2022 Forecast Accuracy Report and Forecasting Improvement Plan

26 October 2022 FRG Meeting

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Purpose and agenda

The purpose of this presentation is to *inform* the FRG of draft 2022 Forecasting Accuracy Report (FAR) results and *consult* on the forecasting challenges and improvement priorities that motivate the 2022 Forecast Improvement Plan (FIP).

Today's Agenda includes:

- Forecast accuracy results summary
  - Results Overview
  - Distributed PV
  - Consumption
  - Maximum and Minimum Demand
  - Supply availability
- Forecast Improvement Plan
- Discussion
- Appendix
  - Other accuracy results
  - 2021 FIP initiatives

Timing	Relevant topic	Responsible
Oct 21 FRG	2021 FAR and Forecasting Improvement Plan presentations	AEMO
Dec 21 – Feb 22	2021 Forecasting Improvement Plan consultation	Stakeholders
Today	**2022 Forecast Accuracy Report and Forecast Improvement Plan**	**AEMO**
Nov 22 – Jan 23	FAR published and FIP consultation	AEMO, Stakeholders

Inaccuracies are generally explainable

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Forecasting results	NSW	QLD	SA	TAS	VIC	Assessability*	Comments
Energy Consumption	🟡	🟡	🟢	🟢	🟡	Strong	New South Wales, Queensland and Victoria all had larger errors driven by a modelling issue in the 2021 ESOO forecast. A fix was provided in the *Update to the 2021 ESOO* in April 2022.
Summer maximum demand	🟢	🟡	🟡	🟢	🟢	Weak - Moderate	Actual max demand in Queensland fell above the forecast range, driven by very high humidity, while South Australia fell just under the forecast range due to the La Niña conditions.
Winter maximum demand	🟢	🟡	🟢	🟡	🔴	Weak - Moderate	Actual max demand outcomes in Queensland and Victoria were above forecast range and Tasmania below. The remaining two regions showed good alignment.
Annual minimum demand	🔴	🔴	🟢	🟢	🟢	Weak - Moderate	Three regions showed good alignment, while New South Wales's actual min was lower than the forecast distribution and Queensland's actual min was above the forecast.
Demand side participation (DSP)	🟢	🟢	🟢	🟢	🟢	Weak - Moderate	Generally less DSP than forecast, in particular for wholesale demand response. Good alignment at time of peak in regions that had substantial prices at those times.
Installed generation capacity	🟢	🟡	🟢	🟢	🟡	Strong	Start date delays and slower commissioning in Victoria and Queensland significantly impacted availability compared with what was modelled.
Summer supply availability	🟡	🟡	🟢	🟡	🟢	Moderate	Planned and unplanned outages of key units during summer months and lower summer availability resulted in actual availability being lower than what was modelled across three regions.

Key:

🟢 Forecast has performed as expected. No actions required.

🟡 Inaccuracy observed in forecast is explainable by inputs and assumptions. These inputs should be monitored and incrementally improved, provided the value is commensurate with cost.

🔴 Inaccuracy observed in forecast needs attention and should be prioritised for improvement.

* Assessability – the extent to which accuracy can be assessed based on a single year of actual data

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Forecast installed PV capacity is much closer aligned with actuals than previously

FIP action: Consider options for tracking battery storage and electric vehicles similar to PV.

ESOO 2021 distributed PV forecast

		NSW	QLD	SA	TAS	VIC
Rooftop PV	Estimated actual* (MW)	4,871	4,781	1,926	226	3,465
	Central forecast (MW)	4,925	4,834	1,999	230	3,494
	Central forecast error (%)	1%	1%	4%	2%	1%
PVNSG	Estimated actual* (MW)	301	227	207	4	338
	Central forecast (MW)	345	258	220	3	368
	Central forecast error (%)	15%	14%	6%	-11%	9%
Total	**Central forecast error (%)**	**2%**	**2%**	**4%**	**1%**	**2%**

***as installed at 30 June 2022**

Significant improvement over last year's result

ESOO 2020 distributed PV forecast

		NSW	QLD	SA	TAS	VIC
Total	**Central forecast error (%)**	**-20%**	**-15%**	**-11%**	**-8%**	**-11%**
	Downside - High DER error (%)	-18%	-15%	-10%	-7%	-6%

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NEM consumption forecast required update in April 2022

Category	2021 Forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Cooling Degree Days	5,177	4,126	25.5%	0.6%
Heating Degree Days	8,211	8,975	-8.5%	-0.4%
Connections Growth	841	559	50.3%	0.2%
Large Industrial Loads (LIL)	45,123	43,565	3.6%	0.8%
Rooftop PV*	17,520	16,746	4.6%	0.4%
PV non-scheduled gen*	2,016	1,742	15.7%	0.1%
Other non-scheduled gen*	4,088	4,407	-7.2%	-0.2%
Network losses	9,300	10,257	-9.3%	-0.5%
Operational sent-out	**169,480**	**178,329**	**-5.0%**	**-4.7%**
Auxiliary load	8,562	8,162	4.9%	0.2%
Operational as-generated	**178,042**	**186,491**	**-4.5%**	

* Components netting off consumption use opposite sign convention

Cooling degree days were below forecast in all mainland states, driven by mild La Niña weather.

LILs were the largest source of difference between forecasts and actuals of the components measured.

Some regions had significant deviations for other non-scheduled generation (ONSG)

A significant residual remained unexplained. A forecast revision was released with the *Update to the 2021 ESOO* in April 2022, reducing the forecast error to 1.1%

FIP action: Review LIL and ONSG forecasts and expand breakdown of residual if possible.

