Economic Regulation Authority

Decision on the Australian Energy Market Operator's 2022/23 ancillary services requirements

27 June 2022

D247532

Economic Regulation Authority

Level 4, Albert Facey House

469 Wellington Street, Perth WA 6000

Telephone 08 6557 7900

Email info@erawa.com.au

Website www.erawa.com.au

This document can also be made available in alternative formats on request.

National Relay Service TTY: 13 36 77

Contents

List of appendices

Executive Summary

The Australian Energy Market Operator (AEMO) is responsible for procuring sufficient ancillary services to operate the South West Interconnected System (SWIS) in a safe and reliable manner.[1] Ancillary services maintain power system security and reliability and ensure that electricity supplies are of acceptable quality. These services maintain technical characteristics of the power system, including frequency and voltage.

The Wholesale Electricity Market (WEM) Rules require AEMO to submit its ancillary services requirements and plan for the forthcoming year to the Economic Regulation Authority for audit and approval.[2] The ancillary services requirements are the levels of ancillary services needed to meet the SWIS operating standards and the ancillary services standards.

If following the ERA's audit and approval of AEMO's ancillary services requirements, AEMO identifies that a considerable shortfall in ancillary services requirements is occurring or is likely to occur, AEMO may reassess the requirements at that time and submit those to the ERA for audit and approval.

The ERA has conducted its audit of the 2022/23 ancillary services requirements and plan submitted by AEMO on 31 May 2022. AEMO must publish a report containing its 2022/23 ancillary services requirements and plan by 1 July 2022.

In conducting its audit, the ERA has considered the information provided by AEMO in its Ancillary Services Report for the WEM June 2022 together with additional data requested from AEMO to support the analysis provided in its report. The ERA has assessed that information against AEMO's obligations under the WEM Rules for determining its ancillary services requirements.

There are several types of ancillary services, as discussed in this report. AEMO has proposed changes to:

- The criteria it will use to set the requirements for spinning reserve services so that it now accounts for the maximum load ramp that may be caused for example, by cloud cover that rapidly reduces the amount of rooftop photovoltaic (PV) generation.
- The quantity of load rejection reserve services to increase the quantity by 7 MW to account for a 30 MW increase in the constraints limiting power flows in the eastern goldfields network.
- The load following ancillary service (LFAS) peak requirement, discussed below.

The ERA has approved all of AEMO's proposed changes to its ancillary services requirements for 2022/23 except for AEMO's proposed increase to its peak LFAS requirement. The ERA does not approve AEMO's proposed peak LFAS requirement of up to +/-120 MW but instead approves retention of the current peak LFAS requirement of up to +/-110 MW. This is

1 Ancillary Services will be re-named to Essential System Services in the new market design commencing in October 2023.

2 AEMO must determine its ancillary services requirements in accordance with the SWIS Operating Standards and the Ancillary Service Standards and on the facilities and configurations expected for the SWIS in the coming year. AEMO may consider location specific differences and different SWIS load levels or other scenarios, that vary by the type of day and time of day, and vary across the year. Wholesale Electricity Market Rules (WA), 1 June 2022, Rules 3.11.1, 3.11.2, 3.11.4 and 3.11.5, (online).

consistent with the peak LFAS requirement that AEMO has stated it intends to initially implement in 2022/23.[3]

LFAS is used to ensure electricity supply and demand are balanced in real time to maintain the frequency of the power system within the SWIS operating standards. AEMO proposed an LFAS requirement of up to +/-120 MW between 5:30 am and 8:30 pm (peak LFAS requirement) for 2022/23. This is a proposed increase of 10 MW from the approved 2021/22 peak requirement and a 20 MW increase from the currently implemented peak LFAS requirement of +/-100 MW.

If AEMO's peak LFAS requirement is increased to the full +/-120 MW as proposed, then the ERA estimates that this could increase LFAS costs by $618,000 per month.[4]

AEMO's reasoning for the proposed change in its peak LFAS requirement is the increasing number of distributed rooftop PV system connections, which increase the power system's volatility. Data extrapolated from AEMO's 2021/22 Electricity Statement of Opportunities estimates the growth rate of new rooftop PV connections as 320 MW in 2021/22 and 273 MW in 2022/23.[5]

However, the information provided by AEMO does not adequately demonstrate the need to increase the peak LFAS requirement to +/-120 MW. The current maximum approved peak LFAS requirement is +/-110 MW but AEMO has implemented a peak requirement of +/ 100 MW as shown in Table 1 for 2021/22. AEMO stated that as conditions unfolded over 2021/22, it did not require the additional 10 MW.[6] This means that AEMO already has a buffer of 10 MW by which it can increase its peak LFAS requirement, without needing the ERA's approval.

To determine its LFAS requirements, for the coming year, AEMO estimates the quantity of LFAS that will be required by calculating the amount of 'frequency keeping mechanisms' (FKM) that have historically been used. AEMO then considers the year-on-year change in its FKM analysis alongside its operational experience. Table 1 shows the year-on-year change in the level of FKM used to maintain frequency (column 5). Table 1 demonstrates that the increase in LFAS proposed for 2022/23 by AEMO is the same or higher than previous years (column 4), even though the FKM change from the prior year is the lowest.[7]

The ERA has concluded that there is insufficient information to justify an increase in the peak LFAS requirement. This is because AEMO already has access to +/-110 MW which it has not fully implemented and is equivalent to the quantity it proposes to initially implement in 2022/23. In recent previous years, AEMO has similarly requested increases in excess to what it has ultimately implemented. Further, the 2022/23 proposed increase is higher or equal to previous years' proposals, despite previous years having had higher estimated quantities of rooftop PV connections (Table 1 column 6) and higher FKM quantity changes (Table 1 column 5).

3 Initially, AEMO will increase the LFAS requirement from the current quantity of +/-100 MW to +/-110 MW. AEMO stated it will monitor and assess the adequacy of this requirement to determine if an increase to the full +/-120 MW is necessary.

4 This estimation was undertaken by analysing LFAS submissions for the period 1 May 2021 to 30 April 2022. The ERA re-calculated the price of the marginal LFAS tranche based upon the updated requirement of +/-120 MW and multiplied the new price by a peak requirement of +/- 120 MW. The assessment does not factor in changes to LFAS submissions based upon updated requirements or the entrance of Synergy's battery energy storage resource.

5 Australian Energy Market Operator's, 2021, *2021 Electricity Statement of Opportunities*, (online)

6 Australian Energy Market Operator, 2022, *Ancillary Services Report for the WEM 2022*, p. 21, (online)

7 AEMO's assessment used FKM data over the summer period where there is less volatility. An assessment over the course of a full year may lead to a higher FKM requirement for 2022/23. However, FKM values have been higher in prior years but AEMO has implemented lower requirements.

The ERA's determination to not approve AEMO's peak LFAS requirement does not immediately affect AEMO's operational practices. This is because AEMO does not propose to increase the LFAS requirement to more than the ERA's previously approved maximum quantity of +/-110 MW until its monitoring indicates that a higher quantity is needed.

Table 1: Comparison of changes to peak LFAS requirements

Year	AEMO's proposed peak LFAS requirement	AEMO's implemented peak LFAS requirement	Increase in LFAS requirement implemented by AEMO over previous year	FKM change from prior year	Increase in distributed rooftop PV[8]	Frequency performance within normal operating range (% of time)
2020/21	+/-105 MW (ERA approved)	+/-95 MW	10 MW	16 MW	341 MW	99.988%[9]
2021/22	+/-110 MW (ERA approved)	+/-100 MW	5 MW	26 MW	320 MW	99.98%
2022/23	+/-120 MW	+/-110 MW (proposed)	10 MW (proposed)	6 MW	273 MW	Not available.

Source: AEMO Data, AEMO's Ancillary Service Reports 2020 to 2022

The ERA considered the risk to the power system in making its determination not to approve AEMO's requested increase in the peak LFAS requirement. The ERA assessed this risk by considering AEMO's frequency performance. AEMO must maintain power system security by ensuring that the frequency of the SWIS is kept within the normal operating band of 49.8 Hz and 50.2 Hz for 99 per cent of the time. LFAS is the primary service AEMO procures to maintain frequency within the normal operating band.[10]

Table 1 shows AEMO's frequency performance since 2020/21. AEMO has achieved frequency performance above the 99 per cent standard without implementing the full quantity of the LFAS requirements requested by AEMO and approved by the ERA for the past two years.[11] For 2022/23, AEMO already has access to +/-110 MW which it has not fully implemented and is equivalent to the quantity it proposes to initially implement in 2022/23. In these circumstances, there is negligible risk that the ERA's determination to not approve the peak LFAS increase to +/-120 MW will result in AEMO being unable to maintain power system security.

If during 2022/23 AEMO requires more LFAS than the amount procured in the LFAS market it can utilise backup LFAS.[12] Backup LFAS is typically more expensive compared to LFAS procured through the LFAS market. However, because it is only used infrequently it is more

8 Distributed PV values are extrapolated from annual capacity year forecasts of installed behind the meter rooftop PV capacity information in AEMO's 2021 ESOO report (online).

9 Australian Energy Market Operator, 2021, *Ancillary Services Report for the WEM 2021*, p. 6, (online)

10 The normal operating frequency band for the SWIS is 49.8 to 50.3 Hz. Wholesale Electricity Market Rules (WA), 1 June 2022, Appendix 13 (online)

11 AEMO may also use back up LFAS to maintain power system security where there is a material shortfall in the enabled quantity of LFAS or a scheduled generator fails to provide its cleared quantities through the LFAS market.

12 AEMO has informed the ERA that it typically only requires the use of backup LFAS in circumstances where a material or considerable shortfall of load following is occurring or is likely to occur.

economically efficient to procure this higher cost service infrequently than to increase the normal quantity to be procured from the LFAS market.

Further, if AEMO considers that a considerable shortfall in its peak LFAS requirement is occurring or is likely to occur, AEMO may submit a proposal to the ERA to increase the requirement at that time.[13]

The ERA's determination of AEMO's 2022/23 ancillary services requirements is set out in Table 2.

Table 2: ERA determination of AEMO's 2022/23 Ancillary Service Requirements

Service	2022/23 requirement proposed by AEMO	Approval
LFAS upwards	Up to 120 MW (between 5:30 am and 8:30 pm)[14]	Up to 110 MW approved[15]
	65 MW (between 8:30 pm and 5:30 am)	Approved
LFAS downwards	Up to 120 MW (between 5:30 am and 8:30 pm)[16]	Up to 110 MW approved[17]
	65 MW (between 8:30 pm and 5:30 am)	Approved
Spinning reserve service	At least the maximum of: 1. 70% of the largest generating unit; 2. 70% of the largest contingency event that would result in generation loss; and 3. The maximum load ramp expected over a period of 15 minutes.	Approved
Load rejection reserve service	A maximum of 97 MW	Approved
System restart service	Three facilities with system restart capability.	Approved

Source: AEMO's 2022 Ancillary Service Report

13 The ERA will consider the evidence provided by AEMO when assessing any proposal.

14 The ERA approved a LFAS upwards quantity of 110 MW in June 2021. AEMO will increase the enabled quantity of this service to this previously approved maximum.

15 The ERA has not approved AEMO's requested peak LFAS upwards requirement of up to 120 MW.

16 The ERA approved a LFAS downwards quantity of 110 MW in June 2021. AEMO will increase the enabled quantity of this service to this previously approved maximum.

17 The ERA has not approved AEMO's requested peak LFAS downwards requirement of up to 120 MW.

1. Introduction

Ancillary Services are essential system services procured by AEMO to operate the SWIS in a safe and reliable manner. These services allow AEMO to manage frequency and voltage within the operational limits set by the Technical Rules and the WEM Rules.

The WEM Rules require AEMO to determine its ancillary services requirements in accordance with the SWIS operating standards and the ancillary services requirements:

> 3.11.1 AEMO must determine all Ancillary Service Requirements in accordance with the SWIS Operating Standards and the Ancillary Service Standards.

AEMO is required to update its ancillary services requirements annually, and when determining the requirements AEMO must consider the facilities and configuration expected for the SWIS in the coming year:

> 3.11.2. AEMO must update Ancillary Service Requirements on an annual basis. The Ancillary Service Requirements must be set based on the facilities and configuration expected for the SWIS in the coming year.

AEMO must seek the ERA's approval, and the ERA must audit AEMO's proposed ancillary services requirements:

> 3.11.6. AEMO must submit the Ancillary Service Requirements to the Economic Regulation Authority for approval. The Economic Regulation Authority must audit AEMO's determination of the Ancillary Service Requirements and may require AEMO to redetermine the Ancillary Service Requirements, in which case this clause 3.11.6 applies to any recalculated requirements.

The ERA must also audit AEMO's proposed plan to procure the required ancillary services:

> 3.11.12. The Economic Regulation Authority must audit AEMO's determination of the Ancillary Services plan submitted to the Economic Regulation Authority under clause 3.11.11. The Economic Regulation Authority may require AEMO to amend the Ancillary Services plan and resubmit it to the Economic Regulation Authority, in which case this clause 3.11.12 applies to any amended plan.

AEMO submitted its report containing the proposed ancillary services requirements and plan to the ERA on 31 May 2022. This report contains the ERA's audit of AEMO's determination of the ancillary services requirements and plan for 2022/23.

2. Load following ancillary services

Load following ancillary services (LFAS) ensure electricity supply and demand are balanced in real time to maintain the frequency of the power system within the operating standards:

> 3.9.1. Load Following Service is the service of frequently adjusting:
>
> (a) the output of one or more Scheduled Generators; or
>
> (b) the output of one or more Non-Scheduled Generators,
>
> within a Trading Interval so as to match total system generation to total system load in real time in order to correct any SWIS frequency variations.

The SWIS power system operates at a frequency of 50 Hz, and in normal operating conditions, the frequency must remain within a band of 49.8 Hz to 50.2 Hz.[18] To ensure the frequency is maintained within the normal operating range AEMO uses LFAS provided by accredited generators to continuously balance supply and demand.

AEMO procures its LFAS requirements from the LFAS markets. The LFAS requirements comprise a component to cater for frequency variations in an upwards direction, referred to as LFAS upwards, and variations in a downwards direction, referred to as LFAS downwards.

AEMO reported that there are currently seven LFAS generators accredited to participate in the LFAS market, in addition to Synergy's Balancing Portfolio. The LFAS market is settled on the quantity of LFAS that AEMO requires up to the maximum amount approved by the ERA. For example, for 2021/22 the ERA approved a maximum of +/-110 MW for AEMO's peak LFAS requirement. AEMO implemented a lower peak requirement of +/-100 MW for 2021/22. The LFAS market settled on the lower value during that period.

On occasion AEMO may identify a shortfall of LFAS. That is, more LFAS is needed than the amount cleared in the LFAS market.[19] This may arise due to large fluctuations in distributed rooftop PV and wind generation. AEMO may require an additional quantity of LFAS above that available through the LFAS market to manage the increased volatility from these generation sources. When this occurs, AEMO may procure 'backup' LFAS from the balancing portfolio.[20] Backup LFAS is typically a higher priced service.

In 2021/22, there were approximately 12 instances where backup LFAS was required for these reasons with the volume of service ranging from +/-35 MW to +/-80 MW.[21] The use of backup LFAS is infrequent and AEMO's report stated that backup LFAS costs only comprised 1.0% of LFAS upward availability costs and 1.8% of LFAS downwards availability costs. The rare use of backup LFAS to cover shortfalls means that it is more economically efficient to procure this higher cost service infrequently than to increase the normal quantity to be procured from the LFAS market. This is because the latter quantity will be procured for each interval during the relevant period, rather than just when needed.

Backup LFAS may also be utilised by AEMO in other circumstances, such as where a scheduled generator is unable to provide its cleared LFAS quantity.[22]

[18] Wholesale Electricity Market Rules (WA), 1 June 2022, Appendix 13, (online)

[19] AEMO has informed the ERA that it typically only requires the use of backup LFAS in circumstances where a material or considerable shortfall of load following is occurring or is likely to occur.

[20] Wholesale Electricity Market Rules (WA), 1 June 2022, Rule 7B.3.8, (online)

[21] Australian Energy Market Operator, 'Real Time Dispatch Advisories' (online)

[22] Wholesale Electricity Market Rules (WA), 1 June 2022, Rule 7B.4.1, (online)

2.1 How the WEM compares to other jurisdictions?

The ERA engaged GHD Advisory to assist the ERA in considering the use of LFAS in the WEM including the risks of having insufficient LFAS. This is in the context of the ERA considering AEMO's obligations to determine its ancillary services requirements in accordance with the SWIS Operating Standards and the Ancillary Service Standards. GHD reviewed the use of LFAS in the WEM and how similar frequency keeping services were procured and used in other jurisdictions. GHD compared the WEM and four other energy markets to benchmark the level of frequency keeping services used in each market.

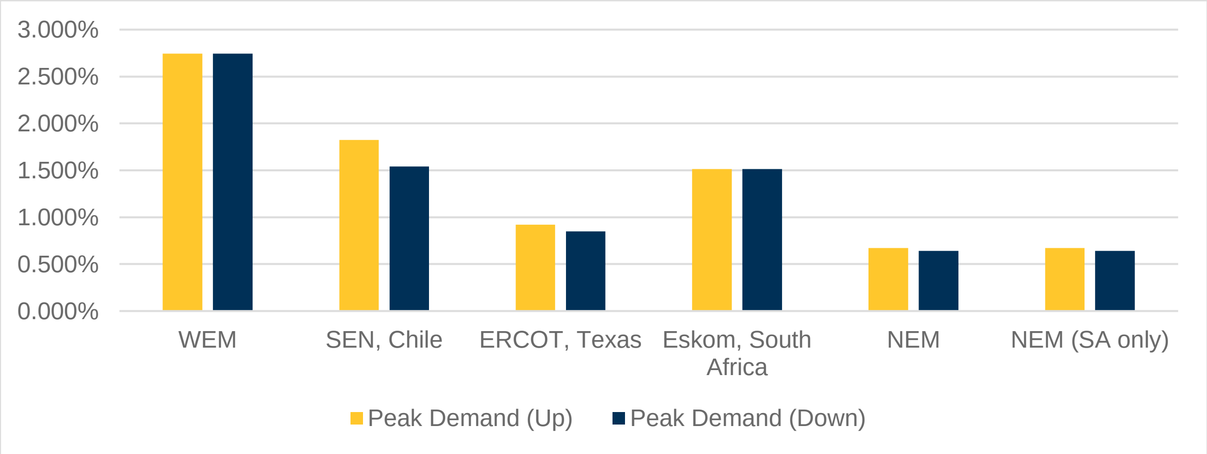
Interstate and international jurisdictions with similar characterises to the SWIS were chosen for this comparison. Jurisdictions with little to no interconnectivity and high penetration of renewable generation were favoured for comparison.

GHD reports that in circumstances where insufficient LFAS is enabled, the frequency is likely to spend a greater amount of time away from 50 Hz but still within the normal operating band. This means there is less 'spare room' for system frequency to move before more extreme actions are required.

GHD also reported that it is likely to be more efficient to adjust the market design to enable maximum quantities during specific periods and avoid manual interventions such as the use of backup LFAS. This will be addressed through the new market design for the WEM commencing in October 2023, which includes co-optimised energy and ancillary services markets.

GHD identified that in terms of gross quantities of LFAS (or comparable frequency keeping service) the WEM had approximately twice the overall quantity of frequency keeping than the next closest jurisdiction as outlined in Figure 1.

Figure 1: Frequency Reserve (LFAS) as a ratio of peak demand in comparison jurisdictions



Source: GHD LFAS in the WEM report.

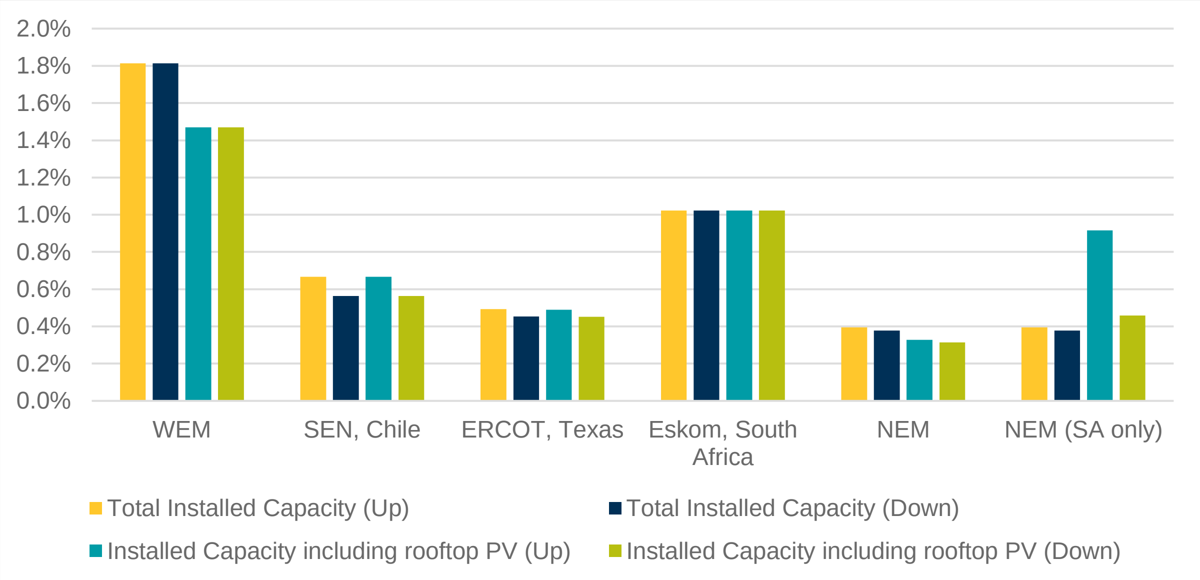
To more accurately compare frequency keeping services across these jurisdictions, GHD developed a series of benchmark ratios. These ratios included comparisons of peak and minimum demand, annual generation and installed capacity for both renewable and non-renewable generation, and also levels of distributed rooftop PV generation.

In almost all comparisons conducted by GHD, the WEM had a greater quantity of frequency keeping services. GHD identified one occasion where the WEM had a lower ratio of LFAS than another jurisdiction, South Australia. This concerned an isolated event where South Australia was isolated from the NEM during a minimum load event. Under these conditions, South Australia had a greater proportion of frequency keeping service (22%) when compared to the WEM during a minimum load event in the SWIS (14.5%).

Two of the most relevant comparisons undertaken by GHD assessed the ratio of LFAS against installed and total generation capacity including distributed rooftop PV. The results of these comparisons are outlined in Figure 2.

When considering LFAS as a proportion of capacity including distributed rooftop PV, the WEM has approximately three times more frequency keeping service than the NEM, and about twice the service compared to South Australia.

Figure 2: Frequency reserve (LFAS) as a ratio of installed capacity including distributed solar PV in comparison jurisdictions



Source: GHD data.

In undertaking these comparisons, GHD considered several factors for each of the selected jurisdictions including generation mix, market size and dispatch interval length.

GHD observed that overall, the percentage of renewable generation in an electricity market was not necessarily a strong indicator of the quantity of frequency keeping services required; the size of the market is likely to be a greater factor. When taking this into consideration, GHD concluded that quantities of frequency keeping services in the WEM were high compared to other similar jurisdictions.

A copy of GHD's report is available at Appendix 3.

2.2 AEMO's load following ancillary services proposal

AEMO has proposed a LFAS requirement of up to +/-120 MW between 5:30 am and 8:30 pm (peak LFAS requirement), and +/-65 MW between 8:30 pm and 5:30 am (off-peak) for 2022/23. This is a proposed increase of 10 MW for the peak requirement from 2021/22, with no change to the off-peak requirement.

Similar to AEMO's past two proposals, AEMO has proposed to implement the peak LFAS requirement for 2022/23 in a staged approach. Initially, AEMO will increase the LFAS requirement from the current quantity of +/-100 MW to +/-110 MW. AEMO stated that following its move to +/-110 MW, it will then monitor and assess the adequacy of this requirement to determine if an increase to the full +/-120 MW is necessary. AEMO has not provided an indication of when the full 120 MW requirement will be needed.

AEMO's reasoning for the proposed change in its peak LFAS requirement is the increasing number of distributed rooftop PV systems connections which increase the power system's volatility. This volatility must be managed through frequency keeping services.

To determine its LFAS requirements, AEMO estimates the quantity of LFAS that will be required by calculating the amount of 'frequency keeping mechanisms' (FKM) that have historically been used. AEMO stated:

> The methodology calculates the generator response, referred to as Frequency Keeping Mechanism (FKM), to maintain frequency. This is a combination of response from the Balancing Portfolio and generators providing LFAS. Through calculation of the underlying FKM, AEMO determines the real system response to frequency deviations, not just LFAS enabled services.

