 to the NT Act, inserting section 88(2a) into the NEL as it applies in the Northern Territory.

150 These are specified Northern Territory systems, listed in schedule 2 of the NT Act.

151 Clause 14B of Schedule 1 to the NT Act, inserting section 88AA into the NEL as it applies in the Northern Territory.

As the rule relates to parts of the NER that currently do not apply in the Northern Territory, the Commission has not assessed the rule against the additional elements required by the Northern Territory legislation.[152]

D.5 Civil penalties

The Commission cannot create new civil penalty provisions. However, it may recommend to the Energy Ministers' Meeting that new or existing provisions of the NER be classified as civil penalty provisions.

The Commission's final more preferable rule amends clause 4.4.2(c1) of the NER. This paragraph is currently classified as a civil penalty provision under NER Schedule 1 of the National Electricity (South Australia) Regulations.

The Commission considers that clause 4.4.2(c1) should continue to be classified as a civil penalty provision. The AEMC consulted with the AER on the amendment to clause 4.4.2(c1) and the AER supports these changes. Therefore, the Commission does not propose to recommend any change to its classification to the Energy Ministers' Meeting.

D.6 Conduct provisions

The Commission cannot create new conduct provisions. However, it may recommend to the Energy Ministers' Meeting that new or existing provisions of the NER be classified as conduct provisions.

The final rule does not amend any rules that are currently classified as conduct provisions under the NEL or National Electricity (South Australia) Regulations. The Commission does not propose to recommend to the Energy Ministers' Meeting that any of the proposed amendments made by the final rule be classified as conduct provisions.

152 From 1 July 2016, the NER, as amended from time to time, apply in the NT, subject to derogations set out in regulations made under the NT legislation adopting the NEL. Under those regulations, only certain parts of the NER have been adopted in the NT. See the AEMC website for the NER that applies in the NT (*National Electricity (Northern Territory) (National Uniform Legislation) Act 2015*).

E ESTIMATED FINANCIAL IMPACTS FROM THE NEW FREQUENCY PERFORMANCE PAYMENTS PROCESS

The IES *Frequency performance payments analysis* produced settlement results that provide an indication of the scale of financial outcomes that would be expected following the implementation of a frequency performance payments process based on the framework set out in the revised rule.[153] The Commission considers that these calculations are equally applicable in the case of the final rule.

The high level findings from the IES analysis are:

- that the scale of gross frequency performance payments (and cost allocations) would be expected to be similar in size to the total costs for regulation services.
- that the net payments, taking into account payments and cost allocations that cancel out over the relevant period, would be expected to be in the order of one third of the costs of regulation services.

These results provide a valuable indication of the scale of frequency performance payments relative to the costs of regulation services. As a point of reference, historical regulation costs in the NEM range from $4.6 million in 2013 to $126.8 million in 2019, with an average over recent years (2019 to 2021) of $93 million.[154] Based on the historical cost for regulation services being an accurate representation of future costs and ignoring dynamic economic effects, the scale of gross frequency performance payments would be expected to be in the order of $90 million per year, while the net payments would be expected to be in the order of $30 million per year.

The Commission notes that the IES analysis is a static analysis based on historical data, it does not account for dynamic economic effects and is not likely to provide an accurate indication of the actual size of frequency performance payments following implementation of the process set out in the revised rule. The Commission expects that the implementation of frequency performance payments would put downward pressure on regulation prices, based on dynamic market effects.

For example, the IES analysis shows that, where the reference trajectory is based on target to target only, and does not include the regulation component, plant enabled to provide regulation services will receive a substantial portion of the frequency performance payments. Provided that the FCAS markets are sufficiently competitive, the additional revenue provided to regulation providers would be expected to place downward pressure on the market prices for regulation services.

Following the implementation of the frequency performance payments arrangements, the price for regulation services would be expected to drop until a new dynamic equilibrium is

153 IES, Frequency performance payments analysis, 19 May 2022, p.6. Available on the AEMC project page: https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

154 See analysis of historical regulation costs included in Appendix C of the Draft Determination.

found, where the combined revenue from frequency performance payments and regulation enablement balances out against the costs of providing PFR and the regulation service(s).