Understanding demand charts

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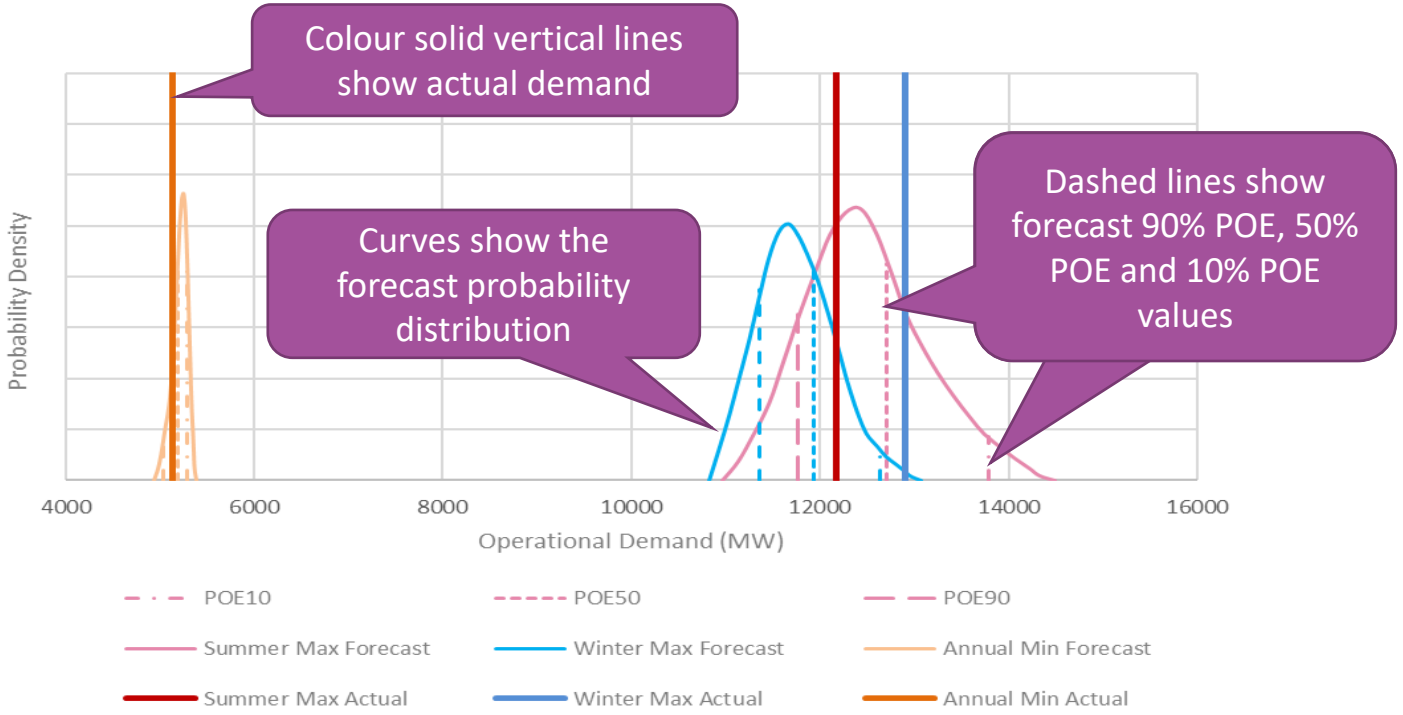
How to interpret Demand Results

- Maximum/minimum demand forecasts are probability distributions.
- Each colour represents a different forecast distribution and actual outcome.



POE – Probability Of Exceedance

General 2022 themes:

- Rooftop PV growth was well aligned with forecast, resulting in good minimum demand forecasts for most regions.
- Strong summer La Niña (rain, cool daytime temperatures) drove milder summer demand outcomes in most cases, but the resulting humidity also led to a very high demand outcome in Queensland.
- Winter was generally mild, but with significant cold snaps affecting some regions (Queensland and Victoria)

Apart from one case (QLD summer maximum), all shown issues remain when assessed against the *Update to the 2021 ESOO*

New South Wales minimum demand over forecast due to time of day change

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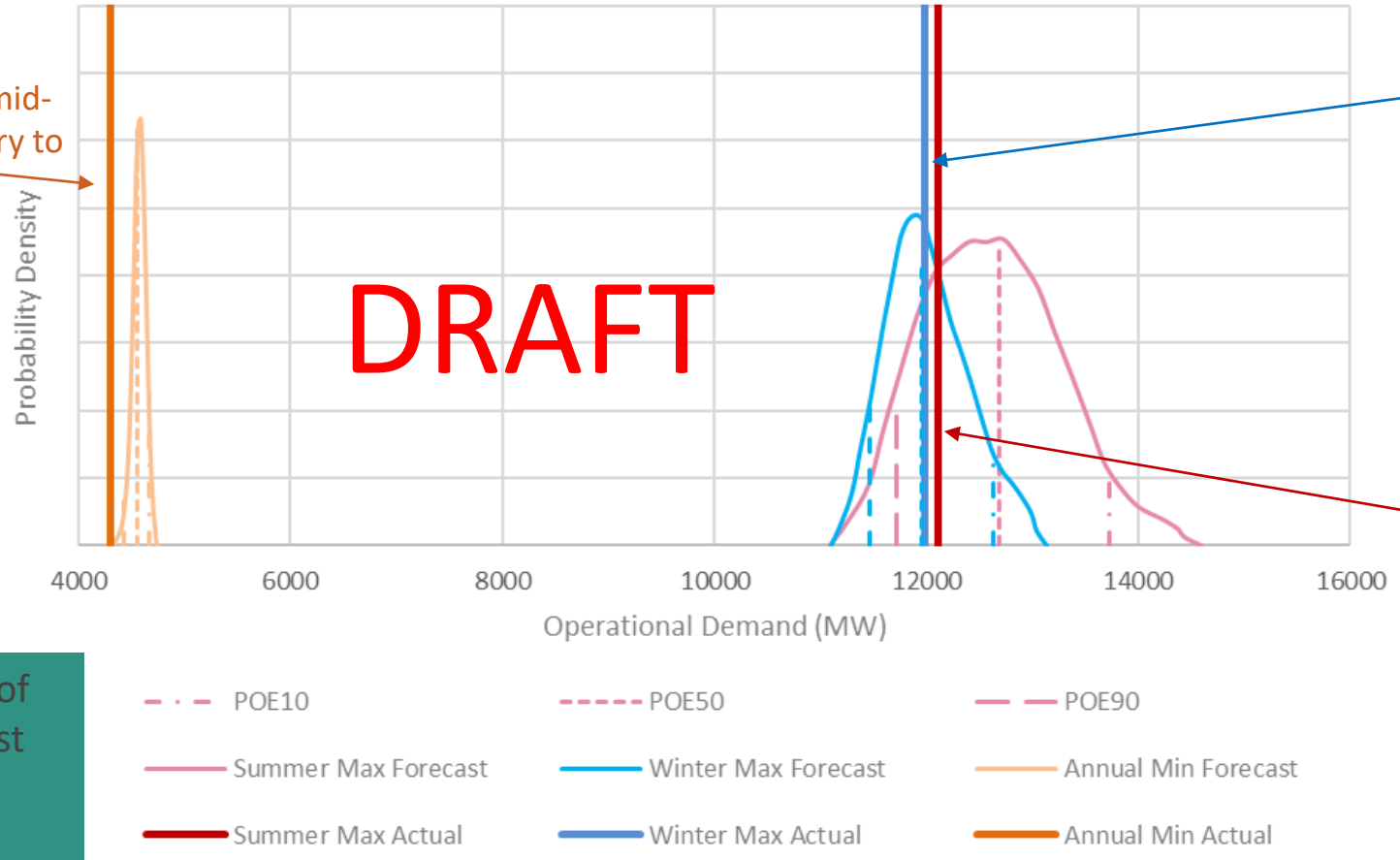
Actual was below forecast distribution. PV forecast was accurate. Only second year of mid-day min demand, so little history to build on.