AEMO uses FKM as a measure for determining its LFAS requirement rather than actual historic LFAS usage. This is because AEMO is unable to measure the quantities of LFAS provided by the balancing portfolio as it is not possible to differentiate between the constant re-dispatch of these facilities during normal balancing market operation and adjustments to these facilities' output targets for ancillary service purposes.[23] AEMO then considers the year-on-year change in its FKM analysis alongside its operational experience and uses this analysis to determine the LFAS requirements.[24]

A summary of AEMO's proposed 2022/23 LFAS requirements compared to the 2021/22 LFAS requirements is provided in Table 3, including the corresponding FKM quantities and the year-on-year growth of those quantities.[25] The ERA considers that the FKM values do not support AEMO's proposed 2022/23 peak LFAS requirements, as discussed in section 2.3.

Table 3: AEMO's proposed LFAS requirements compared to FKM quantities[26]

	FKM from prior year (Peak)	FKM change from prior year (Peak)	LFAS Requirement (Peak)	FKM from prior year (Off-Peak)	FKM change from prior year (Off-peak)	LFAS Requirement (Off-Peak)
2021/22	122 MW	26 MW	+/-105 MW	78 MW	17 MW	+/-65 MW
2022/23	**128 MW**	**6 MW**	**+/-120 MW**	**75 MW**	**-3 MW**	**+/-65 MW**

Source: AEMO Data and Ancillary Service Reports

23 Balancing Portfolio Facilities enabled via AGC provide a combination of services, including LFAS and energy balancing services for the Synergy Portfolio. Therefore, each Facility in the Balancing Portfolio is enabled for its entire operating range, providing LFAS Upwards and LFAS Downwards depending on the output at the time.

24 Through experience operating the power system, AEMO normally requires a lower level of LFAS than the FKM analysis indicates. This reduction is related to the contribution of non-market responses including primary frequency control such as droop response, used to develop the LFAS requirement.

25 Note, AEMO uses FKM quantities from prior years together with its operational experience to provide an indication of its requirements for the coming year.

26 FKM values are used by AEMO to provide an indication of future years LFAS requirements.

2.3 ERA's assessment of AEMO's LFAS proposal

AEMO has proposed a LFAS requirement of up to +/-120 MW between 5:30 am and 8:30 pm (peak LFAS requirement). This is a proposed increase of 10 MW for the peak requirement from 2021/22. AEMO proposed no change to its off-peak requirement +/-65 MW between 8:30 pm and 5:30 am for 2022/23. AEMO has applied variable requirements since July 2020, and this is consistent with the WEM Rules which provides that AEMO's requirements may vary by time of day.[27]

AEMO must also determine its requirements based on the facilities and configuration expected for the SWIS in the upcoming year.[28] AEMO did not report any network configuration or changes to registered facilities relevant to its LFAS requirement. However, as in recent years, AEMO considered the volatility in rooftop PV and grid connected renewable generation for the SWIS when determining its requirements. The ERA has considered these factors when assessing AEMO's proposal.

AEMO's reason for increasing the peak LFAS requirement by +/-10 MW in 2022/23 is the growth of distributed rooftop PV systems that continue to cause increased volatility on the power system. This volatility is managed through FKM services.

However, the ERA has concluded that the information provided by AEMO for the level of FKM services, when compared to the level of LFAS requested by AEMO and the level of LFAS actually implemented by AEMO, does not adequately demonstrate the need to increase the peak LFAS requirement to +/-120 MW.

The ERA has therefore determined not to approve the requested increase in the peak LFAS requirement. This means the peak LFAS requirement will remain at +/-110 MW for 2022/23. AEMO has not proposed any change to the off-peak requirements. The off-peak requirement will remain at +/-65 MW.

The ERA has made its determination considering the negligible risk to the power system as demonstrated through AEMO's past frequency performance which has consistently exceeded the standard.[29] There are also no material costs to the market expected from the ERA's decision. AEMO can also request the ERA to approve a variation to the LFAS requirements at any time. These matters are discussed below.

2.3.1 Insufficient evidence for increase to peak LFAS requirement

Figure 3 shows AEMO's FKM values, proposed requirements and implemented requirements compared to the requirements that the ERA has approved since July 2019.[30] These values are also compared to the installed capacity of grid connected and distributed rooftop PV from July 2019.[31,32] For ease of comparison, the values in Figure 3 are limited to peak LFAS values.

27 Wholesale Electricity Market Rules, 1 June 2022, Rules 3.11.4 and 3.11.5 (online)

28 Wholesale Electricity Market Rules, 1 June 2022, Rule 3.11.2 (online)

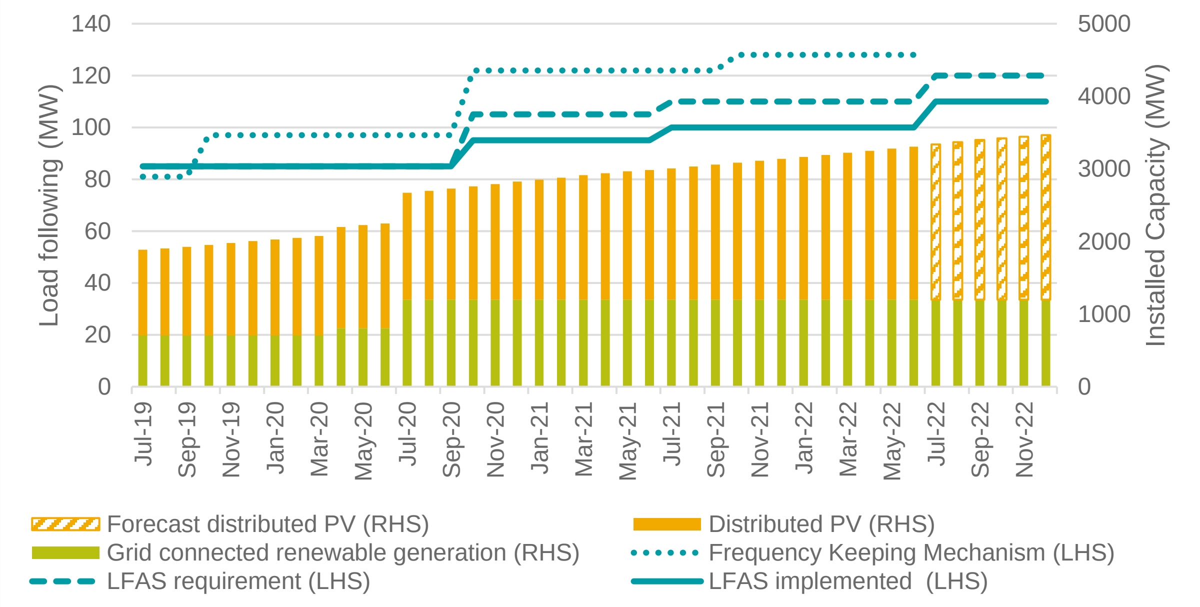
29 Wholesale Electricity Market Rules, 1 June 2022, Rule 3.11.2 and 3.11.1 (online)

30 FKM values are used by AEMO to provide an indication of future years LFAS requirements.

31 Distributed PV values are from annual capacity year forecasts of installed behind the meter rooftop PV capacity information in AEMO's 2021 ESOO report (online).

32 Australian PV Institute, 2022, (online) [accessed 1 June 2022]

Figure 3: Installed capacity of grid connected and distributed renewable generation in the SWIS measured against increases to LFAS[33]



Source: AEMO Data, APVI Data, 2021 WEM ESOO and AEMO's Ancillary Service Reports.

In 2019/20, AEMO revised its static +/-72 MW LFAS requirement to a variable requirement. For peak times, AEMO proposed an LFAS requirement of +/-85 MW. The LFAS requirement remained at these levels until September 2020 following an intra-period approval request from AEMO to increase the peak requirement to a maximum of +/-105 MW.

The reason for the September 2020 increase was due to the connection of approximately 491 MW of renewable generation to the grid in 2020 plus the continued growth of rooftop PV generation. Despite the material increase in these variable generation sources, as shown in Figure 3, AEMO implemented a peak requirement that was 10 MW less than it requested the ERA to approve, requiring only +/-95 MW for peak times.

In 2021/22, AEMO requested a peak LFAS requirement of up to +/-110 MW.[34] AEMO's 2021/22 report stated that the frequency keeping mechanism used during peak times increased by approximately 10 MW and 25 MW over the past two years respectively and that this trend was likely to continue with the increasing pace of distributed rooftop PV connections. However, the peak LFAS requirements implemented by AEMO for 2021/22 were 10 MW less than it requested the ERA to approve, at only +/-100 MW for peak times as shown in Figure 3.

This demonstrates that for the past two consecutive years (2020/21 and 2021/22) AEMO has not utilised the full amount of peak LFAS that it has requested the ERA to approve. For 2022/23 AEMO has again requested a 10 MW change to increase the peak LFAS requirements to +/-120 MW but again is not proposing to implement the full +/-120 MW requirement. Instead AEMO proposes to increase the LFAS requirement from the current quantity of +/-100 MW to +/-110 MW. AEMO stated that following its move to +/-110 MW, it will then monitor and assess the adequacy of the 110 MW requirement to determine if an increase to the full +/-120 MW is necessary. AEMO has not provided any indication of when the full +/-120 MW requirement will be needed.

33 Distributed PV values are from annual capacity year forecasts of installed behind the meter rooftop PV capacity information in AEMO's 2021 ESOO report (online).

34 AEMO requested a lower quantity of off-peak LFAS in 2021/22 lowering the requirement from 75 MW to 65 MW.

The ERA requested AEMO provide additional information to support its proposal of +/- 120 MW. The ERA concluded from its analysis of this information that there is insufficient evidence to warrant approving the full +/-120 MW LFAS requirement. AEMO uses the year-on-year change in FKM levels to estimate the overall quantity of LFAS required by the SWIS together with its operational experience. Table 4 shows that there is no discernible relationship between the year-on year change in the FKM levels and the requested and implemented increase in LFAS requirements.[35] For example, for 2021/22 the FKM data from the prior year indicated an increase in frequency keeping services for peak times of 26 MW. However, AEMO only implemented an LFAS increase of 5 MW for that year.

For 2022/23 AEMO's FKM data from the prior year indicated a 6 MW increase for peak times. However, for 2020/21 and 2021/22, AEMO's data shows significantly higher FKM values for the prior years (16 MW and 26 MW respectively). Despite the smaller increase in the FKM value for 2022/23, AEMO has requested an increase of 10 MW – on par with years that had higher FKM values. The ERA acknowledges that AEMO used FKM data over the summer period to calculate the 2022/23 6MW increase, and this period involves is less volatility, and AEMO would expect more volatility over the course of a full year, leading to a higher FKM requirement for 2022/23. However, FKM values have been higher in prior years but AEMO has implemented lower requirements.

The ERA considers that the already available 'spare' 10 MW will be adequate for AEMO's LFAS requirements for 2022/23. This is also consistent with AEMO's plans to move to the current maximum approved requirement of +/-110 MW. Should +/-110 MW be insufficient, AEMO may seek to further increase the requirement under the rules.

Table 4: Incremental changes to peak LFAS requirements

Year	Change in peak FKM MW from prior year	Difference between current year's requested peak LFAS requirement and prior years implemented peak LFAS requirement	Increase in implemented peak LFAS requirement from prior year
2019/20	Not available	13 MW	13 MW
2020/21	16 MW	20 MW	10 MW
2021/22	26 MW	15 MW	5 MW
2022/23	6 MW	20 MW[36]	10 MW

Source: AEMO's Ancillary Service Reports 2019 – 2022

Further, AEMO explained that the increase in the LFAS requirement is necessary due to the increasing number of distributed rooftop PV systems connections which increase the power system's volatility. Table 5 shows that the growth in distributed PV generation has been

35 Page 21 of AEMO's 2022 Ancillary Service Report, (online) states "Although the FKM enables adequate frequency performance to be maintained, increasing duration of the frequency away from 50 Hz increases the probably that a contingency will result in a frequency exceedance". Page 7 of this report also states that 'the frequency remained in the normal operating band for 99.98% of the time'. AEMO's frequency performance is materially above the standard, indicating that it is unlikely to significantly affect AEMO's frequency performance in 2022/23.

36 This is derived from the difference between the currently implemented +/-110 MW and the proposed requirement of +/-120 MW.

increasing at a steady rate but the rate of growth does not appear to consistently align with the increases in the peak LFAS service that AEMO is requesting. [37]

For example, in 2019/20 341 MW of distributed PV was connected. In addition, 491 MW of grid connected renewables entered the SWIS. AEMO only implemented a 10 MW increase in its peak LFAS requirements to manage the increased volatility of 839 MW of distributed PV and grid connected renewables, despite having an approved increase of 20 MW that it could implement. In 2021/22, there was an estimated 320 MW of new distributed PV connections and no new grid connected renewable entrants - AEMO implemented a corresponding increase of 5 MW for its peak LFAS requirements.

For 2022/23 the ERA has extrapolated from AEMO's forecasts a lower estimated quantity of new distributed rooftop PV connections (273 MW). However, AEMO is proposing to implement a peak LFAS requirement of +/-110 MW, which is an increase of 10 MW, double the previous year's.[38] As shown in Table 5, the ERA already approved the 10 MW peak LFAS increase in 2021/22.

Table 5: Increase in total renewable capacity, peak LFAS changes and AEMO's frequency performance

Period[39]	Increase in grid connected renewable generation	Increase in distributed PV[40]	ERA approved peak LFAS requirement	AEMO's implemented peak LFAS requirement	Frequency performance within normal operating range[41]
2020/21	491 MW	341 MW	+/-105 MW	+/-95 MW	99.988%[42]
2021/22	0 MW	320 MW	+/-110 MW	+/-100 MW	99.98%
2022/23	0 MW	273 MW	+/-110 MW[43]	+/-110 MW[44]	Not yet available.

Source: AEMO Data and Ancillary Service Reports

2.3.2 Power system security

LFAS is required to manage the frequency of the SWIS. AEMO must maintain this aspect of power system security by ensuring that the frequency of the SWIS is kept within the normal operating band of 49.8 Hz and 50.2 Hz for 99 per cent of the time. [45] AEMO reported that for the period May 2021 to April 2022 it maintained the frequency within the normal operating range 99.98 per cent of the time. AEMO demonstrated similar high-level performance in prior years' reports. Since 2020/21, AEMO's frequency performance above the standard has been

---

37 Wholesale Electricity Market Rules, 1 June 2022, Rule 3.11.1 (online)

38 Australian Energy Market Operator, 2021, *2021 Electricity Statement of Opportunities*, p. 7, (online)

39 There may be small timing discrepancies for when AEMO implemented changes in its LFAS requirements. For example, for 2021/22, AEMO did not implement the increase in the peak LFAS requirement until 15 July 2021.

40 Distributed PV values are from annual capacity year forecasts of installed behind the meter rooftop PV capacity information in AEMO's 2021 ESOO report (online).

41 The normal operating frequency band for the SWIS is 49.8 to 50.3 Hz. Wholesale Electricity Market Rules (WA), 1 June 2022, Appendix 13 (online)

42 Australian Energy Market Operator, 2021, *Ancillary Services Report for the WEM 2021*, p. 6, (online)

43 This value is the carried over approved value from 2021/22.

44 Australian Energy Market Operator, 2022, *Ancillary Services Report for the WEM 2022*, p. 22 (online)

45 Wholesale Electricity Market Rules, 1 June 2022, Rule 3.11.1 (online)

achieved without it implementing the full quantity of the LFAS requirements it requested and the ERA approved as shown in Table 5.

AEMO has explained in prior years that the requirements for generators require settings that result in these generators responding to variations in frequency within the normal operating band. LFAS services are needed to return the frequency to 50 Hz. The generator settings work together with LFAS, significantly contributing to AEMO's frequency performance being above the standard.

AEMO may also use backup LFAS to maintain power system security where there is a shortfall in the enabled quantity of LFAS or a scheduled generator fails to provide its cleared quantities through the LFAS market.[46] Between 1 July 2020 and 30 April 2022, AEMO used backup LFAS over 204 trading intervals, which was less than 1.5% of the time.

In the review undertaken by GHD, there was no evidence found that the quantity of procured LFAS through the LFAS market plus backup LFAS had ever been exhausted. GHD further stated that the security risk caused by not increasing procured LFAS is minimal.

For 2022/23, AEMO proposes to increase its implemented LFAS requirement by 10 MW to the currently approved maximum peak requirement of +/-110 MW as shown in Table 5. Given AEMO's past frequency performance has materially exceeded the 99% standard, and that for 2022/23 AEMO will have the already approved additional 10 MW peak LFAS increase to assist it manage frequency, there is negligible risk that the ERA's determination to not approve the peak LFAS increase to +/-120 MW will result in AEMO being unable to maintain power system security.

2.3.3 Economic assessment

Generators are paid for the LFAS quantity implemented by AEMO through the LFAS market irrespective of the LFAS levels required during normal market operation. The ERA estimates that an increase of 10 MW, from +/-100 MW to +/-110 MW in the implemented LFAS quantities from July 2021 could cost an additional $5.6 million over a 12-month period.[47]

In a situation where AEMO increases the peak LFAS requirement by an additional 10 MW from +/-110 MW to +/-120 MW, the ERA estimates that the increased cost to the market could be approximately $618,000 per month ($7.4 million over 12 months) in addition to the $5.6 million referred to above.

If during 2022/23 AEMO requires more LFAS than the amount procured in the LFAS market (that is, +/-110 MW for peak LFAS) it can utilise backup LFAS, as explained in section 2. Historically, the use of backup LFAS for these reasons is infrequent and AEMO's report stated that backup LFAS costs only comprised 1.0% of LFAS upward availability costs and 1.8 % of LFAS downwards availability costs. The rare use of backup LFAS to cover shortfalls means that it is more economically efficient to procure this higher cost service infrequently than to increase the normal quantity to be procured from the LFAS market.

46 AEMO may also use backup LFAS where the quantity of upwards or downwards LFAS in a trading interval required by AEMO is greater than the required upwards LFAS quantity or downwards LFAS quantity for that trading interval.

47 This estimation was undertaking LFAS submissions for the period 1 May 2021 to 30 April 2022. The ERA re-calculated the marginal cost of providing LFAS based upon the updated requirement. The assessment does not factor in changes to LFAS submissions based upon updated requirements or the entrance of Synergy's battery energy storage resource.

2.3.4 Summary of ERA's determination on AEMO's LFAS requirements

The ERA's determination on AEMO's proposed LFAS requirements is summarised in Table 6.

Table 6: AEMO's proposed LFAS requirements

Service	2022/23 requirement proposed by AEMO	Determination
LFAS upwards	Up to 120 MW peak (between 5:30 am and 8:30 pm)[48]	Up to 110 MW approved[49]
	65 MW off-peak (between 8:30 pm and 5:30 am)	Approved
LFAS downwards	Up to 120 MW peak (between 5:30 am and 8:30 pm)[50]	Up to 110 MW approved[51]
	65 MW off-peak (between 8:30 pm and 5:30 am)	Approved

The ERA's determination to not approve AEMO's peak LFAS requirement does not change AEMO's operational practices in the short term. This is because AEMO does not propose to increase the LFAS requirement to more than the previously approved maximum quantity of +/-110 MW until later.

Following an audit of the ancillary service requirements, the WEM Rules state that the ERA may require AEMO to re-determine the ancillary service requirements.[52] The ERA has not required AEMO to re-determine its ancillary service requirements because the amount AEMO intends to implement has been approved. If AEMO considers that a shortfall of its peak LFAS requirement is occurring or likely to occur then it may submit a proposal to the ERA, at any time.

48 The ERA approved a LFAS upwards quantity of +/-110 MW in June 2021. AEMO can increase the enabled quantity of this service to this previously approved maximum.

49 The ERA has not approved AEMO's requested peak LFAS upwards requirement of up to 120 MW.

50 The ERA approved a LFAS downwards quantity of +/-110 in June 2021. AEMO can increase the enabled quantity of this service to this previously approved maximum.

51 The ERA has not approved AEMO's requested peak LFAS downwards requirement of up to 120 MW.

52 Wholesale Electricity Market Rules (WA), 1 June 2022, Rule 3.11.6, (online)

3. Spinning reserve service

Spinning reserve service (spinning reserve) provides a rapid increase in generation following a sudden or unexpected shortfall in supply. This may result from the loss of a large generator or transmission asset. Spinning reserve is currently provided by a mix of gas, diesel, coal, and interruptible load facilities.

Spinning reserve is defined in the WEM Rules as:

> 3.9.2. Spinning Reserve Service is the service of holding capacity associated with a synchronised Scheduled Generator or Interruptible Load in reserve so that the relevant Facility is able to respond appropriately in any of the following situations:
>
> (a) to retard frequency drops following the failure of one or more generating works or transmission equipment; and
>
> (b) in the case of Spinning Reserve Service provided by Scheduled Generators to supply electricity if the alternative is to trigger involuntary load curtailment

The ancillary service standard for spinning reserve is defined in the WEM Rules:

> 3.10.2. The standard for Spinning Reserve Service is a level which satisfies the following principles:
>
> (a) the level must be sufficient to cover the greater of:
>
> i. 70% of the total output, including Parasitic Load, of the generation unit synchronised to the SWIS with the highest total output at that time; and
>
> ii. the maximum load ramp expected over a period of 15 minutes;
>
> (b) the level must include capacity utilised to meet the Load Following Service standard under clause 3.10.1, so that the capacity provided to meet the Load Following requirement is counted as providing part of the Spinning Reserve requirement;
>
> (c) the level may be relaxed by up to 12% by AEMO where it expects that the shortfall will be for a period of less than 30 minutes; and
>
> (d) the level may be relaxed following activation of Spinning Reserve and may be relaxed by up to 100% if all reserves are exhausted and to maintain reserves would require involuntary load shedding. In such situations the levels must be fully restored as soon as practicable.

3.1 AEMO's spinning reserve proposal

In past years, AEMO's spinning reserve requirement has been set as the maximum (in MW) of 70 per cent of the largest generating unit and 70 percent of the largest contingency event that would result in generation loss. AEMO has proposed to include an additional criterion to the spinning reserve requirement for the 2022/23 year. As shown in Table 7, this criterion considers the maximum load ramp expected over a period of 15 minutes.

Table 7: Spinning reserve service requirement 2022/23

Ancillary Service	Requirement
Spinning reserve service	At least the maximum of: 1. 70% of the largest generating unit; 2. 70% of the largest contingency event that would result in generation loss; and 3. The maximum load ramp expected over a period of 15 minutes.

The ERA's assessment of these changes is discussed in section 3.2.

3.2 ERA's assessment of AEMO's spinning reserve proposal

The purpose of spinning reserve is to assist in managing the frequency after the sudden or unexpected failure of equipment including generators or network components. Facilities providing spinning reserve may be required to suddenly ramp up or decrease generation to cover these unexpected outages to prevent involuntary under frequency load shedding.

AEMO's proposed addition to the spinning reserve requirement criteria to consider the maximum load ramp is consistent with the requirements in the WEM Rules. Clause 3.10.2(a)ii expressly requires that the spinning reserve requirement consider the maximum load ramp expected over a period of 15 minutes.

AEMO has not previously needed to include the maximum load ramp quantity in its ancillary services proposals because it would be materially less than the quantities for the remaining criteria and so it would never set the spinning reserve requirement.

However, AEMO reported that the maximum load ramp over a 15-minute period during 2021/22 occurred during a distributed rooftop PV cloud cover event. This resulted in a load ramp of 299 MW, which is very close to the highest spinning reserve requirement (300 MW) set under the existing criteria. Therefore, when planning spinning reserve requirements, AEMO will now consider the forecast maximum load ramp. If this value is greater than the expected spinning reserve quantity, AEMO will adjust the spinning reserve quantity accordingly.

The ERA approves AEMO's 2022/23 proposed spinning reserve requirements.

4. Load rejection reserve services

Load rejection reserve (LRR) provides a quick reduction in generators' output in instances where a large load is suddenly and unexpectedly lost, for example due to a transmission line outage.

The WEM Rules define LRR as:

> 3.9.6. Load Rejection Reserve Service is the service of holding capacity associated with a Scheduled Generator in reserve so that the Scheduled Generator can reduce output rapidly in response to a sudden decrease in SWIS load.

The SWIS operating standards require the frequency to remain below 51 Hz for a single contingency event, such as the outage of one transmission line.

The quantity of load rejection reserve is set by AEMO to meet the standards outlined in clause 3.10.4 of the WEM Rules. The rule states:

> 3.10.4. The standard for Load Rejection Reserve Service is a level which satisfies the following principles:
>
> (a) the level sufficient to keep over-frequency below 51 Hz for all credible load rejection events;
>
> (b) may be relaxed by up to 25% by AEMO where it considers that the probability of transmission faults is low.

