2021 Forecast Accuracy Report (FAR) and Forecast Improvement Plan (FIP)

DRAFT

27 October 2021 FRG Meeting

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Background and Purpose

Purpose: summarise the draft 2021 Forecasting Accuracy Report (FAR) results, and discuss forecasting challenges that motivate the Forecast Improvement Plan (FIP). Stakeholders are asked to provide feedback on improvement priorities and the completeness of the draft FIP.

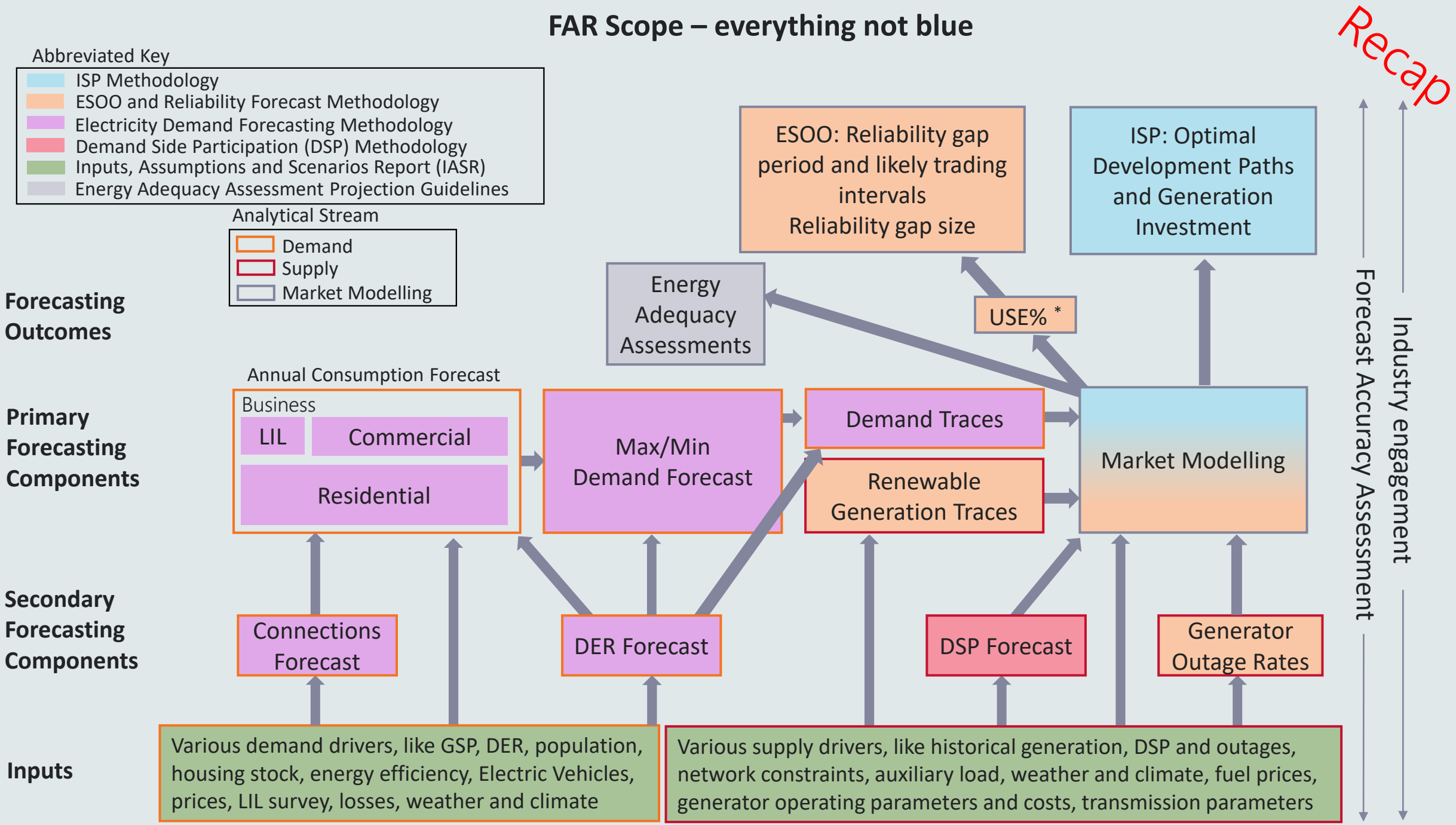
Engagement timeline

Engagement Timing	Details
May – Aug 2020	FAR methodology consultation
Oct 2020 FRG	2020 FAR and Forecasting Improvement Plan presentations
Dec 2020 – Feb 2021	2020 Forecasting Improvement Plan consultation
March 2021 FRG	ESOO 2020 Summer Demand Forecast Preliminary Review
Today	2021 Forecast Accuracy Report and Forecast Improvement Plan
Nov 2021 – Jan 2022	FAR published and FIP consultation

Today's agenda:

- Forecast accuracy results summary
  - Scope of FAR results
  - Results Overview
  - Consumption
  - Distributed PV
  - Maximum and Minimum Demand
  - Demand Side Participation
  - Supply availability
- Forecast Improvement Plan
- Appendix
  - Other accuracy results
  - FIP initiatives map

FAR Scope – everything not blue



Inaccuracies are generally explainable