The winter forecast aligned well with the forecast distribution, with actual outcome consistent with the conditions on the day.

Summer actual outcome was relatively low – driven by La Niña weather with very few, and relatively weak heatwaves.

FIP action: The distribution of the initial year of the forecast horizon requires review. Consider if any behavioural impact from PV owners.

Queensland extreme demand forecasts were all higher than expected

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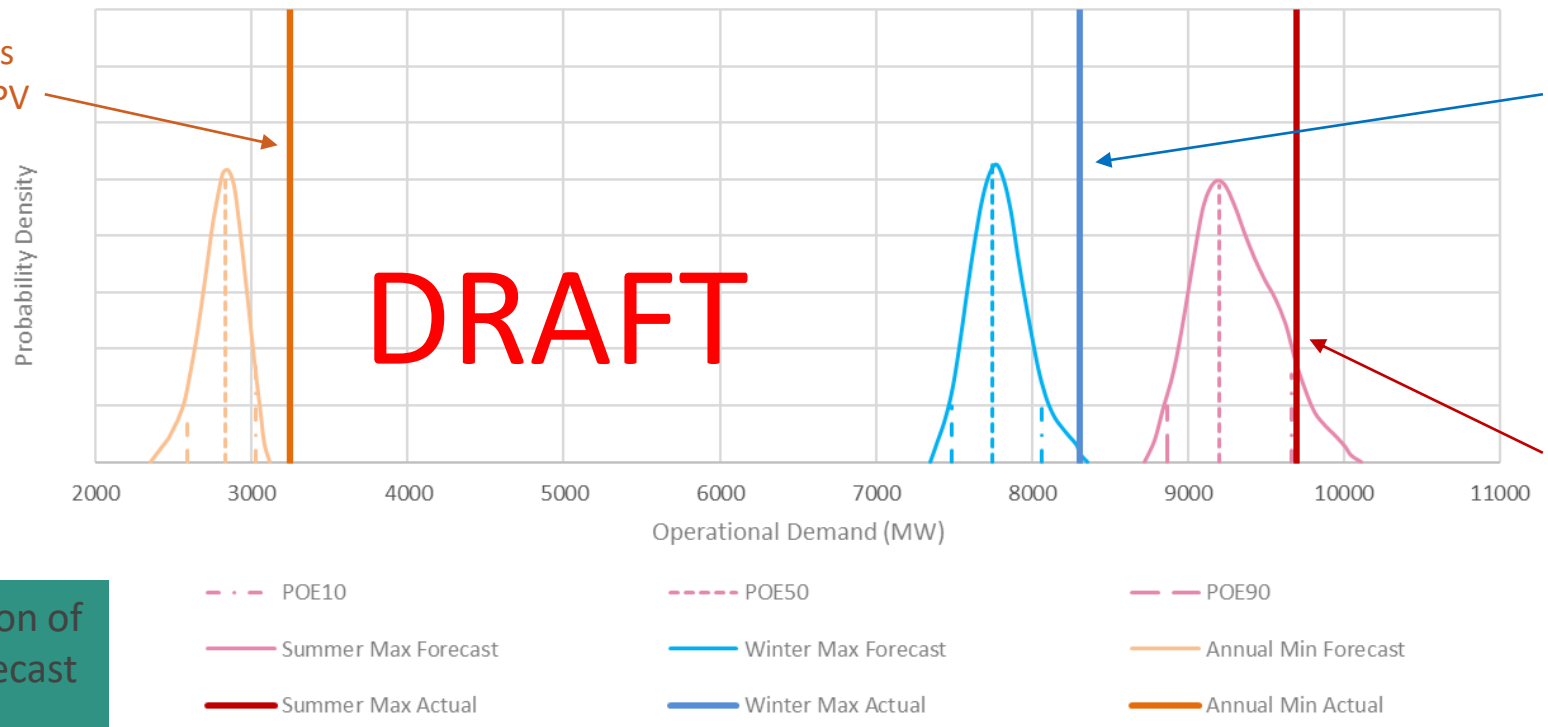
Actual outcome above forecast distribution. This cannot be explained by PV forecast, which was reasonably accurate.



Winter actual above 10% POE. Cold snap resulted in temperature records, with low temperatures recorded all the way up to Mackay.

Summer outcome just above 10% POE, driven by extreme humidity. I was just under 10% POE when assessed against the Update to the 2021 ESOO

DSP at time of maximum demand caused a 103 MW adjustment to the actual. This aligned well with 104 MW of forecast DSP.

FIP action: The distribution of the initial year of the forecast horizon requires review. Consider if any behavioural impact from PV owners.