4.1 AEMO's load rejection reserve services proposal

The quantity proposed by AEMO for its 2022/23 LRR requirement is 97 MW. This is an increase of 7 MW from the previous year's quantity of 90 MW.

Table 8: Load rejection reserve service requirement 2022/23

Ancillary Service	Requirement
Load rejection reserve service	Up to a maximum of 97 MW

4.2 ERA's assessment of AEMO's load rejection reserve services proposal

In January 2020, the constraints limiting power flows (transfer limit) for the eastern goldfields network increased by 30 MW, resulting in the possibility of increased requirements for LRR in circumstances where the network experiences an outage. Analysis undertaken by AEMO incorporating the actual load transfers to the region indicates that following the increased transfer limit for the region, a 90 MW requirement would result in AEMO failing to meet the standard 7 per cent of the time.

AEMO's assessment indicated that the increase in the transfer limit for the eastern goldfields region from 120 MW to 150 MW results in an increase to the LRR of 7 MW.

The ERA has verified AEMO assessment and approves AEMO's proposal to increase the LRR requirement quantity to 97 MW. [53]

[53] This amount is what the ERA believes would be a sufficient level to comply with the Wholesale Electricity Market Rules. Wholesale Electricity Market Rules (WA), 1 June 2022, Rule 3.10.4, (online).

5. Contracted services

The WEM Rules state AEMO may enter ancillary service contracts with a rule participant for LRR or system restart services. [54]

> 3.11.8A. AEMO may enter into an Ancillary Service Contract with a Rule Participant for the provision of a Load Rejection Reserve Service or System Restart Service.

Load rejection reserve services are discussed in section 4 of this report. System restart services are discussed below.

System restart services are provided by generators capable of restarting and providing power to the grid in total blackout conditions. This will enable other generators without this capability to also start.

5.1 System restart services

The WEM Rules defines system restart services:

> 3.9.8. System Restart Service is the ability of a Registered Facility which is a generation system to start without requiring energy to be supplied from a Network to assist in the re-energisation of the SWIS in the event of system shutdown.

The system restart standard is defined in clause 3.7.2. This rule was amended on 1 June 2022 and now states:

> 3.7.2. The System Restart Standard:
>
> (a) must identify the minimum length of time for which a System Restart Service may be required to operate continuously following a system shutdown or major supply disruption;
>
> (b) must specify the technical requirements that a Registered Facility must demonstrate to be eligible to provide a System Restart Service;
>
> (c) must include guidelines addressing the diversity of System Restart Services, including diversity of locations within the SWIS
>
> (d) must include requirements for mitigating against the risk of unavailability of any System Restart Service during a system shutdown or major supply disruption; and
>
> (e) may include any other matters that AEMO determines are necessary to ensure the SWIS is restarted in the event of a system shutdown or major supply disruption.

AEMO has published its system restart standard.[55] The standard outlines the required geographic diversity of spinning reserve services, to effectively restart the SWIS following an interruption. The standard outlines the electrical subnetworks in geographically defined areas of the network where spinning reserve is required.

In its ancillary service report, AEMO has specified that it requires three system restart facilities. System restart service facilities are located in the north metropolitan, south metropolitan and south country regions of the network. The south country contract expires in 2028. The north metropolitan and south metropolitan contracts expire in June 2026.

[54] AEMO may also enter an ancillary service contract with a rule participant other than Synergy for spinning reserve ancillary services. Wholesale Electricity Market Rules (WA), 1 June 2022, Rule 3.11.8, (online).

[55] Australian Energy Market Operator, 2022, *WEM System Restart Standard*, (online)

AEMO has contracted three services in three different geographical locations, consistent with the standard. The ERA approves the system restart requirement for 2022/23.

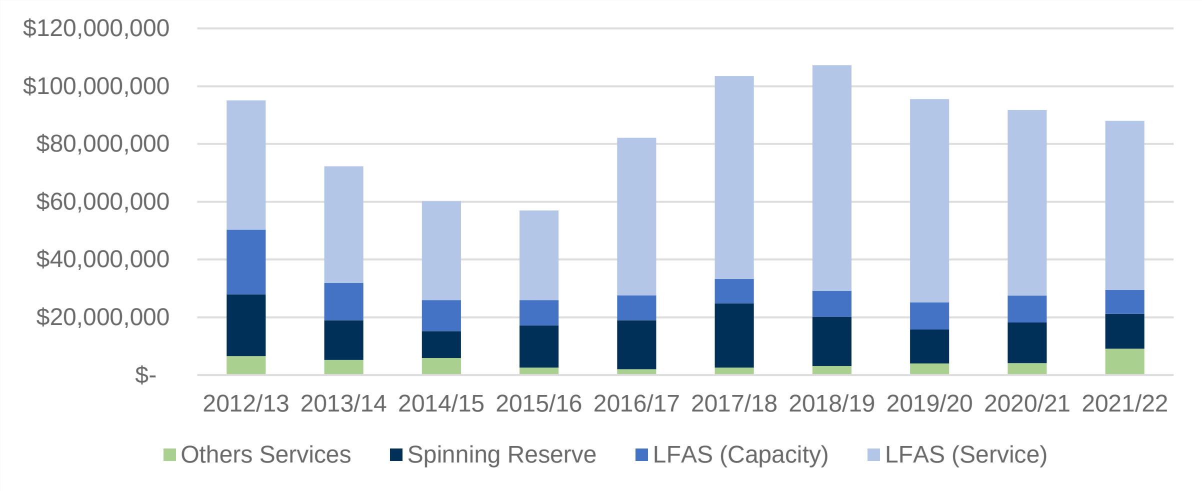
Table 9: System restart service 2022/23 requirement

Ancillary Service	Requirement
System restart service	Three facilities with system restart capability

6. Ancillary service costs

During 2021/22, total ancillary service costs amounted to $88,001,590. This was $3.8 million lower than 2020/21 and represent the fourth consecutive year of declining costs.

Figure 4: Ancillary service costs 2012 to 2020



Source: AEMO Data

This reduction was mostly due to a $6.75 million reduction in LFAS costs and $1.97 million.

Lower LFAS costs were predominantly due to a decrease in LFAS upwards costs of $4.5 million. LFAS downwards costs decreased by $1.25 million and LFAS capacity costs fell by $1 million.

Similar to the previous reporting period, total LFAS costs decreased, despite an increase in enabled quantities, due to clearing price reductions in both LFAS markets.

Spinning reserve costs decreased from $14.1 million in 2020/21 to $12.1 million in 2021/22. Spinning reserve costs are set through the ERA's margin values and Cost_LR determination process. The margin values are used in the calculation that determines the compensation paid to Synergy for the spinning reserve service. The decrease in costs was primarily due to a reduction in the approved margin values used to determine the cost of the service.

LRR costs increased from $1.15 million in 2020/21 to $5.7 million, an increase of $4.54 million in 2021/22. This increase is due to changes to the Cost_LR parameter outlined in the ERA's 2021/22 Margin Values report.[56]

[56] Economic Regulation Authority, 2021, *Ancillary service costs: Spinning reserve, load rejection reserve and system restart costs (Margin Values and Cost_LR) for 2021/22 – Determination*, (online)

Appendix 1 List of Tables

Appendix 2 List of Figures

Appendix 3 GHD Report – LFAS in the WEM

LFAS in the WEM

Final report

Economic Regulation Authority

13 June 2022

→ **The Power of Commitment**

Project name		ERA - Benchmarking LFAS for the WEM					
Project number		12582139					
Status Code	Revision	Author	Reviewer		Approved for issue		
			Name	Signature	Name	Signature	Date
S4	Final	M. Nichol	L. O'Brien		D. Bones		13/06/2022

In addition to the authors and reviewers above we would like to thank the contributions from representatives from Eskom in South Africa, ERCOT in the United States and the Coordinador Eléctrico Nacional in Chile.

GHD Pty Ltd | ABN 39 008 488 373

999 Hay Street, Level 10

Perth, Western Australia 6000, Australia

T +61 8 6222 8222 | **F** +61 8 6222 8555 | **E** permail@ghd.com | **ghd.com**

Contents

Table index

Figure index

Acronyms and abbreviations

The following acronyms, terms and abbreviations have been used in this report.

Table 1 Acronyms, terms and abbreviations

Acronym / term / abbreviation	Meaning
AC	Alternating Current
AEMO	Australian Energy Market Operator
AGC	Automatic Generation Control
BESS	Battery Energy Storage System
CAISO	California Independent System Operator
C-FCAS	Contingency Frequency Control Ancillary Services
CI	Cargas Interrumpibles (interruptible load)
Coordinador	Coordinador Eléctrico Nacional (in Chile)
CPF	Control Primario de Frecuencia (primary frequency response reserve)
CRF	Control Rápido de Frecuencia (rapid frequency response reserve)
CSF	Control Secundario de Frecuencia (secondary frequency response reserve)
CTF	Control Terciariode Frecuencia (tertiary response reserve)
ERA	Economic Regulation Authority (in Western Australia)
ERCOT	Electric Reliability Council of Texas
Eskom	Electricity Supply Commission (in South Africa)
ESS	Essential System Service
FFR	Fast Frequency Response
FOS	Frequency Operating Standard
GHD	GHD Pty Limited
GW	Gigawatt
GWh	Gigawatt hour
Hz	Hertz
IPPs	Independent Power Producers
km	kilometre
kV	Kilovolt
LFAS	Load Following Ancillary Service
LRR	Load Rejection Response
mHz	Millihertz – One-thousandth of a Hertz
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market (in Australia)
NER	National Electricity Rules (in Australia)
NFOB	Normal Frequency Operating Band
Non-Spin	Non-Spinning Reserve
NWIS	North West Interconnected System
OCGT	Open cycle gas turbine

Acronym / term / abbreviation	Meaning
PFR	Primary frequency response
PV	Photovoltaics
SEN	Sistema Eléctrico Nacional (in Chile)
SRAS	Spinning Reserve Ancillary Service
SWIS	South West Interconnected System
TW	Terawatt
TWh	Terawatt hour
UFLS	Under Frequency Load Shedding
WEM	Wholesale Electricity Market (in Western Australia)

1. Introduction

Each year the Australian Energy Market Operator (AEMO) assesses the Wholesale Electricity Market (WEM) ancillary service requirements for the next 12 months and prepares a plan to procure sufficient service to satisfy those requirements. Following the development of AEMO's requirements and plan, the Economic Regulation Authority (ERA) audits AEMO's findings and determines whether to approve AEMO's requirements.

1.1 Purpose of this report

GHD's analysis outlines how selected jurisdictions manage LFAS-equivalent frequency regulation services and compares the quantities of services required to the WEM LFAS requirement. The task required us to identify the mechanisms used for frequency keeping in the benchmarked jurisdictions and whether any services equivalent to backup LFAS are employed. For benchmarking to be developed, information on the characteristics of each power system was collated and compared with the quantities of LFAS-equivalent services required. To the extent possible, our analysis includes data over a period of time to enable any trends to be identified.

GHD also considered AEMO's historic use of Backup LFAS as an alternative frequency regulation mechanism when sufficient LFAS was not available.

This report provides information to assist the ERA as it considers AEMO's 2022/23 Ancillary Service requirements.

1.2 Approach

GHD's findings are informed by a review of publicly available information and discussions with system operators for each of the benchmarked jurisdictions.

The most appropriate and meaningful power systems to benchmark with the WEM are those with similarly sized power systems, that operate using a similar regulatory framework and that have a similar mix of generation (including rooftop solar). There should also be sufficient information available to enable benchmarking to be conducted.

Several of the closest potential comparators to the WEM from a geographic perspective, the NWIS and Darwin-Katherine power systems, lack the required level of sophistication or market design to enable a meaningful comparison. Hence, these were excluded from our analysis. Other power systems that have sufficiently similar and sophisticated regulatory frameworks, including the UK and New Zealand power systems, are either interconnected and use their interconnectors for frequency support (the UK) or do not have a sufficiently similar generation mix and load profile (UK and NZ). Finally, some power systems are interconnected to other power systems such that they are not observing the same frequency regulation challenges as seen in the WEM. For example, the Californian power system operated by CAISO has strong interconnections with the rest of the US Western Interconnected system and this provides a large amount of frequency regulation.

Based on our existing understanding of various power systems across the world, we agreed with the ERA to include the following jurisdictions in the benchmarking exercise:

- National Electricity Market (NEM), Australia,
- South Australian region of the NEM, when operating as an islanded system,
- Eskom, South Africa,
- National Electric Coordinator, Chile, and
- ERCOT, Texas, United States.

While the NEM contains a mix of generation and interconnections that means it can be operated and regulated from a frequency perspective quite differently to the SWIS, including it as a comparison will likely still be meaningful. Particularly, considering the way frequency control is managed within regions of the NEM when they are electrically separated and not synchronised with other regions.

1.3 Terminology used in this report

The following terminology is used in this report:

- Variable generation refers to generation without a predictable fuel source, such as wind and solar. The term captures the generation that would be classified as semi-dispatched generation in the SWIS and excludes distribution connected, non-market dispatched generation such as rooftop PV.
- Non-variable generation refers to generation with a predictable fuel source such as coal, gas, hydro and diesel. The term captures generation that would be classified as dispatchable generation in the SWIS. Similar to the definition for 'variable generation' it excludes distribution connected, non-market dispatched generation such as embedded generators.

1.4 Limitations

This report has been prepared by GHD for the Economic Regulation Authority and may only be used and relied on by the Economic Regulation Authority for the purpose agreed between GHD and the Economic Regulation Authority as set out in section 1.1 of this report.

GHD otherwise disclaims responsibility to any person other than the Economic Regulation Authority 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.

GHD has prepared this report on the basis of information provided by the Economic Regulation Authority and others who provided information to GHD (including Government authorities)], which GHD has not independently verified or checked beyond the agreed scope of work. GHD does not accept liability in connection with such unverified information, including errors and omissions in the report which were caused by errors or omissions in that information.

2. LFAS and Backup LFAS

LFAS provides frequency regulation in the WEM. This essential service maintains the system frequency close to 50 Hz. LFAS acts to correct moment to moment imbalances between load and generation, responding to control signals issued via the Automatic Generation Control (AGC) system. AGC signals are triggered by AEMO from its control centre. These imbalances are sometimes referred to as the 'error' between actual generation and demand levels and that forecast when the balancing market dispatch targets are set.

Many factors give rise to the need for regulation services, some of these are influenced by the behaviour of market participants, others by energy market design, while others reflect the inherent uncertainty in being able to predict demand requirements and the generation from renewable energy generators.

Historically, the LFAS requirement was set at 72 MW. From 2018 onwards, the requirement was split to specify peak (5.30 am to 8.30 pm) and off-peak (8.30 pm to 5.30 am) periods. Table 2 shows the LFAS requirements for the most recent years.

For 2022, AEMO is proposing a 10 MW increase to both the upward and downward LFAS requirements during peak periods. Similar to the approach proposed in recent years, AEMO expects to take a staged approach to increase the enabled LFAS quantity: firstly, increasing daily operation from the existing operational quantity of 100 MW to 110 MW, and then monitoring and assessing adequacy for an increase to 120 MW as required.

The size of the LFAS market is relatively small. In 2020-21, there were five certified LFAS providers in the WEM, and three of them actively participated in the LFAS Market that year.[1] In 2021-22, there were seven certified LFAS Resources from four Market Participants, in addition to the Balancing Portfolio[2].

Table 2 LFAS requirements and use of backup LFAS

Year	LFAS				Backup LFAS required
	Peak (5.30 am to 8.30 pm)		Off-peak (8.30 pm to 5.30 am)		
	Upwards	Downwards	Upwards	Downwards	
2016	72	72	72	72	-
2017	72	72	72	72	-
2018	72	72	72	72	-
2019	85	85	50	50	3 occasions
2020	100	100	65	65	25 MW to 88 MW used on 10 occasions
2021	110	110	65	65	25 MW to 50 MW used on 6 occasions[(a)]
2022 (AEMO proposed)	120	120	65	65	Up to 80 MW used on across 92 intervals[(b)]

Sources: ERA data and AEMO's annual Ancillary Service Reports for the WEM from June 2018 to June 2022.

(a) There were a further 12 occasions where Backup LFAS was utilised when LFAS providers were unable to provide LFAS.However, these are not indicative of a shortfall in LFAS requirements

(b) There were a further 11 occasions where Backup LFAS was utilised when LFAS providers were unable to provide LFAS.However, these are not indicative of a shortfall in LFAS requirements

Synergy is the only provider of Backup LFAS in the WEM[3]. The WEM Rules specify that Backup LFAS can be called upon when an existing LFAS fails or if the required quantity of LFAS exceeds what has been procured from the market. Based on data provided by the ERA, Backup LFAS is more expensive on a per-MW basis than market procured LFAS (Table 3)[4]. However, we understand Backup LFAS is only paid for by the market when it is used whereas the cost of LFAS is covered by the market regardless of if it is enabled and used by the market. As such, it may be less costly to the market to procure additional quantities of Backup LFAS on the limited number of

[1] AEMO, Ancillary Services Report for the WEM 2021, 25 June 2021, p. 8
[2] AEMO, Ancillary Services Report for the WEM 2022, 31 May 2022, p. 8.
[3] Refer to the WEM Rules, clause 7B.4
[4] Based on data supplied by the ERA that provided the LFAS up, LFAS down, Backup LFAS up and Backup LFAS down prices for trading intervals in the period 1 July 2021 to 18 May 2022.

occasions when it is needed compared with increasing the requirements and having a higher quantity of LFAS enabled for all periods of the year.

Table 3 Summary of LFAS and Backup LFAS price data (1 July 2021 to 18 May 2022)

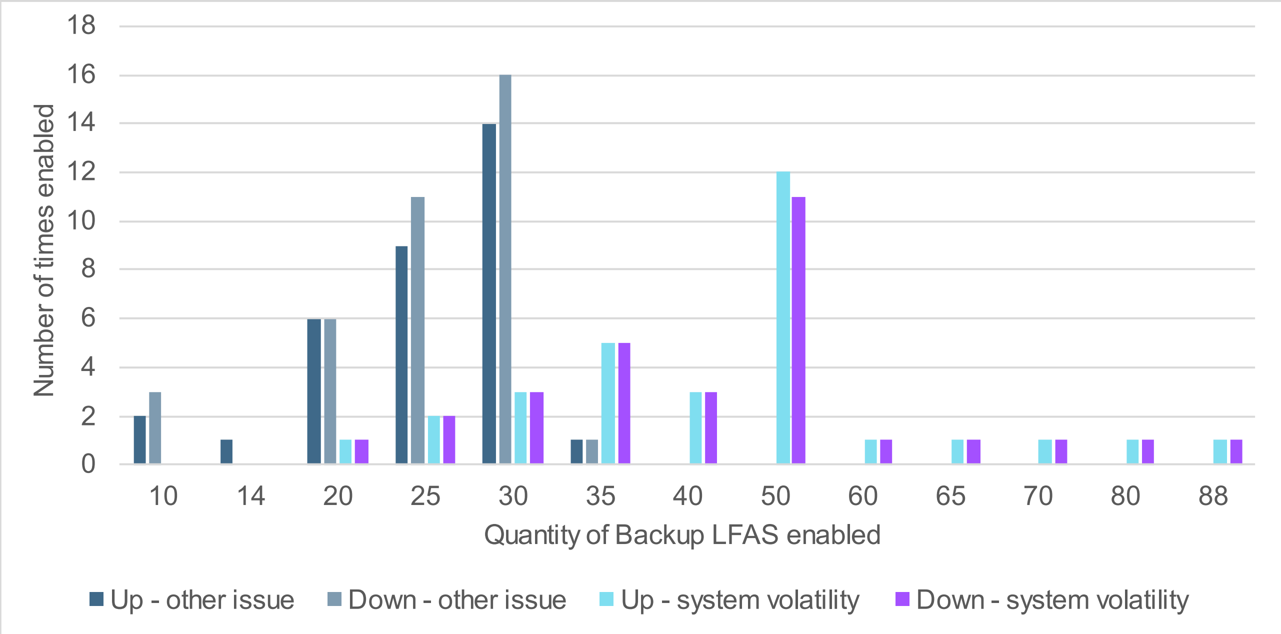
	LFAS up ($/MW)	LFAS Down ($/MW)	Back up LFAS Up ($/MW)	Back up LFAS Down ($/MW)
Maximum price	$54.62	$95.00	$80.44	$95.00
Minimum price	$0.00	$0.00	$0.83	$0.00
Average price	$15.57	$21.07	$25.46	$55.06

Source: GHD analysis of data supplied by the ERA for trading intervals from 8 am on 1 July 2021 to 7.30 am on 18 May 2022.

Based on Dispatch Advisory data, Backup LFAS was required on at least 77 occasions between 22 December 2018 and 18 November 2021. The quantities of Backup LFAS enabled range from a minimum of 10 MW to a maximum of 88 MW (Figure 1). As such, the quantities of Backup LFAS enabled were, in all cases, equal to or greater than the increase from 100 MW to 110 MW that AEMO intends to implement during peak periods in 2023. The Backup LFAS requirement, was also, on average, greater than the 20 MW change that would be observed should the proposed maximum quantities of 120 MW be approved and if that maximum quantity was enabled peak times during 2023.

Consistent with AEMO's annual reports, not all of the incidents where Backup LFAS was enabled represent LFAS shortfalls. Around half of the Dispatch Advisories (56%) indicated the reason for enabling Backup LFAS was driven by issues such as outages or communication problems that resulted in an LFAS provider being unable to have their LFAS offer dispatched (referred to as "other issue" in Figure 1 below). The requirements are driven by variable wind and solar including non-dispatchable rooftop solar (referred to as "system volatility" in Figure 1 below) represented around 44% of the Dispatch Advisories and typically involved higher quantities of Backup LFAS being enabled.

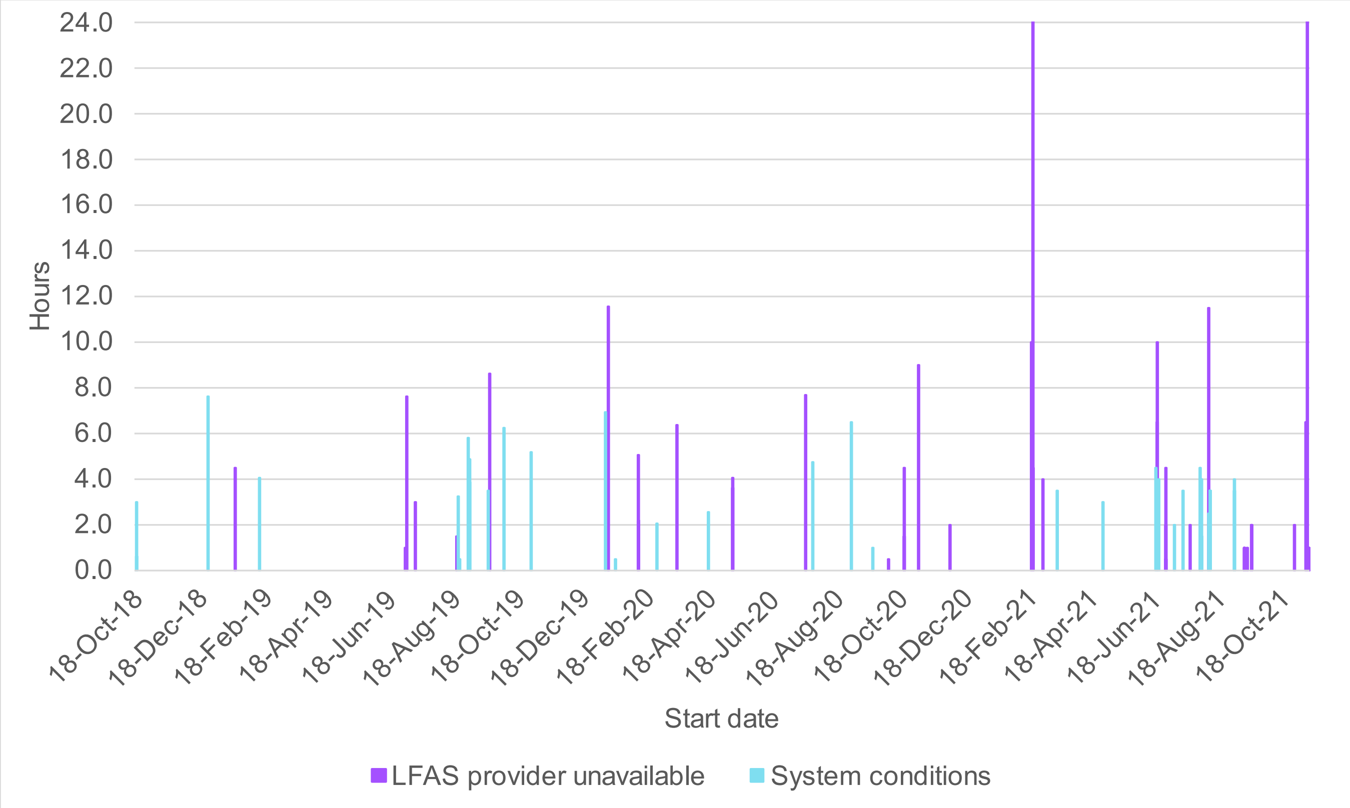
Figure 1 Use of Backup LFAS



Source: GHD analysis of Dispatch Advisory notices available from **http://data.wa.aemo.com.au/**
Note: Analysis required reading the details of each notice (a manual input for controllers) and classifying the information. The data presented in the figure represents information from 71 Dispatch Advisories and excludes 6 Dispatch Advisories where the quantity of Backup LFAS was not detailed.