The high level results from the IES short period analysis are shown in Figure E.1.

The high level results from the IES long period analysis are shown in Figure E.2.

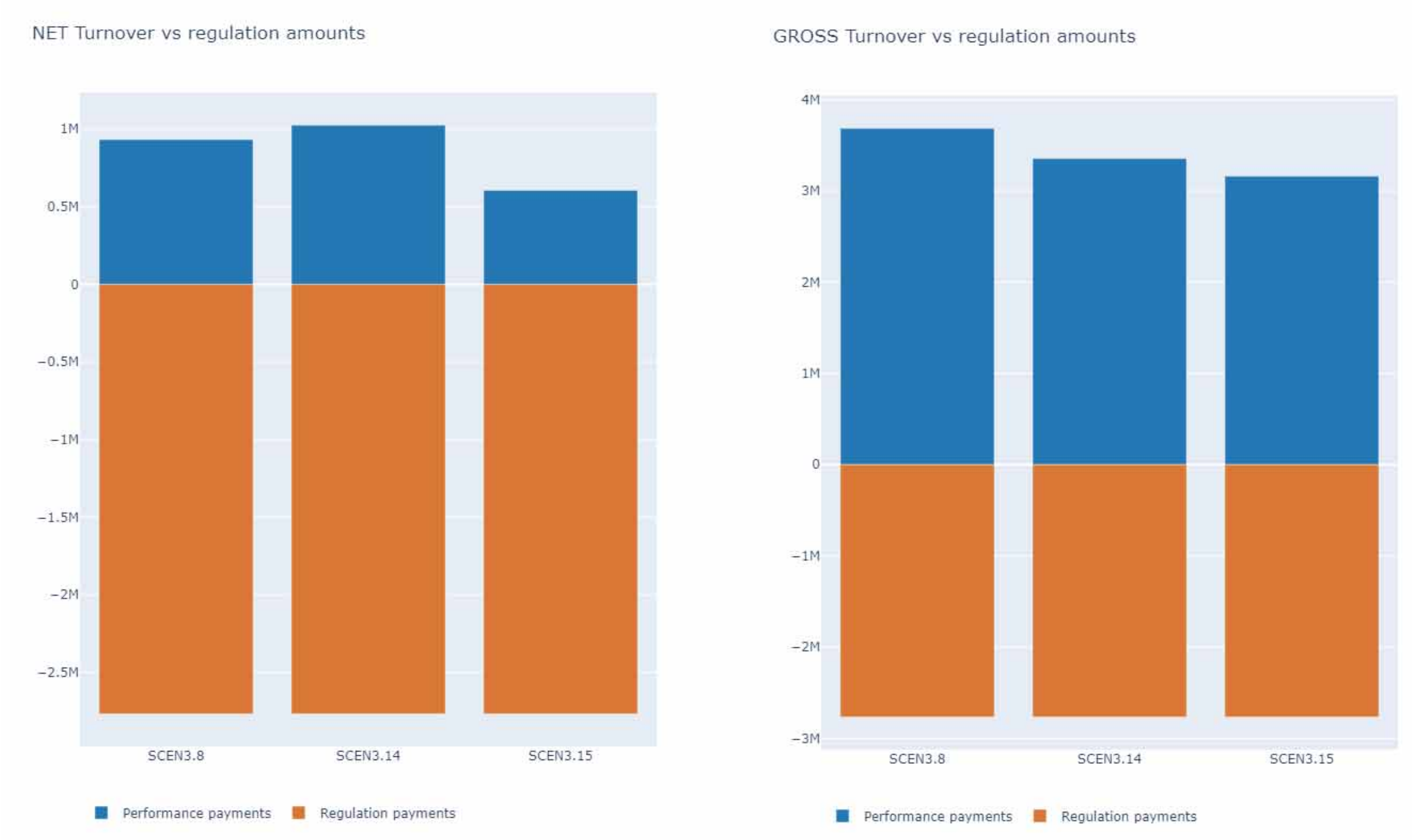
These results are based on the following calculation scenarios:[155]