South Australia extreme demand was well forecast

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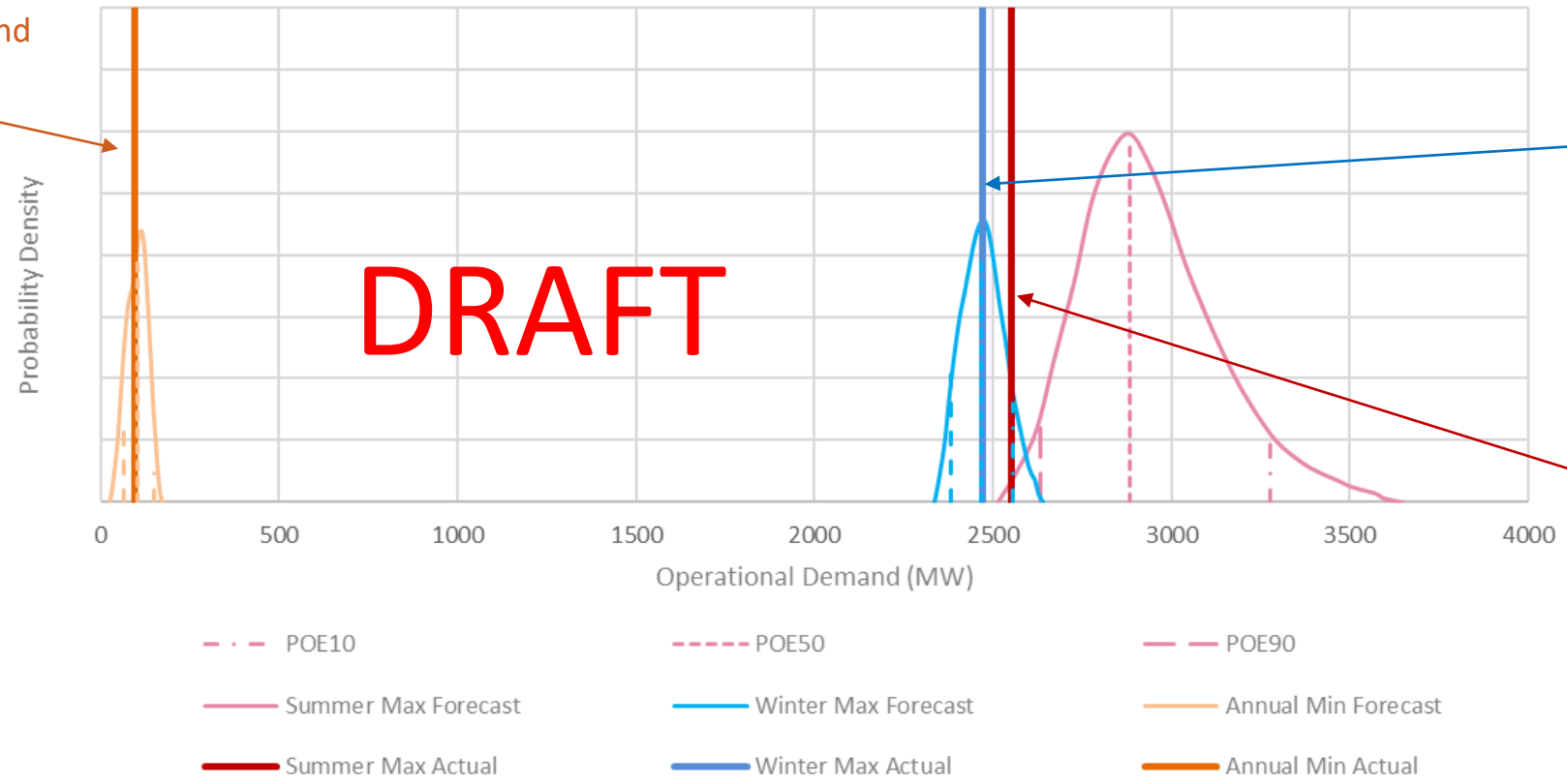
Actual minimum demand outcome well aligned with forecast.



The winter forecast aligned well with the forecast distribution, with actual outcome consistent with the conditions on the day.

Summer outcome below 90% POE, driven by the very mild Summer (La Niña).

Tasmania LIL forecast's impact on winter maximum demand needs review

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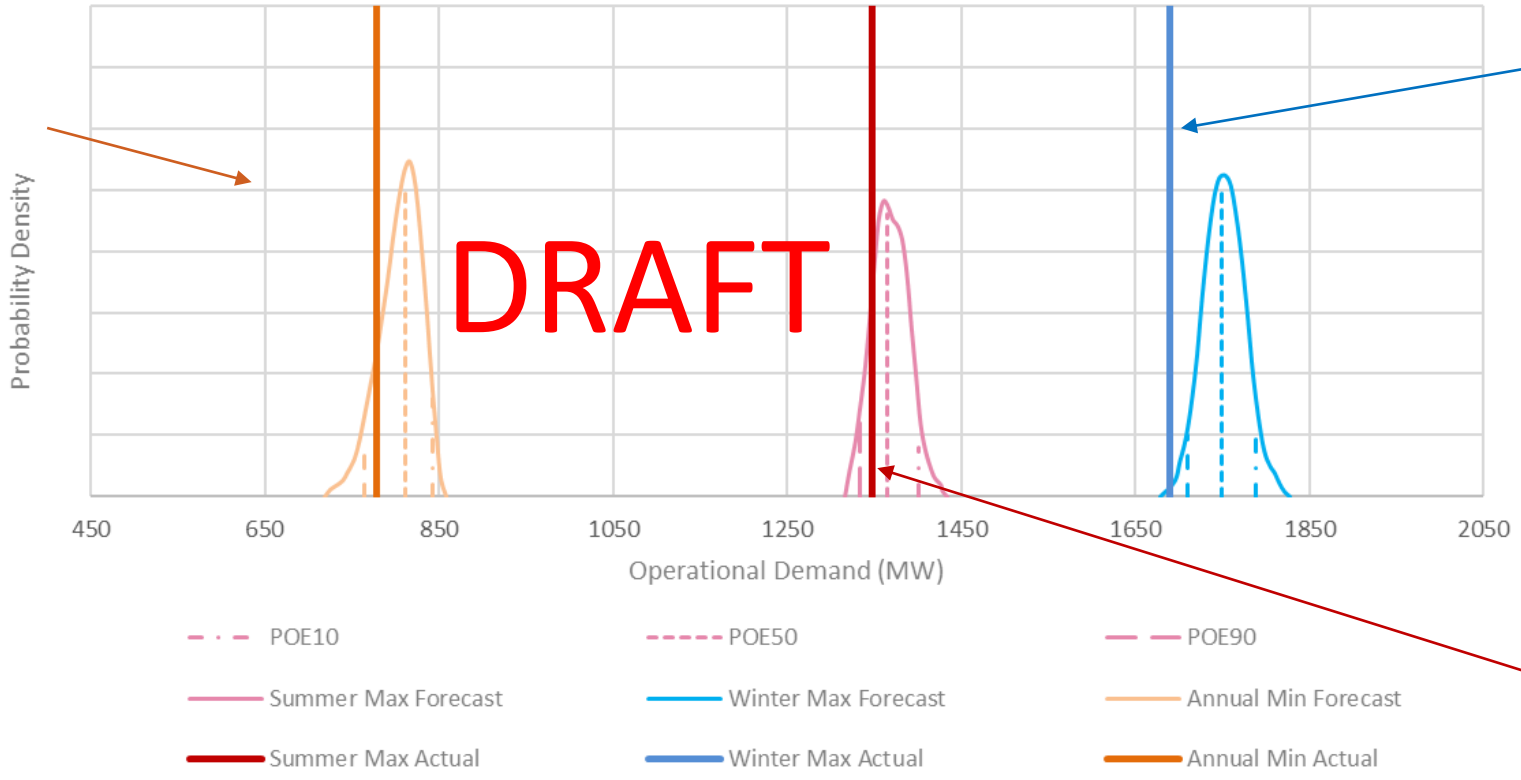
First time annual minimum demand occurred mid-day. Well aligned with forecast outcomes.



