Enduring Primary Frequency Response

CT2 – Power system operation and strategic regulatory advice

Australian Energy Market Commission

16 September 2021

GHD Pty Ltd ABN 39 008 488 373
Level 9, 145 Ann Street
Brisbane, QLD 4000, Australia
T (07) 3316 300 | **F** (07) 3316 3333 | **E** bnemail@ghd.com | **ghd.com**

Printed date	9/2/2021 6:22:00 PM
Last saved date	2 September 2021 6:22 PM
File name	Enduring Primary Frequency Response Final Draft.docx
Author	David Bones, Paul Espie, Christian Schaefer
Project manager	Jack O'Brien
Client name	Australian Energy Market Commission
Project name	Enduring Primary Frequency Response Arrangements
Document title	Enduring Primary Frequency Response | CT2 – Power system operation and strategic regulatory advice
Revision version	Rev 2.2
Project number	12549091

Document status

Status Code	Revision	Author	Reviewer		Approved for issue		
			Name	Signature	Name	Signature	Date
Draft	1.0	Christian Schaefer	Paul Espie		David Bones		15/07/21
Final	2.0	Christian Schaefer	Paul Espie		David Bones	DBones	9/08/21
Revision	2.1	Christian Schaefer	Paul Espie		David Bones	DBones	20/08/21
Minor Review	2.2	Christian Schaefer	Paul Espie		David Bones	DBones	31/08/21

Executive Summary

This report is subject to, and must be read in conjunction with, the limitations set out in Section 1 and the assumptions and qualifications contained throughout the Report.

In their 2020 final rule and determination for managing frequency in the National Electricity Market (NEM) the AEMC placed a mandatory requirement on generators to provide Primary Frequency Response (PFR). This addresses the immediate system concern of reduced primary frequency control in the NEM. However, the Commission recognised that a mandatory requirement is unlikely to meet the National Electricity Objective (NEO) and the system services objective[1]. That is, encouraging efficient investment in and efficient operation and use of generation systems to provide optimal outcomes for consumers over the long-term. This resulted in a sunset clause being included in the final rule; the rule will expire on 4 June 2023.

Ahead of the activation of the sunset clause in 2023, the Commission has published a directions paper on enduring PFR arrangements in the NEM in December 2020 and identified three future pathways:

1. Maintain the existing mandatory PFR (MPFR) arrangement with improved PFR pricing
2. Revise the MPFR arrangement by widening the frequency response band and developing new Frequency Control Ancillary Services (FCAS) arrangements for the provision of PFR during normal operation (primary regulating services)
3. Remove the MPFR arrangement

To support their decision making, the AEMC has sought independent advice from GHD in determining enduring PFR arrangements as identified in the directions paper, with respect to the NEO and the system services objective.

To provide input to the AEMC decision making we have collected information from a variety of sources on the following key topics to establish our analysis for the most effective pathway of enduring PFR:

- Provision of PFR from various generating technologies and their limitations
- Management of PFR in other jurisdictions
- Assessing the wider system impact of aggregated narrow band PFR and frequency performance
- Impact of PFR provision on generating equipment

This information was then used to assess advantages and disadvantages of each of the three pathways for enduring PFR arrangements identified by the Commission and compare them using a Multi Criteria Analysis (MCA) against a number of criteria to capture the effectiveness of each of the pathways.

Based on the outcomes of the MCA and our considerations of broader system performance and plant impact, we consider that mandatory narrow band PFR should be implemented permanently after the sunset clause of the current mandatory frequency responsiveness takes effect in 2023.

We recommend Pathway #1 of continuing **mandatory narrow band Primary Frequency Control** for a number of reasons:

- Aggregate PFR from all online generating systems to effectively manage frequency during normal operating conditions will mean less movement of individual generator active power. We expect more frequent lower magnitude movement which is less likely to create adverse impacts on individual plant.
- Aggregate narrow band PFR will provide additional security and power system resilience to increasingly frequent large system disturbances.
- Allows other FCAS market services to operate most effectively and avoids distortion of those services e.g. regulation, contingency.

[1] The system services objective is defined in section 3 of the AEMC directions paper – Frequency Control Rule Changes 17/12/2020. Available at https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

We further consider that the appropriate policy to support the pathway of narrow band mandatory PFR is to improve PFR pricing by establishing a double side cause pays arrangement (DSCP) in the first instance.

While DSCP will not provide certainty in relation to the volume or availability of frequency control services in the same way that an enablement market does, its implementation is expected to:

(a) incentivise good behaviour in terms of following dispatch targets more closely and

(b) incentivise the voluntary provision of PFR to counter frequency deviation in the normal operating frequency band.

We expect DSCP to do so through:

- Valuation of positive contribution factors by recovering cost for positive contributions from market participants that cause deviations in power system frequency.
- Alignment and shortening of sample and application periods to define transactions for payment and cost allocation to be based on performance in a single dispatch interval.
- Increased transparency through clear definition of the metrics used for incentive payments and cost allocations.

DSCP on its own can be effective while there are sufficient reserves of PFR available in the market. Presently these are provided mainly by online thermal generation and battery storage systems that have low opportunity costs and high rewards for keeping reserves to take advantage of system events and high prices. Renewable generation does not keep reserves and generate to their full capacity, limited only by system constraints, or negative pricing. Hence, it is yet to be seen whether DSCP would effectively incentivise sufficient frequency responsive plant and related reserves to meet system requirements when the proportion of thermal generation is substantially reduced from present levels, as is projected in forecasts.

Looking further ahead, we see that there may be a need to establish stronger market arrangements that provide a greater level of certainty for system operation and send the right price signals to the market for provision of future PFR capacity (reserves), particularly in the lead up to the retirement of a large number of the NEM's coal fired generating fleet at the end of this decade, and beyond.[2] Depending on the rate of renewable uptake and thermal generation retirement this could even become critical sooner. At that time a PFR-FCAS type market to procure the necessary reserves to provide effective primary regulation will be necessary as we do not believe that there will otherwise be any assurance that sufficient responsive plant and available headroom to effectively maintain frequency during normal operation. Without such price incentives for future capacity and given the projected reduction in the level of synchronous generation we would expect a gradual degradation of system frequency performance to the level experienced prior to the AEMC's Rules change for mandatory PRR in mid-2020.

At the same time, a procurement mechanism would provide increased operational certainty for AEMO to plan ahead for system control and security.

> We recommend a policy pathway to support mandatory narrow band PFR that ensures sufficient responsive plant and reserves will be available. As the NEM generation mix evolves, we propose that the market arrangements should similarly evolve through:
>
> - Initially, establishment of **improved pricing through Double Sided Causer Pays** arrangements that incentivise the provision of PFR from generators to counter frequency deviations.
> - Later on, the potential development and implementation of additional market procurement arrangements towards the end of this decade, or earlier if required, that is best facilitated through an **additional primary regulation service** (PFR-FCAS) in combination with continuing DSCP.

The importance of ensuring sufficient PFR reserve is available cannot be understated and hence there is a need to value it. However, we also note the need to ensure unit commitment to provide effective PFR. Essentially, the need for an aggregated PFR response from at least a significant portion of the generating fleet is important because:

[2] We recognise that DSCP provides some financial incentives for voluntary provision of frequency control but deem greater certainty and a procurement mechanism will be more effective to ensure future investment and signaling volumetric procurement to the market.

- Having large number of units online to provide PFR is important as aggressive droop may not be possible for all generating systems, and large amounts of reserve from small numbers of units could either be inefficient or also not be possible due to turn down ratio limitations of some generating technologies. Further analysis is necessary to establish the volume of PFR and number of providers that may be appropriate, and hence the level of droop that is needed to ensure good frequency performance.
- To balance aggressive droop and reserve requirements it is more effective to leverage aggregated frequency responsiveness from across the system. Such aggregated response could be obtained by procuring a small amount of reserve from every generator rather than a large amount from only a few. This is the same mechanism applied in Texas and GB, who allow for reserve of 20% and 10% of rated capacity from each plant contracted to provide PFR.
- Without sufficient reserve i.e. head- and foot room of units enabled for PFR, there will be limited or no contribution to correcting frequency deviations as PFR is subject to the unit being able to provide or absorb energy to counter the change in frequency.

In conclusion, GHD recommend that, based on our analysis outlined in this report, an initial combination of narrow band mandatory PFR in combination with a form of DSCP to incentivise the voluntary provision of frequency control will deliver a balance of operational certainty and appropriate economic signals to provide good control of frequency in the normal operating frequency band. The DSCP arrangements would positively influence regulation FCAS requirements, and reward generators for positive contributions to correct any cumulative frequency error incurred during normal system operation.

Towards the end of this decade, or earlier if a step change in generation development is observed, i.e. retirement of thermal generation and uptake of renewable generation, MPFR and DSCP may have to be complemented through a PFR-FCAS style or other procurement arrangement to ensure that necessary volumes of PFR can be secured. If required, we consider that such a market arrangement with appropriate price signals and specified volumes could be effective to incentivise provision of PFR reserve from new technologies, battery storage and renewable generation. In combination these three mechanisms are anticipated to drive efficient investment in and operation of power system equipment to control power system frequency in the longer term.

Contents

1.	**Introduction**		**1**
	1.1	Background	1
	1.2	Scope and limitations	1
	1.3	Formal Advice Structure	2
2.	**Provision of Primary Frequency Response**		**4**
	2.1	Frequency Management in the NEM	4
	2.1.1	Regulating Frequency Services	4
	2.1.2	Primary Frequency Response	4
	2.1.3	Frequency Control Parameters	5
	2.2	Conventional Synchronous Generation	5
	2.2.1	Overview	5
	2.2.2	Practical Considerations	6
	2.2.2.1	Hydro-Electric Plant	6
	2.2.2.2	Steam Turbines	6
	2.2.2.3	Gas Turbines	7
	2.2.2.4	Combined Cycle Power Plant	7
	2.2.3	Operational Considerations	8
	2.3	Renewable Generation	8
	2.3.1	Wind Generators	8
	2.3.2	Inverter Based Generators and Battery Energy Storage	9
	2.3.3	Distributed Energy Resources	10
	2.4	Frequency Responsiveness by Curtailment	11
	2.5	Limits of Technology	11
3.	**International Primary Frequency Response Approaches**		**13**
	3.1	North America (ERCOT)	13
	3.2	Europe (National Grid ESO)	16
		Current / Existing Position	16
		New Frequency Response Services	17
	3.3	Summary of International Findings	18
4.	**Wider System Impact and Frequency Performance**		**21**
	4.1	System Operator Perspective	21
	4.1.1	Requirement for Primary Frequency Response	21
	4.1.2	Primary Frequency Response Implementation	22
	4.2	Effectiveness of Wide Area Primary Frequency Response	23
	4.2.1	AEMO Implementation Progress Reports	23
5.	**Impact on Generating Equipment**		**27**
	5.1	Generator active power analysis	27
	5.1.1	Generation plant active power mileage calculation	27
	5.1.2	Fleet Active Power Mileage	28
	5.2	Observed Generating Unit Impact	30
	5.3	International experience with impact of PFR	32
	5.4	Cost of Primary Frequency Response	33
6.	**PFR Pathways (Our Analysis)**		**34**
	6.1	Methodology	34

6.2 Changing Generation Mix 34
6.3 Unit Commitment and Reserve Management 37
6.4 Pathways for PFR Implementation 38
6.4.1 Overview of Pathways and policies 38
6.4.2 Pathway 1 - MPFR with existing FCAS 38
6.4.2.1 Improved Pricing Arrangements 39
6.4.3 Pathway 2 - Revised MPFR with new FCAS arrangements 40
6.4.4 Pathway 3 - Alternative market procurement of PFR 43
6.4.5 Alternative and complementary Policy options 44
6.4.5.1 PFR FCAS 44
6.4.5.2 Double Sided Causer Pays 44
6.4.5.3 Frequency Deviation Pricing 45
6.4.5.4 Regulated Pricing 45
6.5 Policy Risk Assessment 45
6.5.1 Mandatory PFR 45
6.5.2 PFR FCAS Market 46
6.5.2.1 Quantification of Required Service Volume 47
6.5.2.2 Calculation of Participant Performance 47
6.5.3 Improved Pricing Arrangements 47
6.5.3.1 Double-Sided Causer Pays 48
6.5.3.2 Deviation Pricing 49
6.6 Learnings from Other Jurisdictions 49
6.6.1 National Grid ESO (GB) 49
6.7 Multi-criteria Analysis 51
7. Observations and Insights 58
7.1 PFR Pathway for the NEM 58
7.2 Future proofing the regulatory framework 59
7.3 Regional procurement of PFR 59
7.4 Modelling specification of requirements 60
7.5 Frequency Performance Testing 60

Table index

Table 1 ERCOT PFR dead band and droop settings 14
Table 2 GB Grid Code Generating Plant Size Definitions 17
Table 3 Changing generation mix as presented by the 2020 ISP Central Scenario 35
Table 4 Seasonal peak demand as predicted by the 2020 ISP Central Scenario 35
Table 5 Ranking of criteria for the Pathways MCA 52
Table 6 Metrics for criteria 52
Table 7 Weighting of PFR criteria for MCA assessment 53
Table 8 Summary of pathways and policy performance assessment from MCA 55

Figure index

Figure 1 Generator frequency responsive power production under droop control 5
Figure 2 Frequency control services procured by ERCOT 14
Figure 3 Summary of GB Dynamic Response Service Technical Requirements 20
Figure 4 Comparison of NEM frequency distribution – Sep 2020 to May 2021 23

Figure 5	Mainland Frequency Changes as new Frequency Settings Implemented	24
Figure 6	Monthly frequency crossings	25
Figure 7	Daily frequency crossings – under 49.85 Hz, across 50 Hz, beyond 50.15 Hz	25
Figure 8	Comparison of NEM frequency distribution – September 2020 to May 2021	26
Figure 9	Generation plant active power mileage	27
Figure 10	Generator mileage for all operational NEM facilities	28
Figure 11	Generation active power mileage analysis by technology	29
Figure 12	Generation capacity and maximum seasonal demand	36
Figure 13	Pathways and policies for enduring Primary Frequency Response	38
Figure 14	Assessment criteria for the Pathways multi-criteria analysis	51

1. Introduction

1.1 Background

The Australian Energy Market Commission (AEMC) published a final rule and final determination for the Mandatory Primary Frequency Response (MPFR) rule change in March 2020. This requires all scheduled and semi-scheduled generators, who receive a generation dispatch instruction greater than 0 MW, to provide Primary Frequency Response (PFR).

PFR is the initial response of generating systems and loads to reduce and correct locally detected changes in frequency by varying their active power output or load to maintain a stable frequency. A stable frequency is a fundamental requirement for a secure and reliable power system.

The rule change was triggered in 2019 when separate rule change requests were submitted to the Commission, identifying that the reduction of PFR has made it more difficult for Australian Energy Market Operator (AEMO) to manage the operation of the NEM and maintain a secure operating state. Decreased PFR has also reduced the resilience of the system to disturbances.

The 2020 final rule and determination place a mandatory requirement on generators to provide PFR. This addresses the immediate system concern of reduced primary frequency control in the NEM. However, the Commission recognised that a mandatory requirement is unlikely to meet the National Electricity Objective (NEO) and the system services objective[3]. That is, encouraging efficient investment in and efficient operation and use of generation systems to provide optimal outcomes for consumers over the long-term. This resulted in a sunset clause being included in the final rule; the rule will expire on 4 June 2023.

Ahead of the activation of the sunset clause in 2023, the Commission has published a directions paper on enduring PFR arrangements in the NEM in December 2020 and identified three future pathways:

4. Maintain the existing MPFR arrangement with improved PFR pricing
5. Revise the MPFR arrangement by widening the frequency response band and develop new Frequency Control Ancillary Services (FCAS) arrangements for the provision of PFR during normal operation (primary regulating services)
6. Remove the MPFR arrangement

To support their decision making, the AEMC has sought independent advice from GHD in determining enduring PFR arrangements as identified in the directions paper, with respect to the NEO and the system services objective.

1.2 Scope and limitations

The high-level questions the Commission is seeking to answer include:

- What is the level of collective effort required from responsive power system plant to achieve differing levels of system performance?
- What is the impact on individual plants from participating in narrow band PFR relative to system frequency performance?
- Are there any practical considerations in relation to individual plant capabilities and limitations in providing continuous PFR?

[3] The system services objective is defined in section 3 of the AEMC directions paper – Frequency Control Rule Changes 17/12/2020. Available at https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

A comparative analysis of the enduring PFR policy pathways identified by the AEMC in the Directions paper for the frequency control rule changes, including the technical viability of Pathway 1 to provide PFR over the long term and the technical feasibility of Pathways 2 and 3 as long-term options for the delivery of PFR.

To address these questions, the Commission has engaged engineering consultant GHD, to provide:

a) Ad hoc advice on request. GHD will support the AEMC by providing advice in response to ad hoc requests from the AEMC across the period of the engagement. The advice provided will not be published and is intended to help inform the AEMC on specific matters. The format for the advice will be agreed with AEMC and may include email correspondence, discussions during meetings, development of short documents and the review of documents and material prepared by the AEMC and AEMO.
b) Formal advice in the form of a report suitable for publication by the AEMC addressing regulatory pathways for PFR in the NEM. Specifically, this report will address the following topics:
   (i) The advantages and disadvantages of maintaining or revising the current mandatory PFR arrangements.
   (ii) The potential benefits and challenges associated with implementing new market arrangements for continuous primary frequency response.
   (iii) The AEMC project team will assist in coordinating the preparation of the consultant's formal advice with AEMO, and the formulation of its draft advice - PFR incentivisation feasibility report.

This report: has been prepared by GHD for AEMC and may only be used and relied on by the AEMC for the purpose agreed between GHD and AEMC as set out in section 1 of this report.

GHD otherwise disclaims responsibility to any person other than AEMC arising in connection with this report. GHD also excludes implied warranties and conditions, to the extent legally permissible.

The services undertaken by GHD in connection with preparing this report were limited to those specifically detailed in the report and are subject to the scope limitations set out in the report.

The opinions, conclusions and any recommendations in this report are based on conditions encountered and information reviewed at the date of preparation of the report. GHD has no responsibility or obligation to update this report to account for events or changes occurring subsequent to the date that the report was prepared.

The opinions, conclusions and any recommendations in this report are based on assumptions made by GHD described in this report. GHD disclaims liability arising from any of the assumptions being incorrect.

1.3 Formal Advice Structure

The structure of our formal advice, in the form of this report, is broken down into the following segments:

Section 2: Review of the provision of PFR

This section reviews current arrangements for management of frequency in the NEM, including the interim arrangements under the Mandatory PFR rule. We further consider the ability of various generating technologies to provide PFR and any inherent limitations to do so.

Section 3: Treatment of PFR in other jurisdictions

Many other jurisdictions have established processes for managing provision of PFR. In this section we have identified valuable insights regarding what could or could not be applicable to the NEM. We reviewed the Texas system managed by ERCOT and the management of PFR and related services in the National Grid ESO managed system in Great Britain (GB).

Section 4: Wider system impact of PFR and frequency performance

In this section we reviewed the work done by AEMO and the advice provided to date, including the initial rules change proposal, the implementation reports, and preliminary advice. Consideration was also given to the measured performance of the system over the past 12 months as presented in the AEMC analysis of the AEMO collected raw data.

Section 5: Impact of PFR provision on generating equipment

This section reviews the potential impact of PFR on individual generating plant, both technically and financially. Results of independent survey advice on the experiences of NEM generators following implementation of PFR to the AEMC by Greenview Strategic Consulting has been reviewed in addition to evidential and anecdotal feedback of international literature.

Section 6: PFR pathways analysis

The section presents our analysis and description of the advantages and disadvantages of each of the three pathways for enduring PFR arrangements identified by the Commission. We considered the material provided in the previous sections and conducted a Multi Criteria Analysis (MCA) against a number of criteria to capture the effectiveness of each of the pathways.

2. Provision of Primary Frequency Response

2.1 Frequency Management in the NEM

Stability of the power system frequency is maintained through a suite of frequency services, automated responses and characteristics. In the National Electricity Market these can be summarised as:

- Inertia and fast frequency response
- Contingency Frequency Control Ancillary Services
- Primary Frequency Response
- Frequency regulation

Of these it is particularly the PFR and regulation services that work to keep frequency within the normal operating band.

2.1.1 Regulating Frequency Services

Frequency services have been developed for the NEM, to help manage frequency to agreed frequency standards. Frequency services are separated into two categories:

- Regulation
- Contingency

Regulation frequency services are the services that correct the generation/demand balance due to small variations in load and/or generation. Contingency frequency services respond to a major contingency event to correct the generation/demand balance. This report is focused on regulation frequency services and their interaction with primary frequency response.

Operationally, regulation services are constantly used to adjust small imbalances in demand and/or supply. The services are provided by generators under Automatic Generation Control (AGC). The AGC system allows AEMO to constantly monitor the frequency of the NEM and to issue control signals to generators providing regulation services to adjust their output to control frequency to within the normal operating band of 49.85 Hz to 50.15 Hz in the absence of contingency events.

2.1.2 Primary Frequency Response

PFR is the second phase of frequency control, following the inertial response, and the first stage of deliberate frequency management in a power system. Facilities providing PFR react almost immediately, by injecting or withdrawing active power, to correct frequency deviations resulting from imbalances between supply and demand. The PFR is triggered by local measurements of system frequency, with the response delivered aimed at arresting any deviations in frequency from 50Hz. PFR is an essential requirement of frequency control and of power system security. Sufficient PFR is a necessity for stable control of system frequency. This is discussed in more detail in Section 4.1.

Traditionally in the NEM, PFR was provided by synchronous machines through their turbine governor action however, non-synchronous machines such as renewable generation (wind, solar) and energy storage (batteries) can also provide PFR. The various forms of generation equipment offer differ in their ability to provide PFR. Those key differences are discussed in sections 2.2 and 2.3.

2.1.3 Frequency Control Parameters

Frequency control under primary frequency response or 'droop' response utilising a generating system's active power control requires several critical factors that define the tightness of control, volumes of reserve and speed of response of providers of these services.

Conceptually this is shown in Figure *1*, where the deadband of the response refers to the range of frequency for which the generating system will not vary its output corresponding to a change in frequency. A narrow deadband therefore implies very responsive power control that is sensitive to small changes in system frequency, and conversely a moderate or wide band control implies less sensitive response.

The governor droop refers to the proportional change in generator's active power to a change in system frequency. Typical values of droop are 4%, which means that for a 4% change in system frequency a governor active power setpoint will change by 100% output, subject to upper and lower production limits defined by fuel availability or other operational constraints. Low droop settings indicate a more aggressive response for a change in system frequency, resulting in larger changes in active power for small changes in frequency.

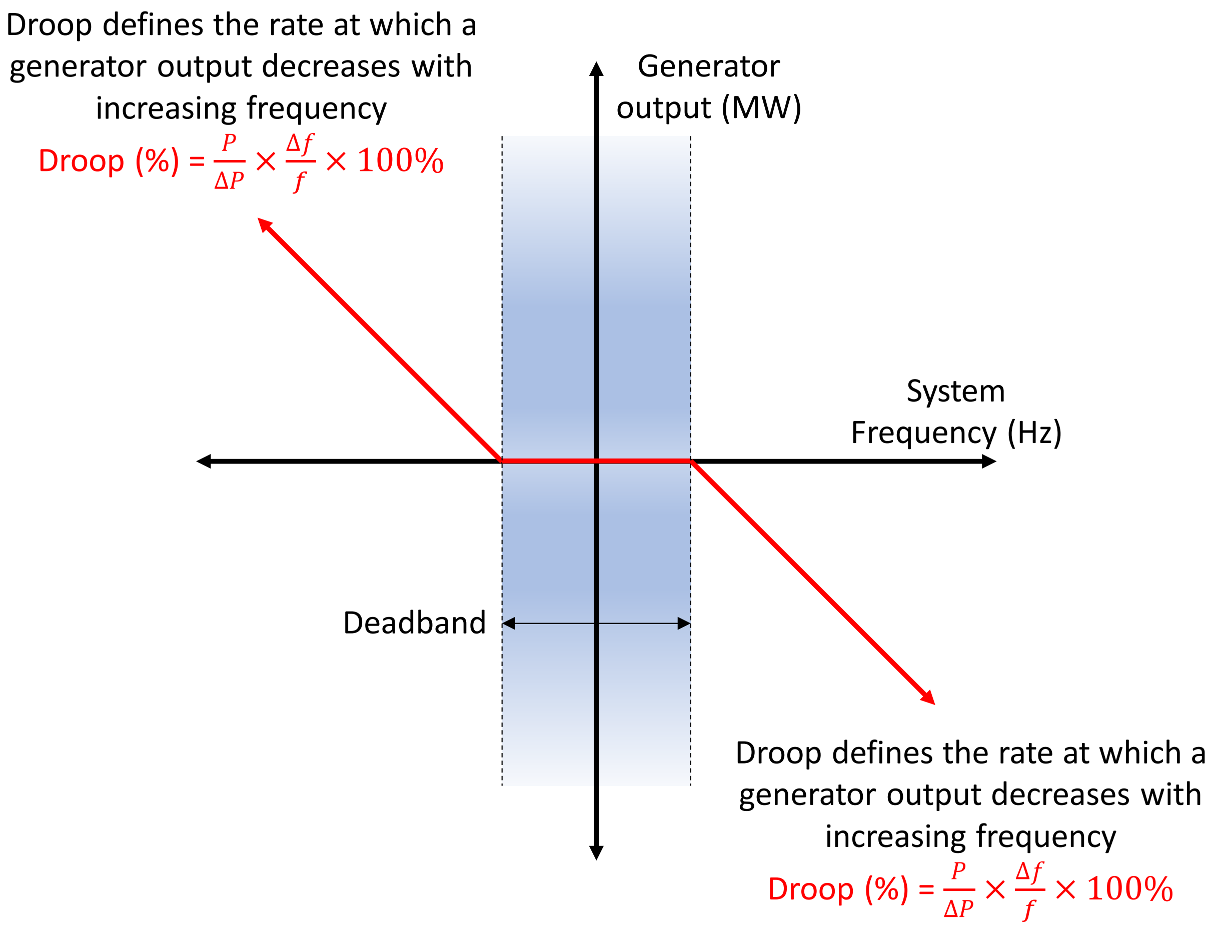


Figure 1 Generator frequency responsive power production under droop control

2.2 Conventional Synchronous Generation

2.2.1 Overview

Conventional generators such as gas fired, steam powered, or hydro-electric plant generate electrical energy through the control of the mechanical power provided by the generator turbine which connected to a synchronous machine (generator alternator) that converts the mechanical to electrical power.)

