2020 FORECAST IMPROVEMENT PLAN

SUBMISSION RESPONSE DOCUMENT

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EXECUTIVE SUMMARY

The publication of this Submission Response document concludes the consultation process conducted by AEMO to improve its forecasting under the National Electricity Rules (NER) Clause 3.13.3A (h)(2). AEMO published its annual Forecast Accuracy Report (FAR) in December 2020 and asked for stakeholder feedback on the Forecast Improvement Plan included in the FAR.

This document outlines AEMO's responses to key issues raised in written submissions[1], specifically:

- Inter-regional transmission elements.
- The Inter-regional transmission element forced outage rate model.
- The forecast impacts of energy storage systems and electric vehicles.

Additionally, AEMO has chosen to respond to several issues relating to the FAR, beyond the scope of the Forecast Improvement Plan consultation.

The responses are compiled in this Submission Response Document, which has been published along with the final Forecast Improvement Plan and each received submission on AEMO's website[2].

[1] Available at: https://aemo.com.au/consultations/current-and-closed-consultations/2020-forecast-improvement-plan-consultation

[2] See https://aemo.com.au/consultations/current-and-closed-consultations/2020-forecast-improvement-plan-consultation

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1. STAKEHOLDER CONSULTATION PROCESS

As required by the National Electricity Rules (NER) Clause 3.13.3A (h)(2), AEMO must publish any improvements made by AEMO or other relevant parties to the forecasting process that will apply to the next Electricity Statement Of Opportunities (ESOO) for the National Electricity Market (NEM), in accordance with the Interim Reliability Forecast Guidelines.

AEMO is currently consulting on its Forecast Improvement Plan that outlines proposed forecasting improvements that may apply to the 2021 ESOO.

AEMO's timeline for this consultation is outlined below.

Deliverable	Indicative date
Forecasting Reference Group discussion of draft Forecast Accuracy Report and Forecast Improvement Plan	28 October 2020
Forecast Accuracy Report and Forecast Improvement Plan Published	2 December 2020
Submissions due on Forecast Improvement Plan	15 January 2021
Final Forecast Improvement Plan and Submission Response document published	12 February 2021
Updated methodology documents	On implementation of improvements

The publication of this Submission Response Document and final Forecast Improvement Plan concludes the consultation process.

A glossary of terms used in this Draft Report is at **Appendix A.**

2. BACKGROUND

2.1. Context for this consultation

As required by NER clause 3.13.3A(h) AEMO must, no less than annually, prepare and publish on its website information related to the accuracy of its demand and supply forecasts, and any other inputs determined by AEMO to be material to its reliability forecasts. This requirement is met by the publication of the Forecast Accuracy Report (FAR).

The FAR includes information related to proposed improvements to the forecasting processes that may apply to the next ESOO, with a particular focus on those arising from forecast deviations.

In accordance with AEMO's Interim Reliability Forecast Guidelines[3], AEMO must consult on the Forecast Improvement Plan part of the FAR using a short-form (single round) consultation process. For this, AEMO has used the process outlined in Appendix A of the Interim Reliability Forecast Guidelines.

2.2. Consultation

AEMO issued a Notice of Consultation on 2 December 2020 along with its Forecast Improvement Plan detailed in Section 8 of the 2020 FAR.

Some of the observed differences between actuals and forecasts have helped steer the direction for additional improvements to be implemented for the 2021 forecasts, to improve forecast accuracy in the

[3] See Section 4.2 in https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2019/interim-reliability-forecast-guidelines/interim-reliability-forecast-guidelines.pdf.

first five years of the reliability forecast relied upon for the Retailer Reliability Obligation (RRO), and for use in the 2021 ESOO and 2022 Integrated System Plan (ISP).

The priority improvements proposed for 2021 and the subject of this consultation are listed below:

- Improved photovoltaic (PV) forecasts.
- Improved visibility and understanding of consumption patterns and trends.
- Better visibility of forecast monthly maximum demand.
- Wind generation trace development.
- Improved modelling of inter-regional transmission elements' forced outages.

AEMO received three written submissions to the consultation.

Copies of all written submissions have been published on AEMO's website[4].