- Scenario 3.8 — normalised factors — Gross dispatch error scaling
  - Performance metric: Combined Hertz
  - Reference trajectory: Target to target
  - Contribution factor normalisation: yes — unit deviations divided by aggregate deviations
  - Scaling: by Gross dispatch error
- Scenario 3.14 — Raw factors — Hz spread scaling
  - Combined Hertz performance metric
  - Target to target reference trajectory
  - Contribution factor normalisation: No — Contribution factors maintained in the raw form, unit deviations multiplied by frequency deviations to produce deviation factor in units of MWHz.
  - Scaling by frequency reference at which the deviations are priced — in this case, the inverse of the mandatory PFR deadband of 0.015Hz was used = 1/0.015.
- Scenario 3.15 — Normalised factors — Gross dispatch error scaling — Inclusion of regulation component
  - Performance metric: Combined Hertz
  - Reference trajectory: Target to target plus regulation component
  - Contribution factor normalisation: yes — unit deviations divided by aggregate deviations
  - Scaling: by Gross dispatch error

For these results, net turnover represents the expected revenues for each eligible unit after the netting out of positive and negative payments over the relevant time period - in this case two weeks. Gross turnover reflects the total positive frequency performance payment for each eligible unit over the relevant period. It does not account for negative frequency performance payments that may occur over the same period.

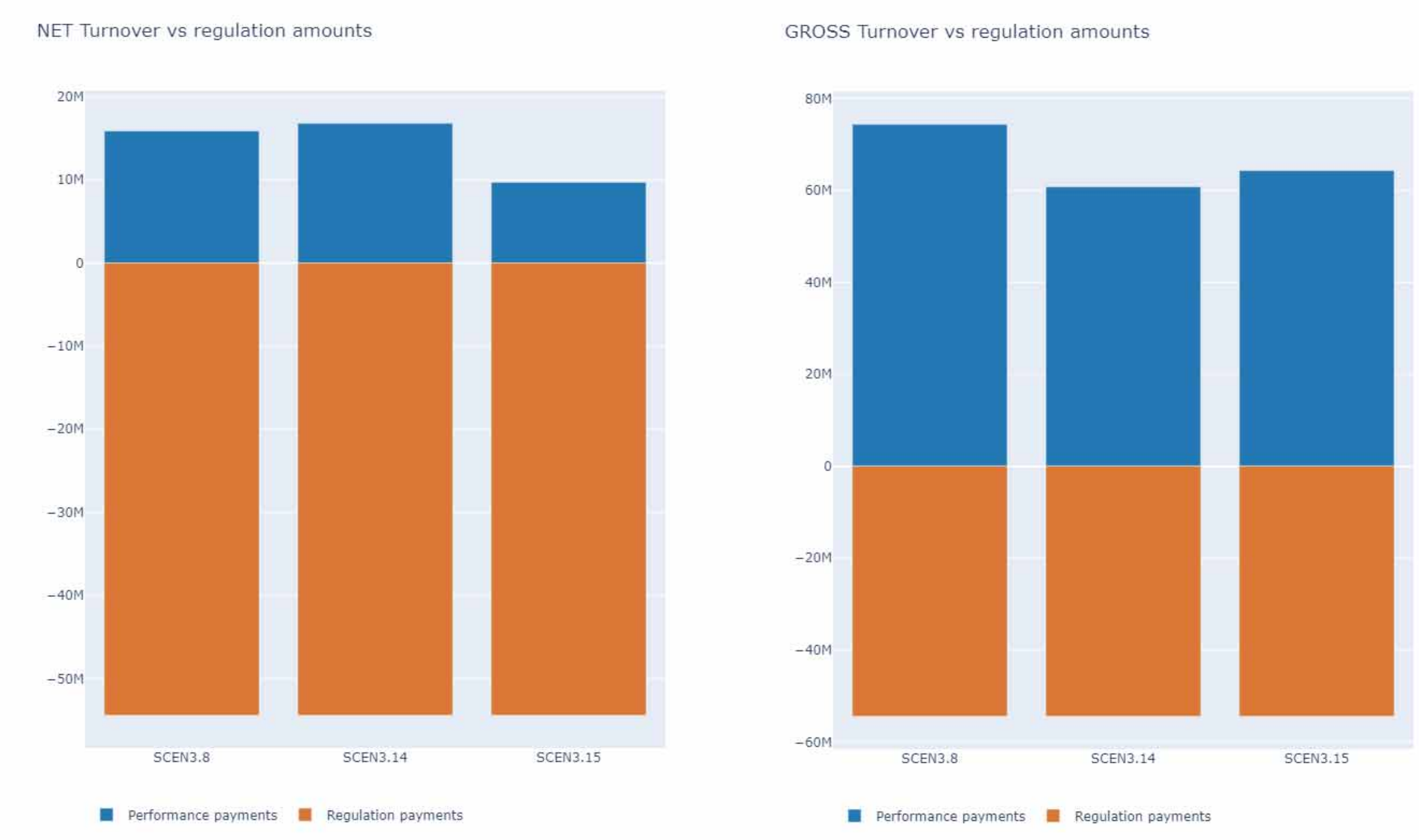
155 Refer to chapter 4 of the IES report for further detail on these scenarios. IES, Frequency performance payments analysis, 19 May 2022.