Subject to the generating facility's available headroom, that is the current power output compared to the maximum machine power output (or minimum power output for over-frequency events), generators can respond to frequency deviations on the electricity system to which they are connected.

The amount of mechanical power applied to the synchronous generator by its prime mover is managed through a sophisticated turbine governor control system. The governor is the control system responsible for setting the rate of change and amount of mechanical torque generated. The rate and proportion at which a conventional synchronous generator will vary its power output with respect to system frequency is dependent on the generator governor droop setting. Conventional synchronous generator droop settings typically range from 2 – 8%, with nominal set-points in the range of 4% or 5%. A droop setting of 4% means that, in responding to a 4% change in system frequency (i.e. 2 Hz for a 50 Hz system such as the NEM) a generator unit's output will change by 100% of the total unit capacity, subject to available headroom of course. Power change is proportional to the change in frequency relative to the nominal frequency i.e. 50 Hz. Thus, assuming a 0 Hz deadband, with a 4% droop setting a generator unit's output will change by 25% of total capacity for a 0.5 Hz variation in system frequency. It is this generator droop response to system variations that allows conventional synchronous generating plant to provide a primary frequency response.

2.2.2 Practical Considerations

Although generation plant generally classed as conventional, e.g. hydro-electric plant, steam turbines, gas turbines, or combined cycle plant, etc. typically, all use a synchronous generator to convert mechanical energy to electrical energy. However, in reality there are a number of key differences in the operating characteristics of each plant type. These differences have some bearing on the ability of each plant type to provide and sustain a primary frequency response to a system frequency variation. These aspects are now briefly considered with respect to primary frequency response.

2.2.2.1 Hydro-Electric Plant

Hydro-electric generators with reservoirs are impacted by the head of water held in the upstream reservoir, both in terms of volume of water available for electricity generation as well the potential impact on plant rating i.e. a lower water level will reduce the maximum generating power available. Additionally, as water has a much higher density than steam, this limits the ability of hydro generator governor to increase the generator output, which will typically by much slower than a steam-electric turbine. Simulations performed in technical literature[4] show that the typical response from a hydro-electric generator is of the order of a few percent over 10 seconds, with a further increase in output over the following 10's of seconds and minutes.

Additionally, it should be noted that run-of-river hydro-electric generation schemes or other schemes with water management restrictions may not be able to provide significant frequency or load following response based on water level constraints.

2.2.2.2 Steam Turbines

Steam-electric turbines are used with a number of primary fuel sources, which in Australia are predominantly hard coal, lignite and natural gas. In all cases water is heated by the burning of fuel driving the process to create steam, which is then fed into and spins a steam turbine that then drives the synchronous generator. Steam turbines typically have two or three pressure related stages e.g. high and low or high, intermediate and low, which are each designed to extract the maximum mechanical energy (torque) from the steam at different pressures and allow the highest net plant efficiency.

In terms of primary frequency response characteristics, the lower density of water in gaseous form allows a steam turbine generator to increase its power output much more quickly than a hydro-electric turbine generator, subject to there being sufficient capacity headroom, with output increases of the order of several percent typically occurring over 10 seconds following an initial system disturbance.

The ability of the steam turbine generator to sustain an increase in power output as a result of a primary frequency response to system frequency depends on the thermal characteristics of the unit, including boiler

[4] Frequency Control Requirements for Reliable Interconnection Frequency Response, J Eto, J, Undrill, C. Roberts, P. Mackin and J. Ellis, Energy Analysis and Environment Impacts Division – Lawrence Berkeley National Laboratory, February 2018.

thermal dynamic considerations and reheat stages, and ultimately whether sufficient steam pressure can be maintained to sustain the required power output.

Note that the above does not apply to steam turbines forming part of combined gas cycle power plants – discussed in Section 2.2.2.3 below – which have different thermal and electrical characteristics.

2.2.2.3 Gas Turbines

In contrast to a steam turbine, which can be considered as an expansion device delivering energy (torque) as the steam passes through the turbine, in a gas turbine there are several specific elements including compressor, combustion chamber and turbine that collectively work to produce energy (torque). The close coupled nature of the individual gas turbine elements means that the speed of response to system frequency events is typically the fastest of the conventional synchronous generating plant types, with output increases in the order of several percent typically occurring in less than 10 seconds.

In terms of the sustainability of a gas turbine generator's primary frequency response, the individual turbine elements are typically designed to allow the maximum generator power output to be produced and sustained[5]. However, this design assumption generally applies when operating at design synchronous speed which is directly related to system frequency i.e. 50 Hz. However, as noted in the Lawrence Berkeley National Laboratories (LBNL) paper "Frequency Control Requirements for Reliable Interconnection Frequency Response"[4], when a gas turbine is operating at lower speed, such as when the system electrical frequency is less than 50 Hz, less air is moved into the combustion chamber. Burning the same amount of fuel but with less air will affect the combustion process and lead to higher exhaust temperatures and potential damage to the plant if sustained. As a result, in such an instance the gas turbine power output will be reduced in order to protect the plant. The above referenced LBNL paper suggests this effective derating factor to be of the order of 10 – 20%.

In terms of the impact on gas turbine primary frequency response, the potential effect is essentially that despite increasing generator power output (based on governor droop response) following an under-frequency event, sometime thereafter the generator controller will progressively lower the unit fuel rate to lower the exhaust temperature once the limiting temperature has been reached. This has the effect of reducing the available headroom capacity for providing a sustained frequency response and is an important characteristic that needs to be considered by system operators.

2.2.2.4 Combined Cycle Power Plant

In order to improve the thermal efficient of gas turbine generators they are often operated in a Combined Cycle configuration in conjunction with other gas turbines and one or more steam turbine generators. This approach essentially allows waste heat from the one or more gas turbines to be captured and utilized in order to generate steam to power a supplementary steam turbine(s). However, an important characteristic of Combined Cycle Power Plant (CCPP) plant is the use of a Heat Recovery Steam Generator (HRSG) which essentially captures the waste gas turbine heat and uses this to create stream that can power the steam turbine generator. In some cases, the HRSG may be accompanied by supplementary or duct firing to increase further steam production.

In terms of the impact on the steam turbines operating within a CCPP configuration, their ability to increase output is dependent on the pressure mode they are operated in, but generally can be considered to follow the gas turbine output albeit over much longer time period. That is, if a gas turbine within a CCPP configuration can increase its power output within a few seconds in response to the system frequency falling below 50 Hz, it is likely to take ten times longer (or more) for the equivalent increase in steam turbine output due to the thermal time-lag. The same relationship also exists in reverse, that is if a gas turbine decreases its output, or is tripped, there will be a slow decrease in steam production from the HRSG over a period of tens of seconds and a concomitant reduction in steam turbine power output.

[5] A combustion turbine's maximum power output is dependent on ambient conditions of air temperature and pressure, with higher ambient air temperatures, and lower air pressure proportionally each contributing to a reduction of maximum power.

The final point worth noting is that the high speed operation of a gas turbine operated in open-cycle mode (as detailed in Section 2.2.2.2) and the associated reduction in sustained power output due to limiting exhaust temperatures would also be expected to affect gas turbines within CCPP plant.

This means that CCPP plant providing PFR will generally require the GT components to provide the frequency response power changes, with the steam turbine running at constant output. This is reflected in more aggressive governor droop settings for the GTs to achieve an overall plant droop of the standard 4-5%.

2.2.3 Operational Considerations

In addition to the inherent technical characteristics and limitations associated with the various conventional generation plant technologies there are also other aspects that will impact on the resultant plant primary frequency response. These include:

1. Generator role / function within power system:
   - A generator operating as the largest unit or sole generating unit within a power system will typically operate in isochronous (speed control) mode. In this setting the generator will set and maintain a specified speed or electrical frequency and maintain this speed irrespective of subsequent load variations and step changes. Therefore, whilst an increased (or reduced) power output will be provided as necessary to achieve a target system frequency, the generator will not provide a droop response i.e. a response that varies in relation to system frequency.
   - The alternative setting, i.e. generator droop response, will allow other generators to follow the frequency reference provided by the generator on isochronous control. This is the main behaviour and control consideration included in this paper.
2. Secondary plant load controllers:
   - As noted in the LBNL Berkeley report[4], generators can also include a plant load controller which seeks to return the generator power output to a prescribed MW set-point value, even after responding to an under-frequency or over-frequency event. This mode is termed Pre-Selected Load Mode without Frequency Bias and essentially leads to the withdrawal of the primary frequency response a short time after being initially provided.[6]
   - The alternative approach, termed Pre-Selected Load Mode with Frequency Bias maintains a generator MW set-point value but only if system frequency is maintained within a generally narrow range, after which it will provide a frequency dependent response. Generators operating with this characteristic will provide a sustained primary frequency response albeit one that might be slightly delayed in commencing until the system frequency drops out-with whatever frequency deadband has been selected.

2.3 Renewable Generation

In comparison with the conventional generation plant types discussed in the previous sub-section, this section summarises the characteristics of renewable generation sources, principally wind generation and solar photo-voltaic generation.

2.3.1 Wind Generators

Horizontal-axis wind turbines have been the deployed in many jurisdictions for several decades, initially starting within sub-MW devices installed onshore and now with significantly larger (>10 MW) generators being considered for deployment offshore in territorial waters. In terms of the electrical characteristics of Wind Turbine Generators (WTGs), in earlier deployments these often used induction (or asynchronous) generators. Unlike synchronous generators these are rotating machines that do not have the self-excitation,

[6] Pre-select load mode without frequency bias is an operating mode generally not present in Australian generating facilities as suggested by various surveys of the operators of the NEM's thermal generating fleet, including the Greenview Strategic Consulting Services work commissioned by the AEMC as part of the Enduring Primary Frequency Response Rules change.

which produces the electro-mechanical field that is required to convert mechanical to electrical energy. Instead, they draw the necessary energy to produce the electro-mechanical field required from the main grid.

Over the last 15 to 20 years wind turbines have transitioned to Doubly Fed Induction Generators (DFIGs) and more recently to fully inverter connected generators. In the case of the former, the induction generator stator is directly connected to electricity system with the rotor connection via a bi-directional back-to-back voltage source converter. This allows independent control of reactive power consumption / generation irrespective of active power.

In comparison full inverter connected wind turbines have the generator machine (which can be synchronous, asynchronous or permanent magnet types) decoupled from the electricity grid system. The generator generates AC electrical power which is then converted to DC and the converted back from DC to AC at 50 Hz at the required terminal voltage.

In terms of primary frequency response, this is can typically be provided by DFIG and full inverter connected WTGs for over-frequency events and many jurisdictions world-wide already include a generator droop response to such events within applicable Grid Code or other technical standards. However, with respect to providing a primary frequency response during under-frequency events, as with other forms of renewable generation i.e. PV, this is typically only achievable where the renewable generator output has already been curtailed to some power output less than the maximum achievable output for the given environmental conditions i.e. provides some capacity headroom. Again, the functionality to provides this capability generally only resides within the newer forms of WTGs which have adequate controls to vary turbine blade pitch or inverter output to the necessary curtailed value.

However, more recently there has also been interest in utilising the effective rotational stored kinetic energy within individual wind turbines as a form of primary frequency control, that is to allow the wind turbines to produce an electrical power in excess of the mechanical input power captured by turbine blades. This effectively allows the WTG to temporarily slow down, although not so low as to trigger aerodynamic stalling. Proprietary products are already available for commercial WTGs to provide this functionality including General Electric’s WindINERTIA function.

The use of this wind generator “synthetic inertia” is also discussed in the Lawrence Berkeley paper[4] which concludes that although such a response can indeed be obtained, as it is not a sustainable service and typically can only be provided for a period of five to ten seconds. As it is not a sustainable service, any additional energy provided by the wind generator as a primary response through this control mechanism will be withdrawn a short time thereafter. It would thus need to be replaced by another form of primary frequency response or stabilizing response until secondary frequency response action can be implemented.

A final issue worth noting with respect to such a synthetic inertia response from wind generators, is that not only would the primary response be withdrawn around five to ten seconds following the onset of the under-frequency event but in the subsequent period i.e. 10 to 60 seconds the wind generator output would then be reduced further beyond the original pre-event value. This is necessary to return the lost rotational kinetic energy back to the WTGs and bring them back to normal running speed. This will effectively reduce the availability of frequency response stabilizing power towards the end of primary frequency period at the point where it interfaces or overlaps with other frequency control services. Consequently, the use of such primary frequency response functionality from WTGs, even if available, will need to be considered carefully to understand the potential impacts on the wider range of frequency control services, including primary, secondary and regulation services.

2.3.2 Inverter Based Generators and Battery Energy Storage

Although the latest generation of wind turbine generator are now adopting full inverter-based controllers, the most wide-spread deployment of inverter based resources (IBR) in Australia is now typically as a result of photo-voltaic solar developments. This includes larger transmission connected solar farms as well as small developments connected at lower voltage and in residential properties. Additionally, Battery Energy Storage Systems (BESS) are also now being deployed in larger numbers and also use power inverter electronics to convert electrical energy into an alternating current form suitable for injecting into the main transmission or distribution system.

In relation to primary frequency response, inverter-based resources can typically provide a response in two main ways:

- By reducing outputs during over-frequency events via a typical droop response, and similarly increasing output during under-frequency events for BESS – subject to available energy storage.
- During periods of curtailment when maximum generation output is not deliverable due to local or wider system issues[7], output can be increased via a droop response in a similar manner to conventional generation for under-frequency events.

In the case of first response approach above, such a droop response capability is already available within current inverter based devices and is also a standard requirement even at LV being required within the latest AS 4777 standard, albeit with an assumed wide deadband[8].

For the second approach, it is important to consider the situations that have given rise to the generation being curtailed below its maximum output. The different scenarios could influence whether it is appropriate to allow the generator to utilise its otherwise curtailed output to respond to an underfrequency event:

- If the output of inverter based resources is being curtailed due to the inability of the connected transmission or distribution system to securely absorb additional power, then it may not be appropriate to allow the curtailed generation to the utilized to respond to an underfrequency event as this could load the network beyond secure transfer levels,
- If the inverter-based resource is curtailed for other reasons such as a low or negative energy market price, then there would be no system security issue created if the curtailed capacity was used to respond to an underfrequency event
- If the inverter-based resource was curtailed solely to provide headroom to respond to an underfrequency event, then there is no reason the inverter based resource should not be able to increase generation in response to an underfrequency event. However, this scenario would essentially sacrifice some energy production on an ongoing basis in order to provide the under-frequency droop response capability and would present a lost opportunity cost to such generation plant owners.

Finally, in relation to the actual ability of inverter based resources to provide a primary frequency response, the use of power electronics within the converters allows a very fast response to be achieved, i.e. achieving maximum change in output in <500 ms, typically much faster than convention synchronous generating plant. Additionally, inverter-based resources also typically have a wider viable droop response range e.g. from 1% to 12%, as the response of the generator output is not restricted by fuel flow rate, or other mechanical limitations. This provides an opportunity to use such devices as part of a fast frequency response capability, which typically demands a response time superior to traditional primary frequency response requirements.

2.3.3 Distributed Energy Resources

DER is also increasingly being considered as capable of providing essential system services when coordinated as a Virtual Power Plant (VPP). Previously the inclusion of frequency responsiveness in the operation of small inverter-based resources was noted as a current inclusion in AS 4777.2. Hence, it is not unreasonable to assume an orchestrated response from multiple DER sources could provide a meaningful contribution to PFR.

Indeed, in 2019 AEMO in collaboration with the AEMC, the AER, and the Distributed Energy Integration Program established a demonstration program to evaluate the feasibility and effectiveness for VPPs to provide not only energy, but also contingency frequency control ancillary services.

[7] Curtailment could be due to transfer capacity limits, wider system stability constraints (security), general oversupply of generation or even price driven self-curtailment by generating facilities; all have occurred in the NEM.

[8] AS/NZS 4777.2:2020 specifies a deadband of +/-150 mHz for inverters in the Australia B region

Following the initiation of the demonstration program AEMO has now commenced a consultation of the Market Ancillary Services Specifications (MASS) to include considerations for VPPs to provide contingency FCAS.

Based on these developments it is feasible that VPP may provide PFR in the future, although this may still be some time away.

2.4 Frequency Responsiveness by Curtailment

Wind and solar generation is able to provide frequency responsiveness to underfrequency events if they are producing below their capability, as is the case when generation is curtailed. Reasons for such curtailment were noted previously as being due to system limitations, oversupply of generation during low demand periods, or even due to price driven self-curtailment by the Generator.

It is reasonable to assume that as renewable penetration increases there will be increasing times of curtailment driven by oversupply of renewable generation, network constraints, or even self-curtailment due to negative energy prices. Additionally, there may be market intervention by the system operator to ensure system security, such as we saw for many months in South Australia. However, the availability of reserves created by curtailment is not predictable, and at times will be excessive and other times non-existent. Furthermore, excessive curtailment of renewable generation presents energy at risk and this will reduce investment, increase energy prices, or possibly both. Similarly, excessive energy curtailment creates positive net present value in economic tests of network expansion, likely supporting network augmentations to remove such constraints. Lastly, significant curtailment of renewable generation would also incentivise increased sector coupling, where the excess energy could fuel hydrogen production, desalination, bit coin mining and so forth.

Consequently, GHD does not view curtailment of renewable generation as a long term solution for the provision of energy reserve that is needed to provide PFR from wind and solar generation. The only exception would be the valuing of reserves that financially incentives self-curtailment by renewable generators.

2.5 Limits of Technology

Our technology review has found the following high-level conclusions:

- While all synchronous generators are able to provide PFR there are key differences in the ability of different types of generating systems employing synchronous generators to provide and sustain PFR. The mainstay of the NEM's PFR is provided by thermal generation, which is predicted to decline in the future as coal fired generation retires.
- Due to the density of water, hydro-electric plants have limits on their ability to increase the generator output and generally respond to frequency changes more slowly than other thermal generators.
- Steam turbines can increase power output quickly and deliver PFR given sufficient headroom. The pre-continency output of these generators sets the available headroom and can effect both the amount of PFR and the ability to sustain the response.
- Gas turbines possess the fastest speed of response, to system frequency events, of the conventional synchronous generating plant types. However, their ability to sustain the response may be limited by the need to control temperatures particularly during under-frequency events.
- DFIG and fuller inverter connected WTGs can provide PFR for over-frequency events. However, to provide PFR during an under-frequency event this is typically only achievable when the generator's output has been curtailed to a power output below the maximum achievable output. The use of WTGs' rotational stored kinetic energy as synthetic inertia could be harnessed to provide PFR a period of five to ten seconds after the contingency, however after this period, the wind generator output would be reduced further beyond the original pre-event value to restore the turbine speed. Utilising the synthetic inertia capability to provide initial PFR requires having addition PFR available that can replace the power deliver by the WTG shortly after the contingency event.

- All Inverter based resources can reduce outputs during over-frequency events via a typical droop response. Depending on their initial state of charge a BESS is able to provide PFR to both over and under-frequency events.
- Inverter based generation that is otherwise curtailed may be able to utilize the curtailed capacity to provide PFR.
- The power electronic control of inverter-based generation allows a much quicker PFR than can be achieved from synchronous generators.

3. International Primary Frequency Response Approaches

3.1 North America (ERCOT)

The Texan electricity grid managed by the Electricity Reliability Council of Texas (ERCOT) is the smallest of three US electricity grids, with installed generation capacity of 115 GW, of which 36.5 GW is wind and solar, and an all-time peak demand of 74.8 GW, set in August 2019. The other two US grids are the Eastern Interconnection and Western Interconnection. The ERCOT managed grid is wholly state owned and as the synchronous grid does not cross state lines, it is not subject to FERC regulation. While there are no synchronous interconnections to other states, there are two high voltage direct current connections to the Eastern Interconnection and three to Mexico. The combined transfer capacity of these is less than 1,250 MW.

The ERCOT market dispatch is not dissimilar to the NEM: ERCOT operates a security constrained economic dispatch (SCED) market with generation dispatch determined every 5 minutes to meet system demand at least cost. In order to manage this process reliably, SCED must dispatch resources to balance generation with load demand, while operating the transmission system within established limits. Security of the ERCOT system is managed using a number of different Ancillary Services (AS).

ERCOT procures AS in the form of regulation services, responsive reserve services (RRS), and ERCOT contingency reserve services (ECRS) to meet the NERC reliability standards[9] (Figure *2*). However, unlike the NEM, AS in the ERCOT system are not co-optimised with energy. Instead, demand is scheduled in real-time, and AS are procured by ERCOT in the Day-Ahead-Market (DAM). However, implementation of real-time co-optimisation (RTC) of energy and ancillary services into ERCOT's energy-only market is underway, with the Public Utility Commission of Texas (PUC) directing ERCOT to implement RTC by 2024. In addition to the AS DAM ERCOT has a Supplementary Ancillary Services Market used to fill real-time shortfalls in AS.

ERCOT statistically determines the amount of required regulation services to ensure 95% of annual operating hours occur without the deployment of RRS. ERCOT's methodology for determination of Regulation Service amounts is based on historical 5-minute net load variability, as well as solar and wind adjustment (forecasting errors per 1,000MW of installed wind and per 1,000 MW of solar). Values are determined on an hourly basis for each month of the year for each of up and down regulation requirements. In 2020 Regulation Up was on average 0.48% of Peak Demand (318 MW) and Regulation Down was 0.42% of Peak Demand (295 MW). Once procured, regulation quantities to be provided are issued to generators every four seconds using ERCOT's AGC system. Economically scheduled dispatch limits for regulations enabled plant ensures reservation of the necessary capacity.

RRS are services that address supply-demand unbalances that cannot be addressed by the 5-minute energy market. These services are provided through governor action (or similar active power control of non-synchronous generators) or underfrequency (relay) Responses (UFR), or as ordered by ERCOT. In 2018 FERC issued order No 842 that mandated the provision of primary frequency response from all generating facilities, both synchronous and non-synchronous, as a condition of their connection[10]. Notably, this was already mandated by ERCOT in 2012 in recognition of significant uptake of intermittent non-synchronous generation. The use of PFR in the ERCOT network is primarily for contingencies and large disturbances, although the narrow deadband applied means that enabled generation will be actively correcting small deviations also.

[9] As per NERC standards BAL-001 (Regulation), BAL-002 (Non-spinning Reserve Services) and BAL-003 (Responsive Reserve Services)

[10] https://www.ferc.gov/sites/default/files/2020-06/Order-842.pdf

Regulation Service	• AGC enabled correction as per NER standard BAL-001 • Generators providing Regulation receive a signal from ERCOT every four seconds to increase or decrease output.
Responsive Reserve Service (RRS)	• Spinning reserve as per NER standard BAL-003 • Capacity from generators or load resources that is reserved from the energy market in order to be readily available to respond to frequency events. • Includes FFR, PFR and Load resources on UFR
ERCOT Contingency Reserve Services (ECRS)	• Includes offline resources able to ramp up within 10 minutes and operate for at least 1 hour to cover loss of resources, forecasting error or ramps. • Load Resources able to ramp to dispatched consumption within 10 minutes and operate for at least 1 hour.
Non-spin Reserve Services	• Non-spinning reserves as per NERC BAL-002 • Capacity that can be started and ramped to dispatched levels within 30 minutes to cover loss of resources, forecast errors or ramps.