3. SUMMARY OF MATERIAL ISSUES

The key material issues arising from the proposal and raised by Consulted Persons are summarised in the following table:

No.	Issue	Raised by
1.	Consideration of inter-regional transmission elements	ERM Power, MEU
2.	Inter-regional transmission element forced outage rate model	ERM Power
3.	Forecast impacts of energy storage systems and electric vehicles	EQL

As noted in the FAR, this consultation focuses on the continuous improvement initiatives outlined in the Forecast Improvement Plan only, and not the FAR methodology (which was consulted on separately in 2020)[5], nor does it cover more material methodological changes that may be suggested as part of the four-yearly review of the Forecasting Approach. AEMO is currently consulting on the Electricity Demand Forecasting Methodology[6] as part of this four-yearly review cycle.

A number of issues have been raised in the responses that do not relate to the Forecast Improvement Plan. These are summarised in Section 5 and, where appropriate, will be captured on AEMO's Forecasting Approach Register[7] for consideration at a later stage

4. DISCUSSION OF MATERIAL ISSUES

4.1. Consideration of inter-regional transmission elements

4.1.1. Issue summary and submissions

AEMO considers the impact of unplanned outages on inter-regional transmission power transfer capability when calculating, and assessing the performance of, the reliability forecast. ERM Power and MEU raised concerns that AEMO incorrectly considers unplanned outages on intra-regional transmission elements when assessing inter-regional transmission power transfer capability in the context of the Reliability Forecast.

[4] See: https://aemo.com.au/en/consultations/current-and-closed-consultations/2020-forecast-improvement-plan-consultation
[5] See: https://aemo.com.au/consultations/current-and-closed-consultations/forecast-accuracy-report-methodology
[6] See: https://aemo.com.au/en/consultations/current-and-closed-consultations/electricity-demand-forecasting-methodology
[7] See: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach

ERM Power suggested that NER clause 3.9.3C should be interpreted such that inter-regional transmission power transfer capability is only provided by the limited number of transmission elements that cross regional boundaries. In the case of Victoria to South Australia, this would include only 'the two 275 kV transmission lines between the Heywood Terminal Station in Victoria and the South East substation in South Australia and the associated 275/500 kV transformers at the Heywood Terminal Station'.

Using this interpretation, ERM Power suggested that AEMO has misrepresented historical outages on transmission lines that do not cross regional boundaries as inter-regional transmission line outages.

ERM Power further suggested that the unplanned network outages referenced by AEMO, including outages in December 2019 and January 2020, should not be considered because sufficient generation supply capability existed at the time.

4.1.2. AEMO's assessment

AEMO disagrees with the interpretation of the NER clause 3.9.3C proposed by ERM and MEU, and suggests that inter-regional power transfer capability is instead provided by transmission elements, including but not limited to those that cross regional boundaries.

NER clause 3.9.3C specifies what should be included and excluded from the calculation of unserved energy (USE). For example, clause 3.9.3(b)(1)(i) requires AEMO to include consideration for 'a single *credible contingency event* on a *generating unit* or an *inter-regional transmission element*'. Additionally, clause 3.9.3(b)(2)(ii) requires AEMO to exclude consideration for '*outages* of *transmission network* or *distribution network* elements that do not significantly impact the ability to transfer *power* into the *region* where the USE occurred'. Collectively these clauses suggest that an inter-regional transmission element it is not only the physical lines that strictly cross a regional boundary, but also network elements that impact the ability to transfer power between regions.

This understanding was further clarified in the recently added clause 3.9.3C(c) through the addition of the phrase 'The reference to "*inter-regional transmission elements*" in this paragraph (c) includes only those *transmission elements* that materially contribute to *inter-regional power transfer'*.

Given the forward-looking nature of the reliability forecast, the correct inclusion of the probability of single credible contingencies on inter-regional transmission elements that materially contribute to inter-regional power transfer capability is required to ensure that sufficient generation, demand response and inter-regional power transfer capability remains available, and delivers outcomes consistent with the National Electricity Objective (NEO)[8]. Historical availability is not sufficient to justify exclusion of these factors.

4.1.3. AEMO's conclusion

AEMO rejects the suggestion that the inclusion of outages on lines that materially contribute to inter-regional power transfer capability is misleading and inconsistent with the NER. AEMO will continue to include single credible contingencies on only those transmission elements that materially contribute to inter-regional power transfer capability in its assessment of historical and forecast USE.