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Forecasting results	NSW	QLD	SA	TAS	VIC	Assessability*	Comments
Demand drivers	🟡	🟡	🟡	🟡	🟡	Moderate	Installed PV capacity significantly above forecast in most regions.
Energy Consumption	🟢	🟢	🟢	🟢	🟢	Strong	All regions within 3%. Tasmania had the largest error, almost entirely explained by lower large industrial load (LIL).
Summer maximum demand	🟢	🟢	🟢	🟢	🟢	Weak - Moderate	All mainland regions within distributions and are consistent with forecast drivers. Tasmania very low, but driven by mild weather and lower LIL.
Winter maximum demand	🟡	🟡	🔴	🟡	🔴	Weak - Moderate	Winter maximum demand in NSW, SA and VIC above forecast distributions. The distribution of the initial year of the forecast horizon requires review.
Annual minimum demand	🟢	🟡	🟡	🟡	🟡	Weak - Moderate	Due to under-forecast PV capacity, actual minimum demand in most regions were below the forecast distribution.
Demand side participation	🟢	🟢	🟡	🟢	🟢	Moderate	Less DSP than forecast observed in South Australia. Adjusted down in 2021 forecast.
Installed Generation capacity	🟡	🟢	🟢	🟢	🟡	Strong	New generator installations matched expectation, except in VIC and NSW where delays impacted availability.
Summer supply availability	🟡	🟡	🟢	🟢	🟢	Moderate	Planned and unplanned outages in Queensland and New South Wales reduced availability against forecast.

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.