The majority of Dispatch Advisories (97%) involved enabling Backup LFAS for less than 12 hours. Excluding two signficant instances[5], Backup LFAS enabled due to an LFAS provider being unavailable lasted, on average, just under 4 hours (3.95 hours). Backup enabled due to system volatility lasted, on average, just over 3 and a half hours (3.64 hours).

Figure 2 Duration of Backup LFAS use



Source: GHD analysis of Dispatch Advisory notices available from **http://data.wa.aemo.com.au/**
Note: Analysis required reading the details of each notice (a manual input for controllers) and classifying the information. The data presented in the figure represents information from 71 Dispatch Advisories and excludes 6 Dispatch Advisories where the quantity of Backup LFAS was not detailed.

It is also noted that the number of Dispatch Advisories related to Backup LFAS has increased over the analysis period and this has been driven by both types of Backup LFAS interventions (Table 4).

Table 4 Dispatch Advisories related to Backup LFAS

	2018	2019	2020	2021
System volatility	3	9	8	14
Other issue	1	5	14	23
Total	**4**	**14**	**22**	**37**

2.1 Risks of underspecifying LFAS

As discussed above, LFAS assists to maintain system frequency within specified bands. If procured LFAS becomes unavailable, or if the procured amount is insufficient then Backup LFAS is called upon.

In the WEM, there are several mechanisms that assist AEMO to control frequency. In particular, LFAS and mandatory primary frequency responses complement each other and assist to control system frequency under normal operating conditions (i.e., no contingency event) so that the system frequency does not deviate significantly from 50 Hz. AEMO may also re-dispatch the state-owned Synergy generating fleet's Balancing Portfolio more

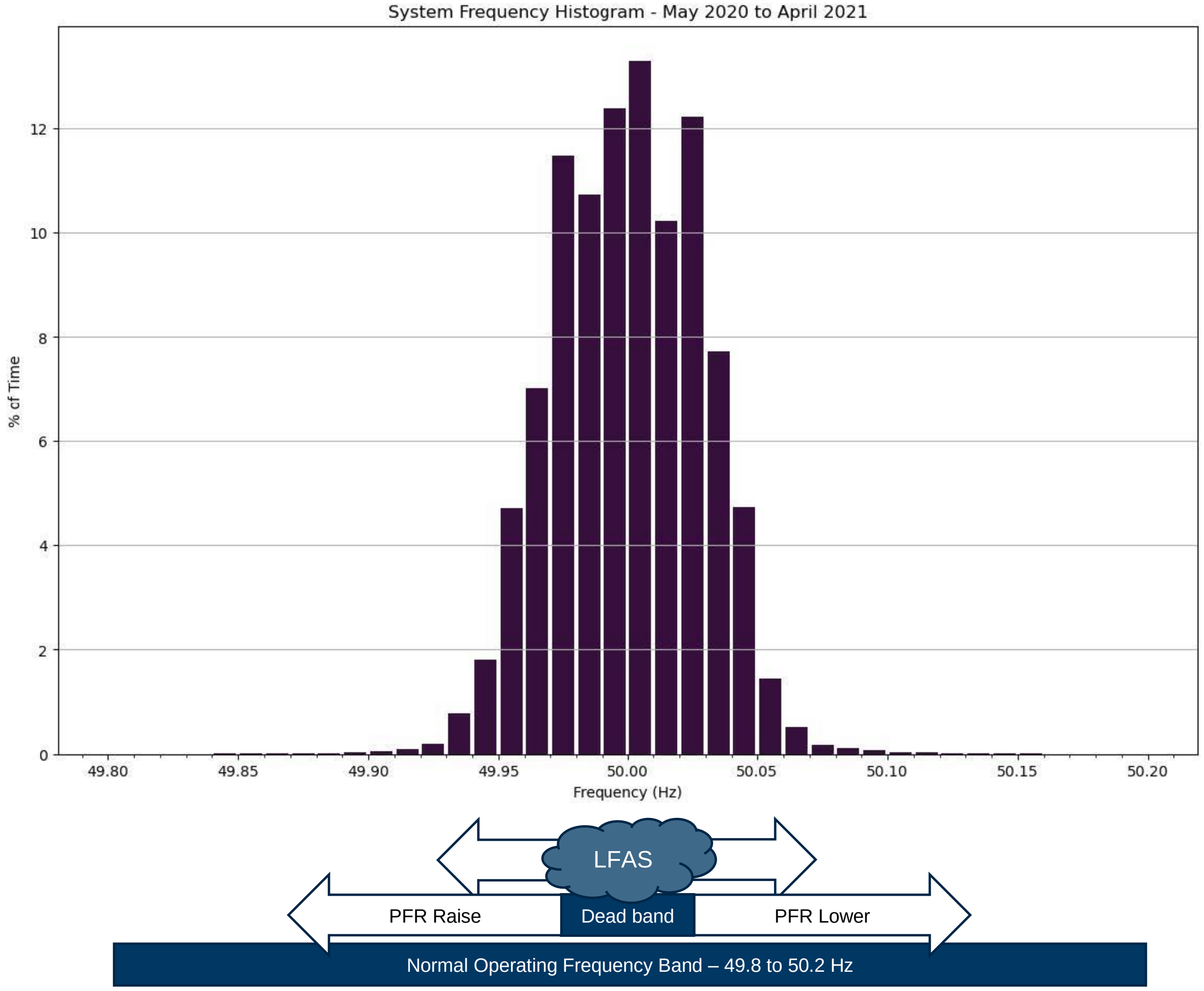
[5] Two instances of Backup LFAS enablement due to LFAS providers being unavailable have been excluded from averages and the below chart – one lastest for 27 hours and the second was for 1,417 hours.

frequently than the 10-minute market dispatch interval as a means of managing imbalancing in supply and demand.

LFAS is dispatched using Automatic Generation Control (AGC). The AGC systems send raise and lower pulses to LFAS service providers if AEMO detects that the system is moving away from 50 Hz. If system frequency were to drift further from 50 Hz generators would also start to provide frequency response consistent with the mandatory Primary Frequency Response (PFR) requirements specified in the Western Power Technical Rules[6]. The PFR assists to arrest any frequency drift. As such, PFR would function to ensure that frequency remains within acceptable bounds should LFAS be unavailable or restricted.

The benefit of LFAS is that it maintains a system frequency closer to 50 Hz than that which would be achieved if only PFR was relied upon and maintains a greater PFR capability to respond to contingency events. Hypothetically, if LFAS did not exist then mandatory PFR should ensure that an acceptable system frequency is maintained. However, the AGC mechanisms used for LFAS complement the control action provided by PFR response and, as evidenced from experience in the NEM (discussed in section 6.3.2 of this report) relying on just LFAS, frequency drift would be wider and more frequent. In short, LFAS complemented by mandatory PFR provides more effective frequency regulation.

Figure 3 ***Frequency performance of the SWIS from May 2020 to April 2021 with frequency response bands***



Source: AEMO, Ancillary Services Report for the WEM, June 2021. Supporting notes added by GHD based on the WEM Rules and Western Power Technical Rule requirements.

[6] Clause 3.3.4.4.(d) of the Technical Rules sets out the maximum 'dead band' for generators connected to the Western Power network. Consistent with this requirement, the sum of increase and decrease in power system frequency before a measurable change in the generating unit's active power output occurs must be less than 0.05 Hz.

Figure 3 illustrates the operating range of the discussed services. LFAS is illustrated as a cloud as it does not operate within a strictly specified band. Importantly, LFAS works by providing for an enabled quantity of service to be available, where that quantity would be used only when needed to counteract the effect of variations in load and generation.

Please note that, as detailed in section 1.1, the purpose of this report is to support the ERA in considering AEMO's 2022/23 Ancillary Service requirements by comparing LRAS in the WEM to other select jurisdictions. Figure 3 and Table 5 are both simplified for this illustration and are not intended to form a comprehensive commentary on ancillary service arrangements in the WEM. Clause references are provided for the reader's convenience should further information be required.

Table 5 Summary of frequency regulation bounds

Service	Frequency	Applicable Rules	Relevant Clause
Normal Operating Frequency Band	49.8 to 50.2 Hz	WEM Rules	Appendix 13
Load Following Ancillary Service Upwards	N/A	WEM Rules	7B
Load Following Ancillary Service Downwards	N/A	WEM Rules	
Primary Frequency Response Raise	>49.975 Hz	Western Power Technical Rules	3.3.4.4.(d) (dead band less than 0.05 Hz)
Primary Frequency Response Lower	<50.025 Hz	Western Power Technical Rules	

In the first instance, the effect of under specifying LFAS will be that Backup LFAS may be needed on a more frequent basis. If both LFAS *and* Backup LFAS are insufficient to counter variations in load or generation then the system frequency would drift until mandatory PFR mechanisms are sufficiently activated and work to arrest the frequency movement. That is, when all available LFAS is exceeded then mandatory PFR should keep the operating frequency within the bounds of the normal frequency operating band specified in the WEM Frequency Operating Standard[7]. LFAS serves to continually drive the frequency back to 50Hz. With insufficient LFAS the frequency is likely to spend a greater amount of time away from 50 Hz but still within the normal frequency operating band.

The key risk caused by system frequency being allowed to vary more widely within the normal frequency operating band is that if a contingent event were to subsequently occur then there is less 'spare room' for the system frequency to move before more extreme measures such as Under Frequency Load Shedding (UFLS) are required.

Spinning Reserve Ancillary Service (SRAS) and Load Rejection Response (LRR) are both contingency frequency control services. Unlike LFAS and Backup LFAS, which are used primarily in normal operating conditions, they provide the response required to arrest frequency changes following large disturbances such as that caused by the unexpected disconnection of significant levels of generation or load. The control systems on generators that provide PFR allow those same generators to provide SRAS and LRR. These two services would be activated in a contingency event before UFLS, which operates only after frequency falls beyond the lower limit of the credible contingency event frequency band (48.75 HZ). However, the initial frequency of the system will play a role in the effectiveness (or 'room' available) for SRAS or LRR to act before more extreme measures are enacted.

More detailed analysis is required to determine to what extent the risk of relying more on PFR and other mechanisms that control frequency, including under contingency circumstances, is prevalent at the quantities of LFAS and backup LFAS that AEMO proposes.

Based on our understanding of how the various frequency response mechanisms in the WEM function and the analysis of the quantities and reasons for enabling Backup LFAS, we have not found evidence to indicate that there would be a risk to power system security from continuing to rely on Backup LFAS as the primary mechanism for covering shortfalls in LFAS.

Considering that reforms to the energy market and to introduce a new Essential System Service framework are expected to be implemented within the next 1-2 years and that will alter the quantities of frequency regulation services required, continuing to rely on current LFAS, Backup LFAS and the PFR mechanisms as a means of controlling frequency during normal operating conditions appears reasonable. Based on our limited analysis, there does not appear to be sufficient use of small quantities of Backup LFAS to justify increasing the quantity of LFAS

[7] Specified in Appendix 13 of the WEM Rules

during peak times given that these higher quantities may be paid for by the market for all peak trading intervals, compared with Backup LFAS which is only paid for when it is enabled.

In considering more fully whether the LFAS requirement should be increased to reduce the need for Backup LFAS, consideration may be given to a broader set of factors, including:

- The marginal cost of procuring additional LFAS through the LFAS market compared with the marginal cost of using backup LFAS more often and enabling greater quantities of backup LFAS. This should also consider any impact greater utilisation of backup may have on the price offered by Synergy for this service. Synergy is the sole provider of backup LFAS whereas multiple providers can bid into the LFAS market.
- The small size of the market and the number of providers may be incentivised differently by the overall requirement and any overlap in the markets where the services are being provided by the same machines.
- AEMO costs and processes associated with procuring and enabling LFAS compared to Backup LFAS. For example, the extent to which interventions are manual versus automatic.
- Effects of future reforms (discussed below in section 2.2 below).

In the longer term and with the appropriate consideration of the above factors, it is likely to be more efficient to adjust the LFAS market design, including the maximum quantities enabled for specific time periods, to enable the automatic use of services and avoid manual interventions such as Backup LFAS.

Several of the jurisdictions analysed in the benchmarking studies use more sophisticated approaches to specifying requirements that enable requirements to match system needs more closely. For example, ERCOT specifies requirements based on the hour of the day and month of the year, resulting in 288 Reregulation-up quantities and 288 Regulation-down quantities specified for each calendar year. They also revisit these quantities as required during the year. Chile has also adopted an increasingly sophisticated approach to specifying quantities. In 2020 and 2021, they had specified static quantities of +/-120 MW and +/-130 MW for CSF for the entire year. By 2022, in response to the proportion of variable renewable generation reaching critical levels, their approach considers six periods throughout the day, distinguishes between autumn-winter and spring-summer times of the year and allows for the future specification of different requirements for working and non-working days.

Going forward, the adoption of a more sophisticated approach than the current peak and off-peak differential may be a means of reducing reliance on Backup LFAS. However, further analysis on the periods when LFAS and Backup LFAS have been required could be undertaken to support a future market that gives a more granular set of requirements than the current peak and off-peak periods.

2.2 Future reforms

Two future reforms, once implemented will alter the quantity of LFAS (or equivalent regulation service) required and the sources of these services:

- LFAS is procured from participants in the balancing market. Interruptible loads do not participate in the balancing market and are therefore excluded from providing LFAS. Under the new Essential System Service framework, Regulation replaces LFAS. This service can be provided by a generator, load, or Battery Energy Storage System (BESS) that can moderate its output in response to AGC commands. Hence, the range of technology permitted to offer this service will increase.
- The WEM currently operates with a 30 minute trading interval and there is a mechanism that allows the marginal generator to be re-dispatched on 10 minute cycles. Longer dispatch interval cycles lead to greater forecast errors than a comparatively shorter interval and therefore a higher requirement for regulation services. The adoption of a 5 minute dispatch cycle will improve the accuracy of forecasts and create an opportunity to reduce the required quantity of regulation services.

These reforms are currently expected to be implemented in October 2023. While our analysis does not cover the effect of the reforms on the quantity, the observations provide important context for understanding how long the current requirements may be affective for.

2.3 WEM data used in benchmarking

The Wholesale Electricity Market (WEM) operates across the South West Interconnected System (SWIS), which supplies electricity to over 1.1 million Western Australian households and businesses each year.

The SWIS, covering 260,000 km, includes 7,750 km of transmission and 93,350 km of distribution powerlines, owned and operated by Western Power.

There are currently 71 generation facilities registered in the WEM. Approximately 20 TWh of electricity is traded and used annually through the SWIS. Collectively, rooftop solar is the largest generator in the SWIS, with installations on one in three households. Commercial and residential solar is expected to reach an estimated 4,069 MW of installed capacity by 2030-31, providing around 45% of the total expected generation capacity.[8]

For the benchmarking exercise, the data in Table 6 for the WEM was used.

Table 6 Power system characteristics – WEM

<table>
<tr><th colspan="2">Characteristic</th><th>Value</th><th>Comment</th></tr>
<tr><td colspan="2">Dispatch interval</td><td>10 minutes</td><td>30 minute trading intervals with the opportunity for re-dispatch of the marginal generator at 10 minute cycles</td></tr>
<tr><td colspan="2">Peak demand</td><td>4,006 MW</td><td>8 February 2016</td></tr>
<tr><td colspan="2">Minimum demand</td><td>761 MW</td><td>14 November 2021</td></tr>
<tr><td colspan="2">LFAS upward</td><td>120 MW (5.30am to 8.30pm)
65 MW (8.30pm to 5.30am)</td><td>AEMO proposed values for 2022-23</td></tr>
<tr><td colspan="2">LFAS downward</td><td>120 MW (5.30am to 8.30pm)
65 MW (8.30pm to 5.30am)</td><td>AEMO proposed values for 2022-23</td></tr>
<tr><td rowspan="3">Annual (dispatchable) generation</td><td>Total</td><td>17,545 GWh</td><td rowspan="3">During 2020/21</td></tr>
<tr><td>Variable generation</td><td>5,060 GWh (28.8%)</td></tr>
<tr><td>Non-variable</td><td>12,485 GWh (71.2%)</td></tr>
<tr><td rowspan="3">Installed capacity</td><td>Total</td><td>6,066 MW</td><td rowspan="3">As of May 2022.</td></tr>
<tr><td>Variable generation</td><td>1,197 MW (19.7%)</td></tr>
<tr><td>Non-variable generation</td><td>4,869 MW (80.3%)</td></tr>
<tr><td rowspan="2">Non-dispatchable rooftop solar</td><td>Installed capacity</td><td>1,421 MW</td><td></td></tr>
<tr><td>Annual generation</td><td>1,984 GWh</td><td></td></tr>
</table>

Source: AEMO, Annual report 2020-2021, p. 9.

Table 7 Installed generation capacity – SWIS (2020)

Fuel type	Nameplate capacity (MW)	Proportion of total
Cogeneration	154	2.5%
Natural gas	2,942	48.3%
Black coal	1,569	25.8%
Distillate	132	2.2%
Waste	2	0.0%
Landfill gas	21	0.3%
Municipal waste	65	1.1%
Solar	188	3.1%

[8] AEMO, The Wholesale Electricity Market Factsheet, March 2022. Available at: **https://wa.aemo.com.au/-/media/files/electricity/wem/wholesale-electricity-market-fact-sheet.pdf?la=en&hash=ED1512DAF6230ABBA3008B1954AB46A5**

Fuel type	Nameplate capacity (MW)	Proportion of total
Wind	1,015	16.7%
All sources	**6,088**	**100.0%**

Source: Energy Policy WA, Whole of System Plan, Appendix B Model Inputs, 12 October 2020.

3. Coordinador Eléctrico Nacional, Chile

The Sistema Eléctrico Nacional (SEN) transmission grid in Chile is operated by the Coordinador Eléctrico Nacional (the Coordinador).

The SEN serves 98.5% of the population and the Coordinador manages 649 companies including generators, private transmission networks, distribution networks, energy storage facilities, and complimentary services.

While this system does have one large 345 kV AC interconnector with Argentina and several smaller unregulated interconnectors, these do not contribute to the frequency control of the system. Two smaller isolated systems (the Aisén and Magallanes systems at 64 MW and 107 MW, respectively) exist in Chile, but these are not relevant for this discussion.

The SEN is a larger network than the SWIS, with an installed capacity of almost 31 GW and a span covering 3,100 km. However, it was selected for comparison as there are some distinct similarities between the systems. Notable among these is that both systems are long and 'stringy', and both have rapid PV generation uptake.

Table 8 highlights relevant system characteristics.

Table 8 Power system characteristics – Coordinador Eléctrico Nacional

Characteristic		Value	Comment
Dispatch interval		60 minutes	While 1 hour dispatch intervals are used, these are determined a day in advance. See 3.2 for further detail.
Peak demand		11,303 MW	Monday, 27 December 2021. The peak demand has increased annually by an average of 235 MW per year since 2017.
Minimum demand		7,520 MWh/h	The hour commencing 7 am on 1 January 2022.
Regulation-up requirement (equivalent to LFAS upward)		Between 130 MW and 206 MW. Average 141 MW	Simplified and only considering the Coordinador's *Secondary* service. Refer to section 3.3 for context and Table 11 and Table 12 for further details.
Regulation-down requirement (equivalent to LFAS downward)		Between -174 MW and -130 MW. Average -134 MW	
Annual generation (net)	Total	81,492 GWh	Calendar year 2021
	Variable generation	17,997 GWh (22.1%)	Calendar year 2021
	Non-variable	63,495 GWh (77.9%)	Calendar year 2021
Installed capacity	Total	30,862 MW	Calendar year 2021
	Variable generation	9,734 MW (31.5%)	Calendar year 2021
	Non-variable generation	21,138 MW (68.5%)	Calendar year 2021
Non-dispatchable rooftop solar	Installed capacity	113.5 MW	As of March 2022.
	Annual generation	Unknown	

3.1 Generation mix

Presently, Chile's National Electric System has a highly diversified generation mix. This is illustrated in Table 9. Hydroelectric generation continues to hold the greatest portion of the generation mix. However, variable renewable generation, especially solar, is increasing rapidly which is contributing to increasing volatility in the network. By 2025 solar generation (transmission connected) is expected to form the single largest portion of installed capacity, at 28%. Wind-based generation is also growing at a slower, but still significant rate. The use of all fossil fuel-based generation is declining steadily.

Figure 4 Installed capacity by fuel type – CEN, Chile

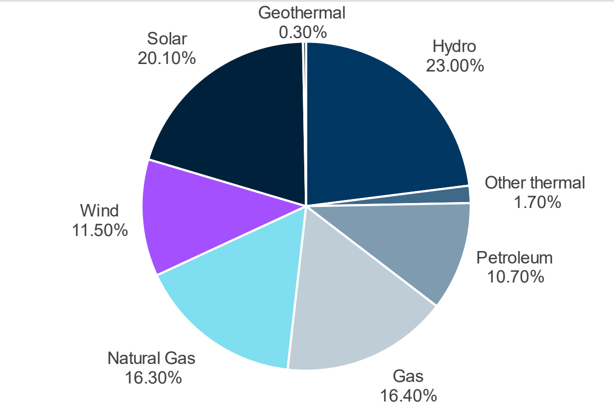


Figure 5 Output by fuel type – CEN, Chile

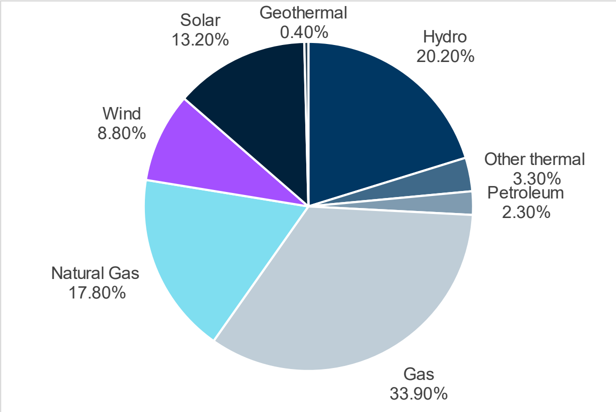


Table 9 Installed generation capacity – CEN, Chile

Primary fuel source	Installed capacity (MW)			Proportion of total nameplate capacity (%)		
	2019	2020	2021	2019	2020	2021
Hydro	6,827	6,814	7,113	27.1%	25.9%	23.0%
Other thermal	474	474	536	1.9%	1.8%	1.7%
Petroleum	2,797	3,030	3,306	11.1%	11.5%	10.7%
Gas	5,192	4,910	5,064	20.6%	18.7%	16.4%
Natural Gas	4,916	4,936	5,031	19.5%	18.8%	16.3%
Wind	2,162	2,527	3,536	8.6%	9.6%	11.5%
Solar	2,799	3,575	6,198	11.1%	13.6%	20.1%
Geothermal	45	45	78	0.2%	0.2%	0.3%
All Sources	**25,212**	**26,310**	**30,862**	**100.0%**	**100.0%**	**100.0%**

Source: Coordinador Eléctrico, National, Capacity and Power Generation for years 2019, and 2020, 2021[9]
Note: Installed capacity as of December each year.

Table 10 Generation produced by energy source – CEN, Chile

Primary fuel source	Generation produced (GWh)			Proportion of total generation produced (%)		
	2019	2020	2021	2019	2020	2021
Hydro	20,803	20,622	16,477	26.9%	26.6%	20.2%
Other thermal	2,254	2,265	2,682	2.9%	2.9%	3.3%
Petroleum	287	561	1,858	0.4%	0.7%	2.3%
Gas	28,372	27,014	27,666	36.7%	34.8%	33.9%

[9] Available at: Reports, Statistics and Frequently Used Platforms | National Electrical Coordinator (coordinador.cl)

Primary fuel source	Generation produced (GWh)			Proportion of total generation produced (%)		
	2019	2020	2021	2019	2020	2021
Natural Gas	14,218	13,791	14,487	18.4%	17.8%	17.8%
Wind	4,798	5,516	7,210	6.2%	7.1%	8.8%
Solar	6,287	7,617	10,787	8.1%	9.8%	13.2%
Geothermal	202	247	326	0.3%	0.3%	0.4%
All Sources	**77,221**	**77,634**	**81,492**	**100.0%**	**100.0%**	**100.0%**

Source: Coordinador Eléctrico, National, Capacity and Power Generation for years 2019, and 2020, 2021[10]
Note: Total generation for each calendar year.