Figure E.1: Turnover vs regulation costs for short period analysis



Source: IES, Frequency performance payments analysis, 19 May 2022.
Note: Based on IES analysis of causer pays data for the two weeks commencing on 1 September 2021

Figure E.2: Turnover vs regulation costs for long period analysis



Source: IES, Frequency performance payments analysis, 19 May 2022.
Note: Based on IES analysis of causer pays data for the two weeks commencing on 1 September 2021

F SUMMARY OF THE FINAL RULE

The following tables summarise the provisions under the final rule and the changes from the draft rule and revised rule drafting including the reasons for change, where relevant.

- Table F.1 relates to the Mandatory PFR requirement, discussed in section 3.1, and the reporting obligations for AEMO and the AER discussed in section 3.3.
- Table F.2 relates to the transactions for frequency performance payments, which are discussed in section 3.2.1.
- Table F.3 relates to the allocation of costs for regulation services, which is discussed in section 3.2.2.
- Table F.4 relates to the process for the calculation of frequency contribution factors, which is discussed in section 3.2.3.

Table F.1: **Mandatory Primary frequency response & reporting obligations**

ELEMENT	DRAFT RULE	FINAL RULE	REASONING
Mandatory PFR requirement Final rule clause 4.4.2 (c1)	Confirmation of the Mandatory PFR obligation as enduring. This involves the removal of the sunset for mandatory PFR by revoking Schedule 2 of the National Electricity Amendment (Mandatory primary frequency response) Rule 2020, which would have ended the existing Mandatory PFR arrangement on 4 June 2023.	**Similar to the draft rule** Confirmation of the Mandatory PFR obligation as enduring and revoking of the sunset provisions. Clarification that the Mandatory PFR obligation applies to each Scheduled Generator and Semi- Scheduled Generator that has received a dispatch instruction, in accordance with clause 4.9.2 to generate a volume greater than zero MW must operate its generating system in	The mandatory PFR requirement supports the secure and resilient operation of the power system, consistent with expert advice provided by AEMO and GHD. The Commission notes that while Mandatory PFR is supported by power system engineers, NSPs and a handful of market participants; many generator representatives oppose its confirmation and the removal of