Figure 2 Frequency control services procured by ERCOT

ERCOT requires the dead band and droop settings of generating systems to be as shown in Table 1. These settings are marginally tighter than the FERC requirements of ±0.036Hz and 5%, based on nameplate rating and linear within 59 to 61 Hz outside of the dead band.

Table 1 ERCOT PFR dead band and droop settings

Generator Type	Max. Deadband
Steam Turbines with Mechanical Governors	+/- 0.034 Hz
Hydro Turbines with Mechanical Governors	+/- 0.034 Hz
All Other Generating Units/Generating Facilities	+/- 0.017 Hz
Controllable Load Resources	+/- 0.036 Hz
Generator Type	**Max. Droop % Setting**
Combustion Turbine (Combined Cycle)	4%
All Other Generating Units/Generating Facilities/ Controllable Load Resources	5%

In making their decision to mandate PFR, FERC noted:

> *"The proposal to require new generating facilities to install equipment capable of providing primary frequency response received broad support from commenters. We find compelling these commenters' observations that requiring newly interconnecting generating facilities to install governors or equivalent control devices is a low cost way to address the erosion of the Interconnections' collective frequency response capability as the generation resource mix evolves."*[11]

Interestingly some commenters also requested that FERC establish penetration level thresholds for PFR requirements i.e. the level of renewable generation present in the generation mix at which point PFR would

[11] Ibid 9, p. 27.

become mandatory for renewable generation. FERC rejected this noting that requiring the provision by all future generation is in the interest of power system reliability. FERC also noted that these universal capability requirements already exist in other regions such as the ENTSOE covered networks of the European Union, and that no adverse impacts on renewable generation have been noted there.[12]

In their determination FERC established the mandated provision of PFR by all future generating facilities, with some noted exemption. However, in their Order, FERC did not impose a headroom requirement, nor did they mandate that compensation be provided for this requirement to install, maintain and operate equipment that could provide PFR.

FERC's order requires the PFR to be sustained at least until frequency returns to within dead band settings.

In addressing their AS requirements, ERCOT procures sufficient RRS to avoid Under Frequency Load Shedding (UFLS) at 59.3Hz for trip of the two largest generating units online, as per NERC standard BAL-003. Concurrently, ERCOT must secure enough RRS to meet the system frequency response obligation of -286 MW/0.1Hz (discounted for load resources tripped at 59.7 Hz). Based on system analysis the minimum amount of RRS procured by ERCOT for 2021 is 2,805 MW.

ERCOT does not specifically procure PFR for the purpose of managing frequency performance in the normal operating band, but rather to manage contingencies. However, the procured volume of narrow band PFR is as a byproduct of system security also providing the necessary small corrections needed. Similar to the NEM arrangements this leaves regulation services to focus on correcting cumulative errors accrued through forecasting errors, dispatch deviations and so forth.

RRS are progressively activated when frequency falls, and consist of several components:

- PFR can be provided by generation or controllable loads with dead bands as shown in Table *1*. For 2021 ERCOT procured a minimum of 1,420 MW.
- A subset of RRS, FFR is triggered at 59.85 Hz and must respond within 15 cycles and be sustained for 15 minutes. ERCOT limits the amount of procured FFR to 450 MW to avoid over-generation that then requires dispatch of regulation down services.
- Load resources on UFR are triggered at 59.7 Hz and must respond in full within 30 cycles. In 2021 ERCOT procured 1,400 MW of load resources in this category.

Provision of RRS from any one generating source is subject to verification of droop performance, but by default is 20% of maximum sustainable capacity.

The ECRS is an energy deployment product designed to activate once RRS is depleted, and to recover frequency to within the normal operating limits within 10 minutes. ECRS can be provided by both loads and generators, but in each case the response must be able to be sustained for at least an hour.

Finally ERCOT has a non-spinning reserve product designed to be available within 30 minutes.

All AS transactions are submitted by the Generator or Load/Retailer who are registered to offer and/or bid in the DAM and real-time market.

There have been significant changes to the ERCOT AS markets in the past four years, from development of new products by unbundling the previous primary response services, to provision of AS from more diverse sources to encouragement of new services for fast response plant such as large scale BESS.

Key Points to note about the ERCOT AS market:

- ERCOT mandates provision of narrowband PFR services from all generating facilities, both synchronous and non-synchronous, subject to available headroom, but does not mandate headroom nor does it compensate for this mandated service.
- PFR dead band is ±0.017 Hz for generators and 0.036 Hz for loads and hydro generators and steam generators with mechanical governors. All generating facilities must have 5% droop with a linear response between 59 and 61 Hz, outside of the prescribed dead band.

[12] Ibid 9, p. 116.

- There is a separate DAM for the various frequency products: Regulation Services (error correction), Responsive Reserve Services (fast), ERCOT Contingency Reserve Services (slow), and non-spinning reserves (very slow).
- The fast RRS services have several components each triggered at different frequency levels: PFR (droop response), FFR (fast response), UFR (load resources).
- The FFR market was only created during the past 2 years market in recognition by ERCOT of changing technology and is dominated by battery energy storage systems.
- Wind and solar generation must also provide PFR for over-frequency events, but generally do not provide raise services during under-frequency events. To do so would require them to preserve headroom and due to the future hedging arrangements most wind farms have for their energy this is not seen as a profitable arrangement.
- The amounts of each services are determined by ERCOT using power system analysis and are calculated for each hour of the day, for every month of the year using inertia conditions, look up RRS tables, and contingency criteria.
- RRS calculations take not only load variability into consideration, but also the variability introduced from wind and solar generation forecasting errors.

Worthy of note is also that in their 2018 submission NPRR863 for consideration by ERCOT for changes to the mandated PFR one Generator submitted that:

> *"…As a result [of mandated PFR], all Generation Resources on the system are providing an uncompensated service to the ERCOT System and are subject to compliance risk regardless of whether the Resource has a RRS Ancillary Service Resource Responsibility at the time. Additionally, this free service results in increased wear and tear and Operations and Maintenance (O&M) costs that are borne by the generator owner. As is the case with most things that are provided for free, Primary Frequency Response has become used most frequently and often masks the requirements needed to operate the ERCOT grid since its usage front runs the usage of other Ancillary Services which ultimately impacts price formation."*

The suggestion was to either remove the mandated requirement or remunerate it appropriately. In their response ERCOT rejected the submission for various technical and efficiency reasons, referring particularly to the security and reliability benefits of having all generation instilled with frequency response capability.[13]

3.2 Europe (National Grid ESO)

National Grid is the Electricity System Operator (NG ESO) in Great Britain (GB) responsible for operating the electricity transmission system covering Scotland, England and Wales. A summary is now provided of the current frequency response management position in GB along with an outline of the proposed new service provisions being introduced by NG ESO and commentary as to relevance in relation to the MPFR pathway proposals in the NEM.

Current / Existing Position

Traditionally system frequency management has been achieved through a mix of mandated generator performance capability typically for larger generating plant, as well as the provision of specific frequency response services. These services have previously been labelled as:

- Mandatory Frequency Response – this is an automatic change (through generator droop response) in active power output in response to a frequency change. This capability is a GB Grid Code requirement (CC.6.3.7(c)(ii)).
- Firm Frequency Response (FFR)– this covers two categories of service, Dynamic Frequency Response which is continuously provided and used to respond to normal system load changes,

[13] http://www.ercot.com/content/wcm/key_documents_lists/144694/863NPRR-06_ERCOT_Comments_021218.doc

and Non-Dynamic Response which is typically a discrete service triggered once a defined frequency deviation has materialised.

In the case of the Mandatory Frequency Response this requirement has been in place for a number of years. The threshold plant size for mandating the requirement to provide this capability varies based on transmission licensee area and the applicable definition of plant 'size' (see Table 2) and is specifically detailed in an individual generator's connection agreement. Generally, all large power stations need to provide a response (subject to underlying energy requirements) for one or more of primary, secondary or high frequency response. Providers must achieve their response based on a 3 – 5% governor droop setting and within 10 seconds for primary response (PFR) and high frequency response (HFR), and 30 seconds for secondary frequency response (SFR).

Note although the service functionality is "mandatory" it is only activated when instructed by the ESO – it is not active at all times.

Table 2 GB Grid Code Generating Plant Size Definitions

	National Grid	Scottish Power	Scottish Hydro Electricity Transmission
Small	< 50 MW	< 30 MW	< 10 MW
Medium	50 MW =< 100 MW	N/A	N/A
Large	=> 100 MW	=> 30 MW	=> 10 MW

One of the issues with the Mandatory Frequency Response above is that each generator submits its own holding payment (£ / hour) for being active and a response payment (£ / MWh) but where there are locational dependencies or limitations the only viable providers could offer very high costs. In order to provide some cost certainty for the ESO they also have the FFR service which in essence provides the same functionality as the mandatory response but allows a wider range of potential market participants including smaller generators. The functions procured are the same though i.e. PFR, SFR and HFR.

New Frequency Response Services

The GB electricity transmission system has changed significantly over the last ten to fifteen years as large synchronous generation has gradually been retired (particularly coal fired plant) and renewable generation has been connected. Whilst the uptake of renewable generation is somewhat slower than currently being experienced in the NEM and other markets across Australia (at least as a % of total demand), there is nonetheless an expectation that as further renewable generation is connected system inertia will continue to decrease and more frequent and potentially larger generation contingency events will arise. It is against this backdrop that NG ESO has now come to market with a new range of dynamic frequency response services designed to address system needs over the coming years. These may in time replace some of the legacy elements of the current FFR / Mandatory Frequency Response but are (will) be procured as additional services - these services are not "co-optimised" with energy dispatch.

The specific individual services within the defined Dynamic Response group are:

- Dynamic Containment (DC)
- Dynamic Regulation (DR)
- Dynamic Moderation (DM)

The Dynamic Containment service is the first of the group of services being procured by NG ESO and has already been referenced by the AEMC in the December Frequency Control Direction paper[14] where they noted that it is a form of service provided for a 24 hour period similar to the FFR (Fast Frequency Response) detailed in earlier sections of the paper. When the service went live in October 2020 500 MW of

[14] AEMC Directions Paper: Frequency Control Rule Changes, December 2020, p.50.

DC low frequency service was sought, with the expectation that this would evolve to 1.4 GW by August 2021[15] and cover also high frequency response.

The other two services are still following a consultation period with a view to being implemented in the near future. The expectation is that Dynamic Regulation will have a capacity range of 400 – 600 MW with Dynamic Moderation having a capacity range if 300 – 500 MW[16]. These services are conceptually similar to the MPFR service proposed by AEMC, with perhaps the distinction that the DR service acts more frequently outside of the notional deadband but is a slower response whereas the DM service has a small linear action up to +/-0.1 Hz that can take up to 5% of available output but then has a quicker response thereafter but that should presumably be called upon slightly less often.

Each of the three Dynamic Response services have specific technical characteristics, particularly with respect to frequency deadband / notional trigger point and speed of response. The following figure (Figure 3) summarises the relationship between the three services and their potential overlap.

From review of Figure 3 it is evident that of the three different new Dynamic Response services being procured / proposed by the NG ESO:

- The Dynamic Containment service appears to be akin to a Fast Frequency Response service (as noted already by the AEMC) as it is focused on providing a post-fault response to mitigate the impact of larger contingency events. It could be relevant for comparison with the proposed NEM MPFR pathways depending on the selected Primary Frequency Control Band setting adopted.
- The Dynamic Moderation service is also relevant for potential comparison with the proposed NEM MPFR pathways as it is targeted at the same type of system frequency response behaviour.
- The Dynamic Regulation service is essentially similar to the normal regulation FCAS service in the NEM.

From review of the above it is evident that the GB Dynamic Moderation service is the potentially most relevant for comparison with NEM Pathways, although it is noted that the Dynamic Containment service is also potential relevant. These aspects are discussed further in Section 6.5.1.

3.3 Summary of International Findings

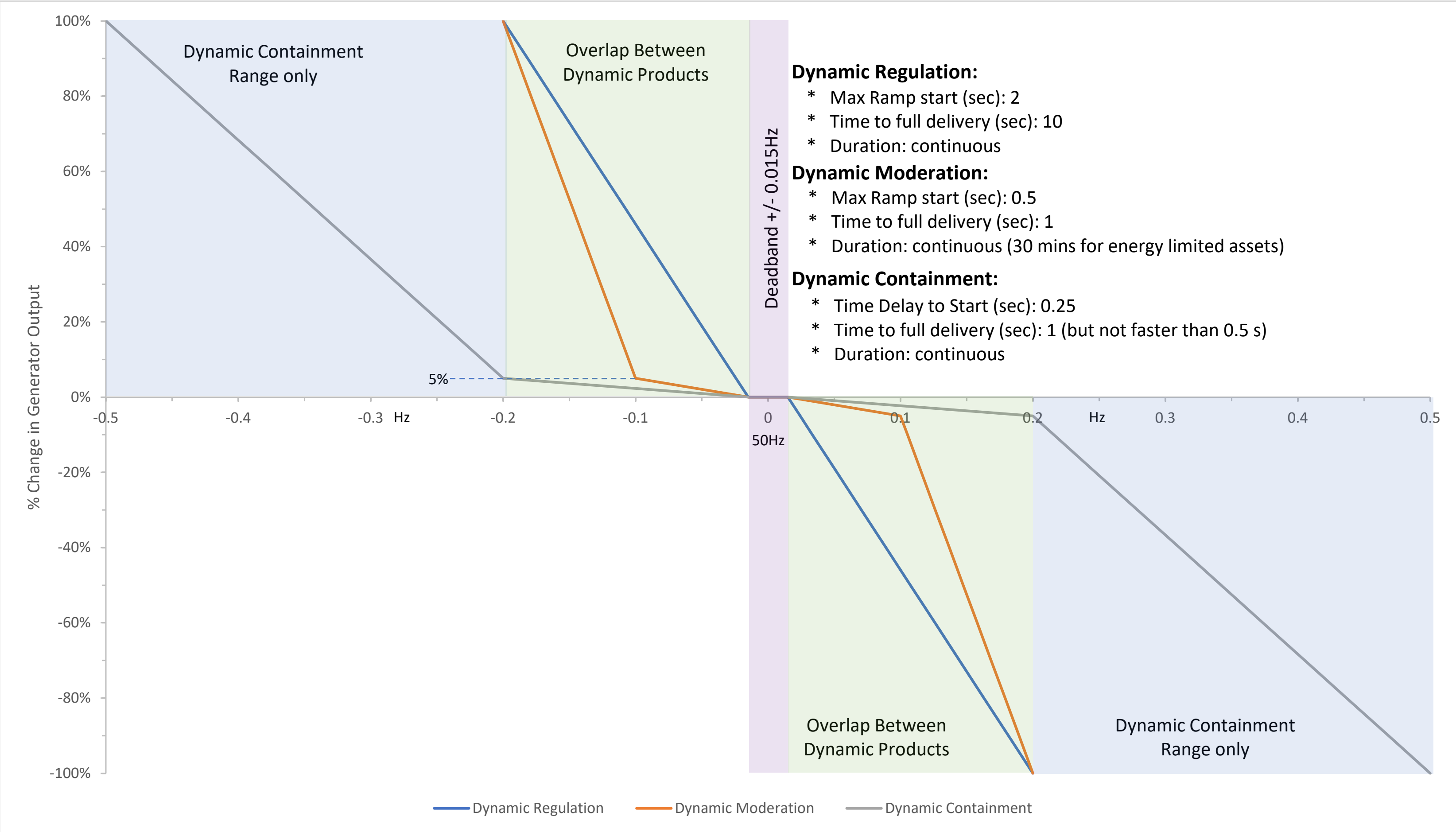
From the review of international practice, the following findings and conclusions can be made:

- In both the ERCOT and GB transmission systems there is a mandatory narrow band generator primary frequency response requirement, subject to available headroom,
- The Mandatory PFR response is achieved through a droop response in the range of 3 – 5% in GB and 4 – 5% in ERCOT, with deadbands of ± 15 mHz and ± 17 mHz respectively.
- For GB, although being able to provide PFR is a mandatory requirement, if enacted a generator is paid for the service. This is in contrast to ERCOT, where the mandatory PFR service is not compensated.
- Mandatory PFR service requirements are accompanied by other renumerated (non-regulation) ancillary services in both jurisdictions:
    - ERCOT – as part of the RRS PFR is procured, along with FFR and load provision of UFR to manage contingencies. The available PFR being frequency responsive with a narrow deadband also maintains frequency close to 60 Hz during normal system operation.
    - ERCOT – Fast Frequency Response, starting when frequency exceeds ±150 m Hz, service response beginning within 250 ms and sustained for 15 mins.
    - ERCOT – Under Frequency Response, starting when frequency exceeds -300 m Hz, service response to begin within 500 ms.

[15] https://www.nationalgrideso.com/document/206021/download
[16] https://www.energy-storage.news/uk-battery-storage-revenues-from-new-dynamic-frequency-regulation-services-wont-take-long-to-fall/

- GB – Dynamic Moderation Service, starting when frequency exceeds ±15 m Hz (but with limited slope response until ±100 m Hz), service response to begin within 500 ms and commence for +30 minutes (30 minutes for energy limited assets)
- GB – Dynamic Containment Service, starting when frequency exceeds ±15 m Hz (but with limited slope response until ±200 m Hz), service response to begin within 250 ms and to be provided continuously.

Figure 3 Summary of GB Dynamic Response Service Technical Requirements



4. Wider System Impact and Frequency Performance

4.1 System Operator Perspective

AEMO as the market and system operator is responsible for managing power system frequency and ensuring that the frequency operating standards[17] (FOS) are achieved, as specified by NER clause 4.4.

To achieve success in effective frequency management during normal operation and emergency conditions AEMO has a number of tools at its disposal to manage frequency drifts and deviations such as area control error correction via the NEM's automatic generator control (AGC), contingency energy reserve procurement via a number of frequency raise and lower markets, and more recently the introduction of mandatory PFR.

This section lays out the initial advice from the AEMO on the need for mandatory PFR, its observations of the implementation of the interim PFR arrangements following the AEMC's 2020 Rules change[18], and GHD's understanding of AEMO's preliminary advice on PFR incentivisation.

4.1.1 Requirement for Primary Frequency Response

AEMO's July 2019 Rules change request to mandate PFR[19] was informed by the findings of the power system separation event that occurred on 25 August 2018 and separate technical advice provided by an international expert. The Commission made a determination on this request in March of 2020, mandating the provision of PFR from all registered generating facilities. The new rule commenced in July 2020 with a three year sunset clause to allow information to be gathered on the effectiveness of PFR to restore effective frequency control to the NEM.

The key driver for the Rules change request made by AEMO in 2019 was the notable decline in power system frequency performance from 2015 onwards, resulting in numerous breaches of the FOS in the 12 months leading up to the Rules change submission. In their submission AEMO summarised root causes of this increasingly poor performance as:

- A decline in the provision of PFR by Generators, which is exacerbated by feedback loops inherent in the NEM's design.
- An increase in the variability of generation and load, which can be exacerbated by increasing levels of renewable generation whose output may be subject to weather driver variability.
- Inappropriateness of Regulation FCAS as a control mechanism for maintaining frequency as close as practicable to 50 Hz.

The new rule made by the Commission under NER clause 4.42A requires AEMO to establish and publish Primary Frequency Response Requirements (PFRR). The interim PFRR[20] require all scheduled and semi-scheduled generating system to provide narrow band PFR with a dead band of ±0.015 Hz and a governor droop of less than 5%. Furthermore, the interim PFRR outlines the requirement to achieve a 5% change in active power output within no more than 10 seconds, as a result of a change in frequency up to ± 0.5Hz.

The interim rule is in place until the sunset clause comes into effect in July 2023. The Commission is now considering the arrangements necessary for enduring frequency responsiveness, including the technical and market arrangements.

[17] https://www.aemc.gov.au/sites/default/files/2020-01/Frequency%20operating%20standard%20-%20effective%201%20January%202020%20-%20TYPO%20corrected%2019DEC2019.PDF

[18] https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2021/pfr-implementation-report-v13-15-mar-21.pdf?la=en

[19] https://www.aemc.gov.au/sites/default/files/2019-07/ERC0263%20Rule%20change%20request%20pending%20i.pdf

[20] https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2020/interim-pfrr.pdf?la=en

4.1.2 Primary Frequency Response Implementation

Since commencement of the new rules in July 2020 AEMO has been working with the operators of both synchronous and non-synchronous generating systems affected by this Rule change to implement the necessary controls and settings to achieve frequency sensitive automatic control. Rollout of the implementation was in distinct tranches that capture the largest synchronous generating units first and successively move on to smaller units and non-synchronous plant. AEMO's latest advice on the process and timetable is targeting completion by middle of 2021:

- Tranche for generating systems with nameplate ratings >200 MW 1 by 28 October 2020.
- Tranche 2 for generating systems with nameplate ratings between 80 and 200 MW by 30 March 2021.
- Tranche 3 for generating systems with nameplate ratings <80 MW by 30 June 2021

These implementation dates are subject to each generator first completing self-assessment, which has largely been completed for all generating facilities subject to the mandatory provision of PFR. In their latest implementation report[21] AEMO has stated that they have determined settings for 253 generating systems, representing around 51,600 MW. Concurrently, the system operator has indicated that Tranche 1 work is 85% complete representing around 30,900 MW of installed capacity, while Tranches 2 and 3 are both 36% complete, representing 5,700 MW and 1,700 MW of capacity, respectively.

AEMO reported that the majority of outstanding PFR implementations are for semi-scheduled generating systems, encompassing predominantly wind farms and solar farms. According to the system operator: "The Mandatory PFR Rule represents a material change to the operation of generation in the NEM, particularly for semi-scheduled generation, many of which have not previously operated in frequency response mode."[22] Consequently, enabling PFR in generating systems that previously have not provided this in the NEM has delayed completion of the overall implementation process.

Developing and implementing changes to power plant controllers is a significant task and AEMO is working with the equipment manufacturers to trial and validate new settings. The system operator has indicated that this will take time and has not yet confirmed expected completion dates for implementation other than stating they would look to progress work with OEMs whose equipment represents the greatest installed capacity first. As of late June 2021 AEMO had confirmed implementation of 13 semi-scheduled generating systems before the end of 2021, all of which use the Vestas wind turbine technology. Notably, two wind farms have already completed implementation of frequency responsive settings, these being the 270 MW Sapphire Wind farm in NSW and the 420 MW Macarthur Wind Farm in Victoria that both use the Vestas wind turbine technology.

During the self-assessment phase of implementation AEMO received and processed a number of applications for variation and exemption by generating systems in accordance with NER clause 4.42B that observed they were unable to apply the necessary controls and settings for PFR as required by the new rule. AEMO noted that the majority of applications for variation were due to response times in excess of the requirements of section 3.4 of the interim PFRR where some plant was unable to meet the required 5% change in active power output within 10 seconds as a result of a 0.5 Hz change in frequency. However, there are also a number of variations approved for wider dead bands and some for higher droops. AEMO has indicated in their latest implementation report that it had received 43 applications for variation of which 39 had so far been granted. Similarly, AEMO reports that it had received 26 applications for exemption of which it had to date granted 6. It is not clear whether there is any material impact on the expected performance of system frequency due to these relaxations.

In parallel to the implementation of PFR, AEMO also reviewed and tuned its AGC settings to ensure better utilisation of Regulation FCAS. The changes commenced on 9th December 2020 and included modifications to AGC dead bands, gain adjustments, integral area control error persistence changes, and basepoint adjustments. AEMO noted that these changes were observed to narrow the frequency distribution curve, but that basepoint adjustments had to be reversed in January 2021 as these changes interfered with the data transfer process used by the causer pays process that allocates Regulation FCAS costs. It is not yet clear whether changes will be made to allow the tuned settings to be reinstated at some time in the future.

[21] AEMO PFR Implementation Report V16, 25 June 2021.
[22] Ibid, p. 7.

4.2 Effectiveness of Wide Area Primary Frequency Response

4.2.1 AEMO Implementation Progress Reports

From July 2020 AEMO has published 3- or 4-weekly progress reports of the implementation process, starting with self-assessment and progressing to implementation of the three tranches.[23] The reports detail the generating systems that have implemented PFR and the progressive performance of system frequency since publication of the previous report.

By June 2021, AEMO had completed enablement of PFR in 38.33 GW of generating capacity, including two wind farms. This represents about 67% of the total of 56.5 GW capacity that in accordance with the PFR Rules change is required to be frequency responsive. The observed and progressive performance of the system frequency from September 2020 to June 2021 is presented in Figure 4.