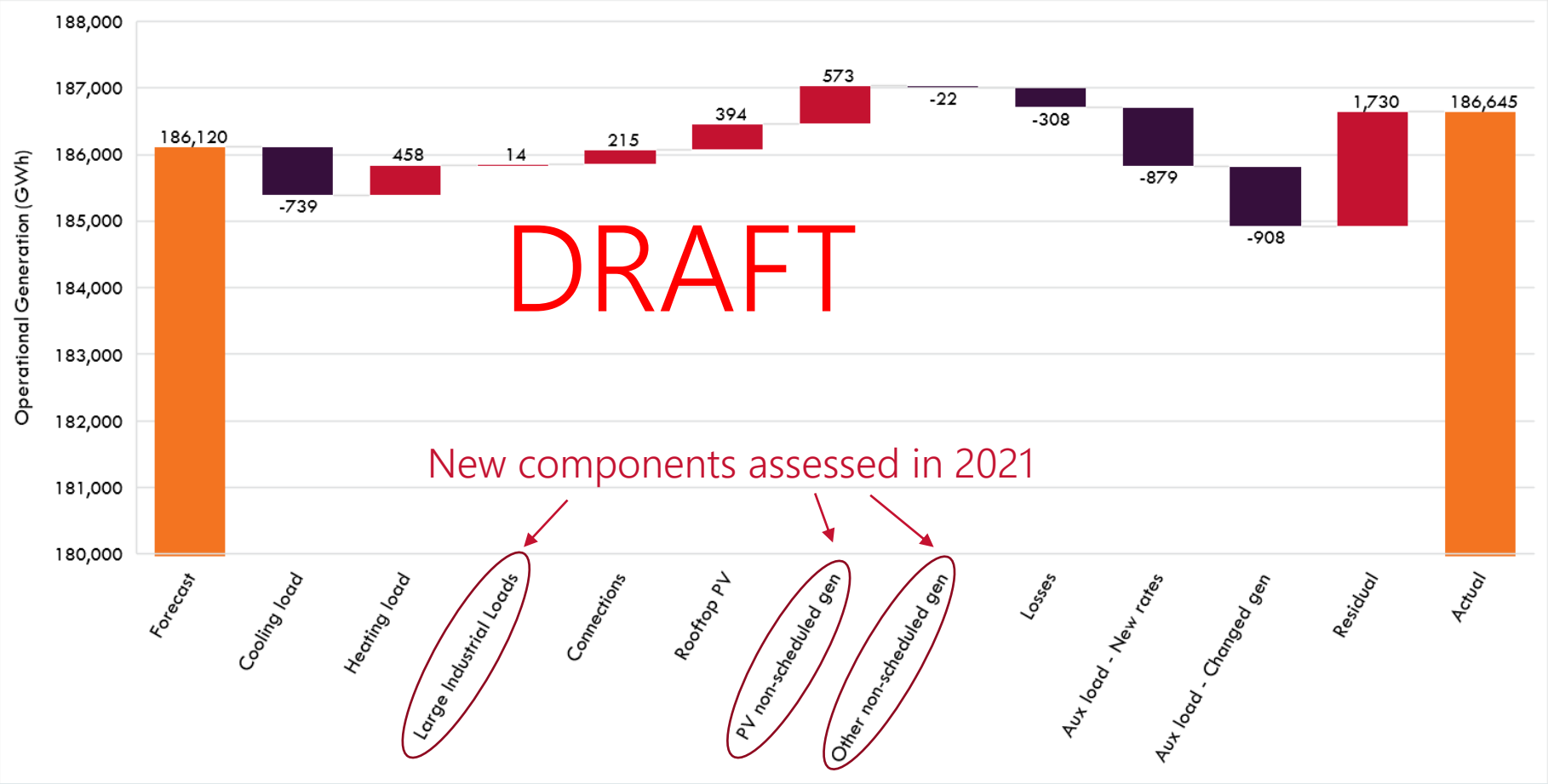
* Assessability – the extent to which accuracy can be assessed based on a single year of actual data

Consumption forecast accuracy – NEM overview (1/2)

At a NEM level, forecast consumption as generated was **0.3%** below the observed actual. This compared to a 1.1% over-forecast in the 2019 ESOO.

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

The components are discussed in more detail on the next slide.



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 sectorial consumption

Drivers for consumption (including PV) (2/2)

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Category	2020 Forecast (GWh)	Actual (GWh)	Difference in net Consumption* (GWh)	Difference (%)
Auxiliary load	10,403	8,616	-1,787	-20.7%
Cooling Degree Days	3,988	3,249	-739	-22.8%
PV non-scheduled generation*	2,014	1,442	573	39.7%
Heating Degree Days	6,409	6,866	458	6.7%
Rooftop PV*	14,278	13,885	394	2.8%
Network losses	10,952	10,644	-308	-2.9%
Connections Growth	453	668	215	32.2%
Other non-scheduled generation*	4,617	4,639	-22	-0.5%
Large Industrial Loads	44,664	44,678	14	0.0%

Big differences for QLD and VIC in particular. Half of this is driven by revised auxiliary load rates used to estimate actuals, the rest due to different generator dispatch than forecast.

Summer was influenced by La Niña causing less cooling demand.

Capacity (MW installed) generally aligns, but generation per MW estimates were too high and are now adjusted down to better reflect observed values.

Winter was colder than the recent median weather years used by AEMO for its forecast.