Winter actual below 90% POE driven by over-forecasting large industrial loads. This subcomponent requires review.

FIP action: The variability of large industrial loads and the impact on maximum and minimum demand in Tasmania should be reviewed.

The summer actual aligned well with the forecast distribution, with the actual outcome consistent with the conditions on the day.

Victoria winter maximum demand under-forecast due to initial forecast year

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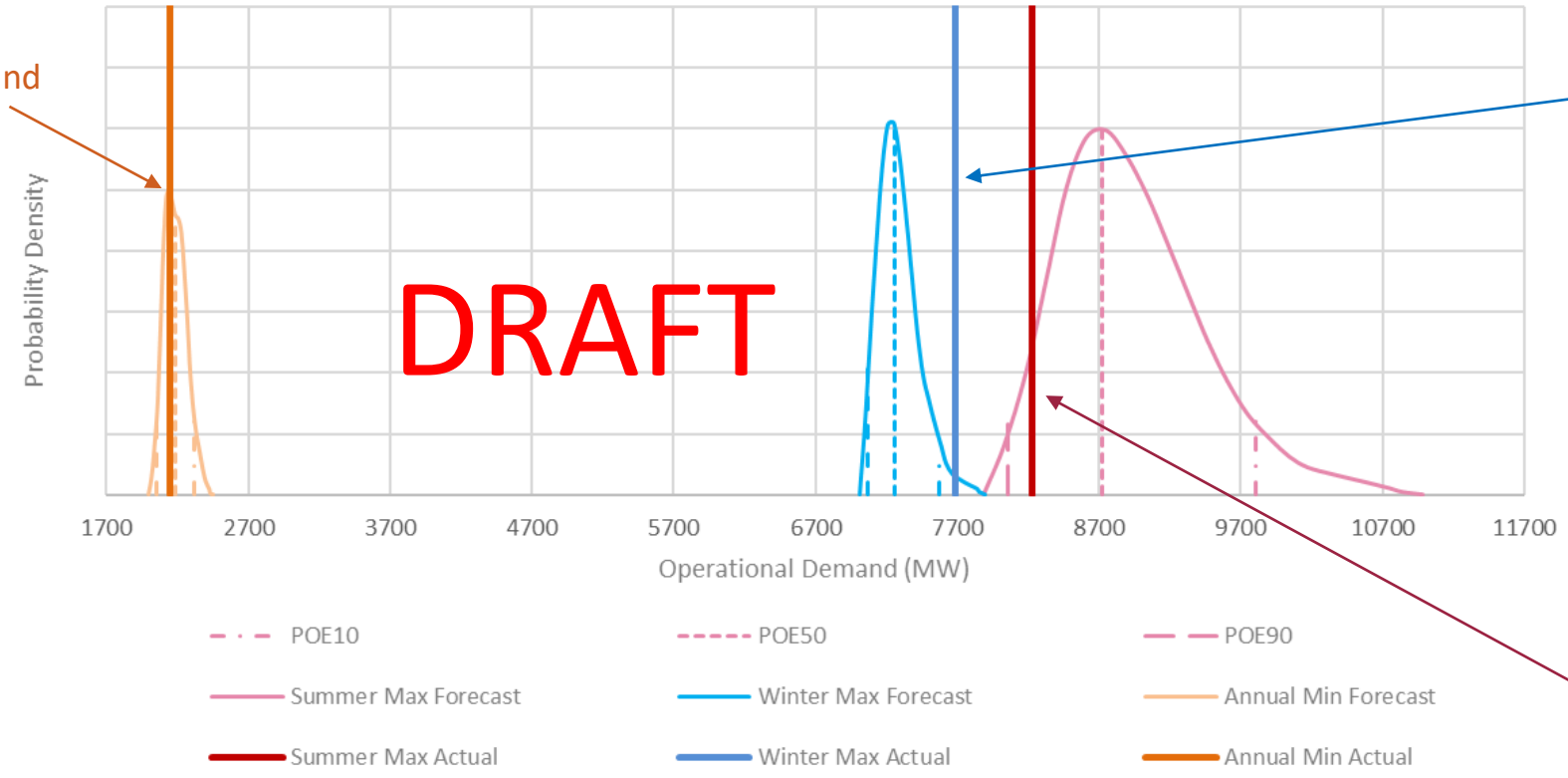
Actual minimum demand outcome well aligned with forecast.



Winter actual above 10% POE. The distribution of the initial year of the forecast horizon requires review.

FIP action: The distribution of the initial year of the forecast horizon requires review. Investigate impact from PV rebound effect.

Summer actual outcome was relatively low – driven by La Niña weather with very few, and relatively weak heatwaves.

Installed generation capacity over-forecast in several regions

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Region	Forecast Installed Capacity (MW) by Summer 2021-22	Actual Operating Capacity (MW) by Summer 2021-22	Difference
New South Wales	19,358	19,238	-1%
Queensland	15,095	14,774	-2%
South Australia	5,295	5,344	-1%
Tasmania	2,918	2,918	0%
Victoria	14,206	13,678	-4%

Participant-provided full commercial use dates proved too optimistic for some projects in New South Wales, Queensland, South Australia and Victoria, with approximately 900 MW of forecast generation capacity unavailable.