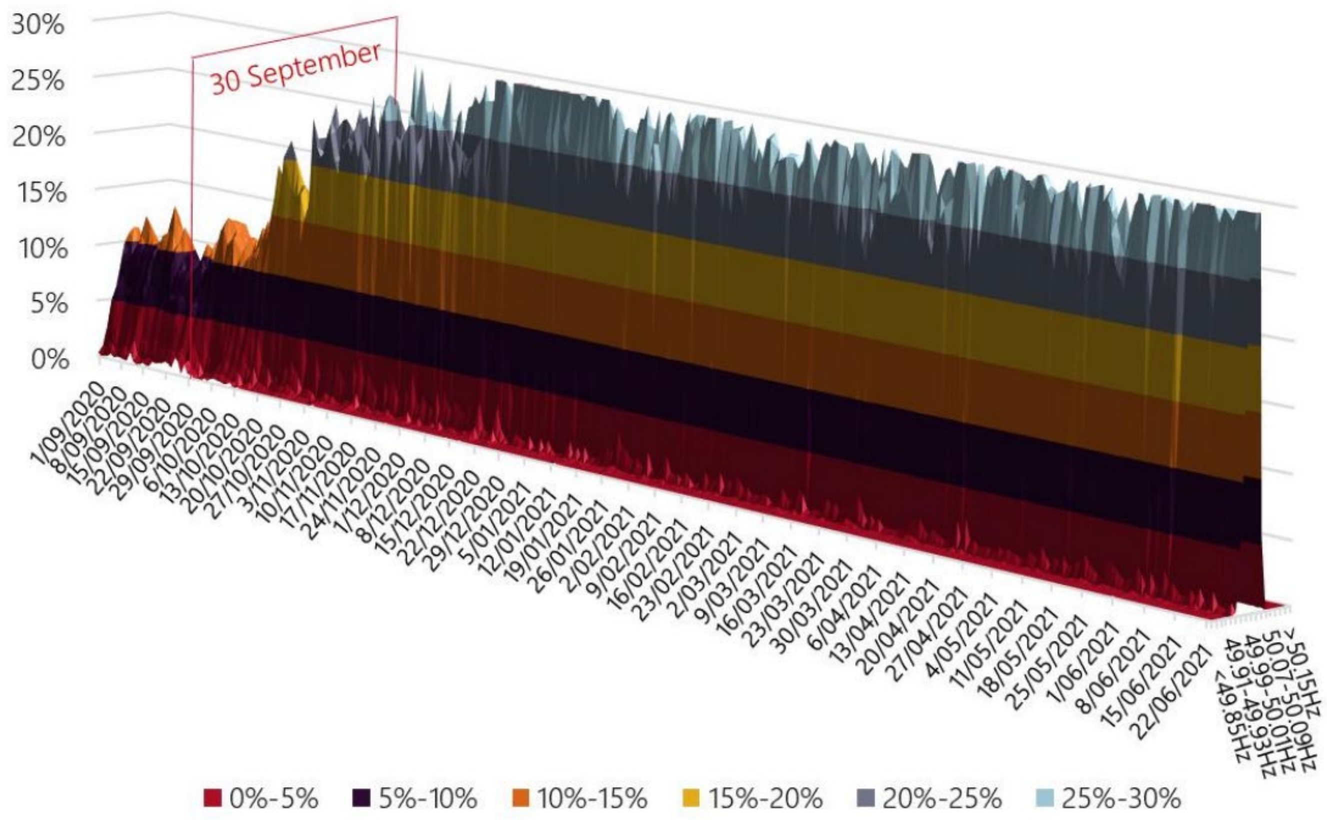


Figure 4 Comparison of NEM frequency distribution – Sep 2020 to May 2021 (Source: AEMO PFR Implementation Report V16, 25 June)

While implementation commenced from July 2020, it did so with initially only agreeing of setting and actual installation of these following thereafter. Consequently, this is also reflected in the observed performance of the system frequency during August and September, which did not mark significant improvements in frequency performance. AEMO suggested this could be further explained by weather and the number of units [with PFR enabled] being online.

The contour plot shows that there is a significant increase in performance of frequency observed from October 2020 onwards, which coincides with the implementation of PFR in the first lot of the large synchronous units of Tranche 1. Frequency performance continues to increase, with more narrowing of the distribution around 50 Hz, until there is an apparent saturation in tightness of the frequency distribution around December 2020. The

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

progressive improvement in the frequency performance mapped against the increasing installed PFR capacity is easily visible in Figure 5, which shows frequency distribution against installed PFR from September to November of 2020.

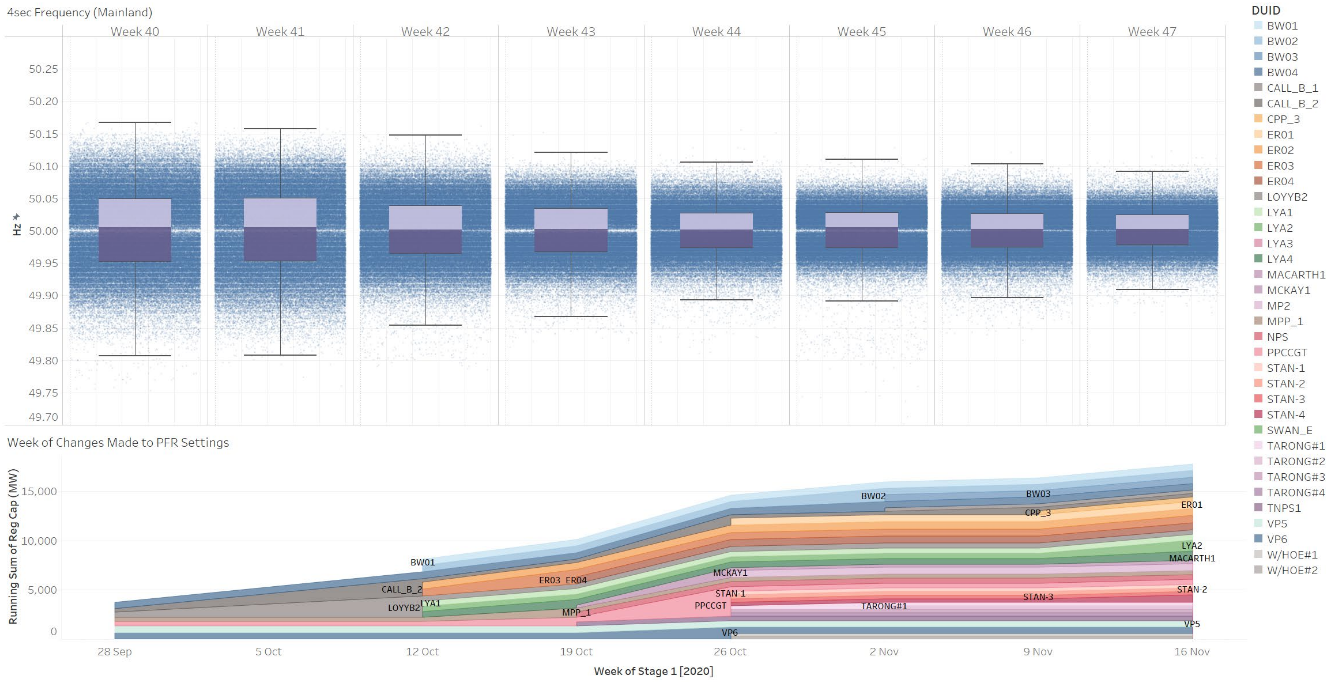


Figure 5 Mainland Frequency Changes as new Frequency Settings Implemented (Source: Greenview Strategic Consulting, 2021)

The effectiveness of the implementation of PFR to maintain frequency within the normal operating band is also highlighted by the tracking of frequency excursions outside of the NOFB shown in Figure 6 and Figure 7. The rapid reductions in the number of excursions outside of the band speaks to the effectiveness of implementing locally measured frequency responsiveness via narrow band PFR, rather than relying on AGC driven set point changes to maintain frequency within the NOFB. The rapid reduction of excursions also suggests that by December sufficient PFR was enabled to contain normal operating frequency within the NOFB, which may have implications on the volumes of PFR needed for effective frequency control. However, the two graphs do not provide additional information of the improvements to frequency performance within the NOFB.

Beyond the time period shown in Figure 5, the effective performance over the entire implementation period and the performance within the NOFB is illustrated on the progressive distribution plots shown in Figure 8. This comparison suggests that while further PFR was enabled after December 2020[24] there is a saturation of the increase in frequency performance, with additional enablement only providing limited improvement. This may be a result of:

- The generators modified since December 2020 typically have lower capacity factors and are not always dispatched reducing the impact they have of frequency performance,
- There is a large quantity of semi-scheduled plant yet to be PFR enabled, or
- Adding additional PFR capacity beyond the amount available in December 2020 offers limited performance improvement.

The last point is relevant for further consideration as it speaks to the matter of whether all or just a portion of the fleet needs to be PFR enabled in order to have good system frequency performance and separates the issue of unit commitment (number of plant online) and reserve capacity (head- and foot room). However, without further and detailed analysis, it is difficult to tell how much PFR was enabled in the online generation fleet at any one time,

[24] As indicated by the AEMO Implementation progress reports, approximately 18,000 MW of PFR was enabled between November 2020 and May 2021.

and hence quantify this hypothesis We do note however, that it was less than 100% because implementation was still in progress, as reported by the AEMO updates. We expand further on this issue in Section 6 of this report.

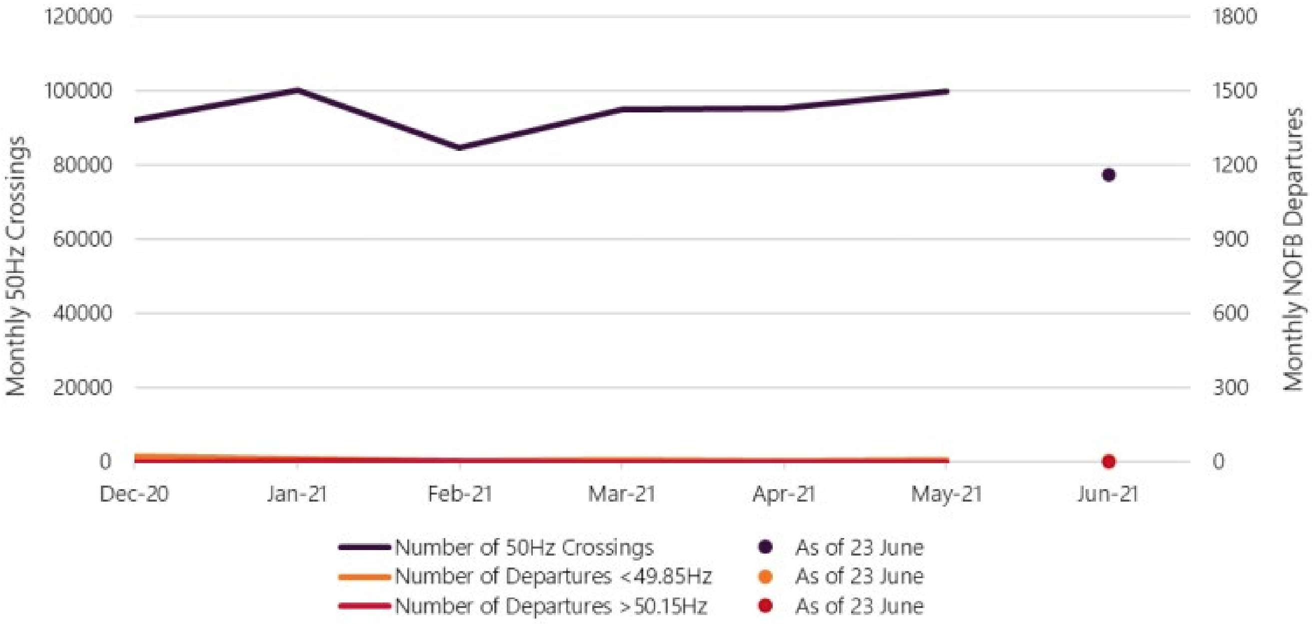


Figure 6 Monthly frequency crossings – under 49.85 Hz, across 50 Hz, beyond 50.15 Hz [Source AEMO PFR Implementation Report V16 25 June 2021]

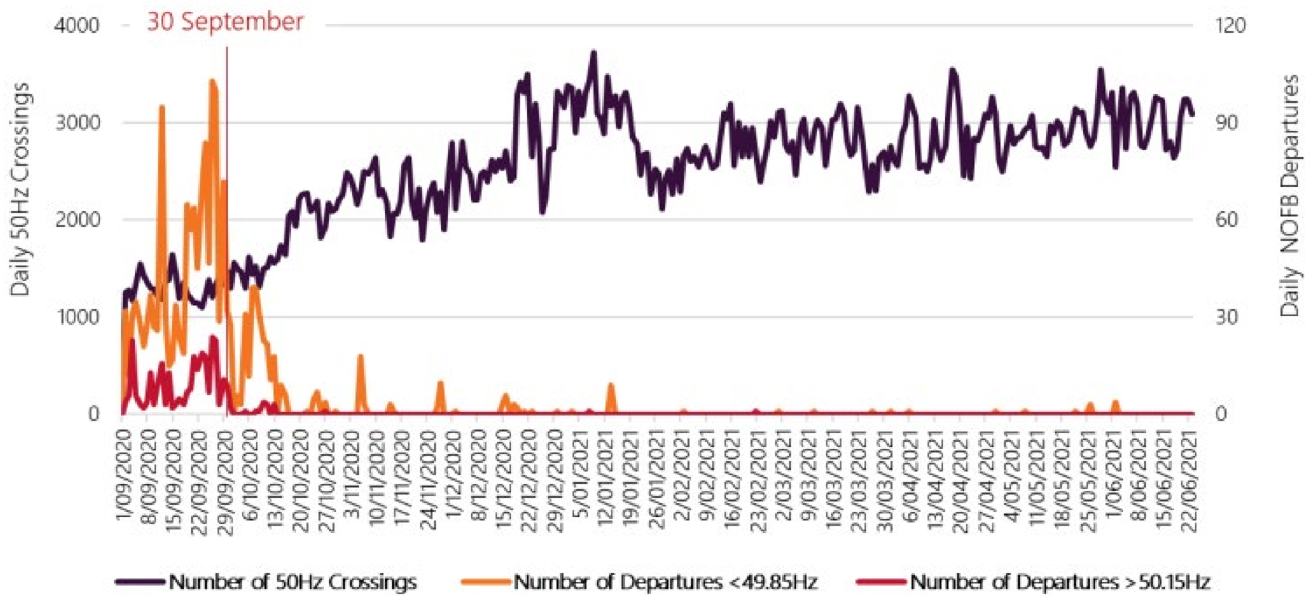


Figure 7 Daily frequency crossings – under 49.85 Hz, across 50 Hz, beyond 50.15 Hz [Source AEMO PFR Implementation Report V16 25 June 2021]

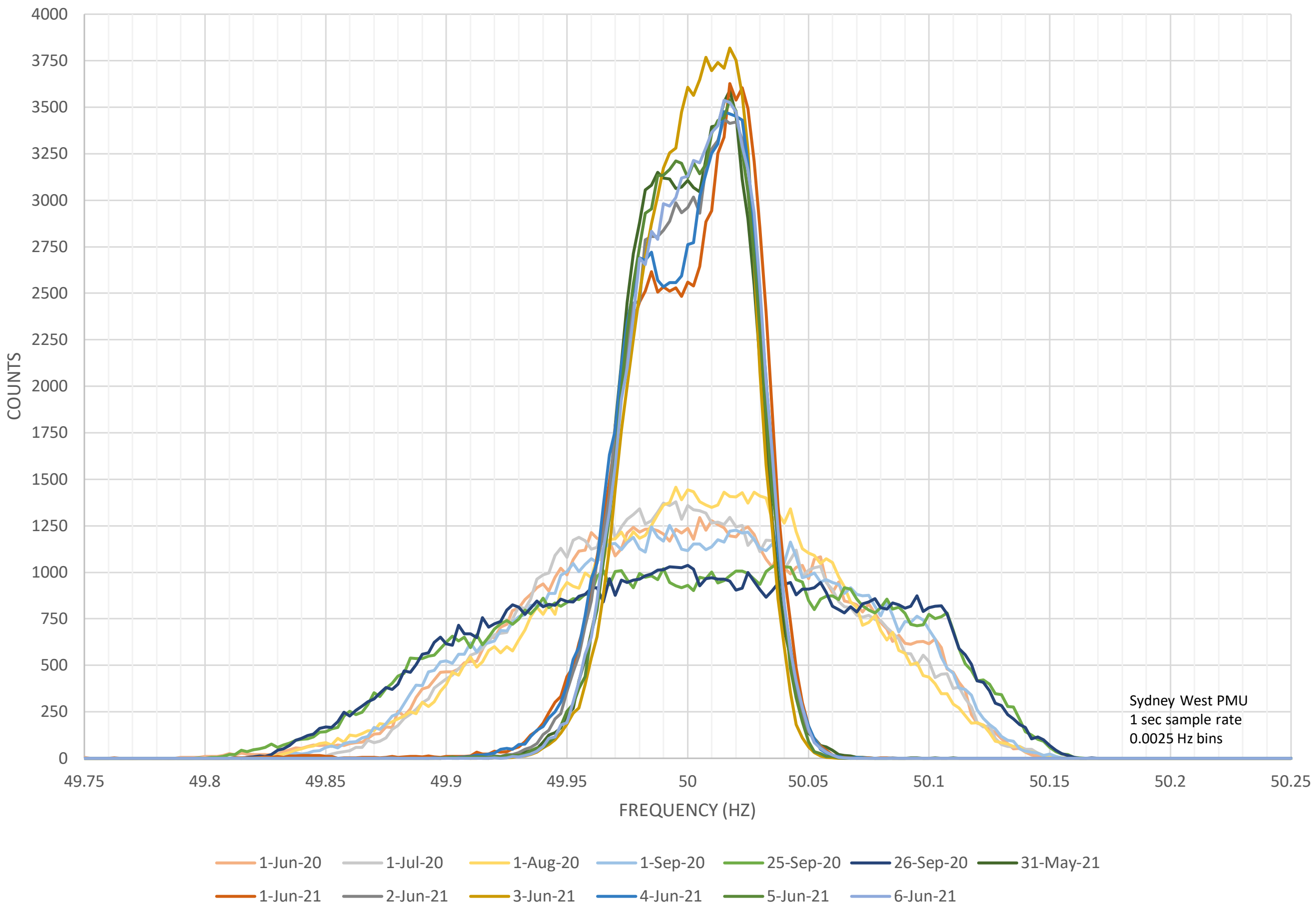


Figure 8 Comparison of NEM frequency distribution – September 2020 to May 2021 [Courtesy AEMO]

In summary:

- The effectiveness of narrow band PFR when provided by aggregated system response is proven by the performance of system frequency since implementation of frequency responsive control, with negligible excursions outside of the NOFB since late 2020.
- Effective PFR is predominantly derived from sufficient availability of headroom from the NEM coal fired generating fleet.
- Frequency distribution curves show frequency control has improved and is now consistent with the performance levels that existed prior to 2015.
- Approximately 67% of the NEM installed scheduled and semi-scheduled generating capacity of 56,900MW has now been enabled for narrow band PFR.
- Only two wind farms with an installed capacity of 690 MW have been enabled to provide PFR.
- No solar farms have been enabled for PFR.
- Some variations and exemptions have been granted to generating systems where they were unable to meet the specifications of the interim PFRR.
- Aggregated response provided by a large portion of the fleet makes PFR effective when implemented using narrow band response. Insufficient information is presently available to comment on whether all or only a portion of the fleet needs to be enabled.

5. Impact on Generating Equipment

This section looks at the observed and reported impact of PFR on generating systems. GHD's considerations include the following inputs that will be reviewed to inform our independent advice to the AEMC:

1. AEMC generator active power analysis
2. Greenview Strategic Consulting Services survey of generating system operators
3. International reports on frequency control

5.1 Generator active power analysis

The AEMC has conducted some initial analysis of the impact that PFR is having on active power variations observed in the NEM generating fleets, breaking these observations down further into generating technology types. The observed deviations from dispatch targets over a four second interval, less regulation, and summed over a five minute dispatch interval (DI) has been termed as active power "mileage" and represents the cumulative variation of generating systems' active power as a result of frequency responsiveness due to PFR enablement.

Mileage could be an important metric for generators as it represents the frequency of governor valve movement, blade pitching or other activities that could affect generating system wear and tear and give indication whether any part of the system is more affected by the implementation of PFR than others.

5.1.1 Generation plant active power mileage calculation

The methodology used, by the AEMC, to calculate this metric is shown graphically in Figure 9, but essentially involves the following steps:

1. Calculate the MW distance between each four second value for plant output - adjusted to remove regulation response. (purple)
2. Calculate the MW distance from the Dispatch start and finish points on a five minute basis. (yellow)
3. Calculate the difference between these two intervals to determine the net active power mileage that is not driven by dispatch and regulation response.
4. Divide the net mileage by the registered capacity of the respective generation unit – for each DI.
5. Sum the generation mileage values across a month by generation technology
6. Compare the generator mileage values before and after the activation of narrow band PFR.

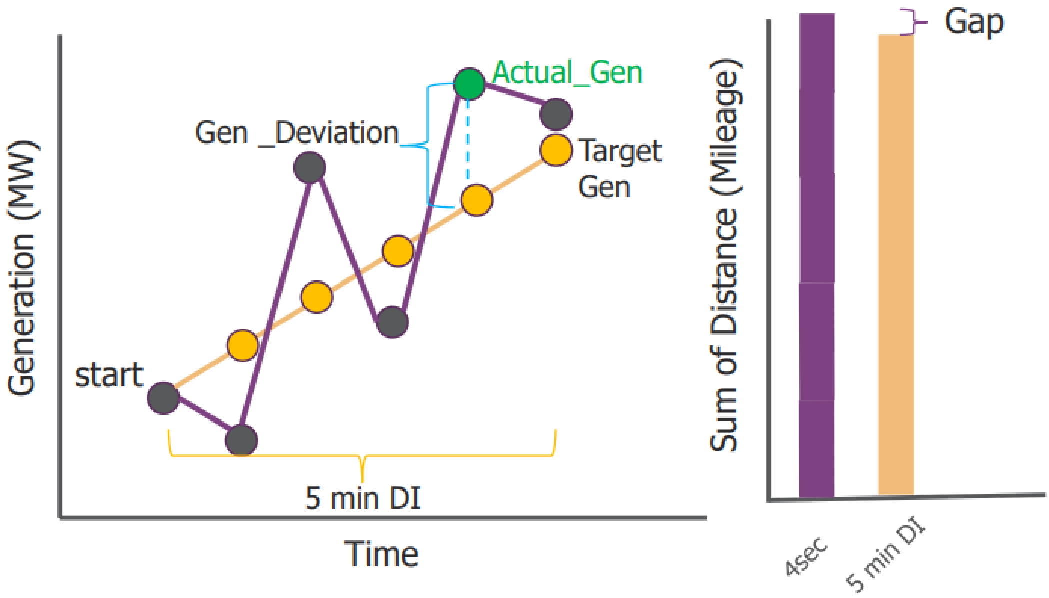


Figure 9 Generation plant active power mileage (source AEMC)

A further metric used for quantifying the active power variations introduced by PFR is the active power "deviation". The AEMC has outlined the methodology for this calculation using the following steps:

1. Determine the unit active power target by adding any regulation component to the dispatch trajectory (target – target) -> Target_Gen
2. Calculate the distance between the actual active power value (purple) and the target Gen (yellow) -> Gen_deviation
3. Plot the Gen_deviation as a monthly distribution for the whole generation fleet and for sample Generation units. Show the monthly distributions prior to the roll out of MPFR and following the implementation.

Based on four second data collected for causer pays calculations the Commissions has established the following observations for the two metrics, as outlined in the following sub-section.

5.1.2 Fleet Active Power Mileage

Using the methodology described, the AEMC has derived the whole fleet active power mileage as shown in Figure 10.

The plots have removed the regulation component of generator dispatch and normalized the mileage by unit capacity by technology. The former allows generator power movement to be examined for variation other than AGC dispatch and tests the frequency sensitive response of plant along with variability that may arise from a number of factors such as fuel availability, forecasting errors, or load changes. The latter permits easier comparison by technology on a per unit basis.