ELEMENT	DRAFT RULE	FINAL RULE	REASONING
		accordance with the Primary Frequency Response Requirements applicable to that generating system.	the sunset. Expert advice provided to the Commission supports i continuation. In response to stakeholder feedback, suggesting a review the governance arrangements under the rule allow for the Reliability Panel to review the appropriate setting for the primary frequency control band through its review of the FOS. In response to stakeholder feedback, the final rule includes clarification that the Mandatory PFR requirement only applies to generators that receive an energy dispatch target that is greater than zero MW. Refer to section 3.1 for further detail.
Frequency performance reporting Final rule clause 4.8.16 (b)(1A)	AEMO must report on the level of aggregate frequency responsiveness in the power system as part of its quarterly report of power system frequency.	**As per the draft rule.**	This requirement provides additional transparency in relation to the aggregate frequency responsiveness in the power system, which will help inform future considerations in

ELEMENT	DRAFT RULE	FINAL RULE	REASONING
			relation to whether sufficient levels of PFR are available in the system and the implications of this for system frequency performance. Refer to section 3.3 for further detail.
Reporting on the costs of frequency control Final rule clause 3.11.2A (b)(1)(v)	The AER must report on the total amount of frequency performance payments paid to market participants in its quarterly report on the costs of market ancillary services.	**Change from the draft rule.** The AER must report on the total amounts paid to a Cost Recovery Market Participant in accordance with the frequency performance payments provisions in its quarterly report	This requirement provides additional transparency in relation to the costs associated with frequency performance payments, consistent with the existing reporting requirements for FCAS costs. The final rule includes a minor drafting change to more accurately reflect what is to be reported. Refer to section 3.3 for further detail.

Note: These issues were not covered or consulted on through the second directions paper and revised rule which was focused on a revised frequency performance payments process as covered by Table F.2, Table F.3 and Table F.4.

Table F.2: Transactions for Frequency performance payments — Final rule cl. 3.15.6AA (b)

ELEMENT	DRAFT RULE	REVISED RULE	FINAL RULE	REASONING
Valuation of positive performance and allocation of costs.	Frequency performance payments made to participants with positive contribution factors. Costs allocated to participants with negative contribution factors.	**As per the draft rule.**	**Change from the revised rule.** Frequency performance payments made to participants with positive contribution factors based only on performance measured during the relevant trading interval. Costs allocated to participants with negative contribution factors.	Stakeholders were generally supportive of the concept of valuing helpful plant behaviour through frequency performance payments and the allocation of the costs to plant with negative contribution factors. In response to feedback from AEMO on the revised rule, the final rule includes changes to reflect that payments can only be made based on verified positive performance for the relevant trading interval, not based on historical unit performance.
Normalisation of contribution factors	Positive contribution factors divided (normalised) by the sum of all negative contributions.	**Change to the draft rule** Positive (or negative) unit contributions are normalised by the sum of all positive (or all negative) contributions.	**As per the revised rule.**	The process is based on a system-wide energy balance that is intended to measure all deviations. This approach results in positive contribution factors being equal to negative factors. As a result, scaling by positive contribution factors divided by the sum of all negative contributions is not required. Refer to section 4.2.1 of the second directions paper for further detail.
Financial weighting of	Frequency performance	**Change to the draft rule**	**As per the revised rule.**	Positive performance is valued through direct reference to the regulation price,

ELEMENT	DRAFT RULE	REVISED RULE	FINAL RULE	REASONING
frequency performance payments	payments weighted by the costs of regulation services (raise or lower).	Frequency performance payments weighted by the price of regulation services (raise or lower) in $/MW for each trading interval.		rather than the costs of regulation services. This approach helps to simplify the Frequency performance payment transactions, relative to the draft rule. Refer to section 4.2.2 of the second directions paper for further detail.
Scaling of frequency performance payments	Frequency performance payments scaled by the ratio of regulation requirement divided by regulation enablement amount (RR/EA).	**Change to the draft rule** Frequency performance payments scaled by a measure of the aggregate requirement for corrective response in MW (RCR).	**Similar to the revised rule.** Frequency performance payments scaled a measure of the aggregate requirement for corrective response in MW (RCR). The final rule clarifies that AEMO may specify parameters that adjust the value of RCR.	Payments are scaled by the aggregate requirement for corrective response. This is intended to measure and account for all helpful deviations and is a simplified version of the RR/EA term from the draft rule. Refer to section 4.2.3 of the second directions paper for further detail. The final rule also clarifies that AEMO may include parameters to adjust the scaling amount. Refer to section 4.2.3 of the second directions paper and section 3.2.1 for further detail.