4.2. Inter-regional transmission element forced outage rate model

4.2.1. Issue summary and submissions

AEMO has proposed a change to the calculation method of forced outage rates on inter-regional transmission elements to better reflect weather as a driver of outage, where relevant.

[8] See https://www.aemc.gov.au/regulation/regulation.

ERM Power did not support AEMO's proposed change, on the basis that it would 'introduce bias in the modelling to align the modelled outages of inter-regional network assets with higher temperature conditions which would generally align with high demand periods in the modelling'.

4.2.2. AEMO's assessment

AEMO's proposal is to develop and implement transmission failure models that predict failure as a function of weather, where relevant. The example provided in the Forecast Accuracy Report shows that outages on some Victoria to New South Wales inter-regional transmission elements can be predicted as a function of bushfire weather.

AEMO notes the submission did not provide evidence of increased bias due to AEMO's proposed modelling of inter-regional transmission outage rates. AEMO notes the inclusion of weather as a predictor of transmission outage is supported in historical trends, and as such is expected to reduce rather than increase bias.

4.2.3. AEMO's conclusion

AEMO rejects the assertion that the proposed change would introduce a bias, or that it would increase the average rate of outage. Where there is sufficient evidence that inter-regional transmission outages are caused by weather that is able to be modelled, AEMO will implement time-varying forced outage rates to improve the accuracy of the reliability forecast.

4.3. Forecast impacts of energy storage systems and electric vehicles

4.3.1. Issue summary and submissions

Historical data, where available, helps validate forecasts for different components and subsequently assess the accuracy of these forecasts. Where no such data is readily available, the forecasts become more driven by assumptions. This is in particular the case for emerging technologies.

EQL noted that while there is significant historical data about rooftop PV, it would be prudent to examine assumptions for batteries and electric vehicles (EVs) on load profiles, energy and demand forecasts, where historical data is not available to guide the forecasts.

4.3.2. AEMO's assessment

AEMO agrees that forecasts for batteries and EV uptake and the resulting impacts on energy and demand forecasts and half-hourly load profiles are more assumption-driven than forecasts for mature technologies like rooftop PV.

For emerging technologies such as battery and EVs, AEMO relies on consultancy forecasts and stakeholder engagement to validate and verify the assumed impact of these devices.

Stakeholders have an opportunity to review and consult with AEMO on the development of these forecasts via:

- Release of interim forecasts in AEMO's Draft Inputs, Assumptions and Scenarios Report (IASR)[9] consultation.
- Release of draft forecasts in AEMO's Forecasting Reference Group (FRG) meetings[10].

[9] See: https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/draft-2021-inputs-assumptions-and-scenarios-report.pdf.

[10] For further information about the FRG, see: https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg.

To improve the knowledge base, AEMO engages with industry to collect data and may occasionally commission or otherwise be involved in research activities looking further into the adoption and use of new technologies, for example through the NEAR program[11].

Specific to batteries, AEMO is working with distribution network service providers (DNSPs) to improve the knowledge of existing battery storage installations within the DER Register, and working with CSIRO through the NEAR project to develop methodologies to identify battery installations from metering data along with their operating profiles. This may allow identification of additional installations and improve the historical data available to assist with forecasting over the next couple of years.

For EVs, AEMO has been leading the EV Data Availability Taskforce under the Distributed Energy Integration Program (DEIP) Electric Vehicle Grid Integration Working Group[12]. The initial work, to be published in the near future, identifies the EV data needs from an energy sector perspective, including EV registration data and the installation of EV charging infrastructure, alongside potential collection mechanisms and delivery options for this data.

4.3.3. AEMO's conclusion

While not explicitly mentioned in the Forecast Improvement Plan, AEMO is working on a number of initiatives to improve the understanding of emerging technologies like batteries and EVs, which will help to form assumptions and validate forecasts. For increased transparency, AEMO will add this as a new point to the Forecast Improvement Plan.

Furthermore, interested stakeholders are encouraged to provide feedback to the inputs, assumptions and draft forecasts when battery and EV forecasts are presented at FRG meetings, to allow further potential improvements to be identified and to assist in validating the assumptions underpinning the outcomes.