Capacity under-forecast, but generation per MW over-forecast. Both addressed for 2021.

The difference reflects updated loss factors provided by the network companies.

Economic forecasts predicted much lower immigration, reducing connections growth. However, construction remained high, so connections came out above forecast.

FIP action: Review Auxiliary load forecast used

* Components netting off consumption use opposite sign convention

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PV installed capacity was higher than forecast across all NEM regions (1/2)

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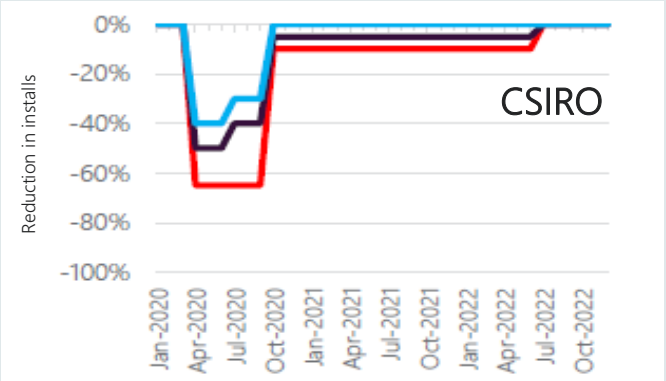
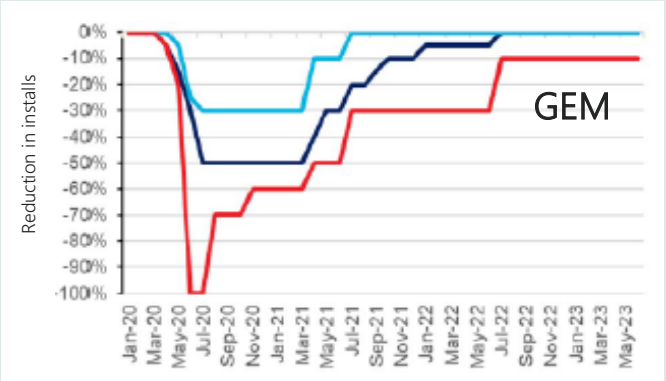
Installed rooftop PV capacity exceeded the forecasts. The forecasts assumed a reduced uptake due to COVID-19 restrictions introduced at the time. Victoria, with its extended lockdowns, was more accurately forecast than other large states.

PVNSG was well aligned with forecast in all regions but Victoria.

	As installed at 30 June 2021	NSW	QLD	SA	TAS	VIC
Rooftop PV	Estimated Actual (MW)	4006	4067	1662	195	2896
	Central forecast (MW)	3160	3433	1447	179	2608
	Downside - High DER forecast (MW)	3151	3410	1439	181	2777
	Central forecast error (%)	**-21%**	**-16%**	**-13%**	**-8%**	**-10%**
	Downside - High DER forecast error (%)	-21%	-16%	-13%	-7%	-4%
PVNSG	Estimated Actual (MW)	270	209	176	3	276
	Central forecast (MW)	277	207	186	4	202
	Downside - High DER forecast (MW)	344	210	209	4	220
	Central forecast error (%)	**3%**	**-1%**	**6%**	**19%**	**-27%**
	Downside - High DER forecast error (%)	27%	0%	19%	21%	-21%
Total	**Central forecast error (%)**	**-20%**	**-15%**	**-11%**	**-8%**	**-11%**
	Downside - High DER forecast error (%)	-18%	-15%	-10%	-7%	-6%

Assumed short term COVID-19 impacts on DER (as presented 13 May 2020 FRG):