3.2 Overview of frequency regulation services

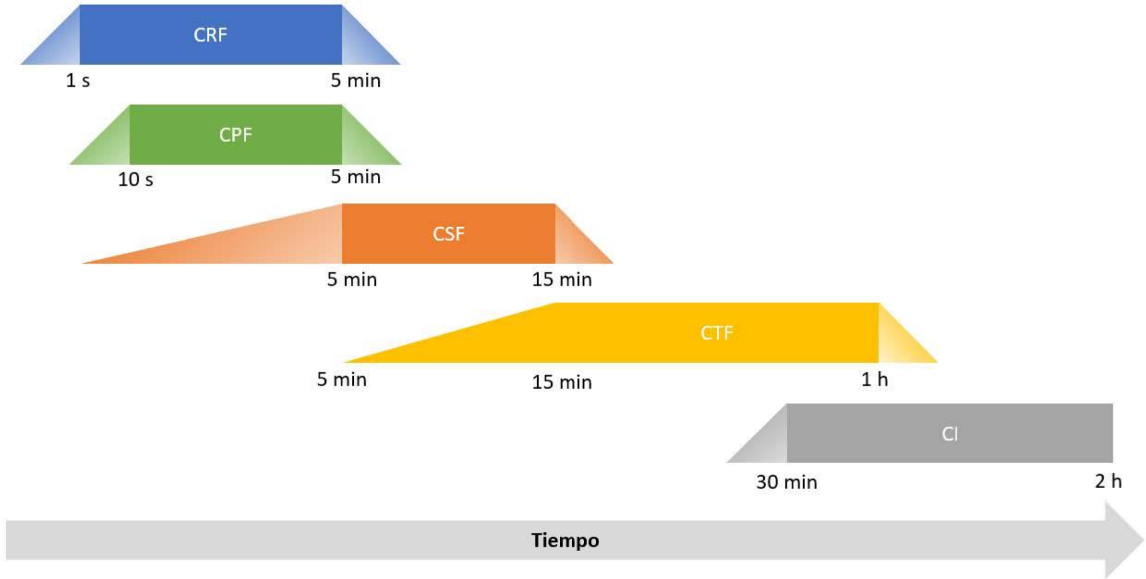
The Coordinador has five designated frequency related services.

- **Control Rápido de Frecuencia (CRF) is the *rapid* frequency response reserve.** CRF automatically responds to local triggers to counter frequency deviations in the system. This service forms a first-line response to stabilise the system when a contingency event occurs, and the full response must be achieved within one second of the frequency deviation occurring. CRF must contribute towards frequency stability for at least 5 minutes, by sustaining the response for that time. This response in the 1 second to 5 minute period.
- **Control Rápido de Frecuencia (CPF) is the *primary* frequency response reserve.** Like CRF, CPF (primary) frequency response service responds automatically to local triggers and is intended to stabilise the system following a contingency event. It must activate within 10 seconds of the frequency deviation occurring and must run for at least 5 minutes. This responds in the 10 seconds to 5 minute period.
- **Control Secundario de Frecuencia (CSF) is the *secondary* frequency response reserve**. These services aim to restore system frequency to its nominal range. This is deployed by the Coordinador's AGC system and generators are expected to ramp to achieve the target output within 5 minutes of receiving a control signal. Output must be able to be held for at least 15 minutes.
- **Control Rápido de Frecuencia (CTF) is the *tertiary* response reserve**. These services begin ramping with 5 minutes' notice to full capacity within 15 minutes and remain at that point for up to an hour. The services are deployed by the Coordinador during real-time operations. CTF supplements the CSF or incorporates additional reserves if it is anticipated that they will be required.
- **Cargas Interrumpibles (CI) is the *interruptible* load.** This service is a demand-side measure where predefined users or groups of users can be disconnected under the instruction of the Coordinador. The Coordinador must supply 30 minutes of notice and the user must be able to remain disconnected for 2 hours. Only one activation per day is allowed and there is a restriction on the total number of activations per year.

The time periods over which the services are used overlap. The relationship between the five services is illustrated in Figure 6.

[10] Available at: **Reports, Statistics and Frequently Used Platforms | National Electrical Coordinator (coordinador.cl)**

Figure 6 Frequency Control Schemes in Chile



Source: Coordinador Eléctrico Nacional, Informe de Servicios Complementarios Ano 2022, Figure 4-1, March 2022[11].

The CRF and CPF most closely align with the mandatory PFR in the WEM, SRAS and LRR. **Together, the Secondary (CSF) and Tertiary (CTF) services are most equivalent to LFAS and Backup LFAS in the WEM**.

The Coordinador determines and publishes the ancillary services requirements (or complimentary services) annually and occasionally supplements this with a mid-year update. In both 2021 and 2022, there have been supplementary mid-year updates to the requirements as the Coordinador refines the quantities required and the approach adopted for specifying services (including allowing for more dynamic requirements) in response to the increasing variable renewable generation on the system.

3.3 LFAS-equivalent requirements

The frequency control and regulation services in Chile are intended to compensate for any deviations between the actual and forecast generation dispatch. The energy market dispatch is determined for each hour with a day-ahead market used to optimise the utilisation of hydro-electric generation and set the merit order for the real-time energy market dispatch. The set of services described above must be capable of addressing deviations between expected and actual load and generation that occur between energy market dispatch intervals each one hour apart.

For 2022, the Coordinador determined the CSF requirement for six daily blocks with a separated frequency raise and lower requirement and different requirements for the autumn to winter period and the spring to the summer period. The Coordinador also allowed for different requirements to be established for working and non-working days (referred to as labour and non-labour days in the below tables). We understand from discussions with representatives at the Coordinador that the ability to distinguish between working and non-working days is a new development that recognises differences in the load patterns for these days. The quantities for 2022 are current the same across the two types of days, as such there are currently 12 different raise services and 12 different lower services specified. The CSF requirements for 2022 are detailed in Table 11.

Similar to the requirements for CSF, the requirements for CTF for 2022, are more nuanced than those adopted in the WEM for LFAS. For 2022, the Coordinador specified requirements based on the time of day, the season of the year and with reference to working and non-working days. Unlike for CSF, the distinction between working and non-working days results in different quantities required for CTF. As such there are 24 different raise services and 24 different lower services specified. The CTF requirements are detailed in Table 12.

[11] Refer to: **https://www.coordinador.cl/wp-content/uploads/2022/04/2022.03.11-Informe_SSCC_2022.pdf**

Table 11 CSF requirements, 2022 (WM)

Block	Autumn-Winter				Spring-Summer			
	Labour days		Non-labour days		Labour days		Non-labour days	
	Lower	Raise	Lower	Raise	Lower	Raise	Lower	Raise
Block 1 (Night 1) 22:00 to 1:59	-130	130	-130	130	-130	130	-130	130
Block (Night 2) 02:00 to 6:59	-130	130	-130	130	-130	130	-130	130
Block 3 (Sunrise) 07:00 to 9:59	-174	130	-174	130	-155	130	-155	130
Block 4 (Morning) Autumn-Winter: 10:00 - 15:59 Spring-Summer: 10:00 - 16:59	-130	130	-130	130	-130	130	-130	130
Block 5 (afternoon) Autumn-winter: 16:00 - 18:59 Spring-Summer: 17:00 - 19:59	-130	206	-130	206	-130	190	-130	190
Block 6 (sunset) Autumn-Winter: 19:00 - 21:59 Spring-Summer: 20:00 - 21:59	-130	153	-130	153	-130	146	-130	146

Source: Coordinador Eléctrico Nacional, Informe de Servicios Complementarios 2022, Reservas requeridas para CSF, March 2022, p. 33, Tabla 5-7[12]

Table 12 CTF requirements, 2022 (MW)

Block	Autumn-Winter				Spring-Summer			
	Labour days		Non-labour days		Labour days		Non-labour days	
	Lower	Raise	Lower	Raise	Lower	Raise	Lower	Raise
Block 1 (Night 1) 22:00 to 1:59	-175	154	-202	145	-146	162	-134	194
Block (Night 2) 02:00 to 6:59	-54	68	-68	36	-42	78	-87	63
Block 3 (Sunrise) 07:00 to 9:59	-253	300	-250	267	-228	314	-230	326
Block 4 (Morning) Autumn-Winter: 10:00 - 15:59 Spring-Summer: 10:00 - 16:59	-211	85	-195	96	-139	54	-123	48
Block 5 (afternoon) Autumn-winter: 16:00 - 18:59 Spring-Summer: 17:00 - 19:59	-317	268	-298	299	-307	179	-334	178
Block 6 (sunset) Autumn-Winter: 19:00 - 21:59 Spring-Summer: 20:00 - 21:59	-102	183	-139	164	-40	210	-56	233

Source: Coordinador Eléctrico Nacional, Informe de Servicios Complementarios 2022, Reservas requeridas para CSF, March 2022, p. 34, Tabla 5-9[13]

Several periodic variations to this schedule are assigned for days with known demand-side variability.

[12] Available at: **https://www.coordinador.cl/wp-content/uploads/2022/04/2022.03.11-Informe_SSCC_2022.pdf**
[13] Available at: **https://www.coordinador.cl/wp-content/uploads/2022/04/2022.03.11-Informe_SSCC_2022.pdf**

3.4 Trends and observations

Chile, like Western Australia, is experiencing strong growth in PV generation. However, unlike in the WEM, this growth has come from both large-scale solar installations as well as residential rooftop PV, whereas in the WEM there is less large-scale solar.

The location of Chile's large-scale solar, predominately in the north part of the country where there is a desert-like climate and few cloud-cover events, and the extreme north-south geography of the SEN means the frequency reserve requirements are very driven by the effect of sunrise and sunset. This compares to the WEM where cloud-cover events that can occur at any point during daylight hours are the more significant concern.

As noted in 3.2, dispatch intervals for the SEN are 60-minutes, which is longer than the WEM's 10 minute dispatch interval. All other things being equal, this leads to a proportionally higher requirement for frequency regulation services.

Discussions with the Coordinador revealed that the frequency control scheme for the SEN has rapidly evolved over the last three years as the proportion of renewable generation reached levels where a changed response was required. The approach has become much more sophisticated. For example:

- In 2020, the CSF service had a fixed reserve consisting of -120 MW lower and 120 MW raise. In 2021, this was increased to -130 and 130 MW respectively. And in 2022, the requirement progressed to the six-period scheme seen in Table 11 with differing raise and lower components and a peak requirement of 206 MW of regulation raise.
- Similarly, the CTF services have evolved from a four-period requirement in 2020 and 2021 to the six-period requirement used in 2022.

Table 13 Maximum and minimum CSF and CTR lower and raise requirements 2020 to 2022 - SEN

	2020		2021		2022	
	Lower	Raise	Lower	Raise	Lower	Raise
CSF	-120 (all times)	120 (all times)	-130 (all times)	130 (all times)	-174 (sunrise, autumn-winter)	206 (afternoon, autumn-winter)
CTF	-270 (sunset)	316 (sunset)	-293 (sunset)	305 (sunset)	-317 (afternoon, autumn-winter)	314 (sunrise, spring-summer)

The SEN has a tiered system of frequency control service as seen in Figure 6. As such, there is no direct equivalent to Backup LFAS. However, CTF may be employed should CST become depleted, so there is a similar supporting service. The SEN also has primary frequency response (CPF) requirements for generators, with the dead band requirements being specified for different technologies. For synchronous machines, a dead band of 25 mHz is required, which is tighter than the WEM.

As Chile is experiencing a drought and this has increased the value of water used in hydro-generation schemes, thermal generation is often being used instead. The ramp rate of these units is far less than that of hydro generators. This is exacerbating issues of frequency control and reserves are being employed frequently, despite the new more detailed 6-period scheme.

The highest requirement for frequency regulation is in the evening, around sunset. Frequency regulation is somewhat stretched into the night period compared with other jurisdictions due to user behaviour and because some commercial loads become active around midnight.

While not directly relevant to the benchmarking exercise, it is interesting that the current requirement for CI (interruptible demand) is zero. We understand from discussions with the Coordinador that they recently went out to the market to procure around 50 MW of this service. However, they did not receive any offers at the price levels determined by the regulator. This differs from other systems included in benchmarking such as Eskom in South Africa where active demand-side participation plays an important role in enabling the operator to manage the system and they have very little trouble procuring these services from the market.

4. ERCOT, Texas

The transmission grid that the Electric Reliability Council of Texas (ERCOT) independent system operator administers is located solely within the state of Texas and is not synchronously interconnected to the rest of the United States.

ERCOT manages the flow of electric power to more than 26 million Texas customers, or about 90% of the state's total electric demand. Every five minutes, ERCOT coordinates the electricity production from more than 710 generating resources that will make electricity to satisfy customer demand and manage the resulting flows of power across the more than 46,500 miles of transmission lines in the region.

Table 14 Power system characteristics – ERCOT

Characteristic		Value	Comment
Dispatch interval		5 minutes	
Peak demand		74,328 MW	13 August 2020. This is about 500 MW lower than the all-time peak demand on 12 August 2019.
Minimum demand		Unknown	
Regulation-up requirement (equivalent to LFAS upward)		Between 73 MW and 684 MW. Average of 359 MW.	The requirement is based on the hour of the day and the month of the year. As such, there are 288 Regulation-up quantitates specified for 2022. Minimum: 73 MW is for 11pm to 12am in August Maximum: 684 is for 7am to 8am in March
Regulation-down requirement (equivalent to LFAS downward)		Between 151 MW and 631 MW. Average of 348 MW.	The requirement is set based on the hour of the day and the month of the year. As such, there are 288 Regulation-down quantitates specified for 2022. Minimum: 151 MW is for 6am to 7am in August Maximum: 631 MW is for 11am to 12pm in May
Annual (dispatchable) generation	Total	473.5 TWh	Calendar year 2020
	Variable generation	9.5 TWh (2%)	Calendar year 2020
	Non-variable	464 TWh (98%)	Calendar year 2020
Installed (dispatchable) capacity	Total	138,894 MW	Calendar year 2020
	Variable generation	34,988 MW (25%)	Calendar year 2020
	Non-variable generation	103,906 MW (75%)	Calendar year 2020
Non-dispatchable rooftop solar	Installed capacity	990 MW	December 2020[14]
	Annual generation	Unknown	

[14] Source: ERCOT Capacity, Demand and Reserves Report December 2020, Rooftop Solar Scenarios worksheet tab. See also ERCOT SAWG meeting supporting documents, 18 May 2021, updated rooftop solar growth projections https://www.ercot.com/files/docs/2021/05/18/SAWG__Meeting_5-18-2021_Updated_Rooftop_Solar_Growth_Projectionsv3.pptx

4.1 Generation mix

In recent years, ERCOT has seen an increase in installed wind and solar generation, which has replaced coal and, to a lesser extent natural gas.

Figure 7 Installed capacity by fuel type – ERCOT

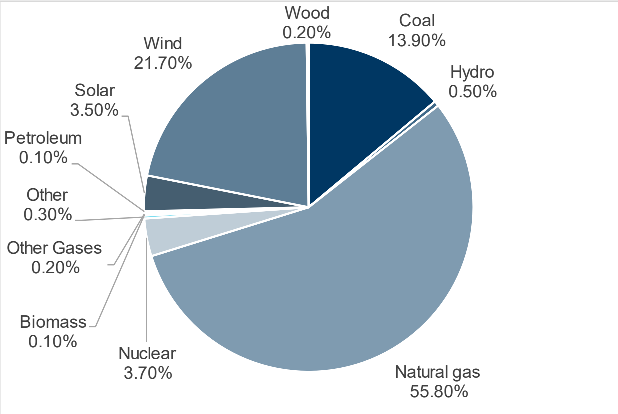


Figure 8 Output by fuel type – ERCOT

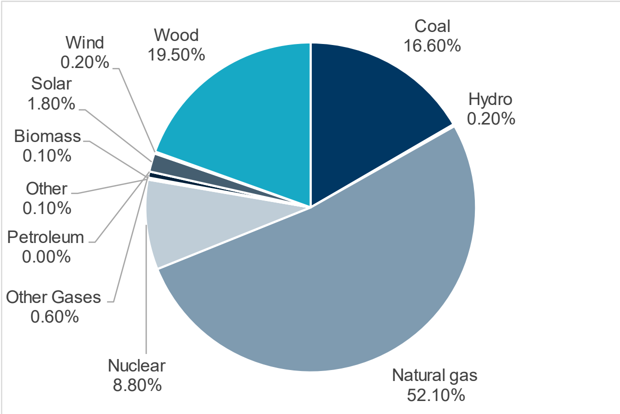


Table 15 Installed generation capacity - ERCOT

Fuel Source	Nameplate capacity (MW)					Proportion of total nameplate capacity (%)				
	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020
Coal	24,862	24,862	20,444	19,990	19,270	19.3%	18.6%	15.4%	14.8%	13.9%
Hydroelectric	709	709	709	708	737	0.6%	0.5%	0.5%	0.5%	0.5%
Natural Gas	76,033	78,244	78,849	77,708	77,460	59.1%	58.4%	59.4%	57.4%	55.8%
Nuclear	5,139	5,139	5,139	5,139	5,139	4.0%	3.8%	3.9%	3.8%	3.7%
Other	297	323	344	349	458	0.2%	0.2%	0.3%	0.3%	0.3%
Other Biomass	125	121	109	97	83	0.1%	0.1%	0.1%	0.1%	0.1%
Other Gases	277	277	474	480	304	0.2%	0.2%	0.4%	0.4%	0.2%
Petroleum	123	117	118	115	115	0.1%	0.1%	0.1%	0.1%	0.1%
Solar Thermal and Photovoltaic	585	1,235	1,943	2,444	4,880	0.5%	0.9%	1.5%	1.8%	3.5%
Wind	20,188	22,583	24,187	28,064	30,108	15.7%	16.9%	18.2%	20.7%	21.7%
Wood and Wood Derived Fuels	340	340	340	340	340	0.3%	0.3%	0.3%	0.3%	0.2%
All Sources	**128,676**	**133,948**	**132,655**	**135,433**	**138,894**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Source: US Energy Information Administration, data as of November 2021, refer to data available at: **Detailed State Data (eia.gov)**

Table 16 Generation produced by energy source -ERCOT

Fuel Source	Generation produced (TWh)					Proportion of total generation (%)				
	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020
Coal	121	135	112	92	79	26.7%	29.7%	23.4%	19.0%	16.6%
Hydroelectric	1	1	1	1	1	0.3%	0.2%	0.2%	0.3%	0.2%
Natural Gas	226	205	240	256	247	49.8%	45.2%	50.2%	52.9%	52.1%
Nuclear	42	39	41	41	41	9.3%	8.5%	8.6%	8.5%	8.8%

Fuel Source	Generation produced (TWh)					Proportion of total generation (%)				
	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020
Other	1	1	0	1	0	0.2%	0.1%	0.1%	0.1%	0.1%
Other Biomass	1	1	1	0	0	0.2%	0.1%	0.1%	0.1%	0.1%
Other Gases	3	2	3	3	3	0.6%	0.5%	0.5%	0.6%	0.6%
Petroleum	0	0	0	0	0	0.0%	0.0%	0.0%	0.0%	0.0%
Solar Thermal and Photovoltaic	1	2	3	4	9	0.2%	0.5%	0.7%	0.9%	1.8%
Wind	1	1	1	1	1	0.2%	0.2%	0.2%	0.2%	0.2%
Wood and Wood Derived Fuels	58	67	76	84	92	12.7%	14.8%	15.9%	17.3%	19.5%
All Sources	**454**	**453**	**477**	**483**	**474**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Source: US Energy Information Administration, data as of February 2022, refer to data available at: **Detailed State Data (eia.gov)**

4.2 Overview of frequency regulation services

There are three day-ahead ancillary services markets that support frequency regulation in the ERCOT region:

- **Regulation Service** – Regulation Service consists of resources that can be deployed by ERCOT in response to changes in ERCOT System frequency to maintain the target ERCOT System frequency within predetermined limits according to the Operating Guides. With these regulation services, ERCOT sends a signal to generators every few seconds to increase or decrease their output.

  This service is automatically deployed in Real-Time Operations by ERCOT’s Energy Management System every four seconds as needed to maintain system frequency within a desired range of around 60 Hz. There are two types of Regulation Services:
  - Regulation up, and
  - Regulation down
- **Non-Spinning Reserve** - Non-Spinning Reserve (Non-Spin) consists of Generation Resources capable of being ramped to a specified output level within 30 minutes or Load Resources that are capable of being interrupted within 30 minutes and that are capable of running (or being interrupted) at a specified output level for at least one hour.
- **Responsive Reserve** – Responsive Reserve is a form of under frequency load shedding and is used for maintaining system frequency at 60 Hz. Load resources providing responsive reserves have relay equipment that enables the load to be automatically tripped when the system frequency falls below 59.7 Hz (when demand exceeds supply).

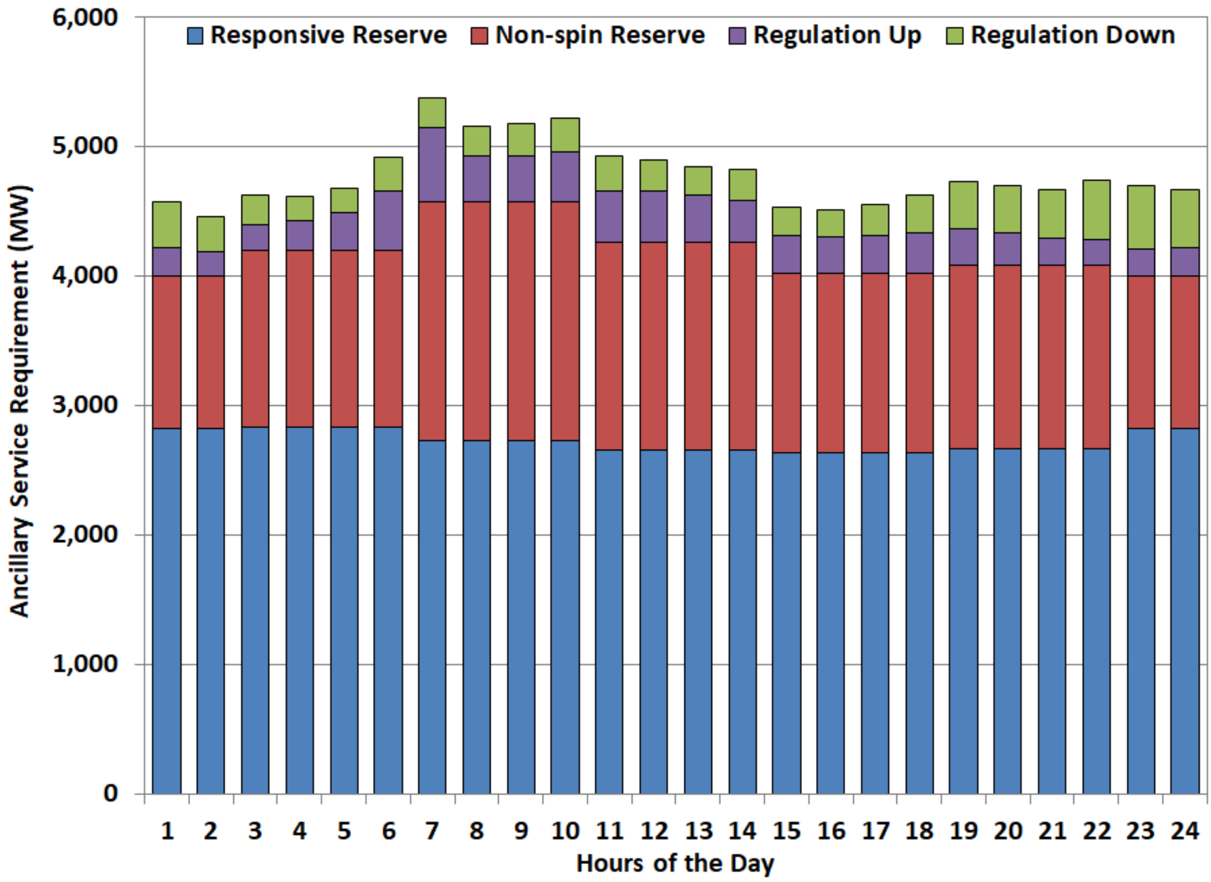
The regulation up and down services are equivalent to LFAS and backup LFAS services in the WEM.