Table F.3: Allocation of costs for enablement of regulation services

ELEMENT	DRAFT RULE	REVISED RULE	FINAL RULE	REASONING
Allocation of costs for regulation services — used Final rule clause 3.15.6AA (c)	Costs of services used allocated based on negative participant contribution factors determined over the trading interval.	**As per the draft rule**	**As per the revised rule.**	The negative contribution factors determined for a trading interval represent a good measure of those who caused the need for regulation services. This is a real time application of the current causer pays process and is generally accepted by stakeholder submissions to the draft determination. Refer to section 3.2.2 for further detail.
Allocation of costs for regulation services — not used Final rule clause 3.15.6AA (d)	Costs of services not used allocated based on energy consumed or generated during the trading interval.	**Change to the draft rule** Costs of services not used allocated based on negative default contribution factors.	**As per the revised rule.**	Stakeholder responses to the draft determination were broadly unsupportive of the proposal to allocate a portion of regulation costs based on energy consumed or generated during the trading interval. The allocation of costs for services not used based on default contribution factors is an approach that reflects the long-term behaviour of power system plant. This provides a longer-term incentive for helpful active power response, while avoiding some of the drawbacks of allocating costs based on energy consumed or generated. Refer to section 3.2.2 for further detail.

Table F.4: **Frequency contribution factors and the frequency contribution factor procedure**

ELEMENT	DRAFT RULE	REVISED RULE	FINAL RULE	REASONING
Contribution factor objective Final rule clause 3.15.6AA (f)	The contribution factor reflects the contribution to the need for, or reduction in the need for, the regulating raise (or regulating lower) service.	**Change to the draft rule** • 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*; • A negative contribution factor should reflect the extent to which the unit contributed to increasing the deviation in frequency of the power system.	**As per the revised rule.**	The revised objective for the contribution factors under the revised rule drafting and final rule provides a closer linkage with the frequency of the power system and removes the reference to regulation services. Refer to section 4.1.1 of the second directions paper for further detail.
Unit aggregation Final rule clause 3.15.6AA(a) local definition of 'eligible unit, and clause 3.15.6AA(e)	Contribution factors determined for each market participant based on the aggregate of all plant within their portfolio.	**Change to the draft rule.** Contribution factors determined separately for each eligible unit (DUID) registered generation and load.	**As per the revised rule.**	Unit contribution factors will avoid distortions due to portfolio aggregation. AEMO already calculates unit factors through the existing causer pays procedure, therefore implementation will be straightforward. Refer to section 4.1.1 of the

ELEMENT	DRAFT RULE	REVISED RULE	FINAL RULE	REASONING
				second directions paper for further detail.
Raise/lower categorisation Final rule clause 3.15.6AA (f)(5)	Separate contribution factors to be determined with respect to the need for raise and lower response.	**As per the draft rule**	**As per the draft rule**	The determination of separate contribution factors with respect to raise and lower response enables each type of behaviour to be valued relative to the respective price for raise or lower response. This reflects the different price signals provided by the market for raise and lower regulation services. Refer to section 4.1.1 of the second directions paper for further detail.
Timing of sample and application periods. Final rule clause 3.15.6AA (f)(5)	Contribution factors for a trading interval to be determined based on data sampled from the same trading interval, unless it is impractical to do so.	**As per the draft rule**	**As per the draft rule.**	There was general stakeholder support for the alignment of the sample and application periods over a single trading interval. Refer to section 4.1.1 of the second directions paper for further detail.
Methodology used to determine the requirement for corrective	N/A	**New element in the revised rule** The procedure must include the	**Similar to the revised rule.** The procedure must include the methodology AEMO will use to	Minor drafting change to clarify that the methodology may include parameters to be determined by AEMO from time