5. OTHER MATTERS

Several issues were raised that related directly to the forecast accuracy assessment, the presentation of the information, and the process around the publication. While these were not up for consultation, AEMO has covered these issues briefly below.

5.1. Forecast Accuracy Report independent review

5.1.1. Issue summary and submissions

AEMO assesses the forecast accuracy and identifies forecast improvements opportunities where deviations between forecasts and actuals are significant. These are published in the annual FAR.

Both ERM Power and MEU noted that the FAR is currently being prepared and reviewed entirely by AEMO. As the forecasts reviewed in the FAR are critical inputs into AEMO's ESOO, submissions proposed that the FAR is reviewed and audited by an independent party selected by either the Australian Energy Regulator (AER) or the Reliability Panel. The FAR should then contain, as an appendix, a statement by the independent auditor setting out details of their review including questions asked of AEMO and AEMO's responses.

5.1.2. AEMO's assessment

The AER reviews the reliability forecast and its components when a Reliability Instrument Request is issued by AEMO, so an independent evaluation of the forecast is undertaken when the reliability forecast has the potential to impact cost to industry and thus end consumers.

[11] See: https://near.csiro.au/.

[12] See: https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/ev-grid-integration-workstream/.

In addition, AEMO supports an independent review of the FAR methodology every four years as outlined in AEMO's draft determination to its Reliability Forecast Guidelines consultation[13]. However, AEMO considers an annual review to be excessive and not constituting value for energy consumers.

5.1.3. AEMO's conclusion

AEMO proposes to undertake an independent review of the methodology to assess forecast performance at least every four years ahead of the formal consultation of the Forecast Accuracy Report Methodology. AEMO then follows the documented methodology to assess forecast performance each year and transparently reports on its assessment. Such an assessment should be able to be replicated by external parties if they have access to all necessary data, which will be made available if not confidential.

5.2. PV forecast accuracy

5.2.1. Issue summary and submissions

Section 3.3 of the FAR discusses the accuracy of the PV forecast component used in the consumption and demand forecasts. The 2020 FAR highlighted significant inaccuracies in most regions, and identified the area as the one it was most important to improve on in future forecasts.

Related to this, ERM Power and EQL sought further detail on:

- ERM Power – how the FAR adjusts the Clean Energy Regulator (CER) PV data to reflect system replacements and the basis for doing so (see Section 3.3 of the FAR).
- EQL – how demand and/or energy forecasts reflect disparate growth rates of PV, EVs and batteries when the FAR assumes all three DER components (PV, EVs and batteries) follow the low growth paths in the slow change scenario (and high growth paths in the step change scenario). EQL noted that EVs and batteries could follow a slow growth scenario while PV follows a high growth scenario, as evidenced in current data.
- EQL – the key reasons behind underestimating PV forecasts in the 2019 ESOO.
- EQL – the approach used to estimate PV internal usages (as impacting energy sales).
- EQL – the relationship between PV and battery adoption in the medium and long term.

5.2.2. AEMO's response

The points are addressed in the table below.

Submission question	AEMO response
How the FAR includes AEMO's adjustment to CER's PV data to reflect system replacements	The FAR mistakenly referred to adjustments to CER data to account for system replacements. The process has this step, but no adjustments are currently made. AEMO will make sure its documentation of the approach in the future reflects this correctly. As the installed PV systems get older, system replacements will become more frequent and AEMO will be looking for ways to estimate the magnitude of this, so it can be accounted for.

[13] See: https://aemo.com.au/en/consultations/current-and-closed-consultations/reliability-forecast-guidelines.