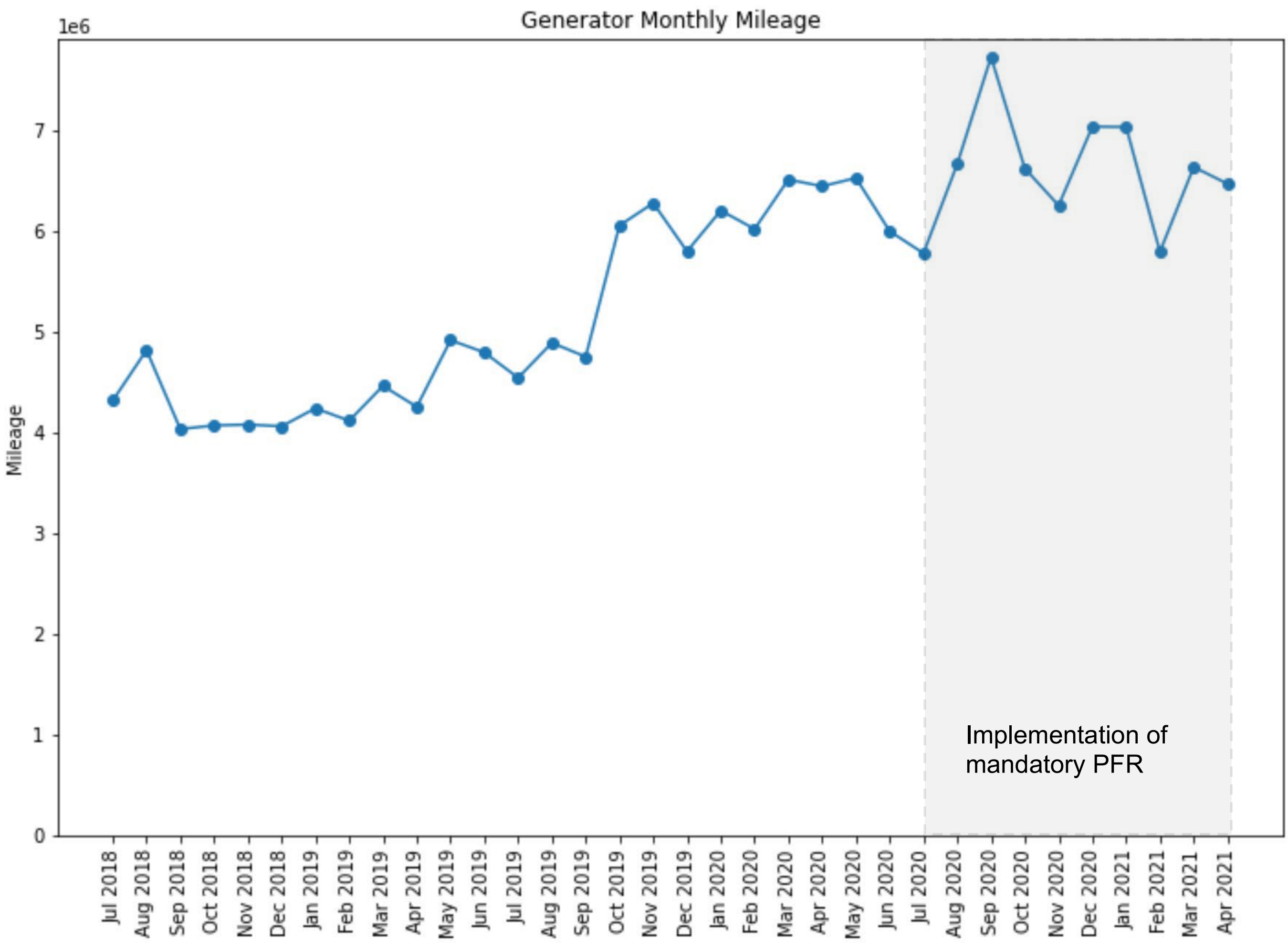


Figure 10 Generator mileage for all operational NEM facilities [source AEMC]

Active power mileage of the whole NEM fleet shows a general trend of increasing active power movement over time. From July 2020 commencement of the mandatory PFR Rules change and implementation of frequency response active power settings continues the trend of increasing movement at a similar rate, but this appears to now be coupled with increasing variability of mileage also.

The overall trend of increasing mileage is likely associated with variability of load and generation driven by continuing renewable integration at transmission and distribution levels. This would increase overall uncertainty errors in forecasting and hence deviation from dispatch. Mileage of synchronous generators responding to frequency changes would then also increase resulting in an overall growth in fleet mileage. More detailed analysis would be needed to confirm this.

The spike in mileage during September 2020 is also likely associated with the implementation of mandatory PFR, initially in the larger generating units in the NEM. Responding to frequency changes these units would experience some increases in mileage as they move to correct frequency deviations within the NOFB. The trend appears to then reverse beyond September, potentially due to increasing volumes of PFR becoming available as the implementation process continues. Greater volumes therefor appear to imply less movement from individual plant, as well as the fleet as a whole.

The normalized mileage grouped by technology rather than the whole fleet is shown in Figure 11.

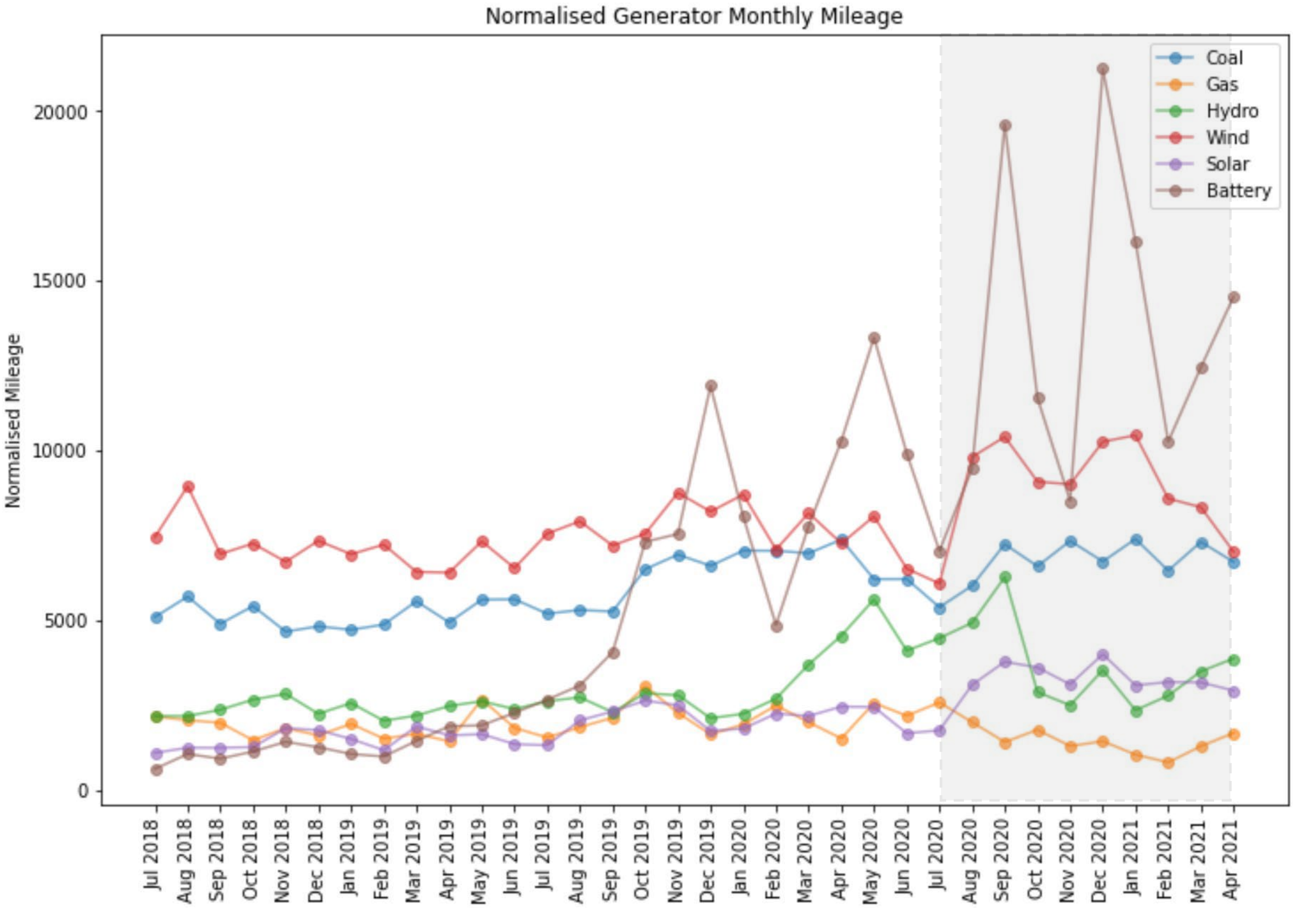


Figure 11 Generation active power mileage analysis by technology **[Source AEMC]**

The normalised mileage plot yields some interesting observations:

- The greatest increase in normalised mileage is presented by battery storage systems. This was to be expected as these units are predominantly providing frequency control services in the form of secondary control, and from September 2020 they additionally provide PFR.
- There is a jump in milage of wind generation coinciding with the commencement of PFR implementation. However, the first two wind farms did not commence frequency responsive operation until February and

March 2021. The Clean Energy Council noted in their 2020 Annual report[25] that around 1,100 MW of new wind farms were added to the NEM. However, it is not clear how much of this was prior and how much post July, and whether the full capacity was added or only a proportion. What is clear is that there was a jump in mileage of wind farm, that appeared to decrease marginally after March 202.
- Coal fired generation saw a small month by month increase over the entire period displayed, with no substantial difference in mileage post July 2020.
- Solar generation saw a marginal increase post July 2020 as a substantial amount of new projects came online throughout the year.
- Hydro-electric generation saw a step change in mileage from May 2020 to October 2020, when levels returned to the prevailing trend observed earlier in the period. This does not appear to be explained by implementation of PFR settings which occurred during December 2020 and March 2021 for Tumut power station, and Murray power station plus a number of Tasmanian generators, respectively.
- Gas generation does not show any significant changes in mileage over the observed period, likely due to the low capacity factors of these units which do not vary significantly throughout the year.

Not shown in this section is a further breaking down of mileage into daytime and evening hours to test the sensitivity of generator mileage to variability of levels of solar and wind generation. These have been excluded as there are no appreciable difference in the trends, indicating that mileage is relatively insensitive to

In summary of the observed active power mileage following the implementation of PFR:

- There appears to be no significant change in mileage trends that can be linked to the introduction of mandatory PFR, with the exception of battery energy storage systems.
- There are step changes in the mileage of wind and hydro-electric generation, with an increase in the former and a drop in the latter. It's not discernable whether this is related to enablement of PFR, installation of more capacity (wind) or some other reason.
- Seasonal and/or diurnal variations, demand and other factors may show greater variability in mileage, and it may be beneficial to collect further data at greater granularity to consider these impacts.

5.2 Observed Generating Unit Impact

To understand the Generator perceived impact of PFR on their generating systems, the AEMC engaged Greenview Strategic Consulting (GVSC) to:

- Conduct a generator questionnaire on the impacts of the Mandatory PFR changes made in the NEM in the past 12 months.
- Perform plant specific data analysis on a smaller subset of units.

The GVSC survey took the form of a questionnaire with set of 65 separate questions seeking information on matters such as:

- Frequency control system settings before and after the implementation of mandatory PFR.
- Impediments to implementing narrow band PFR, and additional equipment that had to be installed to achieve this.
- Changes to typical operating mode of the plant.
- Observed changes to plant stability, flexibility, or efficiency.
- Unexpected behaviour during over- and under frequency events.
- Discernable or expected wear and tear and associated costs, resulting from narrow band PFR operation.

GVSC's question was shared with 36 separate generators reflecting all currently represented generation technology in the NEM, of which 29 provided responses:

- Ten coal (10) fired steam generation (Brown and black coal)
- Two (2) hydroelectric generators (run-of-river and pumped storage)

[25] https://assets.cleanenergycouncil.org.au/documents/resources/reports/clean-energy-australia/clean-energy-australia-report-2021.pdf

- Nine (9) gas generators (open cycle, combined cycle power plant, gas fired steam generators)
- Four (4) Wind generation
- One (1) Solar generation
- Three (3) Battery Energy Storage Systems

GHD's review of the GVSC results summarising the survey responses and their insights found:

- Impediments to narrow band PFR include expected wear and tear, combustion stability, increased plant output cycling, and state of charge management issues (battery systems).
- In most instances enablement of narrow band PFR for synchronous generators was a relatively simple adjustment of droop and dead band settings.
- There was no requirement to install further equipment flagged by the survey respondents, nor major increases in CAPEX costs. However, coal generators particularly predicted additional OPEX costs per overhaul cycle[26].
- First movers that installed narrow band PFR settings reported significantly more plant movement in response to frequency changes, which decreased as more generators enabled PFR. This simple observation supports the need for at least a certain amount of PFR enablement to not only achieve effective PFR, but also to minimise equipment wear and tear.
- Some thermal plant reported reduced plant flexibility to allow for governor head- and footroom. This appears incongruous since there is no mandatory headroom requirement associated with mandatory PFR capability. However, the comment of not reaching dispatch targets seems reasonable if frequency deviations cause PFR to move the plant away from its set point.
- Reflections on plant efficiency were varied, with some reporting improvements and others degradation.
- Operators expressed concerns over large frequency excursions that could result in plant instability if such deviations caused the plant to move below minimum dispatch levels. Indeed for gas turbines this could result in flame instability, or activation of bypass valves for steam generators. Even wind generation operators speculated that increased blade feathering will result in extra 'mileage' and wear.
- Feedback regarding the wear and tear resulting from provision of PFR was largely speculative as no specific data could be provided at this stage. About half of the surveyed operators predicted theoretically and increased wear on mechanical components: valves, bearings, actuators etc. While inconclusive at this stage, more information should be sought once plant have been operating under mandatory PFR for a year or two.
- There was no change to the considerations of causer pays incentives when operating plant. Most operators reported that this was already a focus.

Reflecting on the responses of the surveyed Generators and the insights provided by GVSC, it appears that at present there is little evidence of noticeable adverse impact on plant when there is reasonable aggregate frequency bias provided across the NEM fleet. Anecdotal claims of increases in expected maintenance costs due to additional wear and tear will need further information to be collected to substantiate. Similar conclusions were drawn by AEMO's independent international advisor Dr Undrill[27] and the same author's work at LBNL[28]. Similarly, in the 2017 report prepared by DIgSiLENT on behalf of AEMO it was noted that "Governor response represents a cost in terms of wear and tear and efficiency…"[29] although here also this was not substantially quantified and that it would be less with increasing amount of generation providing PFR. The report did note that it is difficult to distinguish between the effects of frequency response and ageing of plant more generally[30].

[26] Typical maintenance cycles for steam turbines are 5 years, although inspections are carried out more frequently, and older plant may require more frequent major outages. For gas turbines maintenance intervals depend on the capacity factors and operating hours but could also be every 3 or so years.
[27] Ibid 18, pg. 11.
[28] https://certs.lbl.gov/sites/default/files/primary_frequency_response_lbnl-2001105.pdf, pg. 42.
[29] Ibid 19, pg. 6.
[30] Ibid, pg. 45.

5.3 International experience with impact of PFR

PFR is implemented in almost all other large electrical networks around the world. Consequently, there is a wealth of experience around the impact of frequency response on power production plant for almost all types of technology. To highlight some of these we have drawn on the commentary provide by LBNL in their 2018 report prepared for FERC in the USA. While not specifically referred to in our report, similarly good advice was provided in 2017 by Hickory Lodge consultant Nick Miller in his recommendations to the AEMC for the frequency control frameworks review.[31]

In their report[32] the LBNL team examines a number of aspects of system frequency control, the most relevant for this review being as follows:

1. Primary frequency response must be delivered quickly, which requires many participating generators.
2. Primary frequency response must be sustained until secondary frequency response can replace it
3. Gas turbines may not be able to sustain provision of primary frequency response following large loss-of-generation events
4. “Synthetic inertia” controls on electronically coupled wind generation appear not to sustain primary frequency response

The relevance in the context of this review can be summarized as follows:

- Point 1 – whilst the total volume (or headroom) of primary frequency response must exceed the value of generation or load change driving the largest expected frequency deviation, in addition for the PFR to be effective it needs to be delivered quickly, which requires many participating generators. While this is principally referring to security services, in the context of this review, this still infers that for any new market based primary frequency response or regulating service to effective, it must be procured from a sufficiently large enough pool of participants to be delivered effectively.
- Point 2 – As noted by the LBNL team, “Due attention should also be devoted to ensuring primary frequency response is sustained during the period when frequency is stabilizing following the formation of the nadir”. Whilst this statement is made in the context of PFR delivered to arrest decline in system frequency following a generator contingency event, the same observation applies here where PFR is used to resist changes in system frequency driven by load or generation output variations. The actual response provided by individual generators must be sustained until corrected through secondary frequency response or regulation services. Thus, for PFR option pathways that seek to procure or establish new market arrangements for the provision or PFR services, consideration will need to be given to sustainability of the service provision and how this is coordinated with other FCAS markets.
- Point 3 – The LBNL team notes that gas turbines are among the fastest responders that can contribute to arresting changes in system frequency and can readily increase their output within a handful of seconds. However, if an under-frequency deviation calls for maximum output, this maximum will be less than would be reached when running at nominal frequency, due to thermal limitations within the machine. Whilst the need for an individual gas turbine generator to increase its output to maximum during a PFR response to non-continency driven system events is likely to be very low, the LBNL observation does have some potentially practical ramifications with respect to the sustainability of gas turbine based PFR which will need to be considered if being contracted or procured under a new market service.
- Point 4 – Inverter connected wind generation can provide a synthetic inertial type of response for under-frequency events that can approximate the droop based response of conventional generation. However, the sustainability of this response is also questionable, with the LBNL team noting that it is likely to be withdrawn within 5 – 10 seconds. In reality this limits wind generation to providing a droop response to under-frequency events only if the wind generation output is already curtailed, and in essence has some ability increase output, or during over-frequency events when the ability to reduce output would be available. In the short-term this is not likely to present any issues for PFR pathways that require the

[31] “Costs of Primary Frequency Regulation”, N. Miller, December 2017, Advice to the AEMC on the Frequency Control Frameworks Review.

[32] “Frequency Control Requirements for Reliable Interconnection Frequency Response”, J. Eto, J. Undrill, C. Roberts, P. Mackin, J. Ellis, Lawrence Berkeley National Laboratory, February 2018, LBNL-2001103.

provision of a new market based PFR service but could become more of an issue in future years as thermal generation units retire from NEM.

5.4 Cost of Primary Frequency Response

Prior sections address observed operational and technical impact on individual generators and the system as a whole. The financial impact of these operational effects are difficult to estimate. GVSC suggested some changes related to additional operating and maintenance costs, similarly DIgSILENT also suggested some increases. While quantification of costs will vary from plant to plant, qualitatively we observe the following likely changes:

- Once off PFR enablement CAPEX costs (Mostly OEM support).[33]
- OPEX increase for maintenance overhauls (every 5 years) due to increased wear and tear resulting from e.g. increased governor movements.[34]
- OPEX related fuel costs due to production variability.[35]

These figures are the results of Participant suggested influences collected during surveys, rather than evidential figures. It's expected that the true costs of enabling and providing narrow band PFR will be difficult to discern, let alone separate from normal costs of operation. It may be just as complex to understand the cost of frequency response enablement for inverter based resources.

[33] Greenview Strategic Consulting Services, Generator questionnaire results.

[34] Ibid.

[35] Ibid 19, pg.42

6. PFR Pathways (Our Analysis)

6.1 Methodology

A multi-criteria analysis (MCA) has been used to provide a framework that allows different PFR Pathways to be comparatively assessed. The assessment framework is described in detail in section 6.6, but essentially involves the following activities:

(a) defining a number of pathway options characterized by:
- requirement for mandatory PFR,
- mechanism proposed for procuring PFR
- method proposed to allocate PFR costs and reward PFR provision

(b) defining criteria for assessing the merit of each pathway with criteria considering:
- power system performance impacts
- service characteristics
- service participation

(c) weighting the criteria and assigning a score for each criteria

(d) developing a weighted score for each pathway option assuming the pathway option is in place in each of the following time periods: 2022/23, 2030/31, 2040/41.

The highest overall score obtained identifies the preferred pathway based on the range of factors encompassed by the criteria.

6.2 Changing Generation Mix

To ensure that a sustainable solution is adopted, the assessment will be applied to the changing generation mix from 2023 to 2030 and 2040 using the 2020 ISP Central scenario projections. The 2022 ISP input and assumption documents are still being finalised by AEMO and the final ISP won't be published for another 12 months so they have been excluded from our analysis.

FCAS assumptions, for future scenarios in the 2020 ISP, are detailed in the Draft ISP Methodology[36] with the following being a high-level extract from the Methodology detailing the processes used:

> *"The ISP model considers only system normal (network intact) conditions. Under these conditions it is expected that the frequency control ancillary services (FCAS) market will ensure sufficient headroom is available on generation or batteries, as well as provide signals for investment if needed. Given the wide range of potential sources of global FCAS providers, this is not seen to influence the ODP, and given the computational overhead, it has not been seen to be necessary to model the FCAS market as part of the ISP.*
>
> *Where detailed investigation of the potential benefits of FCAS for a specific augmentation is required, it is considered that this is an aspect that can be captured as part of any subsequent RIT-T."*

To summarise, AEMO does not model FCAS in the ISP. FCAS modelling, for the ISP, is not fit for purpose as it adds massively to the optimisation complexity without having material influence on transmission investment. Previous projections have shown that a very large amount of battery and hydro storage is projected, which greatly exceeds the additional FCAS requirements during system normal conditions.

The forward plan also makes no assumptions about PFR and mandatory headroom. However, the 2020 ISP Central scenario forecasts generation capacity needed to meet projected demand and the seasonally expected maximum demand as shown in Table 3. The predicted customer demand levels over the same period, also taken from the 2020 ISP, are shown in Table 4.

[36] https://aemo.com.au/en/consultations/current-and-closed-consultations/isp-methodology

Table 3 Changing generation mix as presented by the 2020 ISP Central Scenario

Capacity (MW)	2022-23	2030-31	2040-41
Black Coal	17,861	14,366	5,216
Brown Coal	4,820	4,120	3,370
CCGT	4,046	3,481	1,509
Peaking Gas+Liquids	6,813	6,430	4,927
Hydro	6,907	6,907	7,210
Dispatchable Storage	1,231	3,740	12,415
Behind the Meter Storage	522	1,001	1,830
Wind	10,093	14,509	25,341
Solar	5,942	9,479	20,508
Distributed PV	11,767	13,982	22,672

Table 4 Seasonal peak demand as predicted by the 2020 ISP Central Scenario

	Maximum demand summer (MW)	Maximum demand winter (MW)
2022-23	38,684	33,014
2030-31	39,878	34,260
2040-41	44,141	38,326

Generation technology influences the ability to provide fast PFR and the droop setting that can be applied to the active power controls i.e. the change in power output for a given change in system frequency. If droop is overly aggressive it could result in issues such as combustion instability in gas turbines, mechanical strain on wind turbine blade pitching drives, or excessive temperature variability in steam turbines. As such historically droop settings for 4-5% have been applied. In CCPP the droop setting of the gas turbine component was often set to lower values of around 2.3% to compensate for the lack of frequency responsiveness of the HRSG. One technology that is capable of very aggressive droop setting is IBR such as BESS and solar inverters. In the NEM single applications of BESS has implemented droop as low as 1.3%. Theoretically it could be lower still. However, as yet, the impact that an aggregated droop of such low values is not known. In summary while there is a transitioning of our generation technology and fuel sources, there is potential for effective replacement of our present primary sources of PFR services as shown by the expansion of dispatchable storage and IBR based renewable generation.

The changing types of generation, in the NEM, may impact PFR and available headroom. In future Central scenarios as shown in previous tables, the proportion of embedded and variable generation increase whilst dispatchable generation decreases. This is illustrated in Figure 12. For the purpose of providing PFR we have assumed that coal fired generation, gas generation, hydro-electric power and dispatchable storage all aggregate to represent dispatchable generation well suited to providing raise and lower PFR, while large scale wind and solar represents variable renewable generation better suited to providing lower PFR, although with sufficient headroom, i.e. if constrained or spilling energy, they could also provide raise services. Behind the meter storage and solar roof top PV represents aggregated DER collectively able to provide raise and lower PFR.

The amount of synchronous generation making up the dispatchable generation is expected to reduce significantly over the outlook period with the retirement of around 75% of the current coal-fired generation fleet by 2040. The total capacity reduction shown in Figure 12 masks the extent of the reduction in synchronous generation as it is offset by large rise in dispatchable storage, as noted previously in Table 3. This means that over time there is a significant change in the type of plant making up the dispatchable capacity in the NEM who would be effectively able to provide PFR services.

Thermal generators face a relatively low opportunity cost and high reward in holding back some capacity to cater for unexpected events and supply shortfalls. The relatively low opportunity cost is because the design of these power stations inherently builds in an appreciable short-term energy storage capacity. That might take the form of coal stored in a bunker, gas in a pipeline or water in a hydro dam. By offering the bands of capacity at prices close to the market cap, these generators are able to extract significant value from storing energy to respond to unexpected events. When those events occur the energy price increases significantly, and the synchronous generators make reserved capacity available at a premium. The incentive to maximise revenue from the energy market encourages this behaviour and also means that synchronous generators (particularly thermal generators) are likely to operate with headroom sufficient to provide a level of PFR. Furthermore while there are significant numbers of synchronous generators providing PFR the actual contribution each is required to make is quite small and does not appear to add significantly to their operating cost.

As the amount of synchronous generation declines, the available headroom to provide PFR may also reduce particularly if there are not appropriate mechanisms in place to remunerate providers of PFR. Dispatchable storage may rely on PFR revenue to ensure financial viability and compensate for the battery life expended in providing PFR response.