ELEMENT	DRAFT RULE	REVISED RULE	FINAL RULE	REASONING
response (RCR) Final rule clause 3.15.6AA (g)(6)(i)		methodology AEMO will use to determine RCR.	determine RCR, which may include parameters to be determined by AEMO from time to time.	to time. Refer to section 3.2.3 for further detail.
Methodology used to determine the 'usage" (U) for regulation raise and lower services Final rule clause 3.15.6AA (g)(6)(ii)	N/A	'Usage' was described as the maximum proportion of the dispatched regulating raise or lower service used by AEMO in that trading interval.	**New element in the final rule** The procedure must include the methodology AEMO will use to determine the usage for regulation services in each trading interval. This 'usage' is defined as the proportion of enabled regulating raise or lower service that contributed to reducing the deviation in frequency of the power system.	The final rule includes additional provisions such that AEMO must specify a methodology used to determine the usage for regulation services. This was included to give AEMO more flexibility as to the approach used to determine 'usage'. Refer to section 3.2.3 for further detail.
Principles related to Default contribution factors Final rule clause 3.15.6AA (f)(8), (f)(9).	No requirement in the draft rule.	No requirement in the revised rule.	**New element in the final rule** The final rule includes the following principles that relate to default contribution factors: • a default contribution factor must be determined based on historical data for that eligible unit unless in *AEMO*'s reasonable	In response to AEMO's feedback on the revised rule, the final rule includes additional principles in relation to default contribution factors. These principles clarify that: • a default contribution factor should be determined based on historical unit data, but AEMO may develop an alternative

ELEMENT	DRAFT RULE	REVISED RULE	FINAL RULE	REASONING
			opinion it is impractical to do so. • in relation to frequency performance payments, a default contribution factor may only be used for the allocation of costs.	method, if it is not practical to use historical unit data. • default contribution factors may only be used for allocation of costs - not for positive frequency performance payments. Refer to section 3.2.3 for further detail.
Methodology for determining Default contribution factors Final rule clause 3.15.6AA (g)(4)	No requirement in the draft rule.	**New in the revised rule** The procedure must include the method AEMO will use to determine a default contribution factor to be used: • where it is impractical to determine a contribution factor for a unit in a trading interval based on data measured for that trading interval. • for the allocation of costs of regulation services - not used.	**As per the revised rule.**	This clarifies AEMO's responsibility to set out in the procedure, the method used to determine default contribution factors. Refer to section 4.1.1 of the second directions paper for further detail.
The system frequency metric Final rule clause	The procedure must include a formula to describe the objective for controlling power	**Similar to the draft rule** The procedure must include a formula (based on system	**As per the revised rule.**	This requirement is intended to provide market participants with transparency in relation to how the plant performance will be

ELEMENT	DRAFT RULE	REVISED RULE	FINAL RULE	REASONING
3.15.6AA (g)(2)	system frequency.	frequency) to be used to calculate the measure of the need to raise or lower the *frequency* of the *power system.*		measured. It provides guidance and flexibility for AEMO in relation to how the system frequency metric is specified in the frequency contribution factor procedure. Refer to section 4.1.2 of the second directions paper for further detail.
Reference trajectory Final rule clause 3.15.6AA (g)(7)	The procedure must describe the method AEMO will use to determine a reference trajectory for plant that has appropriate metering. This <u>must</u> be informed by: • the dispatch target (level) for scheduled (semi-scheduled) plant. • Information provided by non-scheduled market participants.	**Similar to the draft rule** Under the revised rule, AEMO would only be required to include information provided by non-scheduled market participants where it is practical to do so.	**Similar to the revised rule** The procedure must describe the method used to determine a reference trajectory for plant that has appropriate metering. This <u>must</u> be informed by: • the dispatch target (level) for scheduled (semi-scheduled) plant. • information provided by non-scheduled market participants (where practical) It <u>may</u> be informed by any other factor that AEMO determines to	The Commission's determination is that method used to determination a reference trajectory is best decided by AEMO through consultation on the frequency contribution factor procedure. This approach is supported by AEMO and the AEC. AEMO provided feedback to the second directions paper that the voluntary references to the option of including electronic signals relevant to regulation services was not needed as the catch all clause would suffice.