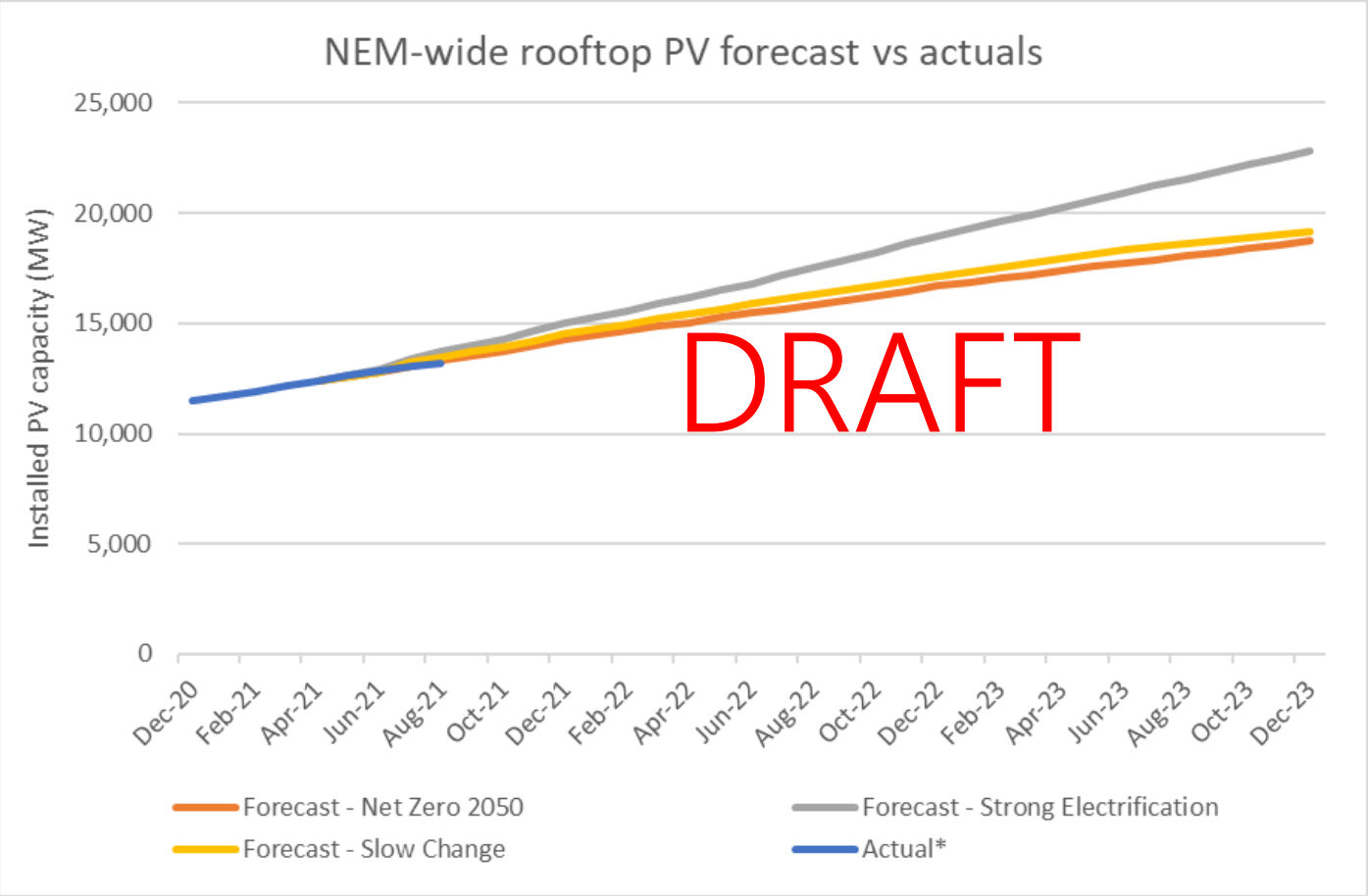


Slow change — Central — Step change

As COVID-19 uncertainty fades, the 2021 forecast for rooftop PV is tracking well (2/2)

- Actual rooftop PV installations are currently tracking well against the 2021 ESOO forecast
- Further installation records for August (and to lesser extent July) may still to be reported to the CER.
- Coming months may see installation rates affected by supply chain issues from China.