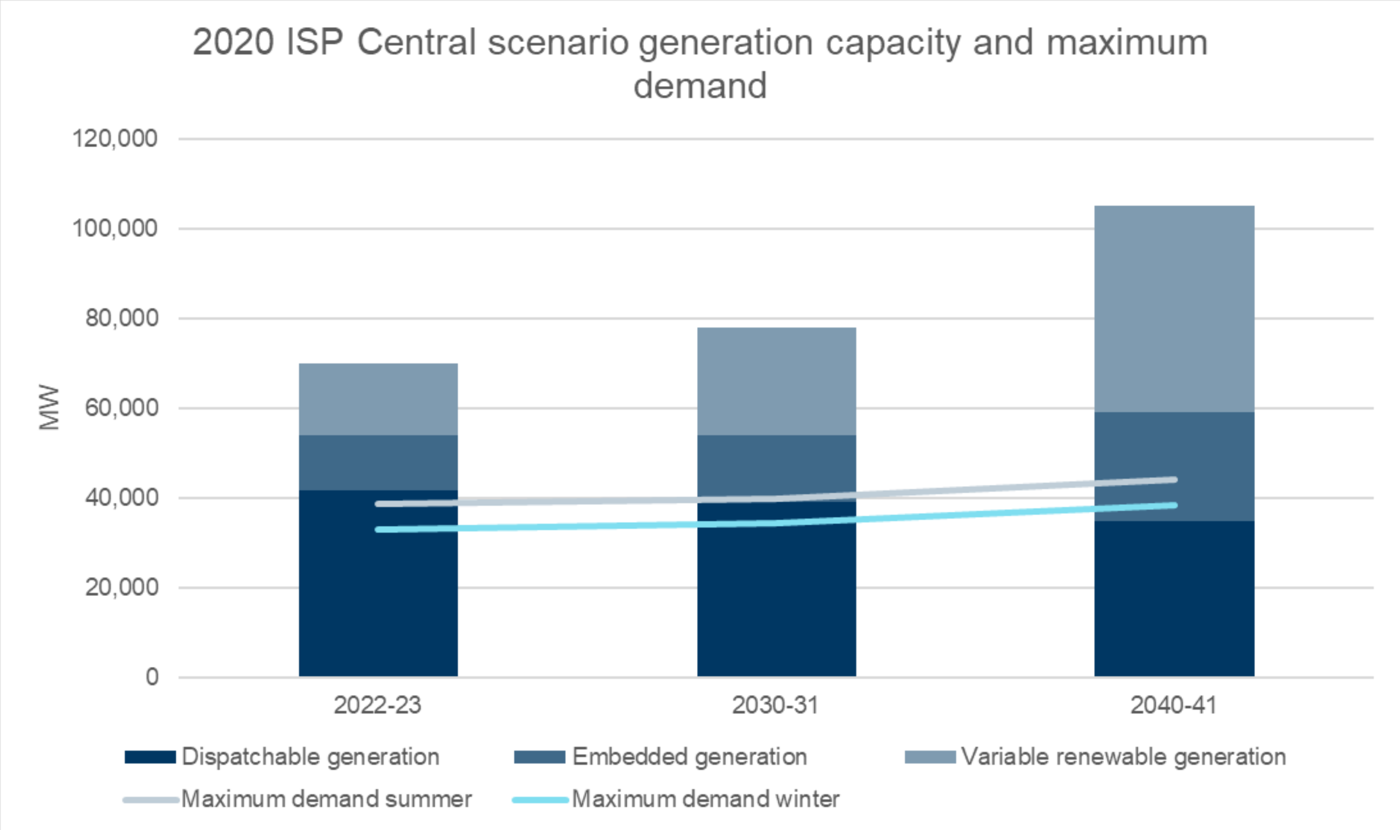


Figure 12 Generation capacity and maximum seasonal demand

Total generation capacity increases during each explored time period with growth deriving exclusively from embedded and variable generation. Dispatchable generation declines during each explored time period which may pose challenges for available PFR headroom in later years. Maximum demand, in both summer and winter, gradually increase, somewhat subdued by energy efficiency and residential behind the meter installations.

The AEMC in their Frequency Control Frameworks Review identified issues with the changing mix of generation and changes will be required to frequency in order to better support frequency control in the long term, concluding that:

> *"A deviation pricing mechanism consists of a transparent system of rewards and penalties that allows participants to easily understand how their actions relate to the costs they are likely to incur. This would likely increase investment certainty for participants and thereby lower the overall long term costs of frequency control."* [37]

[37] https://www.aemc.gov.au/sites/default/files/2018-07/Final%20report.pdf, page 91

Pricing for corrections towards and costs for deviations from 50 Hz would have to be managed dynamically if calculations were based on four second intervals. This would be necessary to evaluate the impact on the system by individual contributions.

The commission has proposed that double sided causer pays may be a suitable vehicle to incentivise provision of PFR for the proposed pathways to achieve enduring PFR for the NEM. However, they also noted concerns expressed by AEMO, Engineers Australia and Neon under such an incentive based PFR.[38]

The central scenario is a "business as usual" one, but in the case of a step change the need for bringing forwards a solution of ensuring reserve capacity is available may be heightened. Such step changes could be triggered by early closure of coal fired generation and/or the increased deployment of large amount of renewable generation. The latter could follow any extensive renewable energy zone developments in NSW or Victoria. In the case of such step change scenarios, the conditions in 2030 could be brought forward by up to four years, resulting in possible PFR reserve shortfalls by as early 2026.

6.3 Unit Commitment and Reserve Management

In Section 4.2 we referred to the issue of unit commitment versus reserve capacity. Both are critical for the effective provision of PFR:

- Without sufficient number of units providing PFR online the amount of reserve to manage frequency deviations has to be caried by fewer units. Consequently, the reserve from online units must be greater and the droop setting of these fewer units will need to be more aggressive to provide the same level of response that would otherwise be available from a wider aggregated quantity.
- Aggressive droop may not be possible for all generating systems as outlined in Section 2, and large amounts of reserve could either be inefficient or also not be possible due to turn down ratio limitations of some generating technologies.
- To balance aggressive droop and reserve requirements it is more effective to leverage aggregated frequency responsiveness from across the system. Such aggregated response could be obtained by procuring a small amount of reserve from every generator rather than a large amount from only a few. This is the same mechanism applied in Texas and GB, who allow for reserve of 20% and 10% of rated capacity from each plant contracted to provide PFR, as outlined in Section 3.
- Without sufficient reserve i.e. head- and foot room of units enabled for PFR there will be limited or no contribution to correcting frequency deviations as PFR is subject to the unit being able to provide or absorb energy to counter the change in frequency.

Synchronous generators have low opportunity cost and high rewards for keeping energy reserves. This is reflected in a thermal generator's ability to store energy in the form of coal stockpiles or gas in pipelines that can be readily converted into electrical energy. At the same time these generators can reserve capacity and operate below rated output by bidding a fraction of their capacity at very high prices. The cost of such storage is relatively low, while the marginal electricity price that would trigger activation of the reserve capacity is often very high.

For renewable generators the reserve retention is generally the opposite. In fact renewable generators are financially disadvantaged from keeping reserve due to commitments to power purchase agreements for most of their energy and not being able to store energy produced instantaneously from the wind or sun. This sees renewable generators often bidding very low energy prices to ensure that they are dispatched rather than constrained.

Hence, there are usually financial mechanisms in place for each participant that are contrary to free provision of reserves, which will shape the effectiveness of PFR in the future. Presently there are still reserves available due to the thermal plant headroom due to said low opportunity costs, but this will decline and the few units predicted to still be operating by next decade will unlikely provide sufficient reserve all the time or be able to accommodate sufficiently aggressive droop to meet the power system requirements for PFR.

[38] Submissions to the AEMC Frequency control frameworks review - draft report, 20 March 2018: AEMO, pp. 5-6; Engineers Australia; p.7. Neoen, Submission to the second consultation paper for the Primary Frequency Response Incentive Arrangements rule change, p.2.

6.4 Pathways for PFR Implementation

6.4.1 Overview of Pathways and policies

The Commission identified a number of future pathways to support enduring PFR that could each in turn implement various policy options, as shown in Figure 13.

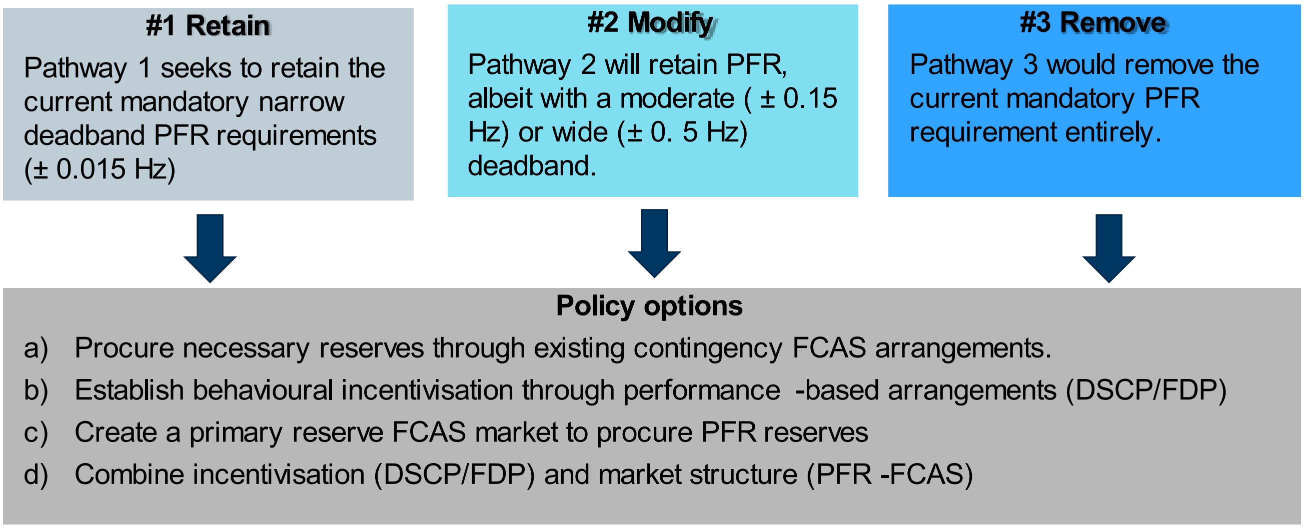


Figure 13 Pathways and policies for enduring Primary Frequency Response

As illustrated, there are three pathways:

1. Maintain the existing narrow band MPFR arrangement (DB ±0.015 Hz, Droop <5%)
2. Revise the MPFR arrangement by widening the frequency response band to a moderate or wide band (DB ±0.15 or 0.5 Hz, Droop <5%)
3. Remove the MPFR requirement [and revert to pre-2020 arrangements] (No PFR settings)
   (a) As an input to this analysis, the AEMC identified several policy options to complement, or replace, the mandatory PFR arrangements under each of the three pathways: No additional arrangements with existing mandated MPFR plus existing FCAS only.
   (b) Narrow band MPFR with improved pricing arrangements using FDP/DSCP or similar structures.
   (c) Narrow band MPFR with a PFR FCAS market providing primary regulating Services.
   (d) Narrow band MPFR with PFR FCAS and FDP/DSCP

The nomenclature used to describe the various options will be N(x) where N represents the pathway, numbered 1 to 3 as shown in Figure 13 and x reflecting the policy option from (a) through to (d). Hence, Option 1(b) represents narrow band mandatory PFR associated with revised pricing in the form of DSCP, while Option 2(d) would be a combination of moderate of wide banded mandatory PFR combined with revised pricing, as well as establishing a primary regulating services procurement process.

6.4.2 Pathway 1 - MPFR with existing FCAS

The key characteristics of pathway 1, as identified in the directions paper are:

- Narrowband mandatory PFR arrangements
- Procurement of reserves through the existing FCAS arrangements (regulation and contingency)
- Improved pricing arrangements

In their directions paper the Commission has proposed that one option to achieving enduring PFR arrangements would be to maintain the existing narrow band response and continue to use existing FCAS arrangements. This essentially describes pathway option 1(a). Variations of this pathway are 2(a) and 3(a), if the deadband is widened or MPFR removed, respectively.

According to the Commission's direction paper[39], under pathway 1(a) frequency control arrangements would:

(a) Maintain the existing PFR technical requirements as outlined in the interim PFRR.

(b) Coordinate PFR headroom requirements with existing Regulation FCAS arrangements.

(c) Procure additional headroom for narrow band PFR through existing Contingency FCAS market arrangements.

(d) Provide a price signal for voluntary provision of narrow band PFR headroom through a double sided causer pays or deviation pricing mechanism.

(e) Set frequency performance against system frequency rather than frequency indicators.

(f) Deliver less risk and less benefits to market participants due to double sided causer pays and reduced volatility.

For the wider system the Commission notes[40] that the foreseeable benefits of mandatory narrow band PFR include:

(a) Increased power system resilience to non-credible contingency events.

(b) Improved frequency control during normal system operation.

(c) Improved ability for AEMO to model and predict power system behaviour.

While, as observed by GHD, conversely, potential limitations or inefficiencies are:

(a) Increased operating costs due to inefficient allocation of PFR duty to responsive plant.

(b) Distortion of frequency control related market systems by passing the cost of PFR through to the energy market and hence consumers.

(c) Inclusion of narrow band PFR costs in contingency FCAS which are then distributed across all generators and avoids performance based cost allocation of causer pays, this providing no incentive for generators to minimise adverse impact on the system.

(d) Mandatory PFR will not necessarily incentivise generators to maintain headroom, as energy held in reserve is a lost opportunity cost. In many instances without sufficient headroom PFR will be less effective, although some generators may see some benefit in providing PFR under revised pricing arrangements.

The potential for mandatory PFR to interact with a new Fast Frequency response arrangement, particularly where there is narrow band requirement close to 50Hz, was also raised by the Commission[41]. To address this the Commission referred to the use of variable droop to elicit less FFR response at narrower frequency bands, and a full response to large frequency variations.

6.4.2.1 Improved Pricing Arrangements

A proposed mechanism to improve pricing arrangements and incentivise the provision of PFR is the double sided causer pays arrangement. This pathway describes options 1(b), 2(b) and to a lesser degree (3b), depending on the mandating of PFR and the width of the deadband selected.

The double-sided causer pays mechanism is a system conceptualised by Intelligent Energy Systems (IES)[42] and proposed by CS Energy to the AEMC as a means of calculating the cost of PFR in real-time. The mechanism was intended as a way to incentivise the provision of PFR in a commercial manner rather than mandating it. The Commission also referred to the valuation of positive contribution factors as an improvement to the causer pays

[39] Ibid 14, p.80-82.

[40] Ibid 14, p.58.

[41] Ibid 14, p.50.

[42] https://www.iesys.com/Content/ProjectDocuments/20200325%20Double-sided%20Causer%20Pays%20for%20PFR%20-%20merged%20final.pdf

pricing arrangements in some detail in their Frequency Control Frameworks Review.[43] IES is continuing to do further development work on DSCP with support of the Australian Renewable Energy Agency and the Australian Energy Council.

The double sided causer pays arrangement is a form of deviation pricing that deals specifically with PFR and is aligned to the approach used in the NEM for the allocation of costs for regulation FCAS, causer pays. The AEMO causer pays process[44] involves the determination of contribution factors based on four second unit measurements of generation/consumption that are aggregated into five minute dispatch interval estimates, which can then be compared against dispatch targets and frequency deviation to allocate appropriate proportion of the frequency regulation costs. However, DSCP would also assign positive contribution factors where the generator dispatch was actually aiding frequency control, and unlike the current causer pays process for allocation of regulation FCAS costs, which is averaged over a four week period, the AEMC has proposed that double sided causer pays would be resolved over each dispatch interval.

Key reforms that would be applied to the causer pays framework to establish DSCP include the following[45], with more specific arrangements to be developed during August 2021:

- Valuation of positive contribution factors by recovering cost for positive contributions from market participants that cause deviations in power system frequency.
- Alignment and shortening of sample and application periods to define transactions for payment and cost allocation to be based on performance in a single dispatch interval.
- Increased transparency through clear definition of the metrics used for incentive payments and cost allocations.

Similarly to DSCP, frequency deviation pricing[46] for frequency performance results in payment to participants that act to help control system frequency relative to their positive contribution i.e. moving system frequency back towards 50 Hz, and conversely assigns the cost for those payments to participants who are found to have caused deviations. Deviation quantities are determined by the difference of metered quantity of generation or demand from the target set point, measured every four second interval. Participants whose deviations from dispatch targets are driving system frequency away from 50 Hz are levied a penalty payment, which is used to pay those Participants whose deviation from dispatch is restoring frequency to 50 Hz. Instead of Frequency Indicators derived from Frequency as per the causer pays process, FDP will be assessed based on actual frequency measurements.

To implement either frequency deviation pricing or DSCP an appropriate means of valuing PFR is required. Once the value is set, frequency deviation pricing of DSCP can be used to penalize those participant who cause the need for PFR and reward those who provide PFR. The one sided causer pays process used to allocate regulation FCAS costs, relies on the offers submitted by regulation FCAS service providers to set the total cost that needs to be recovered and hence the value for the Regulation service. In the absence of offers for PFR service it is unclear how the reference price would be established that is used to reward providers and penalize causers of need for PFR.

Our MCA assessment assumes an appropriate mechanism is established through DSCP to value provision of voluntary PFR and facilitate the transactions to penalize causers of deviations and positive contributions that correct these.

6.4.3 Pathway 2 - Revised MPFR with new FCAS arrangements

The Commission has expressed a position that the pathway of maintaining mandatory PFR, albeit possibly with a wider dead band, and incorporating new market arrangements for procuring narrow band response maintained a good balance between: *"…operational certainty and system resilience while incorporating new market arrangements that are likely to promote efficient investment in, and operation, and use of, electricity services in the*

[43] https://www.aemc.gov.au/sites/default/files/2018-07/Final%20report.pdf

[44] Regulation FCAS Contribution Factor Procedure, AEMO, December 2018.

[45] Ibid 14, p.96.

[46] Ibid 14, p.85-86.

long-term interests of consumers."[47] This preference was also echoed by stakeholders whom the Commission consulted with.[48]

Essentially, this option describes pathway 2(c)[49] and proposes revising the current mandatory narrow band PFR arrangement by:

- widening the mandatory PFCB (e.g. to the NOFB or wider); and
- developing new FCAS arrangements for the provision of narrow band PFR during normal operation (Primary regulating services)

Mandatory PFR, even with a widened band, is still effectively provided for contingency events and the procured narrow band PFR manages small frequency deviations in coordination with existing Regulation FCAS.

Procurement of PFR services could be through[50]:

- New market AS for narrow band PFR
- Incentivised voluntary provision of PFR

Establishing a Primary Regulation FCAS market will require quantification of PFR volumes i.e. headroom and foot room, as well as changes to the FOS to confirm required frequency performance and PFCB.

A variation of this pathway option would be the addition of pricing improvements in the form of DSCP, in which case the option would describe Pathway 2(d), or if retaining a mandatory narrow band PFR requirement Pathway 1(d)

Retaining the narrow band response and implementing the same policy describes pathway 1(c), while adding improved pricing through DCSP presents pathway 1(d). Conversely, removing mandatory PFR in the same manner creates pathways 3(c) and 3(d).

The AEMC expressed a preference for this second pathway based on their concern that mandatory PFR is not a complete solution on its own, at least not in the long term. This is because mandatory PFR on its own does not incentive the keeping of energy reserves or "headroom" by generators that could be injected when required. This hybrid arrangement of mandatory requirements and market arrangements would according to the Commission: *"…provide AEMO with additional operational tools and is likely to provide greater flexibility to future power system developments."*[51]

GHD has interpreted the AEMC's directions paper as proposing two procurement options for the second pathway as follows:

- Option 1 – new market ancillary service(s) required to enable plant to provide automatic frequency regulation and response to small frequency deviations (primary regulating services). The pricing arrangement would potentially be similar to arrangements used for existing market ancillary services and could operate independently of or in combination with additional performance based pricing regimes to incentivize additional PFR provision.
- Option 2 – the voluntary provision of narrow band PFR in response to improved incentive arrangements, there would be no mandatory narrow band PFR requirement. The pricing arrangements would be similar to Pathway 1 either double-sided causer pays or regulated pricing approach.

We envisage that the foreseeable benefits of the second pathway include:

- Distinct market service should provide more transparent view of costs and benefits, including potential attribution to individual parties under double sided causer-pays principle. PFR costs not lumped in with contingency FCAS.

---

[47] Ibid 14, p.89.

[48] Submissions to the *PFR rule changes — consultation paper*, 19 September 2019: CS Energy, p. 2, Delta Electricity, p. 6, Neoen p. 1, Enel X, p. 8, IES, p.2, Enel GreenPower, p. 2, ARENA, p.3.

[49] With mandated narrow band PFR, not subjected to maintaining of reserves and not financially remunerated, this represents Pathway 1(c).

[50] Ibid 14, p. 81.

[51] Ibid 14, p. vi.

- Evolution of market service costs with availability of participants should see costs increase where scarcity of service and hence incentivize participants to take part and maintain headroom
- Operating costs, and hence impact on energy market, should be minimized as only active participants will provide service who are likely to co-optimise their own bids / market behaviour (particularly Option 2)

While, conversely, potential limitations or inefficiencies are:

- Need quantification of necessary volume of PFR to establish effective FCAS market.
- Frequency control may not be good as pathway one due mix of units on narrow band PFR (remunerated) and some on mandatory wider band PFR (unremunerated), although actual difference will dependent relative value of services under both pathways.
- Depending on uptake and provision of PFR service (particularly under Option 2), power system resilience may be worsened to non-credible contingency events, even with mandatory wide band PFR.

GHD understand that AEMO has identified that an aggregate level of frequency responsiveness, MW/Hz, is a key characteristic of PFR required to deliver effective control of power system frequency. We further recognize that there are challenges involved with designing procurement arrangements to deliver a high level of MW/Hz, and that it is appropriate for mandatory PFR arrangement to deliver this characteristic in the short term. However, the challenges of service definition and market design are not insurmountable, as shown by the international examples in GB national grid and ERCOT. Therefore GHD consider that a workable procurement arrangement for narrow band PFR services is achievable.

GHD supports the Commission's observation that mandating the capability alone will not guarantee available capacity, and that incentivisation for provision of headroom and hence enablement of PFR from sufficient generators is necessary in both the short- and long-term. The former to ensure enough synchronous generation is available, and the latter to ensure the uptake of PFR delivery from renewable and storage technologies as thermal synchronous generation retires or is displaced. The importance of providing the necessary PFR price signals to future generation is highlighted in the projected transition in generation technology between now and 2040, which could see the amount of synchronous generation halve by 2040, as was discussed in Section 6.2.

If however PFR is mandated only for moderate (50±0.15Hz) or wide band response (50±0.5Hz) and narrow band capability is to be procured through market arrangements, it becomes critical to ensure the requirements for narrow band PFR are known and the headroom needed to deliver it is available. The process of establishing the necessary quantities should be determined through power system analysis and periodically reviewed based on actual performance; this is similar to how ERCOT quantifies PFR volumes for contingency responses which in turn makes it available also for primary regulation. This will require accurate frequency response modelling to be available for all generating systems that provide mandatory or contracted PFR, as well as loads. Further, an agreed process for assessment will be necessary.

Due to the relatively weak and often constrained interconnections between and within regions of the NEM, as well as the precedence for separation of regions it would be prudent to consider minimum quantities of narrow band PFR that must be procured in each region and possibly even sub-region. The dependence on transmission interconnections to deliver PFR was also raised by Lawrence Berkeley National Laboratories (LBNL) in their 2018 report, in which the authors noted in reference to some of their earlier works: *"If primary frequency response cannot be delivered reliably from generation located behind a transmission constraint, then that generation will not contribute to interconnection frequency response."*[52]

In summary:

- It is feasible to define and develop narrow band PFR procurement arrangements, as shown by GB and Texas examples.
- The service characteristics become more critical depending on the relative role of narrow band MPFR, i.e. for narrow MPFR procurement may not be immediately required, whereas for moderate or wide MPFR procurement arrangements would be necessary and the service settings would be critical.
- Service design should consider and include regional requirements.

[52] https://cms.ferc.gov/sites/default/files/2020-12/frequency-control-requirements-report.pdf, p. 21.

6.4.4 Pathway 3 - Alternative market procurement of PFR

The third pathway proposed in the Commission's direction paper is to not mandate either narrow or wide band PFR and to procure the necessary services through a market arrangement only, such as represented by pathway and policy options 3(c) and 3(d). However, allowing mandatory PFR requirements to expire in 2023 and instead introducing a market arrangement to procure the necessary PFR during normal system operation was according to the Commission the least preferred pathway. The Commission observed that this pathway would not extend to increase power system resilience the way that the other two pathways would. Without any mandatory provision this pathway relies solely on services acquired through procurement arrangements or voluntary provision in response to behavioural incentives.