ELEMENT	DRAFT RULE	REVISED RULE	FINAL RULE	REASONING
	It may be informed by the regulation component for enabled units.		be relevant.	Refer to section 3.2.3 for further detail.
Regional considerations Final rule clause 3.15.6AA (f)(7) and (g)(2)	AEMO must determine contribution factors to apply in a region during asynchronous operation.	**Change to the draft rule** AEMO must determine contribution factors based on the power system frequency measured in each NEM region (where practical).	**Change to the revised rule** AEMO will determine contribution factors with respect to the global or local market ancillary service requirement for the regulating raise service or regulating lower service.	The objective here is to align the economic incentives with operational objectives following islanding of a NEM region and for the operation of the Tasmanian region. For the final rule clarifies the link between the contribution factor and the requirement for a regulation service. Refer to section 3.2.3 for further detail.
Data collection Final rule clause 3.15.6AA (g)(5)	No requirement in the draft rule.	**New in the revised rule** AEMO's procedure must specify the data that AEMO will use to determine contribution factors. The relevant data must include active power output or consumption and may include local frequency, electronic signals received from AEMO	**Changed from the revised rule** AEMO's procedure must specify the data that AEMO will use to determine contribution factors. The relevant data must include active power output or consumption and may include local frequency-and any other	This provides transparency in relation to data collected to support the determination of contribution factors. References to electronic signals are removed in response to AEMO's submission to the second directions paper which

ELEMENT	DRAFT RULE	REVISED RULE	FINAL RULE	REASONING
		and any other data AEMO considers relevant.	data AEMO considers relevant. (Reference to electronic signals received from AEMO removed.)	noted that electronic signals are not directly relevant to unit performance measurement. Refer to section 3.2.3 for further detail.
Publication of relevant data — as soon as is practicable after the relevant trading interval Final rule clause 3.15.6AA(k)	AEMO must publish as soon as is practicable after the relevant trading interval: • contribution factors • data related to the objective for controlling power system frequency.	**As per the draft rule**	**Similar to the revised rule** AEMO must publish as soon as is practicable after the relevant trading interval: • contribution factors • data related to the measure of the need to raise or lower the power system frequency • the requirement for corrective response • the usage of regulation services	The final rule clearly describes the data publication requirements for AEMO, in relation to the frequency contribution factors procedure. These data publication requirements are intended to provide increased transparency to market participants. Refer to section 3.2.3 for further detail.
Publication of relevant data — other Final rule clause 3.15.6AA (i), (j), (l).	AEMO must publish: • any parameters related to the objective for controlling power system frequency, at least 5 business days prior to their	**Similar to the draft rule** AEMO must publish: • any parameters related to the measure of the need to raise or lower the frequency of the power system, at least 5	**Changed from the revised rule** AEMO must publish: • any data that will be used to determine default contribution factors, at least 5 days before	The final rule clearly describes the data publication requirements, with respect to parameters related to the system performance metric, and RCR and data related to the calculation of contribution

ELEMENT	DRAFT RULE	REVISED RULE	FINAL RULE	REASONING
	application. • the data used to determine contribution factors, in accordance with the timetable for provision of market information	business days prior to their application. • the data used to determine contribution factors, in accordance with the timetable for provision of market information. • default contribution factors at least 5 days before the period in which they will apply.	the period in which the default contribution factors will apply. • any parameters related to the measure of the need to raise or lower the frequency of the power system, at least 5 business days prior to their application. • any parameters related to RCR, at least 5 business days prior to their application. • the data used to determine contribution factors, including measured data, in accordance with the timetable for provision of market information	factors and default contribution factors. In response to feedback from AEMO on the revised rule, the final rule requires AEMO to publish any data that will be used to determine default contribution rather than the actual default contribution factors. Refer to section 3.2.3 for further detail.

Note: 1. AEMO, Submission to the draft determination, 2 November 2021, p.8.