FIP action: Changes proposed to the commitment criteria implementation in Reliability Forecasting guideline and methodology consultation

Summer supply availability benefited from mild weather, but NSW, TAS and QLD results did not match expectation

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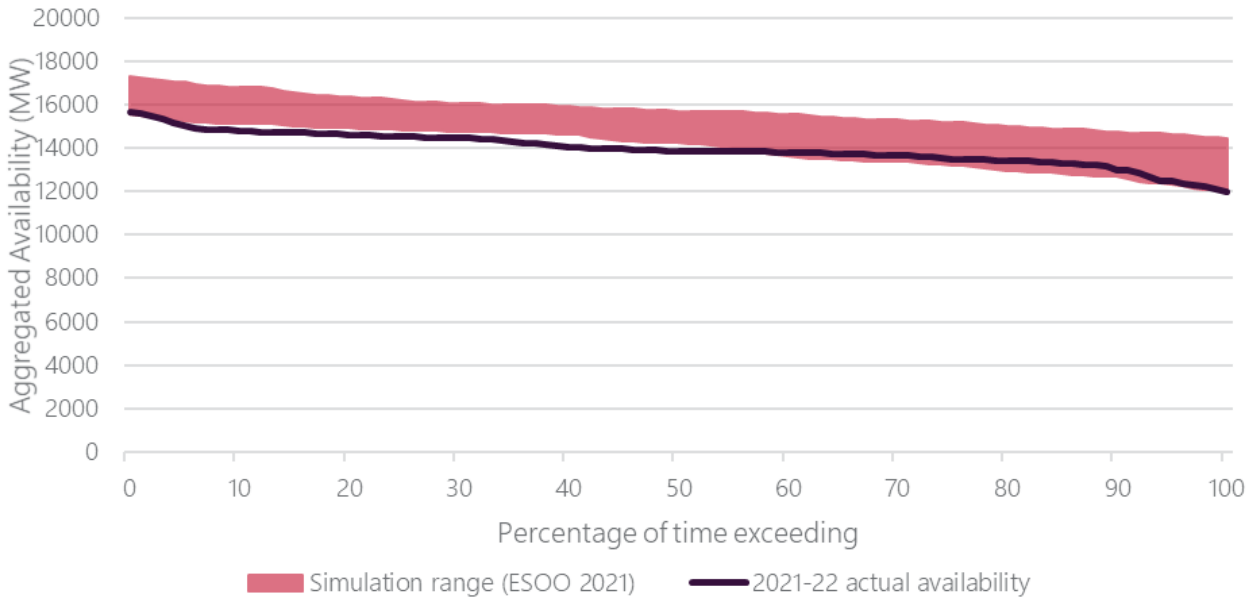
New South Wales supply availability for the top 10 hottest days



Summer 2021-22 was a mild year, absent of high temperature days considered in participant provided Summer Peak ratings. Given the methodology applies these summer peak ratings, actual availability during mild years should be above the simulated range.

Despite this expectation, availability in New South Wales (shown), Tasmania and Queensland, was below the simulated range, driven by a range of factors including: low VRE output, commissioning delays, planned and unplanned outages.

FIP action: Changes proposed to the treatment of random outage parameters in Reliability Forecasting guideline and methodology consultation

Forecast Improvement Plan

The Forecast Improvement Plan guides AEMO's ongoing technical improvements

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Reliability Forecasting Guidelines – accuracy and fit for purpose of Reliability Forecast

Forecasting Best Practice Guidelines – stakeholder engagement

Forecasting Approach and register – logical layout of Forecasting Components, log of actions

Forecast Improvement Plan*

Rule changes
Efficiencies
Emerging technologies

Actuals vs Forecast

Forecast Accuracy Report

Research → Monitor → Review → Improve

Implement continuous improvement initiatives

Conduct research initiatives

FAR methodology

Stakeholder feedback and external reviews

*This year, "Review" items related to the supply forecasts will be progressed through separate consultation

Proposed Forecast Improvement Plan overview - review and improve

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	Forecast Accuracy issue	Forecasting Improvement Plan	Details
IMPROVE	Improve demand traces – as presented at previous FRGs	Improve demand trace inputs, shape and quantity	Increase the number of weather reference years modelled in the ESOO to better account for the impacts of the growing share of weather-dependent generation.
IMPROVE	Limited ability to support sectoral level insights and inform future scenarios at sectoral level (slide 5)	Improve visibility of sectoral consumption	Continue to expand on individual consumption drivers within LIL and broader sectoral consumption. Informed by research project on ANZSIC code mapping.
REVIEW	Observed extremes in several cases fall outside the forecast distribution (slides 7, 8 and 11)	Review forecast maximum and minimum distribution of the initial year of the forecast horizon	The distribution of the initial year of the forecast horizon requires review. Consider improvements to the GEV model or alternatives to it if required.
REVIEW	Significant ONSG and LIL deviations observed for regional consumption (slide 6), and for LIL at time of max demand in Tasmania (slide 10)	Review LIL and ONSG component forecasts	Review ONSG and LIL consumption forecasts for opportunities to improve alignment with actuals. LIL affects max demand in Tasmania and the current modelling of this should be reviewed.

Proposed Forecast Improvement Plan overview – monitor and research

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	Forecast Accuracy issue	Forecasting Improvement Plan	Details
MONITOR	Opportunity to track uptake of electric vehicles (EVs), batteries and other emerging technologies (slide 4)	Monitor data availability of emerging technologies. Adopt if required	Since last year, good data sources for EV sales have been identified, allowing tracking of EV uptake. AEMO keeps monitoring data sources for other technologies
MONITOR	Potential change to the level of demand side participation following introduction of wholesale demand response (WDR) (slide 21)	Monitor demand side participation. Escalate as required	Monitor observed DSP against actuals to see if historical responses remain an accurate estimation of current level of DSP, following introduction of WDR.
RESEARCH	Limited data available for usage (charge and discharge data) for battery storage systems (including VPP) and electric vehicles (slide 4)	Collaborate with industry participants to share knowledge	Continue knowledge sharing meetings with parties doing research in EV and battery storage
RESEARCH	Risk of maximum and minimum demand forecast errors if not accounting for behavioural change (slides 7, 8 and 11)	Estimate behavioural change from customers with PV and batteries	Consider how to measure and account for the impacts (on overall consumption and max/min demand) of behavioural change for customers with rooftop PV and/or batteries

Discussion

Stakeholders are asked to provide feedback on improvement priorities and the completeness of the draft FIP:

- Are there other initiatives, approaches or directions AEMO should pursue to improve forecast accuracy?
- How well do the draft FIP priorities reflect stakeholder input at the FRG and other engagement opportunities?
- What improvement initiatives would the FRG like to be kept updated on throughout the coming year, and how is that best done?