In accordance with ERCOT’s annually updated procedure[15], the requirements of the ancillary services are determined annually and published on 20 December each year for the following year. If necessary, incremental adjustments may be made and must be posted by the 20th of each month for the upcoming month.

In addition, if the ancillary service requirements are found to be insufficient for a particular operating day, ERCOT may make updated requirements for the day if the need is identified a day ahead and make use of the Supplemental Ancillary Service Market process for adjustments made closer to Real-Time.

[15] ERCOT Methodologies for Determining Minimum Ancillary Service Requirements, Effective Date 1/1/2022

Figure 9 Yearly average ancillary service capacity by hour



Source: Potomac Economics[16], 2020 State of the Market Report for the ERCOT Electricity Markets, May 2021, Figure A23, p. A-28

4.3 LFAS equivalent requirements

ERCOT defines its ancillary service requirements based on the time of day and the month of the year. The result is a highly nuanced specification for each service. Figure 10 and Figure 11 (overleaf) show the requirements for 2022. Coloured data bars overlay the quantities to aid with the interpretation of the data.

For Regulation Up Services, we observe:

- The requirement ranges from a minimum of 73 MW from 10 pm to 11 pm in August (late-summer) to a maximum requirement of 684 MW from 7 am to 8 am in February (late winter).
- The highest requirements are around sunrise (the 6 am and 7 am hours) throughout the year and in the middle of the day (10 am through to around 2 pm) around the warmer months (May through October). There is also a noticeable trend of higher requirements for the 5 pm and 6 pm hours (likely driven by load changes business close and residential demand increases given that sunset in Texas is after this period).
- The requirements appear to be the lowest overnight, which may suggest a correlation with any variable solar generation being offline but also the nature of load on the system during this time.

For Regulation Down Services, we observe:

- The requirement ranges from a minimum of 151 MW from 6 am to 7 am in August (late-summer) to a maximum requirement of 631 MW from 11 am to 12 pm in May (early summer).
- The highest requirements are around mid-morning (the 9 am and 10 am hours) and in the late evening (10 pm and 11 pm). Colder months (February to May) typically have higher requirements.
- The requirement appears lowest in the very early hours of the morning each day (2 am to 8 am) when people are likely sleeping.

[16] Potomac Economics fulfils the independent market monitor reporting role for ERCOT on behalf of the Public Utilities Commission of Texas.

4.4 Trends and observations

The quantification of the required amount of Regulation Service has evolved over time. In particular, the average hourly quantity of Regulation Service required gradually decreased from ~580 MW in late 2010, when the five-minute dispatch market was first implemented, to ~300 MW in 2017. Commentary suggests the historical reductions have primarily been due to the continuing refinement in determining the required amount of Regulation Service and note that the decrease in Regulation Service requirements occurred even though the installed capacity of wind generation on the ERCOT grid had risen from 9,400 MW in January 2011 to over 21,000 MW in 2018, meaning the refinement in determining the required quantities has offset increased variability from wind generation[17].

In more recent years, the minimum Regulation Up quantity has declined from 176 MW in 2017 to 73 MW in 2022, while the average quantity required for this service has increased by 42 MW. The average quantity of Regulation Down has also increased over the period, suggesting the system is generally experiencing increased volatility. Factors that help offset the requirement for increased frequency regulation despite increasing volatility are that new renewable resources are geographically dispersed, variable renewable generation and dispatchable loads must comply with a 5-minute ramp, and governor-response requirements are mandatory for all online resources. The minimum quantity for this service has remained fairly stable over the analysis period.

Table 17 Historical maximum, minimum and average regulation services - ERCOT

	2017	2018	2019	2020	2021	2022
Regulation Down						
Minimum	156	156	148	138	137	151
Maximum	626	604	604	617	588	631
Average	295	293	289	287	329	348
Regulation Up						
Minimum	176	157	142	119	109	73
Maximum	693	687	669	710	732	684
Average	318	312	310	303	342	359

[17] Energy Systems Integration Group, 'ERCOT Regulation Service', 30 July 2018, refer to: **ERCOT Regulation Service - ESIG**

Figure 10 ***ERCOT - Regulation up requirements for 2022***

HE	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	233	229	302	215	200	251	191	202	212	203	205	191
2	194	208	254	197	266	170	148	131	168	168	225	230
3	222	248	233	197	257	219	171	155	185	163	212	214
4	268	265	260	261	267	267	205	191	186	212	259	249
5	373	384	309	274	288	277	249	259	244	258	326	335
6	534	539	447	400	363	366	319	322	368	374	443	476
7	654	684	533	520	511	435	390	427	472	526	579	590
8	393	371	401	317	357	408	350	307	288	356	323	373
9	312	382	358	366	404	432	369	437	314	333	358	340
10	357	381	450	457	502	568	570	542	425	450	348	382
11	340	356	455	412	580	629	618	675	552	476	349	428
12	378	374	435	468	565	607	631	667	597	518	352	379
13	334	451	482	467	535	552	546	599	575	489	366	346
14	320	416	457	468	511	492	498	539	526	447	348	375
15	346	424	442	473	486	455	437	481	465	414	373	392
16	436	455	453	472	491	402	410	436	469	435	380	507
17	563	549	564	481	503	378	389	399	443	396	624	681
18	676	622	549	510	417	370	382	379	397	516	564	679
19	367	514	590	534	454	398	310	346	385	544	392	260
20	187	241	512	481	445	348	367	290	273	262	178	238
21	242	255	253	313	304	245	304	257	149	216	161	187
22	179	182	211	279	471	219	117	73	154	152	160	215
23	181	244	296	174	239	259	177	121	185	150	177	181
24	204	164	217	225	171	178	93	112	190	172	152	165
Total	**8293**	**8938**	**9463**	**8961**	**9587**	**8925**	**8241**	**8347**	**8222**	**8230**	**7854**	**8413**

Source: ERCOT

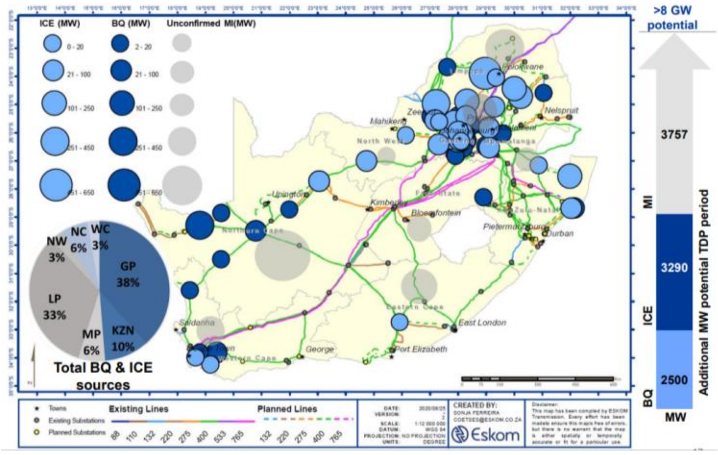
Figure 11 ***ERCOT - Regulation down requirements for 2022***

HE	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	270	297	392	363	425	424	443	421	390	357	298	277
2	220	259	268	295	331	355	348	308	298	275	216	237
3	213	252	262	241	246	314	264	268	253	219	178	185
4	204	194	230	229	227	221	226	224	188	209	174	181
5	200	302	233	210	230	189	183	173	196	192	206	194
6	269	522	303	257	304	214	192	151	214	264	248	308
7	243	306	263	236	263	245	262	171	163	174	234	230
8	270	359	391	292	319	236	164	188	208	211	381	281
9	503	549	477	394	468	304	283	267	295	366	497	542
10	510	540	596	489	442	364	250	294	324	392	350	437
11	480	504	505	403	631	241	158	543	583	305	354	399
12	417	486	442	416	395	213	245	234	592	322	334	376
13	397	503	456	406	386	222	179	278	270	306	320	352
14	374	498	449	372	361	345	233	299	255	270	355	344
15	403	466	447	419	345	307	260	327	300	311	372	359
16	343	425	427	455	388	338	341	301	423	321	318	347
17	272	409	437	450	415	378	371	408	362	413	279	331
18	245	376	399	412	489	432	458	442	419	401	204	223
19	284	319	339	431	490	481	510	484	400	319	312	339
20	278	340	328	371	418	373	383	389	361	425	358	283
21	325	323	390	408	402	337	375	471	500	489	329	311
22	374	366	419	456	526	528	508	589	522	432	341	347
23	383	380	426	470	547	557	564	579	517	442	372	372
24	328	337	401	446	473	519	506	515	479	424	337	373
Total	**7805**	**9312**	**9280**	**8921**	**9521**	**8137**	**7706**	**8324**	**8512**	**7839**	**7367**	**7628**

Source: ERCOT

5. Eskom, South Africa

Eskom is the state-owned and operated, and vertically integrated electricity provider in South Africa. The company is divided into Generation, Transmission and Distribution divisions. Eskom's generation division produces approximately 90% of the electricity used in South Africa.



The Eskom network consists of approximately 391,784 km of cables and power lines.

Eskom supplies and manages the flow of electric power to around 6.7 million direct customers (up from 5.6 million in 2017). It owns and operates 30 power stations with a nominal generating capacity of 45,117 MW.

Around 5% of electricity generation capacity is provided by Independent Power Producers. These are mostly solar and wind generator with 20-years Power Purchase Agreements to supply Eskom.

There are no wholesale or ancillary markets for energy in the Eskom region. However, Eskom is the system operator and dispatches generation (including IPPs) every 60 minutes.

Eskom is part of the South African Power Pool, through which it supplies power to 11 international customers. With a peak demand of around 35,001 MW, Eskom's size is an order of magnitude larger than all other power systems in the Pool. The next largest systems are Zambia (2,510 MW) and Zimbabwe (1,724 MW).[18]

Table 18 Power system characteristics – Eskom

Characteristic		Value	Comment
Dispatch interval		60 minutes	No energy market
Peak demand		35,000 MW	2020.
Minimum demand		Unknown	
Regulation-Up requirement (equivalent to LFAS upward)		530 MW	There are four requirements specified for 2022 that differentiate between summer and winter as well as peak and off-peak times. However, the requirement is the same across the four times for 2022.
Regulation-Down requirement (equivalent to LFAS downward)		530 MW	
Annual (dispatchable) generation	Total	214,926 GWh	Generation produced by Eskom and IPPs in 2021, excludes imported energy (8,812 GWh)
	Variable generation	14,983 (7.1%)	
	Non-variable	201,095 (92.9%)	
Installed (dispatchable) capacity	Total	51,866.7 MW	Installed capacity as of 1 December 2021. Eskom only data, excludes IPPs.
	Variable generation	161.4 MW (0.3%)	
	Non-variable generation	51,705.3 MW (99.7%)	
Non-dispatchable rooftop solar	Installed capacity	Unknown or 0 MW*	
	Annual generation	Unknown or 0 GWh*	

*While rooftop solar is apparent in South Africa, we understand from discussions with Eskom that domestic rooftop solar installations are not permitted to export to the power system and no government incentive is provided for the use of solar systems.

[18] South African Power Pool 2021 Annual Report, Available at: **https://www.sapp.co.zw/sites/default/files/Full%20Report%20SAPP.pdf**

5.1 Generation mix

As of 1 December 2021, Eskom's installed generation capacity (excluding IPPs) was just under 52,000 MW. The significant majority of installed capacity and also power generated was from the region's 15 coal-fired power stations. Variable renewable energy came from the Sere 100 MW wind farm and from 'other hydroelectric stations' which are non-dispatchable mini-hydro power stations.

The generation mix also includes two conventional hydroelectric power stations, three hydro pumped storage schemes and four non-dispatchable mini-hydro stations. These stations are used when there is a sudden increase, or peak, in the demand for electricity that cannot immediately be met by the base load stations. They have a combined installed capacity of 3,393.4 MW.[19]

Eskom generated 201,400 GWh in 2021, from the primary energy sources outlined in Table 20. Furthermore, IPPs supplied 13,526 GWh, with another 8,812 GWh being imported to supply customers.

The proportion of variable renewable installed generation capacity and generation produced remains very small compared to other power systems. Wind and non-dispatchable hydroelectricity accounts for less than 2% of installed capacity and represent less than 1% of the total energy produced.

Figure 12 Installed capacity by fuel type – Eskom

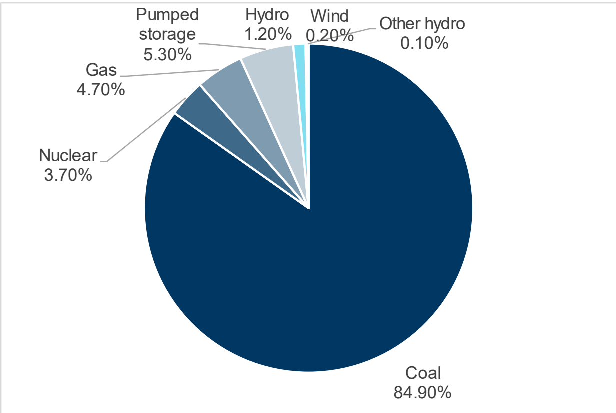


Figure 13 Output by fuel type – Eskom

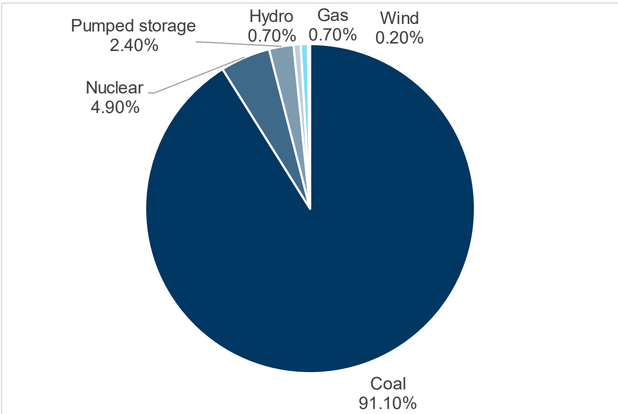


Table 19 Installed generation capacity – Eskom, 1 December 2021

Primary energy source	Total installed capacity (MW)	Proportion of total capacity
Coal-fired	44,013.0	84.9%
Nuclear	1,934.0	3.7%
Gas/liquid fuel turbine stations	2,426.3	4.7%
Pumped storage schemes	2732.0	5.3%
Hydroelectric stations	600.0	1.2%
Wind energy	100.0	0.2%
Other hydroelectric stations	61.4	0.1%
Total	**51,866.7**	**100.0%**

[19] Refer to: **https://www.eskom.co.za/wp-content/uploads/2022/03/GX-0001-Generation-Plant-Mix-Rev-25.docx.pdf**

Table 20 Generation produced by primary energy source - Eskom

Primary energy source	Generation produced (GWh)		Proportion of total generation	
	2020	2021	2021	2020
Coal-fired stations	194,357	183,553	90.4%	91.1%
Nuclear power	13,252	9,903	6.2%	4.9%
Pumped storage stations	5,060	4,795	2.4%	2.4%
Hydroelectric stations	688	1,387	0.3%	0.7%
Open-cycle gas turbines (OCGTs)	1,328	1,457	0.6%	0.7%
Wind	283	305	0.1%	0.2%
Total	**214,968**	**201,400**	**100.0%**	**100.0%**

Source: Eskom, Integrated Report, 31 March 2021, p. 6.[20]

5.2 Overview of frequency regulation services

Eskom procures the following ancillary services relevant to frequency regulation:

– **Instantaneous reserve** - Generating capacity or demand-side managed load that must be fully available within 10 seconds to arrest a frequency excursion outside the frequency dead-band. This reserve response must be sustained for at least 10 minutes. It is needed to arrest the frequency at an acceptable level following a contingency, such as a generator trip, or a sudden surge in load. Generators contracted for instantaneous reserve are also expected to respond to high frequencies (above 50.15 Hz) as stipulated in the South African Grid Code.

– **Regulating reserve** is generating capacity or demand-side managed load that is available to respond within 10 seconds and is fully activated within 10 minutes. The purpose of this reserve is to make enough capacity available to maintain the frequency close to the scheduled frequency and keep tie line flows between control areas within schedule. Regulating reserve capacity (regulating up + regulating down) is determined by AGC high and low limits set at the generator or demand-side managed load, as such there are two types of Regulating reserve:

  - Regulating up
  - Regulating down

– **Ten-minute reserve** - Ten minute reserve is generating capacity or demand-side managed load that can respond within 10 minutes when called upon. It may consist of offline quick start generating plant (e.g. hydro or pumped storage) or demand-side load that can be dispatched within 10 minutes. The purpose of this reserve is to restore Instantaneous and Regulating reserve to the required levels after an incident.

– **Emergency reserve** - Emergency reserves include interruptible loads, generator emergency capacity, and gas turbine capacity. The reserves should be fully activated within 10 minutes under the direct control of the National Control. Emergency reserve capacity is required less often than Ten minute reserve. These requirements arise from the need to take quick action when any abnormality arises in the system.

– **Supplementary reserve** - Supplemental reserve is generating or demand-side load that can respond in 6 hours or less to restore operating reserves. This reserve must be available for at least 2 hours. This capacity is used to ensure an acceptable day-ahead risk.

The Regulating Reserve ancillary service is equivalent to LFAS and backup LFAS services in the WEM.

Eskom (in it's capacity as the System Operator) develops and publishes the Ancillary Services Technical Requirement report annually. The report sets out the technical requirements and quantities of ancillary services for the following financial year for contracting purposes. The report also gives a forward-looking project of the requirements for the upcoming 5-year time horizon.

[20] Available at: **https://www.eskom.co.za/wp-content/uploads/2021/08/2021IntegratedReport.pdf**

Historically, the approach to determining the Reserve requirements has been deterministic. However, for the last two or three years, the approach has considered load and renewable generation variations to develop an expected generation/load and any residual load profile to be solved for.

5.3 LFAS-equivalent requirements

The minimum Regulating Reserve requirements, taking load variation and renewable energy unpredictability into consideration for 2022/23 to 2026/27, are given in Table 21. The method adopted for specifying the requirements enables different quantities to be established for peak and off-peak times as well as summer and winter periods. However, the current requirements are consistent across the year.

Table 21 Regulating up and down reserve requirements

Reserve	Period	2022/23 MW	2023/24 MW	2024/25 MW	2025/26 MW	2026/27 MW
Regulating up	Summer (Pk/off pk)	530	545	560	575	600
	Winter (Pk/off pk)	530	545	560	575	600
Regulating down	Summer (Pk/off pk)	530	545	560	575	600
	Winter (Pk/off pk)	530	545	560	575	600

Source: Eskom, Ancillary Services Technical Requirements for 2022/23 – 2026/27, 30 November 2021, Table 2, p. 10

5.4 Trends and observations

The Reserve Requirements are currently primarily driven by load fluctuations, which is not surprising given the relatively low proportion of variable generation in the system compared with other power systems. Eskom also reflected they have not observed any significant trends in the requirement over time. However, they are aware it may be an emerging issue as the transition to renewables continues in the region. They noted:

- Large-scale solar is spread out geographically, predominately in the Southwest of the region (where the first of Eskom’s solar plants is being constructed), so changes in requirements driven by cloud cover events and sunrise/sunset have not emerged as an issue yet.
- The incentives for residential solar are not the same as in other regions and so they have not seen the large uptake in this observed elsewhere. However, they are observing that residential solar is being installed as an ‘off-grid’ solution in response to load shedding as an emerging trend.
- Wind generation is located in the north of the cape. They have observed an interesting phenomenon when cold fronts move through this northern region and then pass through to Johannesburg, a population and demand centre. As the front passes through the northern region, the proportion of generation coming from wind increases. When the front then moves lower towards Johannesburg, the proportion of wind generation drops at the same time as demand in that region increases in response to the front causing the temperature to drop.

Eskom (in its capacity as the System Operator) can, from a regulatory perspective, procure additional regulation services from other service providers. Eskom are looking at procuring more services from the Independent Power Producers (IPP) through Power Purchase Agreements (PPA) going forward.

Many of the generators that supply the required Regulation services are old and not well maintained. As such, Eskom can often be operating with less than the required quantities available. This ongoing performance issue is well known and difficult to manage. As a consequence, the frequency in the Eskom power system can ‘wobble’ more than it would otherwise or compared to other power systems.

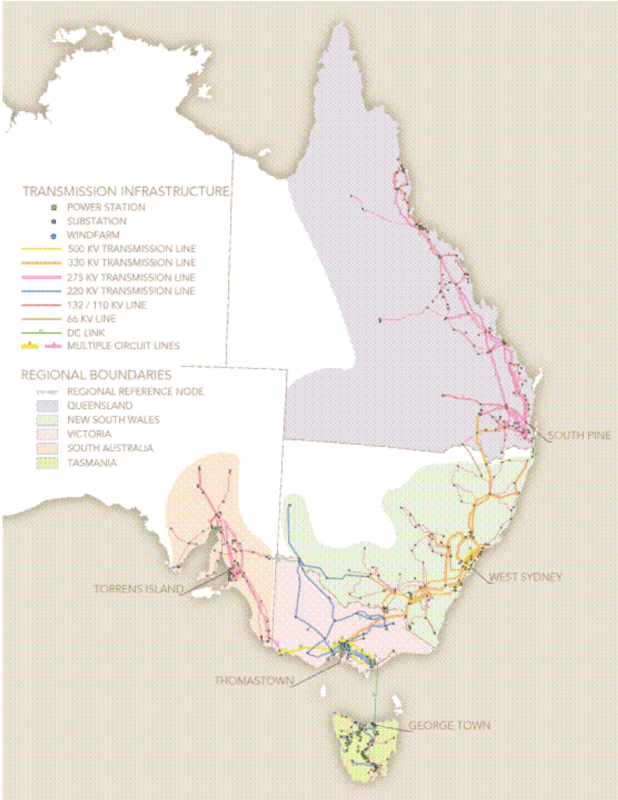
A relatively sophisticated demand-side participation market has emerged as a solution to manage frequency variations, alongside conventional load-shedding. Eskom makes use of around 1,500 MW of instantaneous demand response (or contracted load shedding). This load responds in the 2-3 second period, so is not the same as LFAS. The instantaneous demand response is bilaterally contracted or agreed on a day-before basis in return for payment.

Unlike other regions, such as Chile, Eskom has not had problems finding willing participants. The service is typically provided by industrial customers such as large smelters and the service is used towards the end of the day as residential load changes.

Going forward, Eskom is looking to batteries to provide fast frequency response services that will reduce the reliance on Regulation Services. The first large-scale battery is currently being built in South Africa and is expected to be operational and provide Reserve Services by late-2023. Eskom views battery participation in the markets as particularly important as they retire their aging coal-fired power station fleet. In addition, Eskom is exploring ways in which renewable energy sources can contribute to frequency regulation in the network.

6. National Electricity Market

The National Electricity Market (NEM) incorporates around 40,000 km of transmission lines and cables. It supplies about 200 terawatt-hours of electricity to 10.7 million customers each year.[21]



Operation of the NEM as a wholesale spot market began in December 1998. It interconnects five regional market jurisdictions – Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia, and Tasmania.

The NEM is a wholesale market through which generators and retailers trade electricity in Australia. It interconnects the six eastern and southern states and territories and delivers around 80% of all electricity consumption in Australia. There are over 504 registered participants in the NEM, including market generators, transmission network service providers, distribution network service providers, and market customers.

In the NEM, AEMO dispatches the market every 5-minutes. Commencing 1 October 2021, Five-Minute Settlement shifted the wholesale electricity spot market from what was previously a 30-minute settlement period to five minutes. This provides a better price signal for investment in faster response technologies, such as batteries and gas peaking generators. The change brings the market settlement periods in line with the pre-existing 5-minute dispatch interval.[22]

The NEM has a total electricity generating capacity of 65,252 MW (as of December 2021). Approximately 14 GW of distributed solar is present in the NEM (as of December 2021). Similar to the situation in the WEM, collectively, distributed solar is the largest source of generation in the NEM.[23] This growth in rooftop solar is driving a shift in the minimum demand, which previously occurred overnight, to the middle of the day.[24]

Table 22 Power system characteristics – NEM

Characteristic	Value	Comment
Dispatch interval	5 minutes	
Peak demand	32,761 MW (NEM) 2,834 MW (South Australia)	NEM: Summer 2022/21 South Australia data from AER, State of the Energy Market Report 2021. Data for 2020
Minimum demand	South Australia (when islanded): 318 MW	South Australia's minimum was on 11 October 2020.