Based on the AEMO observations of frequency performance since implementation of the mandatory PFR settings[53,54], GHD consider that there is currently sufficient synchronous generation available to provide a number of readily available sources of narrow band PFR to effectively maintain frequency within the NOFB. The contribution of non-synchronous sources other than BESS may also provide capacity. However, the latter is of course subject to energy availability. Theoretically, this suggests that there would be a sufficient pool of resources to provide narrow band PFR without mandating it as long as the right price signals are set to incentivise the service through for example price improvements. This would however also present the greatest risk to overall frequency performance as procurement of frequency control services is a key of Pathway 2 and 3. Furthermore, due to the lack of mandatory PFR, Pathway 3 also provides no additional resilience in the way the other two pathways do.

Looking further ahead, as synchronous generation retires, is withdrawn, or displaced by renewable generation there may be a time in the coming decade(s) when there will be insufficient capacity to effectively provide PFR (and possibly even contingency FCAS). This would require sufficient incentivisation for new participants to invest in the control system necessary to provide narrow band PFR and the sequestering of sufficient energy reserves (headroom) through the right pricing mechanisms to make this worth for providers. As such it would be Long Run Marginal Costs (LRMC) rather than Short Run Marginal Costs (SRMC) that would set the prices for this service. Also, the cost would always have to be higher than Levelised Cost Of Energy (LCOE), along with provision of some assurance by the new procurement mechanism of sufficient opportunity for investment cost recovery.

The Commission's proposal for pathway 3 was that the mandatory PFR arrangements would be removed and the mechanism for pricing PFR would be through frequency deviation pricing / double sided causer pays, and the procurement would be via a primary regulation FCAS market. However, this process would also mean that it is unlikely this service could be effectively optimised with energy dispatch in the way that contingency services are. Instead it would need to be quantified and procured separately by AEMO.

The foreseeable benefits of the alternative market procured PFR include:

- Support provision of PFR from existing synchronous generation in the short term.
- Distinct market service should provide more transparent view of costs and benefits, including potential attribution to individual parties under double sided causer-pays principle. PFR costs not lumped in with contingency FCAS.
- Evolution of market service costs with availability of participants should see costs increase where scarcity of service and hence incentivize participants to take part and maintain headroom

While, conversely, potential limitations or inefficiencies are:

- Removal of mandatory PFR will likely degrade frequency control and expose system to wider frequency variations for both credible and non-credible contingency events.
- Revision of contingency FCAS capacity / market may also be necessary to subsequently improve response.
- Needs quantification of necessary volume of PFR to establish effective FCAS market.
- Require incentivisation of capability and capacity development from future generation.

[53] Ibid 21.

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

- Necessitate sufficient price incentivisation to procure sufficient volumes (headroom) of PFR.

6.4.5 Alternative and complementary Policy options

The pathways describe the treatment of mandatory PFR in future, comparing between maintaining the existing arrangements of narrow band PFR, widening the band to a moderate or wide dead band, or removing the mandatory requirements altogether; mandatory requirements are subject to energy availability and maintaining head room is not a requirement of the mandatory requirement. Laid over this and with the intention of incentivising or procuring the necessary PFR from participants are various policy options, which are described in the AEMC Directions paper[55], and informed by further discussion at the industry Technical Working convened by the Commission[56]:

- New market ancillary services (PFR FCAS)
- Performance based pricing through improved pricing arrangements:
    - Double Sided Causer Pays
    - Frequency Deviation Pricing
    - Regulated pricing

To contextualise our analysis and advice, we provide a short summary of our understanding of the above policies

6.4.5.1 PFR FCAS

A new PFR frequency control ancillary service would be created to procure pre-determined quantities of narrow band PFR in terms of volumes of energy and unit commitment to ensure a required sustained aggregated response (frequency bias) can be achieved to control frequency within the normal operating frequency band.

The new service delivers primary regulation and would be additional to the existing contingency and secondary regulation services, as well as the recently determined fast frequency response services. Each service would be procured separately, although there may be an opportunity to compliment and even co-optimise these services.

Transparency of the service design and performance requirements would be captured by expansion of the FOS to include a NOFB PFR standard section and including the additional design needs in the Market Ancillary Services Specifications.

Participants in the new services would submit bids for PFR FCAS, which AEMO would select a sufficient amount from and dispatch through the normal market dispatch procedure.

6.4.5.2 Double Sided Causer Pays

Double sided causer pays is an extension of the existing causer pays arrangements for recovery of secondary regulation costs. However, we understand that these new DSCP costs would be additional to the existing secondary regulation costs, which would remain in place.

The new process would consider both positive and negative contributions to frequency performance and reward Participants who are restoring frequency to nominal 50Hz through payments levied from those Participants who are causing frequency to deviate from nominal 50Hz. Contributions and deviations would be based on a Participants active power deviation from the dispatch target.

While using the same structure and processes as Causer Pays, the new arrangements would be operating based on SCADA measurements of frequency, i.e. in 4 second cycles, rather than averages calculated from dispatch intervals over a week and again averaged over four weeks. We see the retaining of existing processes as a strength which will provide transparency in the initial application of such arrangements.

[55] Ibid 14.

[56] “Fast frequency response market ancillary services – final determination”, AEMC, July 2021, p.5.

While this process will not procure reserves or a specific system frequency bias, incentivisation (if sufficient) can deliver an aggregate frequency response to the system. This is more likely while there are still reserves available in our generation mix. Once thermal plant retires, we expect the available reserves to decline.

6.4.5.3 Frequency Deviation Pricing

FDP is not dissimilar to the proposed DSCP mechanism in that it proposes to reward or charge Participants for correcting or causing frequency deviations in real time, with performance assessed in 4 second cycles based on active power compared to dispatch targets. It would be in addition to the cost recovery mechanism for secondary regulation and would operate alongside it.

However, rather than using Frequency Indicators, FDP would use actual frequency deviations, with the price function used to determine payments and costs derived from system frequency. Such calculations would be more accurate, but also more complex as they will be highly dependent on metering accuracy and enhanced telemetry. Hence, we see FDP as necessitating some significant planning and investigation before being able to be implemented.

6.4.5.4 Regulated Pricing

A further option is to simply pay Participants who provide PFR a set amount, based on the measured performance, rather than recovering it from causers and based on the relative contribution they are making. The payments would be derived from the costs of providing the service i.e. fuel, operation and maintenance of equipment. We understand that costs for these service would be recovered from all Participants, and that one of the key challenges is to achieve a good level of cost reflective pricing of these services.

6.5 Policy Risk Assessment

The various PFR pathways detailed earlier in this report have a number of inherent characteristics that present a range of policy risks and opportunities on implementation. This section provides a summary of these policy issues which should be considered prior to evaluating each of the considered pathways.

Section 6.5.1 looks at the benefits of narrow band mandatory PFR compared to moderate or wide band performance.

Section 6.5.2 considers the quantification of PFR volumes and assessment of performance needed to establish effective market arrangements

Section 6.5.3 and 6.5.4 consider the risks and opportunities of behavioural incentivisation rather than procurement under DSCP and FDP, respectively.

6.5.1 Mandatory PFR

At the time of the rule change decision in March 2020 several options were considered with respect to the applicable maximum allowable deadband, which was ultimately selected as narrow band of 50 Hz of ± 15 mHz. The other options considered were a moderate deadband (± 150 mHz) and a wide deadband (± 500 mHz).

Prior to the AEMC selecting the narrow deadband AEMO provided some commentary in relation to the potential implications of each option. The AEMO preferred, and ultimately selected option, was considered by AEMO to produce the most stable control of frequency under normal operating conditions, reducing variations in observed NEM frequency to lowest practical level. A narrow deadband would also provide the maximum resilience within the NEM to frequency disturbances, regardless of the origin of the disturbance e.g. load step change, contingency event, etc. AEMO considered that a moderate deadband setting would also provide some improvement in system frequency resilience, albeit not to the extent of the narrow deadband, but would provide little improvement under normal operating conditions. A wide deadband setting was considered to have even more limited prospective benefits, largely being confined to providing a PFR safety set under larger / more extreme contingency events.

As the AEMC considers options with respect to providing a long term pathway for PFR within the NEM, the above considerations of PFR deadband are again open to debate and consideration along with whether PFR should be a mandatory or voluntary provided service. These alternative policy combinations are already being considered by the AEMC within the considered pathway options:

- Pathway 1 is explicitly based on a mandatory PFR service with a narrow deadband requirement. This includes the continuation of the current MPFR requirement,
- Pathway 2 would retain a mandatory PFR service, with the deadband being widened either to the moderate or wide setting.
- Pathway 3 would not retain a mandatory PFR requirement. This approach is generally acknowledged as being a retrograde step with respect to NEM system frequency performance and although included in the current AEMC pathway options is not considered a series contender.

In the case of Pathway options 2(c) and 2(d), and 3(c) and 3(d), a new primary regulating service could be implemented or alternatively a voluntary narrow deadband PFR service provided that responds to revised incentive arrangements. Pathway options 2(c) and 2(d) would be supported by a mandatory PFR requirement commencing at either a moderate or wide deadband setting. In relation to this latter aspect selecting a moderate MPFR deadband would mean that the MPFR "safety net" provision would commence when frequency deviations exceeded ± 150 mHz. Alternatively, selecting a wide MPFR deadband would mean that the MPFR "safety net" provision would commence when frequency deviations exceeded ± 500 mHz. A MPFR deadband with this setting is likely to lead to a less resilient NEM than with the moderate or narrow setting, although combined with a new primary regulating service (or alternative) the overall combined effect would still be superior to just a MPFR with wide deadband setting considered by the AEMC when making the 2020 rule change determination.

It is noted that under Pathway 2 and 3, narrow band PFR would be provided through new procurement or incentive based arrangements. The implications of these arrangements are discussed in the following sections.

A new primary regulating service (or voluntary incentivized narrow band PFR) for Pathways 2 and 3 would still operate with a deadband in order to distinguish the new service functionality from the existing secondary frequency regulation service. In such circumstances it would seem appropriate to retain the existing ± 15 mHz deadband for the new primary regulating service.

Retaining a deadband for the new primary regulating service setting close to 50 Hz would also ensure that overall aggregate response from prospective service providers is provided in a timely manner in response to system frequency deviations. This would also result in minimum impact on individual participating units because a wider deadband setting for the new primary regulating service would require a more aggressive generator droop setting to obtain the same overall aggregate system frequency response. Additionally, aggressive droop may expose some generators / participants to providing a greater proportion of the delivered service volume. Concurrently, a wider deadband for the voluntary service would likely lead to a significant decline in the effectiveness of frequency regulation under normal conditions, trending back to a level of performance seen prior to the implementation of the PFR rule in 2020.

With Pathway 3 there would be no mandatory PFR requirement, and hence no deadband setting that needs to be considered in relation to a mandatory response. However, this pathway would still utilize some element of voluntary or market based primary regulation and hence a deadband setting in relation to this new service could ostensibly still be adopted. In the first instance it would seem appropriate to adopt the suggested ± 15 mHz deadband for the primary regulating service outlined under Pathway 2.

6.5.2 PFR FCAS Market

The Commission's directions paper noted the potentially important role for procurement arrangements for narrow band PFR, especially as part of Pathway 2 and 3, which do not include a narrow band MPFR arrangement.

GHD agrees that procurement of narrow band PFR would be vital to meeting power system requirements under Pathway 2 and 3 both now and in the future. In addition, GHD considers that procurement arrangements for narrow band PFR may also be required in the future as the provision of narrow band PFR through the mandatory arrangements is likely to be reduced by the withdrawal and/or retirement of thermal generation and an increase of variable renewable generation.

In the medium to long term, mandating all generators to be capable of providing PFR will not guarantee the necessary reserve to provide the service. In the absence of explicit procurement arrangements, behavioural incentivisation may achieve reserve capacity. However, it is not certain it will do so and could instead add volatility to the market. This is because behavioural incentivisation could result in:

- Withholding of capacity from the energy market to achieve positive contribution factors or avoiding negative ones, leading to increased prices, which in turn could consequently result in an oversupply of energy and a shortfall of reserves in a scenario already observed during price contingencies today.
- Not being sufficiently incentivized into providing reserve in operational timeframes thus leading to poor frequency performance and increased need for procurement of services.

Such risks would become more likely as we see more thermal generation retire and may not be an immediate issue. To avoid either of these possibilities in the long term, an eventual procurement arrangement would be better suited to procure reserves without unduly affecting electricity prices.

We believe that procurement of sufficient PFR to control frequency during normal system operation could most effectively be achieved through establishment of PFR FCAS Market or similar arrangements. An FCAS style procurement arrangement provides some certainty of volume and price for procurement, sufficient to incentivise the establishment of reserve capacity.

Such an approach was supported by a number of Participants noting that the provision of PFR comes at a cost to Participants such that there should be an incentive to provide the service. However, this was qualified further that if a well-functioning arrangement could not be established then a mandatory requirement may be appropriate.

In addition to the variation in technical characteristics of each of the PFR pathways there are also differences in relation service incentivization and market requirements that are important considerations. The aspects are:

1. Quantification of required volume of service
2. Calculation of participant outturn performance

6.5.2.1 Quantification of Required Service Volume

The quantification of the required volume of PFR to stay within designated steady state frequency limits is one of the key considerations with respect to whether providing a PFR response should be mandatory or voluntary action by market participants. Under Pathway 1 there would be no immediate need to quantify a specific volume or quantity of PFR to be procured, as providing PFR would be a mandatory requirement. Given the prevalence of existing synchronous generating plant there is expected to be sufficient generator responsive capability for MPFR actions in the short term. In any case, monitoring of the NEM system frequency deviation would also be expected to show when future system performance was starting to worsen and hence additional service requirement quantities were needed.

In comparison with the above, both Pathways 2 and 3 would require an explicit volume of PFR service to be calculated for each dispatch interval which could be procured against. This presents a potentially significant computational burden if a precise quantity is to be calculated. AEMO have also highlighted this issue in their own preliminary advice[57] where they believe taking appropriate account of the characteristics of the available plant to provide the service and how such plant are dispatched (including PFR headroom) is potentially challenging to implement and may lead to a degrading of overall system frequency control.

In responding to the above, GHD notes that a primary regulating service or similar function is adopted in other jurisdictions and whilst we are cognizant of the concerns raised by AEMO there are practical solutions to address issues. For example, an alternative and less precise calculation approach could be adopted to simplify the procurement strategy but would need close attention to outturn service costs and overall system frequency deviation distribution in order to correct for any under or over procurement of service. In other words, simplifications and inaccuracies in the calculation input could be corrected by feeding back the outturn characteristics in order return the calculations / procured volumes to obtain a more optimal overall performance in terms of costs and system performance.

6.5.2.2 Calculation of Participant Performance

An inherent feature of all of the proposed PFR pathways is the need to calculate some outturn performance of market participants in order to remunerate the provided service or allocate costs / rewards in the case of DSCP

[57] PFR Technical Advice, AEMO, August 2021.

type incentivization schemes. However, the requirement to provide such individual participant outturn performance calculations varies across the considered PFR pathways:

- Under mandatory narrow band PFR, it is possible that existing FCAS procurement arrangements are potentially sufficient to ensure the needed PFR service capability, which could also be supplemented by some form of additional incentivisation function to remunerate those providers not covered through existing FCAS market arrangements. Thus, depending on the extent of supplementary remuneration procurement required, it is possible that monitoring outturn PFR responsiveness would only be necessary for certain market participants being captured under the supplementary incentivization function.
- In case of a moderate or wide band PFR mandate, either a new FCAS market arrangement would be required for primary regulating services or some form of voluntary service responding to market pricing based signals. In both cases, it is conceivable that the pool of market participants where outturn performance needs to be calculated and monitored may be shallower than under narrow band PFR where there is a mandatory requirement. This is because the service is essentially voluntary under both approaches i.e. a specific volume of PFR is procured from dedicated participants for the primary regulating service, or voluntary responses under an incentivization approach, and may attract only a small number of prospective provides. However, on the other hand, this may simplify the calculation of outturn participant service provision and renumeration.
- Pathway 3 is also similar to Pathway 2 in this regard.

6.5.3 Improved Pricing Arrangements

6.5.3.1 Double-Sided Causer Pays

In addition to the technical and market considerations relating to the alternative PFR pathway options there are also further considerations in relation to the financial incentivization and pricing characteristics. This sub-section considered opportunities and risk associated with the proposed Double-Sided Causer Pays approach to improve pricing arrangements.

Opportunities:

- Existing AEMO causer pays FCAS regulation approach adopts 4 second assessment from dispatch trajectory, with penalties accumulated over four weeks. Participants must fund AEMO’s FCAS regulation costs in the following four weeks in proportion to the size of penalty previously accrued. With new double sided cause pays approach 4 second assessment intervals can again be used but penalties / rewards settled at each dispatch interval. Although calculation settlement would take place on 4 second reconciled basis, financial settlement could still take place over a period of days or weeks to give participants some time to allow rewards to offset penalties or align with other settlement period. Payments in this case would be a lagging indicator but related to performance in an actual interval.
- Pricing mechanism can be set to allow net-zero gain, or allowing AEMO to deduct costs, such that all monies received in penalties are paid as rewards making the initiative cost neutral as far as total market costs are concerned.

Risks:

- Whilst the existing AEMO FCAS regulation causer pays approach can be extended to be double sided and apply to SFR (as per AEMO proposal) or PFR performance, it is likely that there will be considerably more participants (either voluntary or mandatory) than the AEMO FCAS regulation service. This may present some questions around the workability of the service, if 4 second calculations essentially have to be collated for all generators and demand participants in the energy market to attribute rewards / penalties.
- The approach of assessing PFR performance against dispatch instruction variation rather than frequency (whether system frequency or frequency indicator) is essentially a reactive solution, final variations against frequency would need to be picked up via another service i.e. FCAS regulation

6.5.3.2 Deviation Pricing

Whilst the Double Sided Causer Pays approach would represent a move in the right direction as far as incentivising positive behaviour with respect to minimising frequency deviations, a frequency response deviation pricing approach would potentially take this one step further to bring further transparency and responsibility with respect to individual market participant impacts on system frequency deviations. However, more work would have to be done to investigate the nuances of FDP in more detail, and additionally FDP may not give AEMO the same level of oversight to procure and remunerate these participations.

This sub-section considered some of the opportunities and risks associated with FDP.

Opportunities:

- Existing AEMO causer pays FCAS regulation approach uses Frequency Indicators (FI), which is an interval AEMO calculated variable for AGC responses, as the deviation trajectory indicator. However, FI is only known after the fact when published by AEMO, and due to the nature of calculation does not always reflect required movements in actual system frequency. Hence, there is an opportunity with frequency deviation based pricing to explicitly target system frequency, as ultimately that is the variable that is desired to be controlled and managed.
- From the AEMC PFR Directions Paper:

  "System frequency is a readily measured at any point in the power system and is thus a transparent system variable that market participants can respond to in real time."
- Measurement of plant performance with respect to system frequency will align the economic incentives with the real time operational goal of maintaining system frequency close to 50Hz

Risks:

- As with double sided causer pays, the use of a double sized deviation pricing approach would involve all market participants. Whilst deviations per participant would all be calculated against a common system frequency (recognising that localized deviations are relatively minimal across a full power system) which may simplify things, this approach may end up requiring a significantly greater number of calculations rather than just calculating the exceptions in dispatch compliance required under the double sided causer pays approach whereby if a participant maintains their dispatch instruction then there is no impact. In this case, as system frequency is largely always moving, calculations will be required for all participants when outside of the notional deadband e.g. ±15 m Hz.

6.6 Learnings from Other Jurisdictions

6.6.1 National Grid ESO (GB)

Section 3.2 has summarised the current approach to primary frequency response management in GB and has detailed both the current position and the new system services that have been recently introduced. This subsection now sets out a comparison of the new GB primary frequency related services with requirements in the NEM

Comparing the GB Dynamic Moderation service with the current Mandatory PFR requirement in the NEM:

- The deadband is the same for both services at ±15 mHz, although the bulk of the GB Dynamic Moderation service is only provided for frequency deviations in excess of ±0.1 Hz making this the effective de-facto deadband.
- For the MPFR a governor droop setting of ≤5% is mandated. For the GB Dynamic Moderation service a specific governor droop response is not mandated however a provider of this service must be able to provide 95% of their capability range when the frequency deviation exceeds 0.1 Hz up to 0.2 Hz. Whilst this does not necessary restrict the governor droop response range that can be applied, in principle in order to offer a meaningful capability then a droop setting of ≤5% is required, and ideally much lower e.g. 2%.
- Renumeration arrangements for GB Dynamic Moderation service are not yet clear but if following the approach for the Dynamic Containment service then both Pay as Bid and Pay as Clear contracts may be

considered. Under the former each successful bidder would receive the price they bid for the service, whereas under the latter all bidders receive the same price as the highest cost unit that was successful in the auction, the "clearing price". There are pros and cons with each approach relative to the scarcity of the service provision i.e. the last smallest unit accepted could result in a higher payment to other larger bidders who would have otherwise accepted a lower bid cost if each bidder submits their own bid individually. However, the key facet is that the functional capability is a "paid for" service and is not mandatory requirement.

Comparing the GB Dynamic Response services as a whole with the three pathways detailed in the AEMC directions paper:

- Pathway 1 essentially retains the existing MPFR service as above but seeks to address pricing and renumeration questions around the current un-paid for service i.e. through a double-sided causer pays principle. The mandatory PFR functionality under this pathway would be similar to a combination of the GB Dynamic Regulation and Dynamic Moderation services.
- Pathway 2 would maintain a MPFR functionality but widen the Primary Frequency Control Band (PFCB) to the previously considered moderate (±150 m Hz) or wide (±500 m Hz) thresholds and introduce some form of market renumeration mechanism for PFR actions within the PCFB – similar again to a combination of the GB Dynamic Response & Moderation services. Comparing with the GB Dynamic Moderation service, the moderate PFCB is not too dissimilar to the effective deadband with the GB service i.e. essentially ±100 m Hz, as 95% of capability is provided for frequency deviations outside of this range (up to ±200 m Hz). In comparison, the alternative wide frequency operating deadband of ±500 m Hz is at the outside of the GB Dynamic Containment frequency deviation range shown in Figure 3, although it would result in a new market service offering in the NEM effectively covering the same frequency range i.e. 49.5 to 50.5 Hz as in GB.

In terms of renumeration arrangements, as indicated above the mechanism for Dynamic Moderation has not yet been settled. For comparison, the currently launched GB Dynamic Containment service is being procured as Pay as Bid, at least initially, and may move to a Pay as Clear principle after a few months of operation. Both approaches are conceptually similar to the establishment of a market service for primary regulating reserves indicated under Pathway 2 – Procurement Option 1, i.e. interested suppliers bid / compete to economically provide the service capability. This is opposed to Pathway 2 – Procurement Option 2, where with the voluntary incentive-based provision providers of the service would either be remunerated through a reference price payment or through a double-sided causer pays principle - in effect being paid is a response to providing a positive service contribution, but one that is not mandatory.

The main difference between the AEMC Pathway 2 and the GB approach is that both Dynamic Moderation and Dynamic Regulation services, are both paid for services. With the AEMC Pathway 2, frequency deviations outside of the Primary Frequency Control Band (PFCB) i.e. 49.85 Hz to 50.15 Hz if the moderate setting was adopted, would still be subjected to mandatory unpaid PFR response, but for frequency deviations between the PFCB and the deadband the new renumerated market service would apply.

Pathway 3 would allow the current MPFR requirement to lapse in June 2023 and be replaced with new market arrangements, either through the establishment on an explicit new market service for primary regulating reserves or through an incentive based voluntary provision approach. Whilst this approach could conceptually be considered to have some have similarity with the GB situation as all of three outlined GB services (Dynamic Containment, Dynamic Moderation and Dynamic Regulation) are (or will be) paid for market procured services, it should be noted that GB still has a mandatory generator frequency response capability required by the GB Grid Code. This sits outside of the above three services and can still be requested by the ESO if required and essentially provides a mandatory backstop capability if the market procurement process fails for whatever reason to procurement sufficient primary response capability. A lack of a backstop mandatory capability under Pathway 3 is therefore considered a potential crucial omission in this regard.

Reviewing the current and proposed GB dynamic response market services the following key observations and statements can be made that are relevant for the consideration of the proposed AEMC pathways

A mandatory primary frequency response capability exists within GB as an explicit Grid Code requirement.

The principle providers of PFR functionality in GB will all be paid for their service capability through one of three new dynamic response service offerings that NG ESO will procure.

Of the considered NEM pathways, Pathway 2 with a moderate PCFB setting would yield a new market service similar to a combination of the GB Dynamic Moderation and Regulation services, and a revised MPFR essentially covering the same functionality as the GB Dynamic Containment service, but unpaid.

Alternatively, Pathway 2 with the wide PCFB setting would yield a new market service offering covering the same frequency range as all three of the GB dynamic response services. The revised MPFR functionality would then provide a backstop capability, similar to the GB Grid Code mandatory requirement.

6.7 Multi-criteria Analysis

In identifying the strength and weaknesses of the three pathways for PFR identified by the AEMC, and the variations created through application of different policies as outlined in Section 6.3, we have used a multi-criteria analysis technique to frame the assessments and rank the pathways. The proposed criteria have been broadly grouped into three categories with three criteria each, as shown in Figure 13.