Submission question	AEMO response
How demand and/or energy forecasts reflect disparate growth rates of PV, EVs and batteries when the FAR assumes all factors such as PV, EVs and batteries all follow the low growth paths in the slow change scenario	The role of the FAR is to present the actual uptake against the ESOO scenarios being assessed. A large number of scenarios can be created from permutations of individual component drivers, including the one proposed by EQL above. As part of AEMO's new biennial review of scenarios and annual review of inputs and assumptions (as required by the Actionable ISP Rules framework and the Forecasting Best Practice Guidelines), AEMO engages and consults on the appropriate settings for each scenario, including DER settings used in its forecasts. AEMO encourages stakeholder engagement throughout that consultation process to ensure a broad and distinct range of plausible scenarios are considered.
The key reasons behind underestimating PV forecasts in the 2019 ESOO	The key reasons behind underestimating PV forecasts are summarised in Section 3.3 of the 2020 FAR[A.] To summarise, the main issue was an inaccurate estimate of installed capacity in the period up to the forecast being produced, failing to fully account for the substantial time lag of PV installations being reported to the CER. This had two main impacts: • It caused the starting point of the forecast to be set too low. This can be seen from Figure 5 in the FAR, where the estimated PV capacity (red line) at time of making the ESOO (May 2020) is somewhat under what more recent updates to CER data has revealed (dashed line). • The estimate of the current rate of installations was lower than its true value, causing the installation trend slope to be too low as well. The compounding effect of starting too low and not growing fast enough caused a significant under-forecast of capacity even within the first forecast year.
The approach used to estimate PV internal usages (as impacting energy sales)	AEMO obtains forecasts of the number of installed PV systems and the combined size in MW from one or more consultants. To estimate the generation of this installed capacity, AEMO uses estimated historical half-hourly traces of generation, normalised to show generation in MWh per MW of installed capacity. AEMO gets these normalised generation (normgen) traces from an external provider (Solcast), who calibrates these traces with data from a large number of existing systems to ensure they reasonably reflect actual observed generation. These profiles account for any internal use, such as losses, panel shading and inverter efficiency. This is explained in Section A3.1.2 in the Electricity Demand Forecasting Methodology[B] currently under consultation. To forecast the impact of rooftop PV on annual consumption, the annual median of the various historical normgen traces is used to the forecast generation from the forecast installed capacity. For maximum/minimum demand forecasting a probabilistic approach is used instead, with the normgen traces being used directly (rather than the median), but still scaled with the forecast installed capacity.

Submission question	AEMO response
The relationship between PV and battery adoption in the mid and long term	AEMO relies on PV and battery forecasts provided by consultants who are subject matter experts. In 2019, these forecasts were produced by CSIRO and Energeia. CSIRO, who has also provided subsequent forecasts for AEMO, specifically uses a technology adoption model that takes into account a mix of financial and non-financial incentives. There is no fixed relationship assumed, but as technology costs change over time, the relative adoption of PV systems vs PV systems with storage changes too. A chart is shown in CSIRO's 2020 forecast report[C] (Figure 5-8) which shows the share of PV installations with battery storage by customer type. As battery costs reduce in the 2020s, more and more PV systems will have battery storage as the payback time improves. Longer term, battery cost reductions are assumed to level out, flattening the uptake, as PV systems are assumed to continue to improve. There is also a potential longer term for EVs to affect the relativity between the payback of stand-alone PV systems and system with PV and battery storage combined.

A. See: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/forecast-accuracy-report-2020.pdf

B. See: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/electricity-demand-forecasting-methodology/first-stage/draft-electricity-demand-forecasting-methodology.pdf

C. See: https://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2020/CSIRO-DER-Forecast-Report

5.3. Network loss percentage over time

5.3.1. Issue summary and submissions

To convert between operational demand and underlying customer demand within its forecasting process, AEMO uses estimated network losses as a percentage of both annual consumption and half-hourly demand.

ERM noted that in Section 3.5 of the FAR, AEMO states that it assumes the loss percentage for the latest financial year is a reasonable estimate for losses over the entire forecast period. ERM recommended that this assumption is carefully monitored by AEMO, as this can change with the changing patterns of generation.

5.3.2. AEMO's response

AEMO agrees that this assumption needs to be carefully monitored. The FAR itself mentions that AEMO has assessed this assumption against recent trends and found it was appropriate. Furthermore, the draft Electricity Demand Forecasting Methodology[14] currently under consultation reflects that an increasing or decreasing trend, if statistically significant, will be used instead of an assumed constant loss percentage.

5.4. Involuntary load shedding use of terminology

5.4.1. Issue summary and submissions

Section 5.1 of the FAR discusses the extreme demand events observed in 2019-20 outlining the date and time for each regional maximum and minimum demand event.