[21] AEMO, 'About the NEM', refer to: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/about-the-national-electricity-market-nem#:~:text=About%20the%20National%20Electricity%20Market%20%28NEM%29%20The%20National,each%20year.%20It%20supplies%20around%209%20million%20customers

[22] AEMO, The National Electricity Market Factsheet, December 2021, p.3. Refer to: **https://www.aemo.com.au/-/media/Files/Electricity/NEM/National-Electricity-Market-Fact-Sheet.pdf**

[23] AEMO, The National Electricity Market Factsheet, December 2021, p.1. Refer to: **https://www.aemo.com.au/-/media/Files/Electricity/NEM/National-Electricity-Market-Fact-Sheet.pdf**

[24] AER, State of the Energy Market Report 2021, 2021, p. 72. Available at: **https://www.aer.gov.au/system/files/State%20of%20the%20energy%20market%202021%20-%20Full%20report_1.pdf**

Characteristic		Value	Comment
Regulation Raise requirement (equivalent to LFAS upward)		NEM: 220 MW (7901 hours during 2021) South Australia (when islanded): 35 MW to 70 MW (<10 hours in 2020)	NEM data is from 2021. Note, an additional 60 MW for each 1s of time error below -1.5s was used for 964 hours to correct the frequency-time error in 2021. South Australia data is from 2020 and applied to <10 hours.
Regulation Lower requirement (equivalent to LFAS downward)		NEM: 210 MW (7690 hours during 2021) South Australia (when islanded): 35 MW (<10 hours in 2020)	NEM data is from 2021. Note, an additional 60 MW for each 1s of time error above 1.5s was used for 544 hours to correct frequency-time error in 2021. South Australia data is from 2020 and applied to <10 hours.
Annual (dispatchable) generation	Total	192,253 GWh	Financial year 2019/20, excludes residential solar
	Variable generation	24,213 GWh (12.6%)	
	Non-variable	168,040 GWh (87.4%)	
Installed (dispatchable) capacity	Total	55,599 MW	Financial year 2019/20, excludes residential solar
	Variable generation	18,678 MW (33.6%)	
	Non-variable generation	36,921 MW (66.4%)	
Non-dispatchable rooftop solar	Installed capacity	11,411 MW (NEM) 1,527 MW (South Australia)	AER, State of the Energy Market Report, 2021. Data for 2020.
	Annual generation	13,042 GWh (NEM) 1,835 GWh (South Australia)	AER, State of the Energy Market Report, 2021. Data for 2020.

6.1 Generation mix

The proportion of variable renewable generation in the NEM has rapidly increased in recent years, such that large scale-solar and wind now represents more than 25% of installed capacity (Figure 14). Despite this, fossil fuel generators continue to produce the majority of electricity in the NEM (Figure 15).

Figure 14 Installed capacity by fuel type – NEM

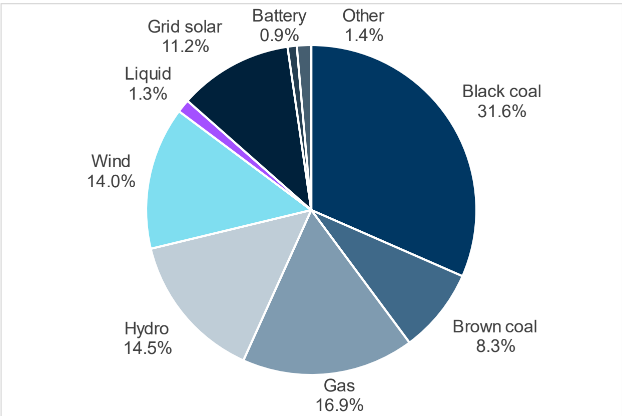
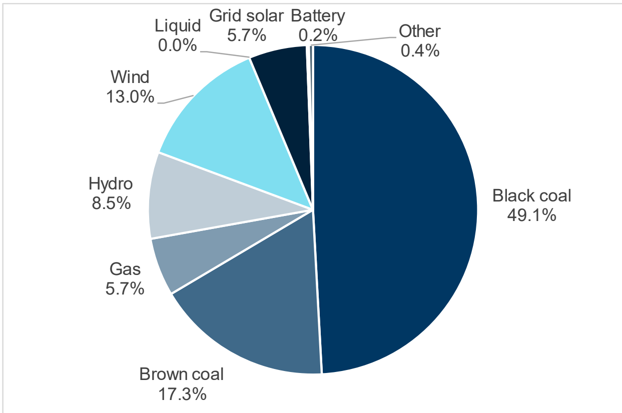


Figure 15 Output by fuel type – NEM



Source: AER, Generation capacity and output by fuel source for the 2021/22 financial year. Data is as of 31 March 2022.

Table 23 Installed generation capacity - NEM

Fuel Source	Nameplate capacity (MW)					Proportion of total nameplate capacity (%)				
	2015/16	2016/17	2017/18	2018/19	2019/20	2015/16	2016/17	2017/18	2018/19	2019/20
Coal	24,656	23,056	23,056	23,121	23,086	49.0%	44.6%	41.5%	38.1%	34.8%
Gas and other fuels	10,836	11,605	11,970	12,274	13,200	21.5%	22.4%	21.5%	20.2%	19.9%
Water	7,569	7,569	8,020	7,981	7,982	15.0%	14.6%	14.4%	13.1%	12.0%
Wind	2,458	4,070	5,114	6,141	7,481	4.9%	7.9%	9.2%	10.1%	11.3%
Utility solar	211	274	960	3,087	3,850	0.4%	0.5%	1.7%	5.1%	5.8%
Residential solar	4,587	5,150	6,441	8,100	10,696	9.1%	10.0%	11.6%	13.3%	16.1%
All Sources	**50,316**	**51,724**	**55,561**	**60,704**	**66,295**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Source: AEMC, Annual Market Performance Review 2020, NEM Generation Capacity (Installed megawatts) by fuel type 2001-2020. Data available at: **NEM generation capacity (installed megawatts) by fuel type 2001-2020 | AEMC**

Table 24 Generation produced by energy source – NEM

Fuel Source	Generation produced (GWh)					Proportion of total generation (%)				
	2015/16	2016/17	2017/18	2018/19	2019/20	2015/16	2016/17	2017/18	2018/19	2019/20
Black coal	101,634	104,779	110,528	109,940	102,191	52.3%	54.5%	56.4%	56.2%	53.2%
Brown coal	48,036	42,638	36,052	34,589	33,731	24.7%	22.2%	18.4%	17.7%	17.5%
Gas	19,201	18,163	19,972	16,519	17,215	9.9%	9.4%	10.2%	8.4%	9.0%
Hydro	14,280	15,253	15,070	15,261	14,610	7.4%	7.9%	7.7%	7.8%	7.6%
Wind	10,235	10,406	13,044	15,637	18,168	5.3%	5.4%	6.7%	8.0%	9.4%
Liquid	82	102	29	26	17	0.0%	0.1%	0.0%	0.0%	0.0%
Solar	362	566	799	3,419	6,046	0.2%	0.3%	0.4%	1.7%	3.1%
Other	338	327	350	308	276	0.2%	0.2%	0.2%	0.2%	0.1%
All Sources	**194,167**	**192,234**	**195,844**	**195,700**	**192,253**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Source: AEMC, Annual Market Performance Review 2020, NEM generation output (megawatt hours) by fuel type 2011/12-2019/202. Data available at: **NEM generation output (megawatt hours) by fuel type 2011-12 - 2019-20 | AEMC**

The installed capacity and generation mix varies between the different jurisdictions. The installed capacity for South Australia (6,109 MW) is the most similar in size to the SWIS (6,088 MW) (Table 25). The proportion of gas-fired generation in the two jurisdictions is similar (48% in South Australia compared with 50.8% in the SWIS). However, South Australia does not have any coal-fired generation and consequently has a higher proportion of variable renewable generation compared to the SWIS (27.1% in South Australia compared with 19.8% in the SWIS).

For benchmarking purposes, the following sections consider the overall frequency regulation services in the NEM and the quantities required for South Australia when that section of the NEM is islanded from the rest of the system.

Note: The totals for data outlined in Table 22, Table 23 and Table 24 differ from the total for data shown in Table 25 due to differences in the timing of the data and the classification methods employed by the AEMC and the AER respectively.

Table 25 Installed generation capacity by jurisdiction – NEM (MW)

Generator Type	NSW	QLD	VIC	SA	TAS	Total	Proportion of Total
Black Coal	10,185	8,126	0	0	0	18,311	29.8%
Brown Coal	0	0	4,775	0	0	4,775	7.8%
OCGT	1,388	1,486	1,900	947	178	5,899	9.6%
CCGT	625	1,597	0	709	208	3,139	5.1%
Gas-powered steam turbine	0	0	500	1,280	0	1,780	2.9%
Liquid Fuel	50	458	0	265	0	772	1.3%
Hydro	4,565	722	2,219	0	2,170	9,677	15.7%
Wind	2,133	1,177	4,337	2,140	573	10,360	16.8%
Solar	2,429	2,426	1,100	353	0	6,307	10.3%
Gas	0	0	0	210	0	210	0.3%
Battery Storage	0	20	75	205	0	300	0.5%
All sources	**21,374**	**16,011**	**14,906**	**6,109**	**3,129**	**61,530**	**100.0%**

Source: AEMO, 2020 ISP Inputs and assumptions workbook, December 2020.

6.2 Overview of frequency regulation services

The 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 (FFR)** - FFR generally refers to the delivery of a rapid active power increase or decrease by generation or load in a timeframe of two seconds or less, to correct a supply-demand imbalance and assist in managing power system frequency. Many inverter-connected technologies, such as wind, photovoltaics (PV), batteries and other types of storage can deliver FFR, as well as some demand-side resources. Given that FFR can act faster than other frequency control services in the NEM, it can also assist in managing challenges related to high Rates of Change of Frequency.
- **Primary Frequency Response (PFR)** - 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 aimed at arresting any deviations from the target frequency. PFR is an essential requirement for frequency control and power system security. Sufficient PFR is a necessity for stable control of system frequency. 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 when configured to do so.
- **Regulation frequency services** are the services that correct the generation/demand balance due to small variations in load and/or generation. Operationally, regulation services are constantly used to adjust small imbalances in demand and 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 that provide regulation services. Signals instruct generators to adjust their output to control frequency within the normal operating band of 49.85 Hz to 50.15 Hz in the absence of contingency events. Regulation services are procured through market arrangements and those services are co-optimised with the energy market. There are two types of regulation services:
    1. Regulation Raise: Regulation service that is used to correct a minor drop in frequency.
    2. Regulation Lower: Regulation service that is used to correct a minor rise in frequency.
- **Contingency Frequency Control Ancillary Services (C-FCAS)** – These services respond to a major contingency event to correct the generation/demand balance. There are six types of C-FCAS.

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

The Regulation frequency services are equivalent to LFAS and backup LFAS services in the WEM.

6.3 LFAS-equivalent requirement

Regulation services are procured through market arrangements and those services are co-optimised with the energy market. There are two types of regulation services:

- Regulation Raise: Regulation service that is used to correct a minor drop in frequency.
- Regulation Lower: Regulation service that is used to correct a minor rise in frequency.

The required level of service for each 5-minute dispatch interval is specified by constraint equations. The following types of constraints may be used to set the requirement for services in either direction. All FCAS constraint equation identifiers begin with the letter F:

- System normal requirements which include local and global requirements are specified by equations with the following identifiers F-" / Region(s) / "_NIL_" / Event Type:
  - A global requirement is signified by the inclusion of I as the region descriptor eg F_I+RREG_0220 is a constraint specifying a global requirement for raise regulation.
  - A local requirement is signified by the region identified after the F eg F_T+RREG_0050 which sets the Tasmanian raise regulation requirement to 50 MW when Basslink is unable to transfer FCAS
  - An equation that adjusts the regulation requirement to address time errors eg F_MAIN+NIL_DYN_RREG, this equation increases the raise regulation requirement in mainland regions (SA, VIC, NSW and QLD) by 60 MW for each 1s of time error below -1.5s
- Outage constraints that reflect a change regulation requirement as a result of a network outage:
  - e.g. F_T+FASH_N-2_RREG, this constraint is invoked when the loss of the Farrell to Sheffield lines is declared to be credible. The constraint sets the Bastyan, John Butters, Reece 1 & 2, Mackintosh and Tribute Raise Regulation Requirement to 0MW
  - When there is a risk of a region operating as an island a local regulation requirement may also be enacted, e.g. F_S+RREG_0035 which set the SA Raise Regulation Requirement at 35 MW

6.3.1 Statistical reporting of requirements and performance

AEMO produces annual constraint reports for each calendar year[25]. A review of the regulation FCAS constraints in the 2021 report reveals the following:

- In FY 2021:
  - Under system intact conditions the raise regulation requirement in the mainland regions of the NEM was 220 MW. This constraint applied for 7901 hours during the year.
  - During an additional 964 hours of the year, the regulation requirement was increased to correct the frequency-time error. The requirement is increased by 60 MW for each 1 s of time error below -1.5s.
  - Under system intact conditions the lower regulation requirement in the mainland regions of the NEM was 210 MW. This constraint applied for 7690 hours during the year.
  - During an additional 544 hours of the year the regulation requirement was increased to correct the frequency-time error. The requirement is increased by 60 MW for each 1 s of time error above 1.5s.
  - There were no instances where the specific regulation requirements were procured in each of the mainland regions of the NEM.
- In FY 2020:
  - Under system intact conditions the raise regulation requirement in the mainland regions of the NEM was 220 MW. This constraint applied for 5017 hours during the year.

[25] AEMO | Statistical reporting streams

- During an additional 3202 hours of the year, the regulation requirement was increased to correct the frequency-time error. The requirement is increased by 60 MW for each 1 s of time error below -1.5s.
- Under system intact conditions the lower regulation requirement in the mainland regions of the NEM was 210 MW. This constraint applied for 7771 hours during the year
- During an additional 314 hours of the year, the regulation requirement was increased to correct the frequency-time error. The requirement is increased by 60 MW for each 1 s of time error above 1.5s.
- For < 10 hours local regulation requirements were specified for SA. These requirements are specified when SA is islanded or considered to be at risk of islanding from the rest of the NEM. During this time the lower requirement was specified as 35 MW and the raise requirement varied between 35 and 70 MW.

  The constraint reports do not identify a specific reason for the local SA raise requirement being increased for a short period of time (1.4 hours).

6.3.2 Historical changes to Regulation Requirement and PFR Rule Change

AEMO publishes quarterly reports on frequency and time performance for the NEM[26]. The February 2022, report summarises the performance achieved across Q4 2021 and provides summary information on historical performance.

Figure 16 is extracted from the Q4 2021 frequency and time error monitoring report. It shows the variation in the frequency distribution for each month since January 2007. A signification deterioration in performance can be observed from about 2014-15. The improvement since 2020 has been achieved by changing the NER to require all generating systems to provide primary frequency response (PFR) with narrow dead bands (+/- 0.015 Hz). The revision to the NER requires generators to start responding to correct frequency once the locally sensed frequency moves outside the range 49.985 to 50.015 Hz. This change to the NER aligns the frequency response requirements in the NEM with those in other markets such as the WEM and Darwin Katherine Power System in the Northern Territory.

Before the change generators could choose to opt out of providing frequency response. This led to a power system in which the AGC regulation service was unable to maintain sufficient control of frequency and the frequency histogram flattened with significant periods of operation occurring toward the edge of the Normal Frequency Operating Band (NFOB) (49.85 Hz to 50.15 Hz), defined in the NEM Frequency Operating Standard (FOS).

Despite the significant degradation in performance during the period before narrow dead bands for PFR were required, the minimum frequency standard was been maintained throughout the period. In April 2022, the Australian Energy Market Commission's Reliablity Panel commenced the 'Review of the frequency operating standard 2022', in which the Panel will consider whether further specifrication of the standard is needed to better reflect the desired shape of frequencies observed.[27]

[26] AEMO | Frequency and time deviation monitoring
[27] Refer to the **Review of the frequency operating standard 2022 | AEMC**

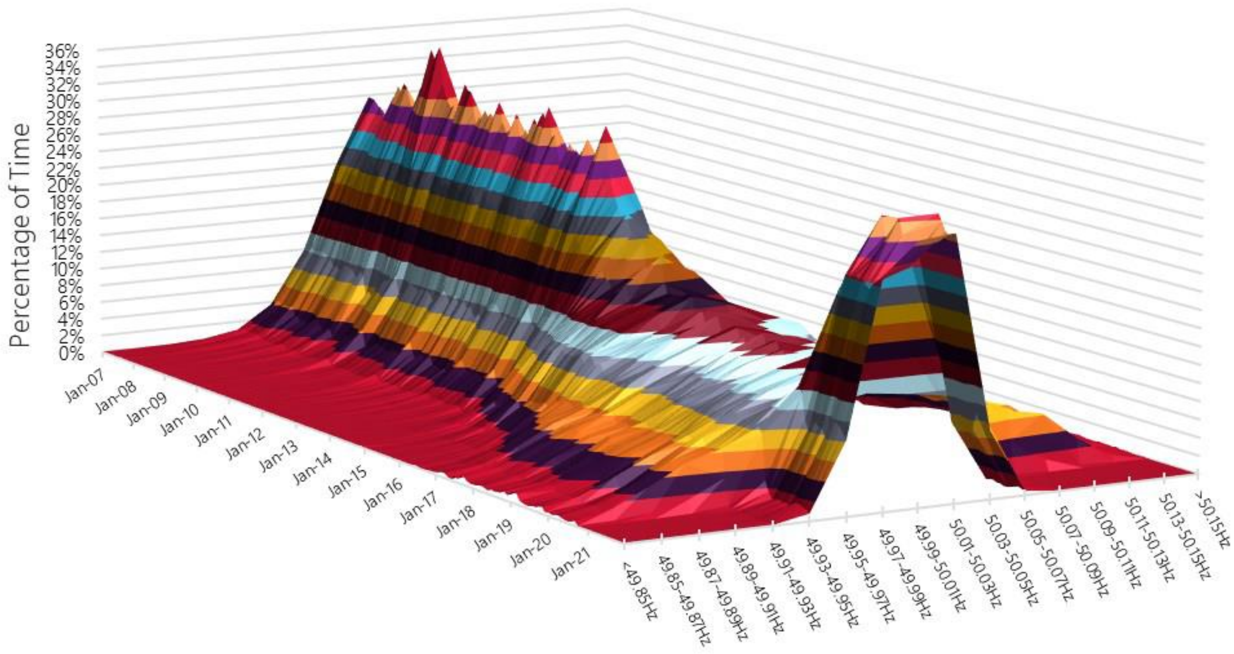


Figure 16 ***Monthly frequency histogram for the NEM***

In the period leading up to the introduction of the change to the NER to re-introduce mandatory PFR, AEMO increased the frequency regulation requirements for the NEM. The changes made are summarised in the Regulation FCAS changes updated dated June 2019.[28] That document indicates the following changes to the mainland regulation requirement occurred:

- Raise and lower regulation requirement increased by 50 MW on 22 March 2019 to 180 MW raise and 170 MW lower
- Requirement increased by a further 20 MW on 23 April 2019 to 200 MW raise and 190 MW lower
- Requirement increased by a further 20 MW on 23 May 2019 to 220 MW raise and 210 MW lower

The increases were made to try and improve the ability to control frequency within the NFOB. The NEM FOS requires frequency to be controlled within the NFOB 99% of the time. Figure 2 extracted from the Regulation Changes factsheet produced by AEMO[29], shows that by January 2019 the frequency regulation did not meet the requirements in the NEM FOS. This was the trigger for increasing the regulation requirements.

[28] https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/frequency-and-time-error-reports/regulation-fcas-changes_june-update.pdf?la=en
[29] https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/frequency-and-time-error-reports/regulation-fcas-factsheet.pdf?la=en

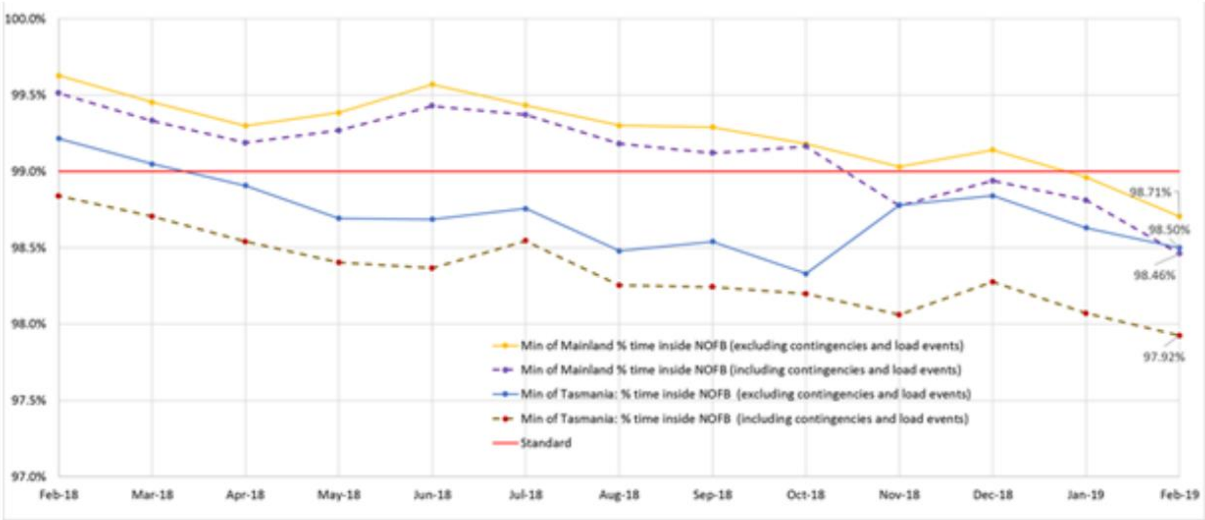


Figure 17 ***Observed decline in regulation performance - NEM***

The factsheet included the following reasons for the decline in the frequency regulation.

- This decline is due to multiple factors, including:
  - Reduction in regulation FCAS procured due to relaxation of constraints governing time error (in line with FOS changes that relaxed time error standards).
  - System conditions, including extreme weather.
  - Increase in grid load and generation volatility.

There has been no further change to the mainland regulation requirements since 2019.

6.4 Summary

While the mainland regulation requirement was increased in 2019 and, at the time, some of the reason for the increase was attributed to generation volatility, the reintroduction of mandatory PFR has meant that no further increase has been necessary despite increasing levels of renewable generation since 2019.

It is expected that the geographic size of the NEM and the level of interconnection means that increasing quantities of renewable generation will have less influence on the amount of regulation service required compared with the WEM.

Additionally, in the NEM renewable generators are allocated some of the frequency regulation costs through a causer pays process. Renewable generators that closely adhere to their generation forecasts will incur a lower portion of the regulation costs. The causer pays process in the NEM may encourage renewable generators to implement better forecasting and control systems to align their generation output with their forecast.

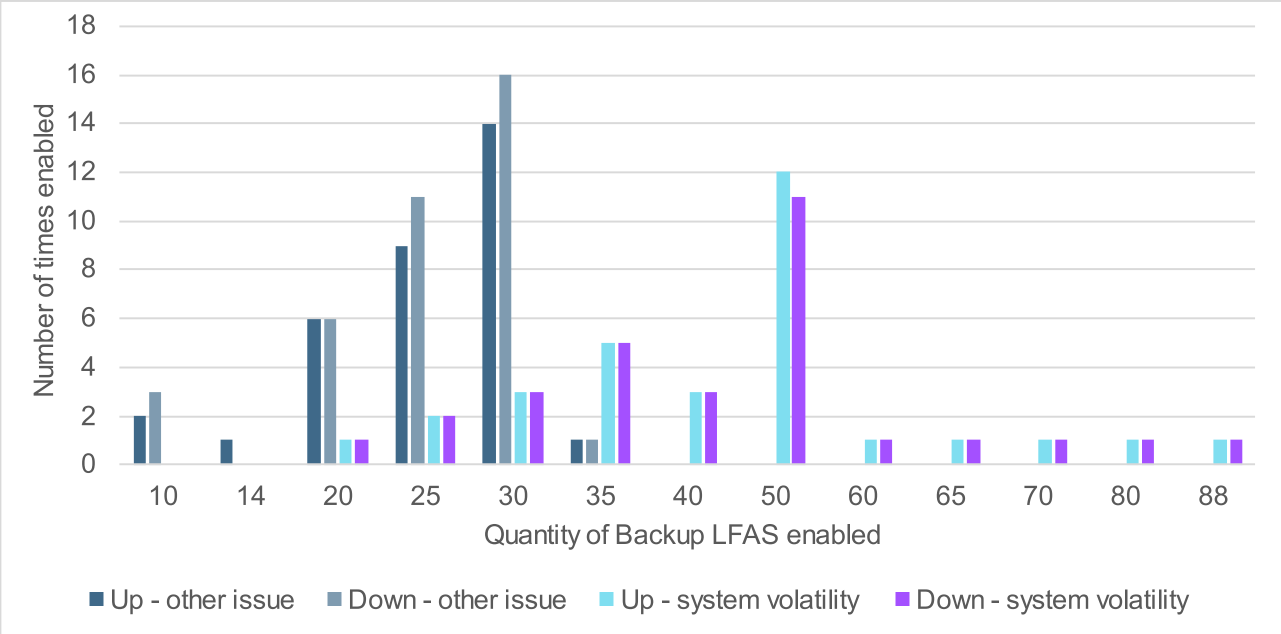
7. Findings

7.1 Use of LFAS and Backup LFAS

Consistent with AEMO's annual reports, our analysis of Dispatch Advisories suggests the use of Backup LFAS continues to be limited to a relatively small number of intervals each year. However, also consistent with AEMO reporting, the number of incidents that represent a shortfall in the total quantity of LFAS (as opposed to incidents when Backup LFAS was used due to LFAS providers being unavailable) has increased in recent years.