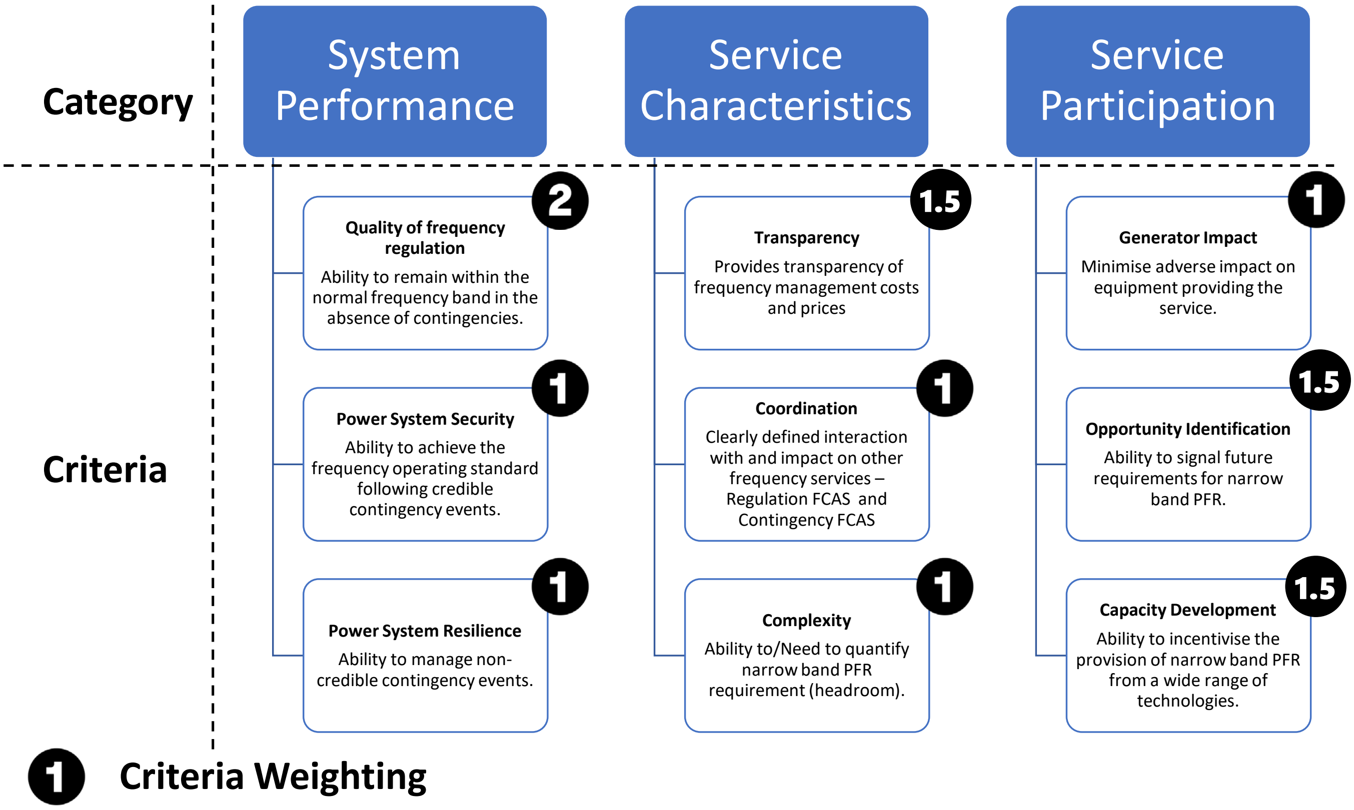


Figure 14 Assessment criteria for the Pathways multi-criteria analysis

The categories proposed look to qualitatively compare the three pathways and the various policy options to identify:

1. System performance impact and benefits to the primary objective of maintaining frequency within the NOFB during normal system operation, and secondary effects of power system resilience and power system security.
2. Suitability of the new service's characteristics to ease implementation of the new service in the in the form of being accessible and transparent to Participants, not being overly complex to manage and implement, and reasonably coordinated with other frequency services.
3. Effectiveness to encourage participation in the service by existing and future generators by considering the material impact of providing the service, providing opportunity indicators well in advance of additional capacity being required, and providing the right price signals to incentivise capacity development.

Each pathway for enduring primary frequency control has been assessed against the nine criteria described in Figure *14*, assigning a ranking based on the envisaged performance, as shown in Table 5

Table 5 Ranking of criteria for the Pathways MCA

Rating	Definition
1	Does not meet the criteria
2	Somewhat meets the criteria
3	Meets the criteria
4	Somewhat exceeds the criteria
5	Exceeds the criteria and provides additional benefits

The ranking for each criteria were based on the metrics laid out in Figure *13* and expanded on below to indicate the performance necessary to meet or exceed a particular criteria. The sum of the values assigned to the criteria for a pathway were then used to compare these against each other.

Table 6 Metrics for criteria

Category	Criteria	Metric
System Performance	Quality of frequency regulation	If the performance of system frequency is restored to the levels it was pre-2015 then the pathway is considered to meet the criteria and is assigned a ranking of 3. Additional improvements beyond the pre-2015 levels or additional benefits to frequency performance would result in a higher ranking being assigned.
	Power system security	Ability to achieve the frequency operating standard following credible contingency events will meet the criteria ranking of 3. If the pathway enables further contingency FCAS capacity or reduces the volume of required FCAS then it will exceed the criteria.
	Power system resilience	Provides resilience against large credible and non-credible contingencies identified in the PSFRR. Reducing the depth of the frequency nadir following a large credible and non-credible contingencies to prevent UFLS would meet the criteria.
Service Characteristics	Transparency	Generates a clear valuation of frequency control, prices and management costs across the potential markets that are visible to Participants. Documented market arrangements used to procure services with regular reporting and clarity of process would meet the criteria.
	Coordination	Identifies interdependencies, dependencies, overlap, and uncertainties between the various frequency services, and provides means to manage these. Clear market signals for each service likely to incentivise participation will meet the criteria.
	Complexity	Is the accurate determination of PFR headroom through analysis necessary or are simple processes available to procure sufficient PFR to ensure adequate frequency bias is provided through an aggregated response?

		Meeting the criteria requires an effective and efficient means to establish at least minimum PFR volumes to control frequency during normal system operation.
Service Participation	Generator impact	To meet the requirements of meeting the criteria there should not be adverse impact equipment wear and tear, increased cost of operation, or creating uncompensated risk to the generating equipment providing the service.
	Opportunity identification	Identifies gaps in PFR service provision well ahead of these occurring and communicates this to the market. Meeting the criteria will be through an appropriate forward looking assessment that quantifies PFR requirements with sufficient time to allow the market to respond.
	Capacity Development	Establishes the right financial incentives for future synchronous and non-synchronous generation technologies to provide narrow band PFR.

Recognising that some of the criteria are more critical than others we have assigned a weighting that will prioritise some and value good performance in critical areas. Priorities are based on fulfilling primary objectives e.g. restoring frequency performance, as well as providing a sustainable solution. The weighting is a multiplier to the ranking assigned to a pathway option for a particular criteria as shown in the table below.

Table 7 Weighting of PFR criteria for MCA assessment

Criteria	Weighting	Reasoning
Quality of frequency regulation	2	Primary objective of the implementation of PFR
Power system security	1	Additional benefit, but reason for contingency FCAS
Power system resilience	1	Additional benefit, but considered and managed through PSFRR
Transparency	1.5	Industry participation will require clear and effective markets
Coordination	1	Principle design question
Complexity	1	Important aspect
Generator impact	1	Minimised through aggregate provision or remunerated
Opportunity identification	1.5	Critical to provide price signals to market well ahead of time
Capacity Development	1.5	Incentivisation of PFR delivery from future generation critical

GHD compared the three pathways for PFR implementation and associated policy options for each of three time periods (2022, 203, 2040) using the MCA. For each time period twelve combinations of pathway and policy options were assessed. A high level summary of our findings is shown in Table 8. With the pathways and time periods identified in the columns and the options identified by the row headings.

At a high level we found that initially Pathway 1(b) was the most effective means of managing frequency performance over the next decade. This pathway avoids the potential complexity of developing a new frequency service, while providing incentivisation through encouragement of good performance behaviour i.e. following dispatch targets more accurately. However, these incentives are not seen as sufficient to develop long-term capacity in the market in the form of new technologies or providers.

By the end of this decade the retirement and withdrawal of synchronous generation will reduce the readily available reserves that currently provide primary regulation through mandatory narrow band PFR. By that time some market arrangements or similar incentivisation that values the provision of PFR will be necessary to attract future capability and reserves. For this reason GHD assess that the most effective policy is expected to be (d), a combination of price improvement (DSCP) and market arrangements (PFR-FCAS).

Pending the rate of retirement of synchronous generation and hence available reserves, GHD expect that the effectiveness of narrow band MPFR will eventually reduce also. However, it is likely still more effective than moderate or wide band PFR when it is available. In this case narrow band PFR would likely still be preferable as it may provide some reserves pending demand and generation levels, and potentially add some benefits to regional capability. Hence, by 2030 the preferred pathway changes to 1(d). Although the MCA suggests that 2(d) could also be effective since the bulk of primary regulation will be procured and the security and resilience benefits of the moderate band would still be providing some remaining benefit. However, we do not see the benefit of widening the deadband after the narrow band technical arrangements has been in place for several years.

We observe that the valuation of pathways does not change appreciably beyond 2030, narrow band PFR is still preferable, along with improved pricing and new market arrangements. Particularly, the means of procuring reserves and providing market signals to incentivise provision of reserves and new entrants is still critical. For these reasons GHD assess that option 1(d) remains the most effective beyond 2030 [??].

What is abundantly clear from the results is that removal of the mandatory requirements for PFR (pathway #3) will provide the weakest of the pathways in the long term and should be avoided. Some PFR, even if moderate, will provide significant benefits to system security and resilience, even if not to frequency performance in the NOFB during normal operation.

Table 8 Summary of pathways and policy performance assessment from MCA

Pathway / Policy	1. Maintain the existing narrow band MPFR arrangement			2. Revise the MPFR arrangement by widening the frequency response band to a moderate or wide band			3. Remove the MPFR requirement [and revert to previous arrangements]		
Year	**2022/23**	**2030/31**	**2040/41**	**2022/23**	**2030/31**	**2040/41**	**2022/23**	**2030/31**	**2040/41**
A – Existing FCAS	35	26	23	24	24	24	18	18	18
	• Mandatory narrow band PFR provides excellent system performance in terms of frequency regulation, security and resilience in, gradually weakening over time due to potential for lack of reserve • Using the existing FCAS arrangements provides only mediocre results due to lack of transparency and paying for procurement of PFR through C-FCAS • With no incentivisation for future service provision, participation is only adequate in the early years when there is headroom			• Average system performance in early years, weakening by end of decade due to moderate/wide band response only available meaning poor performance in NOFB • Average service characteristic scores due to complexity of pricing PFR and C-FCAS through same service and lack of transparency • Poor participation due to lack of incentives for future reserves to be available.			• Very poor system performance with no mandatory PFR or significant PFR procurement opportunity other than C-FCAS • Poor service characteristics performance with no clear valuation of frequency control or ability to quantify requirements. • Poor service characteristics with no ability to incentivise future reserve and capacity developments		
B – FDP/DSCP	41	31	27.5	27	27	27	21	21	21
	• Strong system performance in early years, weakening in next decade • Good service characteristics as the process is relatively known and interaction with other AS is known • Poor participation due to lack of direct incentivisation and only behavioural influencing through DSCP, means exposure to insufficient future reserve			• Average performance in early years, weakening by end of decade as no mechanism to procure PFR reserves. NOFB performance will revert to dependance on secondary control • Average service characteristics as process is known but has no ability to procure PFR reserves for NOFB. • Poor participation due to lack of incentives			• Very poor system performance with no mandatory PFR or significant PFR procurement opportunity other than C-FCAS • Poor service characteristics performance with no clear valuation of frequency control or ability to quantify requirements. Some behavioural incentivisation provided through DSCP • Poor participation due to lack of direct incentivisation other than behavioural (lag) influences		

C – PFR FCAS	39.5	35	35	35	35	35	32.5	34	34
	• Strong system performance in early years, weakening in next decade as synchronous generation retires • Average service characteristics as policy creates potentially complex PFR-FCAS that may not be required since there is reserve provided through mandatory narrow band PFR • Good participation score due to valuing of services and quantification of reserve requirements provides clear market signal			• Good system performance throughout timeline due to procurement of narrow band PFR reserves • Average service characteristics as policy creates potentially complex PFR-FCAS that may not be required since there is reserve provided through mandatory narrow band PFR • Good participation score due to valuing of services and quantification of reserve requirements provides clear market signal			• Average performance with only necessary reserves for normal operation that provide limited security and resilience benefits • Average service characteristics as policy creates potentially complex PFR-FCAS that may not be required since there is reserve provided through mandatory narrow band PFR • Good participation score due to valuing of services and quantification of reserve requirements provides clear market signal		
D – PFR FCAS + DSCP	39.5	36.5	36.5	36.5	36.5	36.5	32.5	34	34
	• Strong system performance in early years due to MPFR with plenty of reserve, weakening slightly in next decade as synchronous generation retires • Average service characteristics as policy creates potentially complex PFR-FCAS that may not be required since there is reserve provided through mandatory narrow band PFR • Good participation score due to valuing of services and quantification of reserve requirements provides clear market signal			• Good system performance throughout timeline due to procurement of necessary narrow band PFR reserves and mandated moderate or wide band to assist security and resilience • Average service characteristics as policy creates potentially complex PFR-FCAS that may not be required since there is reserve provided through mandatory narrow band PFR as well as overlaying further DSCP • Good participation score due to valuing of services and quantification of reserve requirements provides clear market signal			• Average performance with only necessary reserves for normal operation that provide limited security and resilience benefits • Average service characteristics as policy creates potentially complex PFR-FCAS that may not be required since there is reserve provided through mandatory narrow band PFR as well as overlaying further DSCP • Good participation score due to valuing of services and quantification of reserve requirements provides clear market signal		

Performance evaluation of the pathways will always be somewhat subjective and our assessment of the service characteristics in particular has been influenced by:

- Likely adverse and/or conflicting interactions between existing and new services, and the ability to differentiate which is providing the necessary response to a particular service e.g. contingency FCAS or PFR, mandatory PFR or procured PFR.
- Transparency of the interactions between services and the ability of Participants to view and assess these.
- Ability to appropriately assign costs for a service to the correct party.
- Requirement to accurately determine reserve volumes for procurement that could necessitate complex analysis or else a reactive adjustment of volumes based on observed performance that could result in over- and/or under procurement at times.
- Participant familiarity with the processes.

Similarly, assessing the Service Participation criteria, we recognise that based on the projected uptake of renewable generation that there may be at times an abundant oversupply that could result in no services for narrow band PFR needing to be procured. GHD agrees that this could indeed be the case for certain time of the year, particularly middle of the day during shoulder season. However, this would not always be the case and there will be many times during the year when there will be no reserves available, and if generators were curtailed for excessive periods the resulting energy at risk would likely result in a slowdown of investment or Generators finding an alternate off taker for their product.

Somewhat less complicated is the assessment of system performance under a narrow, moderate or wide band PFR, or no PFR at all. Narrow band PFR is necessary to provide primary regulation within the NOFB, whether mandated or procured. Moderate or wide band PFR will not make any contributions within the NOFB. Mandated narrow and moderate band PFR will also provide good support for credible and non-credible contingencies, while wide band PFR will provide some support to very large frequency disturbances, although less effectively since these services will begin to contribute later than tighter deadbands.

The MCA shows that there is some flexibility in the management of pathways and policies over the considered outlook period, but that a narrow band approach will be a more effective solution in the short term, after which additional or complementary arrangements will be necessary to ensure frequency performance.

7. Observations and Insights

7.1 PFR Pathway for the NEM

Based on the outcomes of the MCA and our considerations of broader system performance and plant impact, we consider that mandatory narrow band PFR should be implemented permanently after the sunset clause of the current mandatory frequency responsiveness takes effect in 2023.

We recommend mandatory narrow band control for a number of reasons:

- Aggregate PFR to effectively manage frequency during normal operating conditions will mean less movement of individual generator active power even if more frequently, which is less likely to create adverse impacts on plant.
- Additional security and power system resilience to increasingly frequent large system disturbances.
- Allows other FCAS market services to operate most effectively and avoids distortion e.g. regulation, contingency.

We further consider that the appropriate policy to support the pathway of narrow band mandatory PFR is to establish DSCP. While not providing certainty in relation to the volumes of frequency responsive plant and provision of PFR to support frequency control, implementation of a DSCP arrangement is expected to incentivise good behaviour from market participants. This good behavior is expected to include:

- Following dispatch targets more closely, thus removing some of the need for additional regulation FCAS.
- Voluntary retention of operational headroom to manage risks associated with causer pays allocations
- Expansion of the pool of market participants that are metered to measure the performance of their plant with respect to system frequency
- Investment in frequency responsive plant, outside of the requirements place on scheduled and semi-scheduled generators.

DSCP, as a behavioral incentive arrangement, is not considered to provide sufficient certainty, on its own, in relation to aggregate frequency response provided by frequency responsive plant, compared to the mandatory PFR arrangements. At the same time DSCP is regarded to complement the mandatory PFR arrangements to deliver effective frequency control along with the economic signals to reflect the value of frequency control services in the NEM.

Looking further ahead, we see that there is growing need for increased certainty in relation to the provision of narrow band PFR. This view is based on the projection that the existing mandatory PFR arrangements will deliver decreasing levels of frequency responsive plant over time, as the proportion of large-scale thermal generation plant in the power system reduces and is progressively replaced by variable renewable generation and distribution connected generation, such as rooftop PV. Under these outlooks, we see a future need to establish additional market arrangements that send the right price signals to the market for provision of future PFR capacity (reserves), particularly in the lead up to the retirement of a large number of the NEM's coal fired generating fleet at the end of the decade and beyond. At that time a PFR-FCAS type market to procure the necessary reserves to provide effective primary regulation may be required to deliver a satisfactory level of certainty that the requirements for control of power system frequency will be met. We consider that there may otherwise not be an appropriate level of assurance that sufficient headroom will be available to maintain frequency during normal operation. Without such incentives for future capacity and reducing levels of synchronous generation, we would expect a gradual return to the level of performance experienced prior to the AEMC's Rules change for mandatory PRR in mid-2020.

Concurrently, our projections are based on the standard ISP scenario. A step change one could accelerate the possible need for procurement by four or more years, based on the accelerated thermal generation retirement and increased renewable uptake.

The incentives provided by DSCP are expected to drive improved plant behaviour, however it remains to be seen as to whether these behavioral incentives will be sufficient to negate the need for direct procurement of narrow band PFR services.

Under the proposed pathway we expect that the final arrangements could be narrow band PFR with a PFR-FCAS procurement process of some kind combined with a DSCP to positively influence regulation FCAS requirements, and reward generators for positive contributions to correct any cumulative frequency error incurred during normal system operation. The market arrangements would be used to incentivise provision of PFR reserve from new technologies, BESS and renewable generation, as well as ensuring the system operator was able to procure the necessary reserves.

7.2 Future proofing the regulatory framework

According to the 2020 ISP, the NEM is expected to undergo some profound changes in the way it produces energy, with an increase in variability, decentralisation and IBR penetration. Such changes will also see the existing coal fired generation fleet reduce to around a quarter of current capacity, accompanied to a lesser degree by reductions in some gas fired plant technologies.

However, such changes will see a significant rise in the installed capacity of large scale solar and wind generation, as well as increases in installed solar rooftop capacity. AEMO also expects an increase in battery storage, both large scale and embedded over the coming two decades.

Still, this transition will likely see a reduction in readily available PFR reserves in some instances, particularly for frequency raise requirements, coupled with oversupply of renewable generation at other times. We would expect that even if there was a glut of renewable energy at times and consequently curtailment or constraints imposed on renewable energy, such conditions would see operators of commercial facilities look for an alternate offtake for their energy since energy at risk is a business loss model. Additionally, even if there were constraints imposed on generation, NEMDE dispatches the most expensive plant downwards first, then the next etc. This means that there may not be headroom from all generators unless changes are imposed on the current economic dispatch model that would see renewable generation share constraints. We do acknowledge that equal sharing of constraints could be could a realistic outcome for generators in close proximity, all bidding at the market floor. In any case artificial constraints imposed on a generator to create reserves for PFR will likely trigger a withdrawal of investment since this represents another risk to a participant in an energy only market.

In the long term the creation of a price incentive for the provision of PFR headroom and frequency responsiveness is the most meaningful means of encouraging the uptake of suitable technologies and control systems for the provision of PFR and participation in the procurement process. DSCP is a good behavioral incentive mechanism, but it is not expected to provide certainty in relation to control of power system frequency. The effectiveness and tuning of the behavioral incentive arrangements will take some time to flow through the system with substantial lag. As such the effectiveness will need to be closely monitored to assess the need for retuning of the pricing arrangements and the development of stronger procurement arrangements as required.

As noted in the previous section we see that there is sufficient capacity in the market at present, but withdrawal of synchronous generation and increase in renewable generators operating at maximum output capacity will result in likely shortfalls in PFR raise capability. However, based on the scheduled retirements and renewable developments we would expect that this will not happen until the end of the decade. This means, when combined with DSCP and an effective monitoring regime, there is sufficient time to assess the need for stronger procurement arrangements. We note that any projected shortfall must be identified well in advance to allow sufficient time for design and consult on appropriate market incentives for the procurement of PFR reserves. Indeed, this process is likely going to require significant time to develop suitable arrangements, consult with the market, and subsequently design and implement. We would expect such as process to likely take four or more years, based on the observed implementation of five minute settlement and the AEMC’s post-2025 market arrangements process.

7.3 Regional procurement of PFR

While not a pressing matter in the short term, assuming mandatory PFR is in place, the procurement of PFR on a regional basis is an important matter to raise. This may even be more relevant for some regions such as South Australia that are likely going to be without significant amounts of synchronous generation in the medium term.

Even in most recent times we have observed the benefits and challenges when there was insufficient frequency responsive generation available in an islanded region following a separation event:

- South Australian blackout of 28 September 2016 following a frequency collapse on separation from Victoria.
- NEM separation into three large mainland islands on 25 August 2018 following a lightning strike on the Queensland to New South Wales Interconnector that saw frequency in an islanded Queensland remain excessively high for several dispatch intervals.
- Queensland separation from NSW on 25 May 2021 following cascading Queensland generator trips that triggered protection of the Queensland to NSW Interconnector to trip. Because frequency was returned very close to 50 Hz by the remaining generators with PFR enabled, QNI was able to resynchronise within 30 seconds of disconnection.

While thankfully, islanding events are rare and in the short term we expect there to be effective PFR reserves to be available in all regions, observations of system response when there is no good frequency control within the islanded system points to the benefits of regional procurement of PFR in the long terms to assist system security and power system resilience overall. Obviously, such regional requirements could only be addressed once an effective procurement process was available. In this regard we note that the introduction of a DSCP mechanism now, with appropriate attribution to individual participants in each region, may provide some visibility of the potential regional requirements for procuring PFR in the future.

7.4 Modelling specification of requirements

Defining the necessary volumes of PFR reserves will become an important aspect of incentivising the provision of such services in the future. We expect that there are a number of way to specify PFR quantities, including:

Adjustment of procured quantities based on observed frequency, similar to the way AEMO increased regulation FCAS quantities in an incremental manner during 2019, or the way that NEMMCO reduced the original amount of regulation FCAS progressively after establishing the FCAS markets in 2004.

Determination of appropriate volumes through power system analysis. While not for the purpose of primary regulation, ERCOT uses this approach to establish quantities of RRS, including PFR, on an hourly basis for the year ahead. This level of granularity captures diurnal and seasonal variations in the necessary levels of RRS and sends appropriate price signals to the market.

Develop suitable training sets of frequency response measurements and enabled reserves and use these with probabilistic methods such as Bayesian networks to establish reserve requirements. AEMO currently uses Bayesian networks to predict lack of reserve conditions in the short term as part of their operational forecasting.

Notably National Grid ESO will also determine volumes of PFR to procure against when the changes to their frequency management arrangements are implemented, suggesting that there is a feasible means of valuing the provision of PFR., whether it be one of the above or something else entirely. It may be of value to look more closely how this market is looking to establish their PFR procurement process and draw on the lessons learnt by the UK ESO.

7.5 Frequency Performance Testing

Performance of system frequency control should be tested and assessed on a regular basis, using techniques such as:

- Verification of PFR settings and individual generator performance through the Generator Compliance Monitoring program of NER clause 4.15.
- Monitoring of system frequency and revaluation of PFR volumes, aggregate droop, appropriate deadband, and frequency bias requirements.
- System wide testing of the performance of aggregate PFR, e.g. by temporarily switching off AGC.

Furthermore, the impact of PFR on other ancillary services should also be assessed e.g. use of regulation and contingency FCAS, to ensure they are not doing the same thing or displacing an existing service from the designed position.