As noted, there are ***additional points*** to review/improve related to the supply side. These are covered by a separate consultation and hence not covered in this plan. See FRG presentation 4 for an overview.

Appendix

NEM consumption forecast showed a significant residual error

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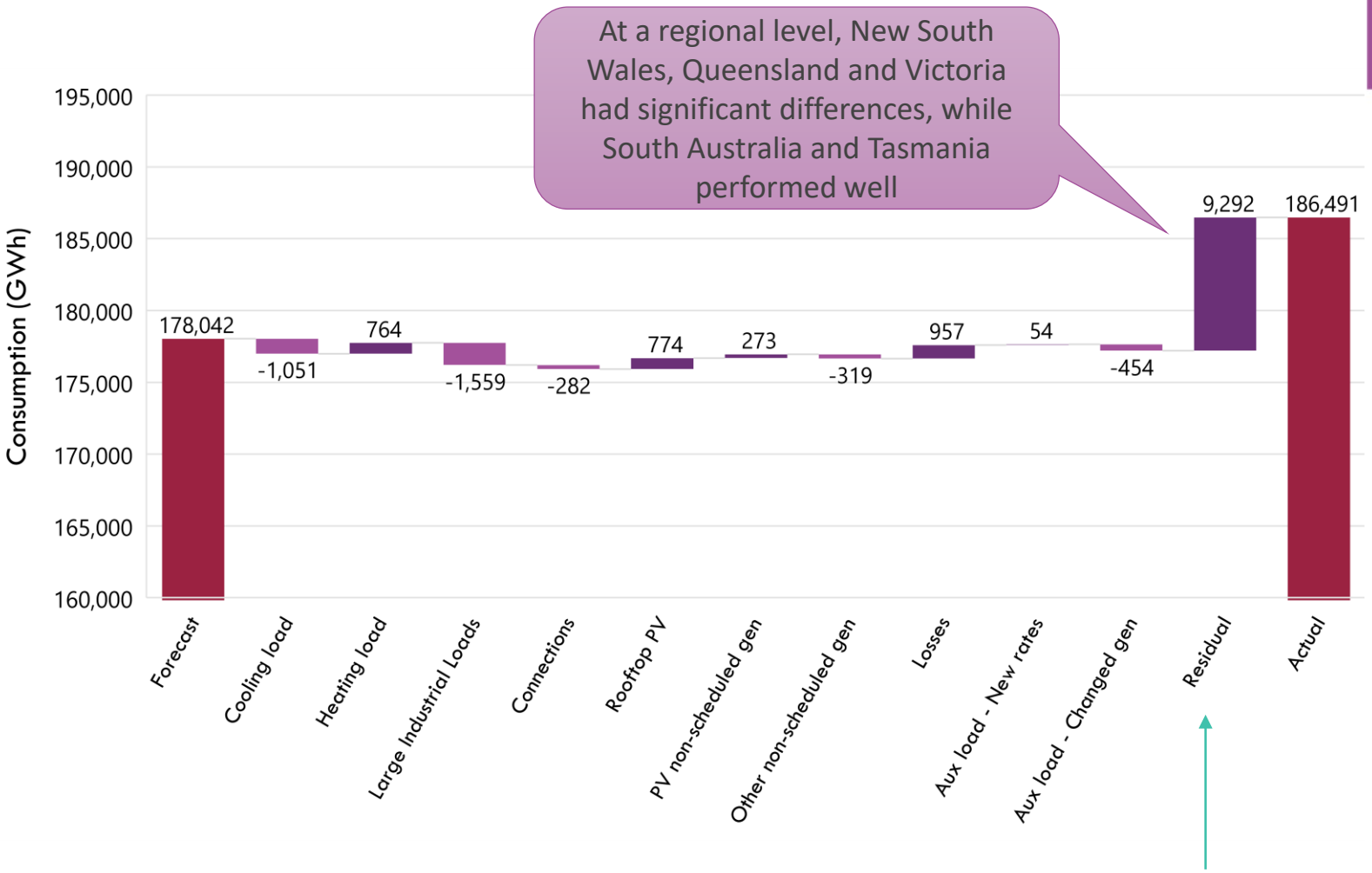
At NEM level, forecast consumption (as generated) was **4.5%** below the observed actual. This compared to a **0.3%** under-forecast in the 2020 ESOO.

Looking at the individually monitored components that make up the forecast, there are some larger differences, though they mostly net out.

The residual (made up by the residential and mass market business load) causes the vast majority of the difference.

The Update to the 2021 ESOO, reduced this difference to 1.0% below the observed actual.



Negative number: Forecast higher than actual
Positive number: Forecast lower than actual

FIP action: Continue to expand on individual consumption drivers within LIL and broader sectoral consumption, to understand reasons for residual