The quantities of Backup LFAS enabled in response to these system volatility events are, on average, higher than the amount of Backup LFAS used for other reasons (Figure 18). The quantities of Backup LFAS enabled were, in all cases, equal to or greater than the increase from 100 MW to 110 MW that AEMO intends to implement during peak periods in 2023. The Backup LFAS requirement, was also, on average, greater than the 20 MW change that would be observed should the proposed maximum quantities of 120 MW be approved and if that maximum quantity were enabled peak times during 2023.

Figure 18 Use of Backup LFAS



Source: GHD analysis of Dispatch Advisory notices available from **http://data.wa.aemo.com.au/**
Note: Analysis required reading the details of each notice (a manual input for controllers) and classifying the information. The data presented in the figure represents information from 71 Dispatch Advisories and excludes 6 Dispatch Advisories where the quantity of Backup LFAS was not detailed.

Based on our understanding of how the various frequency response mechanisms in the WEM function and the analysis of the quantities and reasons for enabling Backup LFAS, we have not found evidence to indicate that there would be a risk to power system security from continuing to rely on Backup LFAS as the primary mechanism for covering shortfalls in LFAS.

Under normal operating conditions, frequency in the WEM is managed primarily through LFAS but is supported by mandatory Primary Frequency Response (PFR). The benefit of LFAS complemented by PFR is that it maintains a system frequency closer to 50 Hz than would otherwise be achieved. Maintaining tight regulation of frequency also maintains a greater PFR capability to respond to contingency events. AEMO may also re-dispatch the state-owned Synergy generating fleet's Balancing Portfolio more frequently than the 10-minute market dispatch interval as a means of managing imbalances between supply and demand.

The approach of using several mechanisms to control frequency is consistent with the approach in other jurisdictions.

AEMO's 2022 Ancillary Services Report for the WEM indicates that system frequency remained in the normal operating band for 99.98% of the time. This is significantly greater than the frequency standard specified in the WEM Rules and in the Technical Rules which requires the frequency standard for normal operating circumstances to be maintained 99% of the time.

Considering that reforms to the energy market and to introduce a new Essential System Service framework are expected to be implemented within the next 1-2 years and that will alter the quantities of frequency regulation services required, continuing to rely on current LFAS, Backup LFAS and the PFR mechanisms as a means of controlling frequency during normal operating conditions appears reasonable. Based on our limited analysis, there does not appear to be sufficient use of small quantities of Backup LFAS to justify increasing the quantities of LFAS given that these higher quantities may be paid for by the market for all trading intervals in the peak LFAS period, compared with Backup LFAS which is only paid for when it is enabled.

In considering more fully whether the LFAS requirement should be increased to reduce the need for Backup LFAS, consideration may be given to a broader set of factors, including:

- The marginal cost of procuring additional LFAS through the LFAS market compared with the marginal cost of using backup LFAS more often and enabling greater quantities of backup LFAS. This should also consider any impact greater utilisation of backup may have on the price offered by Synergy for this service. Synergy is the sole provider of backup LFAS whereas multiple providers can bid into the LFAS market.
- The small size of the market and the number of providers may be incentivised differently by the overall requirement and any overlap in the markets where the services are being provided by the same machines.
- AEMO costs and processes associated with procuring and enabling LFAS compared to Backup LFAS. For example, the extent to which interventions are manual versus automatic.
- Effects of future reforms (discussed below in section 2.2 for context purposes only).

In the longer term and with the appropriate consideration of the above factors, it is likely to be more efficient to adjust the LFAS market design, including the maximum quantities enabled for specific time periods, to enable the automatic use of services and avoid manual interventions such as Backup LFAS.

Several of the jurisdictions analysed in the benchmarking studies use more sophisticated approaches to specifying requirements that enable requirements of equivalent LFAS to match system needs more closely. In particular, ERCOT and Chile both use an approach that enables closer matching of the system requirements based on the hour of the day, time of the year and, for Chile, whether it is a working day or not.

Going forward, the adoption of a more sophisticated approach than the current peak and off-peak differential may be a means of reducing reliance on Backup LFAS. However, further analysis on the time periods when LFAS and Backup LFAS have been required could be undertaken to support a future market that gives a more granular set of requirements than the current peak and off-peak periods.

7.2 Comparison with benchmark jurisdictions

Table 26 (at the end of this report) summarises the benchmark data collected for the WEM and comparator jurisdictions. Figure 19 compares the maximum LFAS or LFAS equivalent services required for each of the benchmarked power systems. While Figure 20 summarises the peak demand and installed generation capacity and Figure 21 shows the installed generation capacity by type for benchmarked power systems.

In terms of the gross quantities of LFAS and LFAS-equivalent services required, the WEM requirements are lower than all jurisdictions except for South Australia when it is islanded. South Australia is dispatched twice as often as the WEM (every 5 minutes compared to every 10 minutes for the WEM). However, it has a much higher proportion of variable generation.

The SEN in Chile is the most directly comparable in terms of the size of the market and proportion of renewable generation installed. However, the WEM requirement for upward services is almost half that required in the SEN despite the WEM having 6 times as many dispatch intervals (WEM is dispatched on 10 minute cycles, compared to the SEN which is dispatched every 60 minutes).

The WEM quantities are also lower than the requirements for ERCOT, Eskom and the NEM, although these systems are an order of magnitude larger in terms of the power required compared to the WEM. ERCOT and the NEM both have shorter dispatch intervals than the WEM, which counteracts the size of the system in terms of the quantities required. The Eskom region has a much lower proportion of renewable generation than the WEM and residential rooftop solar is not able to feed into the grid, which, on balance, should mean the quantities of frequency regulation required should be lower but for the size of the power system.

We consider the quantities of LFAS and LFAS equivalent services using a series of ratios in section 7.3.

Figure 19 ***Maximum LFAS (or LFAS equivalent) quantities required (MW) for benchmarked power systems***

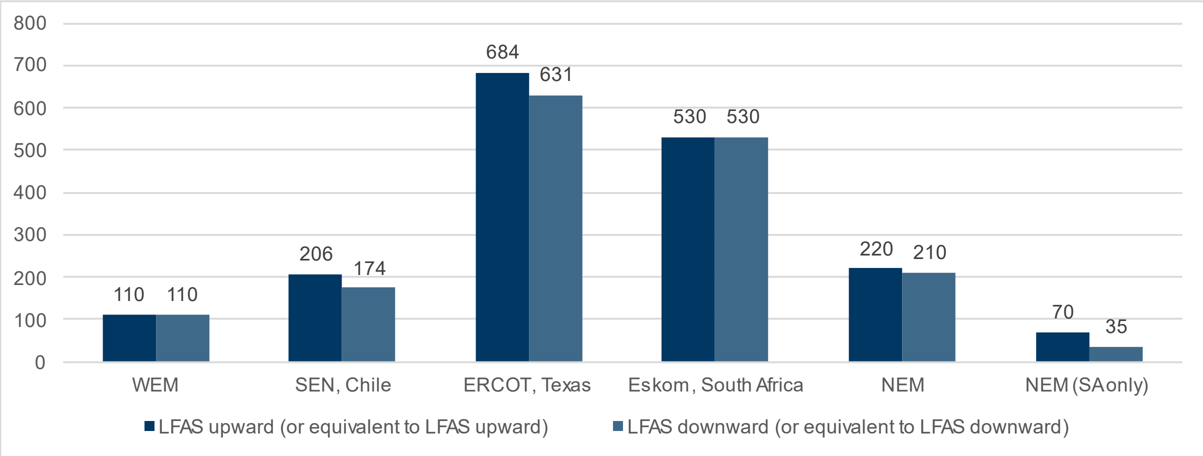


Figure 20 ***Peak demand and installed generation capacity (MW) for benchmarked power systems***

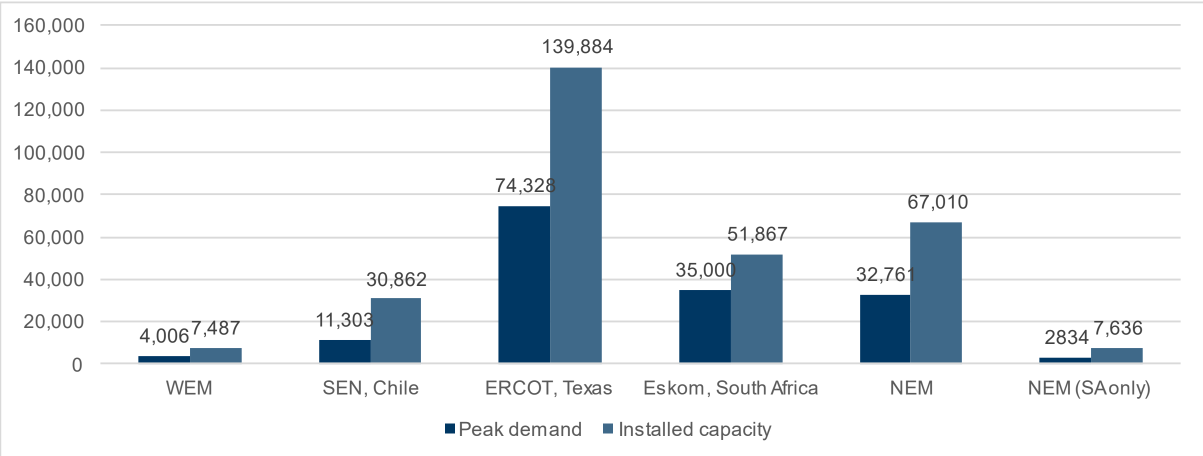
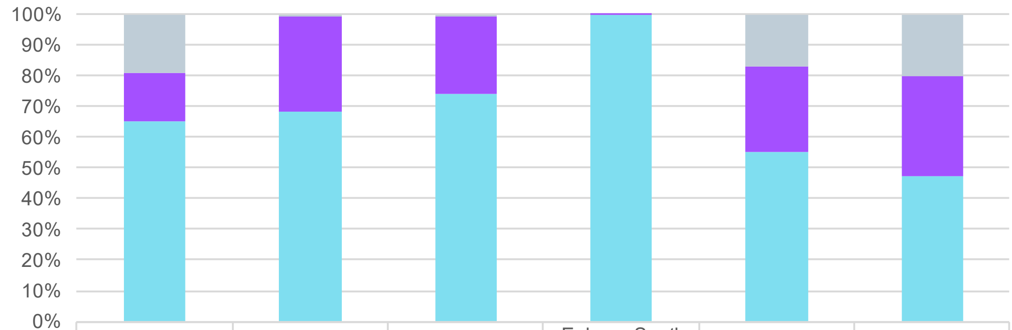


Figure 21 ***Installed generation capacity by type (MW) for benchmarked power systems***



	WEM	SEN, Chile	ERCOT, Texas	Eskom, South Africa	NEM	NEM (SA only)
Rooftop solar PV	1,421	114	990	0	11,411	1,527
Variable capacity	1,197	9,734	34,988	161	18678	2,493
Non-variable capacity	4,869	21,138	103,906	51,605	36921	3,616

Note: Variable capacity includes generation that is centrally dispatched, and the fuel source is uncontrolled. Wind, solar and non-controlled small-scale hydro are included in this category. A fuller description of the categories is given in section 1.3 of this report.
Data reported for Eskom relates to Eskom generation only and excludes generation owned by Independent Power Producers.

While the review of other jurisdictions has identified that no other region has a directly comparable network and frequency management regime to the SWIS, some conclusions have been observed from the regions experiencing high growth and deployment of renewables:

- **Shorter dispatch intervals influence the quantity of frequency regulation that is required.** For example, ERCOT is the largest system considered in benchmarking, yet it has relatively minimal frequency regulation requirements. Chile operates an hourly energy market dispatch and has a maximum regulation requirement that is comparable with the NEM despite the NEM being a significantly larger power system. Change to adopt a 5 minute dispatch in the WEM is likely to reduce outturn variations between dispatch intervals and reduce the LFAS requirement
- **The quality of the existing generation fleet to provide frequency response affects how much regulation service is needed.** If it is essential to maintain the integrity of the grid, then operators procure a larger quantity of frequency regulation response capability. Whereas, if there are multiple mechanisms or if the generating fleet is responding (through mechanisms like PFR) then there is a lower requirement. The recent experience in the NEM shows the benefit of using mandatory PFR to complement frequency regulation providing more effective frequency control.
- **The proportion of renewable technologies on the grid directly affects how much frequency regulation is required.** The greater the penetration of variable renewable sources of generation, the greater the requirement for frequency regulation. Both Chile and the WEM have experienced the need to increase frequency regulation requirements as the proportion of variable renewable generation has increased. From discussions with power system operators, there appears to be a limit at which the cumulative effect of increasing variable generation necessitates a change in the frequency regulation requirements.
- **The geography of the system plays a role in the variability of generation and demand and therefore the quantities of services required.** For example, a large portion of Chile's requirements is driven by the effect of sunrise and sunset simultaneously affecting demand and large scale solar at almost simultaneous times across the grid due to the north-south arrangement of the system. Similarly, a weather phenomenon in South Africa drives the quantity of fast-acting frequency regulation services. In the winter Eskom experiences cold fronts driving up from the south of the African continent. These cause winds to blow past the southern wind farms before reducing. The front continues up towards Johannesburg, the largest population centre, and triggers an increase in demand for heating. Consequently, there is a near-simultaneous increase and then reduction in wind output that is followed by an increased grid load from heating. Understandably, a greater quantity of frequency regulation is needed during these periods.
- **The extent of interconnection plays a role in establishing the frequency regulation requirement.** Power systems with greater levels of interconnection can share frequency regulation sources with neighbouring power systems. Interconnected systems also provide greater geographic diversity in renewable generation which helps to reduce the volatility seen at a whole power system level. These factors will tend to reduce the required amount of frequency regulation capacity.

In several of the systems, including Chile (which has 6 different requirements) and ERCOT (which has 228 requirements), the ability to specify different quantities depending on the time of day and time of year appears as a more flexible mechanism for specifying quantities based on factors that drive the requirements. In particular, the approach used in Chile has rapidly evolved over the last three years both in term terms of the quantities required and the sophistication as to when different requirements are needed. For Chile, the adoption of revised, more sophisticated approaches has enabled them to tailor the quantities more closely to system requirements.

Most of the entities benchmarked rely on the analysis of historical forecasting errors and the historical utilisation of frequency regulation services to inform the future regulation requirements. Of the entities benchmarked, ERCOT, Chile and the WEM have all identified through this process that the regulation requirement varies at different times of the day. Chile and ERCOT have identified the need to divide the year into a number of blocks to appropriately specify regulation requirements. There may be a benefit in exploring this approach in the WEM as a way of optimising the regulation requirement.

7.3 Use of ratios for comparison

To compare the quantities of LFAS and LFAS-equivalent services more directly, GHD developed a series of benchmark ratios based on the data in Table 26.

The ratios presented below show the quantity of LFAS and LFAS-equivalent services required in the jurisdiction compared to one of the other power system characteristics. For example, the peak demand ratio is calculated as follows:

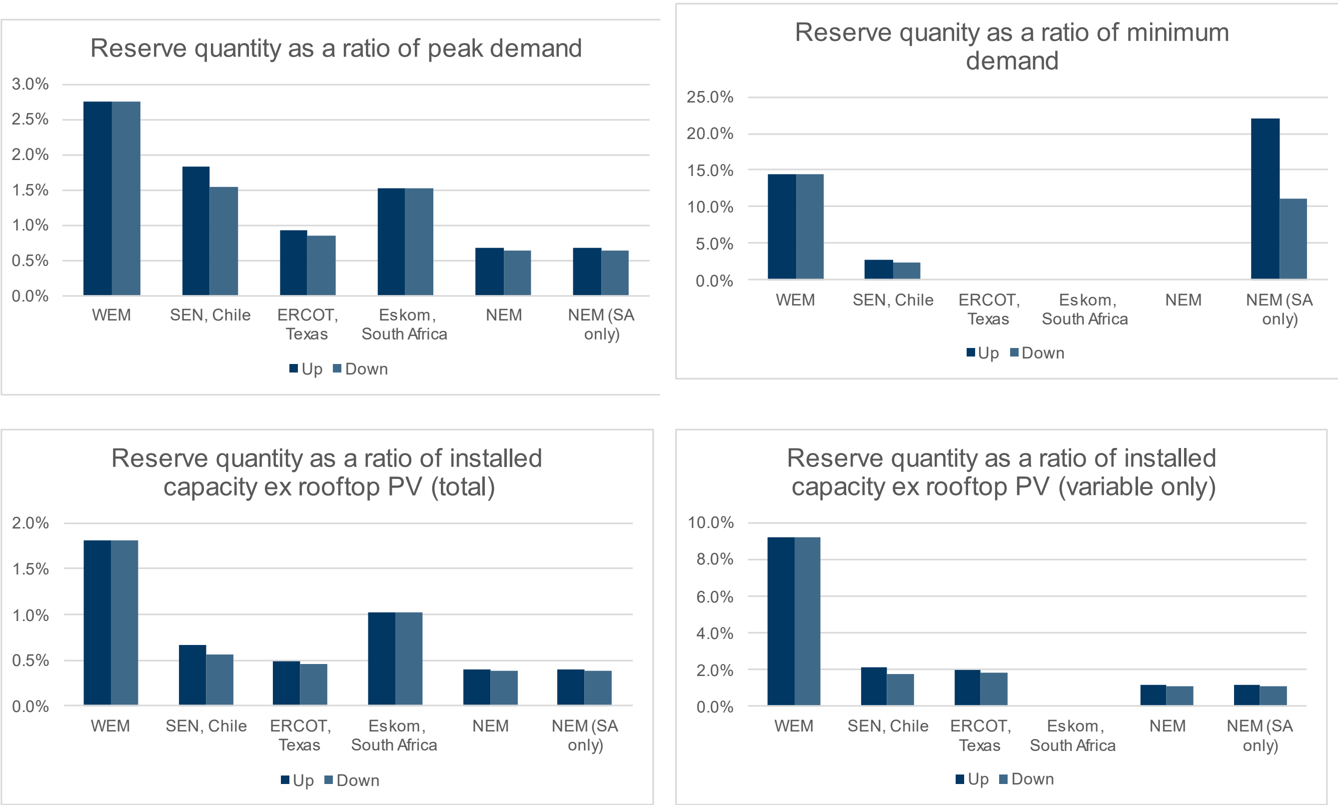
$$Peak\ demand\ ratio_{System\ A} = \frac{Equivalent\ LFAS\ up_{System\ A}}{Peak\ demand_{System\ A}}$$

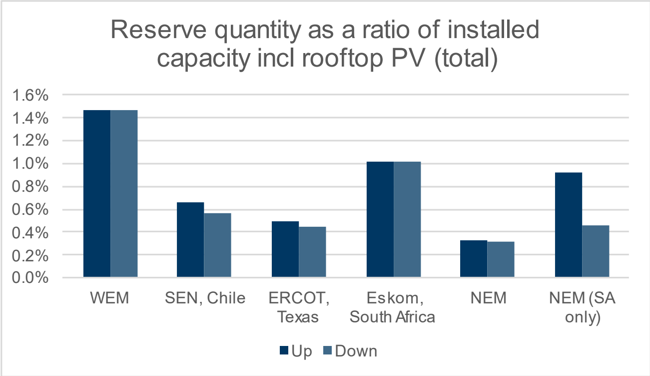
Note: Where a range of quantities are provided for the required services, benchmark ratios are based on the maximum quantities required.

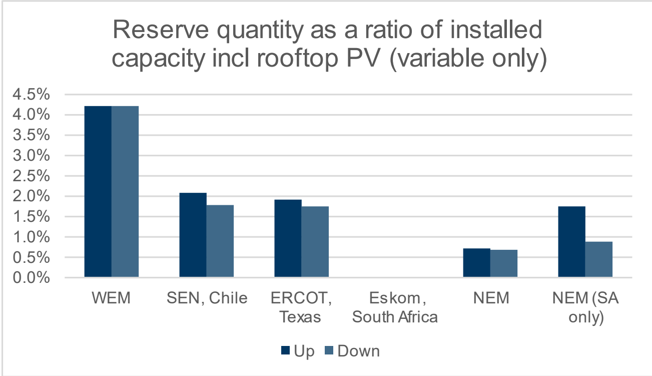
Several of the ratios developed are presented below. These ratios indicate, in general, that the quantity of LFAS required in the WEM is relatively high compared to LFAS-equivalent requirements used in other power systems. However, there are significant limitations to the interpretation of the ratios, in particular, the method does not take into account how multiple factors may play out simultaneously to determine the quantities required for the safe and reliable operation of the power system. For example, the Eskom quantities look relatively high compared to other systems once the large size of this system and the very low proportion of variable generation is considered.

Considering the limitations of using ratios, we have not been able to reach any firm conclusions about the quantity of LFAS required for the WEM based on these metrics alone. However, from a qualitative point of view and considering other factors such as the size of the market and the proportion of variable generation, the WEM quantities benchmark as high compared to other similar jurisdictions.

Figure 22 Benchmark ratios







Note: Variable capacity includes generation that is centrally dispatched, and the fuel source is uncontrolled. Wind, solar and non-controlled small-scale hydro are included in this category. A fuller description of the categories is given in section 1.3 of this report.
Data reported for Eskom relates to Eskom generation only and excludes generation owned by Independent Power Producers.

Table 26 Summary of benchmark data

Characteristic		WEM, Western Australia	SEN, Chile	ERCOT, Texas, USA	Eskom, South Africa	NEM, Eastern Australia	NEM, South Australia (when islanded from NEM)
Dispatch interval		10 minutes	60 minutes	5 minutes	60 minutes	5 minutes	5 minutes
Peak demand		4,006 MW	11,303 MW	74,328 MW	35,000 MW	32,761 MW	2,834 MW
Minimum demand		761 MW	7,520 MWh/h	Unknown	Unknown		318 MW
LFAS upward (or equivalent to LFAS upward)		120 MW (peak) 65 MW (off-peak)	Between 130 MW and 206 MW. Average 141 MW.	Between 73 MW and 684 MW. Average of 359 MW.	530 MW	220 MW (7,901 hours during 2021)	35 MW to 70 MW (<10 hours for 2020)
LFAS downward (or equivalent to LFAS downward)		120 MW (peak) 65 MW (off-peak)	Between -174 MW and -130 MW. Average -134 MW.	Between 151 MW and 631 MW. Average of 348 MW.	530 MW	210 MW (7,690 hours during 2021)	35 MW (<10 hours for 2020)
Annual (dispatchable) generation	Total	17,545 GWh	81,492 GWh	473.5 TWh	214,926 GWh	192,253 GWh	
	Variable generation	5,060 GWh (28.8%)	17,997 GWh (22.1%)	9.5 TWh (2%)	14,983 (7.1%)	24,213 GWh (12.6%)	
	Non-variable	12,485 GWh (71.2%)	63,495 GWh (77.9%)	464 TWh (98%)	201,095 (92.9%)	168,040 GWh (87.4%)	
Installed (dispatchable) capacity	Total	6,066 MW	30,862 MW	138,894 MW	51,867 MW	55,599 MW	6,109 MW
	Variable generation	1,197 MW (19.7%)	9,734 MW (31.5%)	34,988 MW (25%)	161.4 MW (0.3%)	18,678 MW (33.6%)	2,493 MW (41%)
	Non-variable generation	4,869 MW (80.3%)	21,138 MW (68.5%)	103,906 MW (75%)	51,705 MW (99.7%)	36,921 MW (66.4%)	3,616 MW (59%)
Non-dispatchable rooftop solar	Installed capacity	1,421 MW	113.5 MW	990 MW* *As at December 2020	Unknown or 0 MW* *See note in section 5	11,411 MW (2020)	1,527 MW (2020)
	Annual generation	1,984 GWh	Unknown	Unknown	Unknown or 0 GWh* *See note in section 5	13,042 GWh (2020)	1,835 GWh (2020)

GHD Advisory

ghd.com

→ The Power of Commitment