In the discussion of maximum demand outcomes for the 2019-20 summer, ERM questioned AEMO's use of the term "involuntary load shedding". Specifically, for the peak demand day in Victoria, AEMO stated that due to extreme wind damaging transmission assets, there was also involuntary load shedding. ERM

[14] See: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/electricity-demand-forecasting-methodology/first-stage/draft-electricity-demand-forecasting-methodology.pdf.

suggests the term "involuntary load shedding" within the industry generally refers to consumer load which has been reduced or disconnected due to the issue of an instruction by AEMO as per NER Clause 4.8.9.

5.4.2. AEMO's response

AEMO notes "involuntary load shedding" is not a defined term in the NER, but *load shedding* is and AEMO agrees the NER definition of *load shedding* – "reducing or *disconnecting load* from the power system" – indicates load shedding is a reduction in load following an active action by AEMO or other parties, such as NSPs.

Involuntary load shedding is, however, used in a more general sense of USE in the Regulatory Investment Test for Transmission (RIT-T) section of the NER[15] along with AER's Cost Benefit Analysis Guidelines[16] and RIT-T Application Guidelines[17], and AEMO is using the term in this broader sense.

The FAR did point out that the involuntary load shedding observed in Victoria was due to "extreme wind damaging transmission assets" and AEMO will commit to provide such explanations of the driving force behind any reported involuntary load shedding.

5.5. Adjustment to Victorian maximum demand

5.5.1. Issue summary and submissions

AEMO forecasts what regional maximum demand would be in the absence of any load shedding, network outages and any customer response to price and/or reliability signals, known as Demand Side Participation (DSP). To allow observed (metered) demand to be compared with the forecast distribution, tables 14-16 in Section 5.1 of the FAR summarise both the observed demand and the adjusted demand, accounting for any events not reflected in the forecast.

ERM Power sought more detail in relation to adjustments of Victorian region's maximum demand outcomes as set out in FAR Table 14. The submission noted that the FAR contains no detail with regards to what loads were interrupted or, in the case of the "potential" adjustments, of the breakdown of the basis for such adjustment. ERM Power recommended future reports contain more detail on such adjustments.

5.5.2. AEMO's response

AEMO thanks ERM Power for identifying where provision of further details would assist stakeholders in better understanding the analysis, and will seek to provide more explanation around adjustments to demand in future reports.

In this case, to protect confidentiality of consumption data, AEMO cannot be too specific. Around half the firm adjustment was due to an interruption of customer load, with the remaining covering the Reliability and Emergency Reserve Trader (RERT) response (84 MW dispatched). The RERT response included AusNet's Critical Peak Day program (adjusted to exclude any loads that also are within a RERT portfolio) with the remainder being price driven DSP response.

The potential adjustment has been estimated using the process outlined in AEMO's Forecast Accuracy Report methodology[18] and includes a 40 MW reduction of air conditioner load and 69 MW of reduction of other appliance load.

[15] Clause 5.16.1(c)(4) of the NER.

[16] See: https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%20 2020.pdf

[17] See: https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20application %20guidelines%20-%2025%20August%202020.pdf.

[18] See: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/forecast-accuracy-reporting-methodology-report-aug-20.pdf

5.6. FAR monthly maxima reporting

5.6.1. Issue summary and submissions

The regional subsections within the extreme demand forecast section (Section 5 of the FAR) present a box plot of the distribution of the monthly maximum demand outcomes used across the demand traces used for the ESOO and Medium Term Projected Assessment of System Adequacy (MT PASA) modelling, along with the actual observed monthly maximum demand for the region.

ERM Power supported the inclusion of the regional monthly maxima data graphs, but noted that the forecast range for both the 50% and 10% probability of exceedance (POE) values are combined as a single distribution. ERM Power suggested more added value to stakeholders if the 50% and 10% POE ranges were shown as two separate distributions.

To complement the above, ERM Power further recommended the addition of a new graph setting out details of the daily maximum temperature on the day of maximum regional demand, the daily maximum temperature during the month (if these are different values), and the historical range of monthly maximum daily temperature outcomes for the relevant regional reference weather station.

5.6.2. AEMO's response

For the regional monthly maxima data graphs, AEMO believes combining the two is most accurate. The 10% POE and 50% POE targets are percentiles of the full seasonal maximum demand distribution, and combining the two gives a better representation of where the actual should fall than using a single set of traces. Ideally, it should include a 90% POE as well, but for computational reasons, these are not modelled in MT PASA.