Demand Side Participation generally well aligned with forecast where measurable

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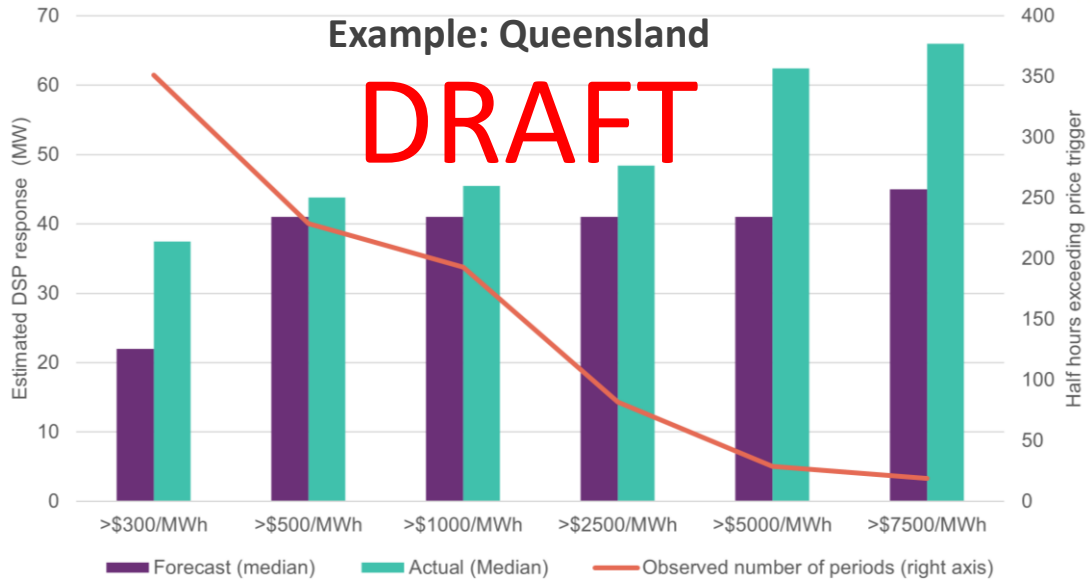
DSP forecasting errors are generally small in magnitude compared to all other forecasting. Main reason for differences was lower than forecast Wholesale Demand Response (WDR)

Median observed price-driven DSP against forecast:

- New South Wales: Actuals well aligned with forecast for lower price triggers, but under for higher prices driven by lower WDR. There were too few observations (<10 half hours) to reliably estimate high price DSP though.
- Queensland: The forecast was well aligned for lower price triggers, but under for the highest price bands
- South Australia: Observed DSP was well under the forecast across all price levels >$500/MWh. Forecast does exclude some very flexible loads.
- Tasmania: Forecast exceeded observed actuals in general. Too few observations to reliably conclude anything for prices above $500/MWh.
- Victoria: Actuals well aligned with forecast for lower price triggers, but under for higher prices driven by lower WDR. Too few observations to reliably conclude anything for prices above $2500/MWh.

FIP action: Monitor DSP in all regions for changes following WDR.



Reliability-driven DSP:

- Only Queensland reached conditions consistent with reliability DSP.
- At the time of maximum summer demand, 103 MW of DSP has been estimated to have been deployed, consistent with the forecast of 104 MW.

Update on delivery of 2021 Forecast Improvement Plan

Improvement	Status
Review initial year of forecast maximum and minimum demand distribution AEMO noted examples of winter maximum demand outcomes that could not be explained fully by input drivers. Review of models and their inputs to be undertaken as part of ongoing review process.	**Mostly completed.** AEMO reviewed its maximum and minimum demand models when producing the 2022 ESOO forecast, taking into account the issues flagged in the 2021 FAR. Refinements to the methodology has been considered, with an improved residual model potentially giving better forecast outcomes. AEMO will continue to explore this. Higher than forecast outcomes observed for the 2019 and 2020 ESOO forecasts could be driven by changed daily consumption trends from owners of rooftop PV systems. A NEAR project provided an estimate of this impact in June 2022. AEMO to consider whether and if so how to apply this information in its forecasting processes as part of the 2022 FIP.
Review auxiliary load forecast AEMO to review the best source of auxiliary load forecast for the 2022 ESOO consumption and demand forecasts.	**Completed.** AEMO has moved to use a different source of auxiliary load forecast, which better aligns with the represents actual generator dispatch.
Improved visibility of sectoral consumption AEMO to investigate the opportunities for a further breakdown of consumption into specific industry sectors to gain a better understanding of the reasons behind observed forecast variance and guide future forecasting improvement initiatives.	**In progress.** AEMO has made reasonable progress with this priority initiative through the NEAR project. Progress to date includes: • Identification of suitable datasets that could assist with breaking down sectoral consumption. • Preliminary mapping of a significant number of business NMIs to Australian and New Zealand Standard Industry Classification (ANZSIC) codes • Development of an initial breakdown of sectoral consumption for both LIL and business mass market components. • Validation of sectoral consumption across datasets, including commercial data, NGER and AEMO's internal databases. While the NEAR project is complete, AEMO will continue work on this initiative as part of the 2022 FIP, focussing on improving NMI mapping to ANZSIC codes, and developing a plan to incorporate insights into AEMO's consumption forecast process.

Update on delivery of 2021 Forecast Improvement Plan

Improvement	Status
Improved and additional renewable generation and demand traces With the growth in weather-dependent (wind and solar) generation capacity in the NEM, more weather years should be assessed, matched with consistent demand years.	**In progress.** AEMO has uplifted the simulation code to be significantly faster, which enables the extra complexity from producing traces through the demand simulation process. Bootstrapping weather, which retains ENSO climate cycles has been implemented. Review of other key subcomponents in progress: the residual model, the LIL model and the ONSG model. The uplift of the latter two will be coordinated with the reviews of these components flagged in the 2022 FIP. AEMO will continue to deliver this as part of the 2022 FIP.
Monitor for change in trends for key inputs Monitor for changes in historical trends for: • Distributed PV uptake and generation • Generator commissioning and full commercial use dates • Generator forced outage rates • DSP trends	**Ongoing process.** For the specific items: • Uptake of PV has shown good alignment over the last year as outlined in this report. • Generator commissioning dates are still imprecise in many cases and AEMO will in late 2022 consult on changes to the implementation of the commitment criteria in this reliability studies. • The past year have highlighted continued issues as well as a need for an additional category for generator forced outage rates. AEMO will consult on this in late 2022. • At the time the 2022 DSP forecast was produced, AEMO accessed the impact of WDR and 5-minute settlement on DSP. There were generally too few high-price observations during the 2021-22 summer to estimate the impact of these changes with any statistical significance. AEMO keeps monitoring this.
Monitor emerging technologies uptake and usage Monitor and if possible onboard data sources to track uptake and use of emerging technologies, such as battery storage and EVs.	**Ongoing process.** In particular, the following should be noted: • AEMO continue to work with DNSPs to improve battery storage data in the DER-Register. • Through the ESB, AEMO is involved in scoping how EV Supply Equipment Standing Data can be collected. • EV sales data now available, which include Tesla sales. This is of a quality that can be used to track forecast accuracy. • AEMO has undertaken research in the usage profile of EV fast charging stations to inform the 2023 Draft IASR. • AEMO has had knowledge sharing sessions with organisations running trials investigating EV charging behaviour.

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