AEMO also notes that for most months, the way the traces are produced, the monthly maximum values for the 10% POE and 50% POE traces will be identical, as only the highest demand periods during summer (typically occurring in January-February) are grown[19] to meet the forecast targets for 10% POE and 50% POE maximum demand. Similarly, only top winter peak days (typically in June-July) are grown according to the winter maximum demand forecast targets. For the shoulder months in between, the shown distributions of monthly maximum demand outcomes in the traces are typically identical.

AEMO maintains a Forecasting Approach Register, one of the purposes of which is to capture matters for consideration in future consultations. As ERM Power's suggestion on a temperature graph relates to a change in the Forecasting Accuracy Reporting Methodology, it will be noted in the Forecasting Approach Register. AEMO may consider trialling this proposal on a voluntary basis ahead of the next formal consultation on the Forecasting Accuracy Reporting Methodology.

5.7. Presentation of forecast versus actual regional supply in the FAR

5.7.1. Issue summary and submissions

Section 6 of the FAR assesses the accuracy of the supply forecast and specifically compares actual regional supply availability with the simulation outcomes of supply availability in the ESOO modelling.

ERM Power expressed concerns around the charts presented in this section:

1. ERM Power said that while AEMO utilises the full extent of actual generator supply data, this is then compared to a truncated simulated forecast that does not fully represent the full range of simulated supply forecasts used in the modelling. The submission said this creates a biased representation of actual regional generation supply vs simulated forecast in the FAR, which can result in a

[19] As per AEMO's Electricity Demand Forecasting Methodology, only the single highest summer demand day in a reference year is grown to meet the forecast 10% or 50% POE with other high demand days are grown proportionally.

misrepresentation that actual supply outcomes are lower than the simulated forecasts. ERM Power recommended the full range of simulated forecasts should be represented in the graphs.

2. ERM Power also submitted that AEMO provides no detail of what reported availability data (maximum availability or PASA availability) on which the actual generator supply outcomes were based, and said this can vary significantly between the highest and tenth highest demand days represented in the graph, as generating units may have temporarily withdrawn on the basis that they were not required to ensure supply reliability. ERM Power recommended AEMO provide additional details in the FAR regarding the basis on which actual generator supply data was calculated.

5.7.2. AEMO's response

In response to the two issues:

1. AEMO notes that it has previously responded to this in detail and refers to Section 3.3.4 in the Forecast Accuracy Report Methodology Draft Determination[20].
2. The Forecast Accuracy Report Methodology[21] allows for AEMO to use either maximum availability or PASA availability, with PASA availability being the preference. However, in years where there are data quality issues with PASA data, maximum availability will be used instead. In the 2020 FAR specifically, PASA availability was used. In future FAR documents, AEMO will commit to specify which one is used.

6. SUBMISSION RESPONSE

Having considered the matters raised in submissions, AEMO has responded to each issue and published this Submission Response Document along with the final Forecast Improvement Plan and each received submission on its website[22].

[20] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/forecast-accuracy-report-methodology/forecast-accuracy-reporting-methodology-draft-determination.pdf.

[21] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/forecast-accuracy-report-methodology/forecast-accuracy-reporting-methodology-report-aug-20.pdf.

[22] See https://aemo.com.au/consultations/current-and-closed-consultations/2020-forecast-improvement-plan-consultation.

APPENDIX A. GLOSSARY

Term or acronym	Meaning
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CER	Clean Energy Regulator
DSP	Demand Side Participation
ESOO	Electricity Statement of Opportunities
EQL	Energy Queensland
EV	Electric Vehicles
FAR	Forecast Accuracy Report
FBPG	Forecast Best Practice Guidelines
FIP	Forecast Improvement Plan
FRG	Forecasting Reference Group
IASR	Inputs, Assumptions and Scenarios Report
ISP	Integrated System Plan
MEU	Major Energy Users
NER	National Electricity Rules
NSP	Network Service Provider
PASA	Projected Assessment of System Adequacy
POE	Probability of Exceedance
PV	Photovoltaics
RERT	Reliability and Emergency Reserve Trader
USE	Unserved Energy