FIP action: Continue to monitor uptake of distributed PV against forecast



*Actual estimated by the end of August 2021

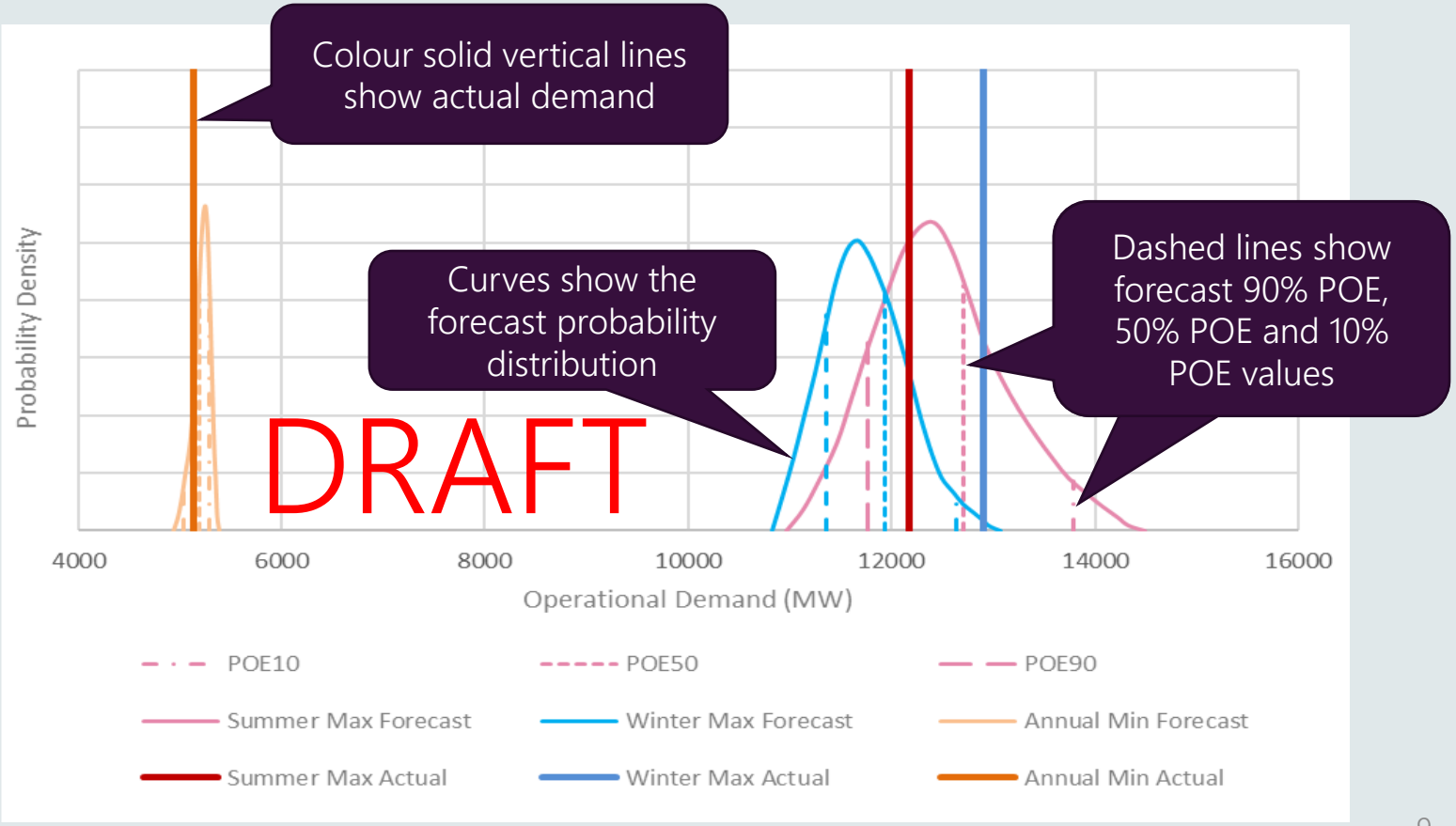
Understanding Demand

General themes:

- Rooftop PV growth was stronger than expected driving lower minimum demands than forecast
- Strong summer La Niña (rain, cool daytime temperatures) drove milder summer demand outcomes
- The winter was generally mild, but with significant cold snaps affecting some regions (New South Wales and South Australia)

How to interpret Demand Results

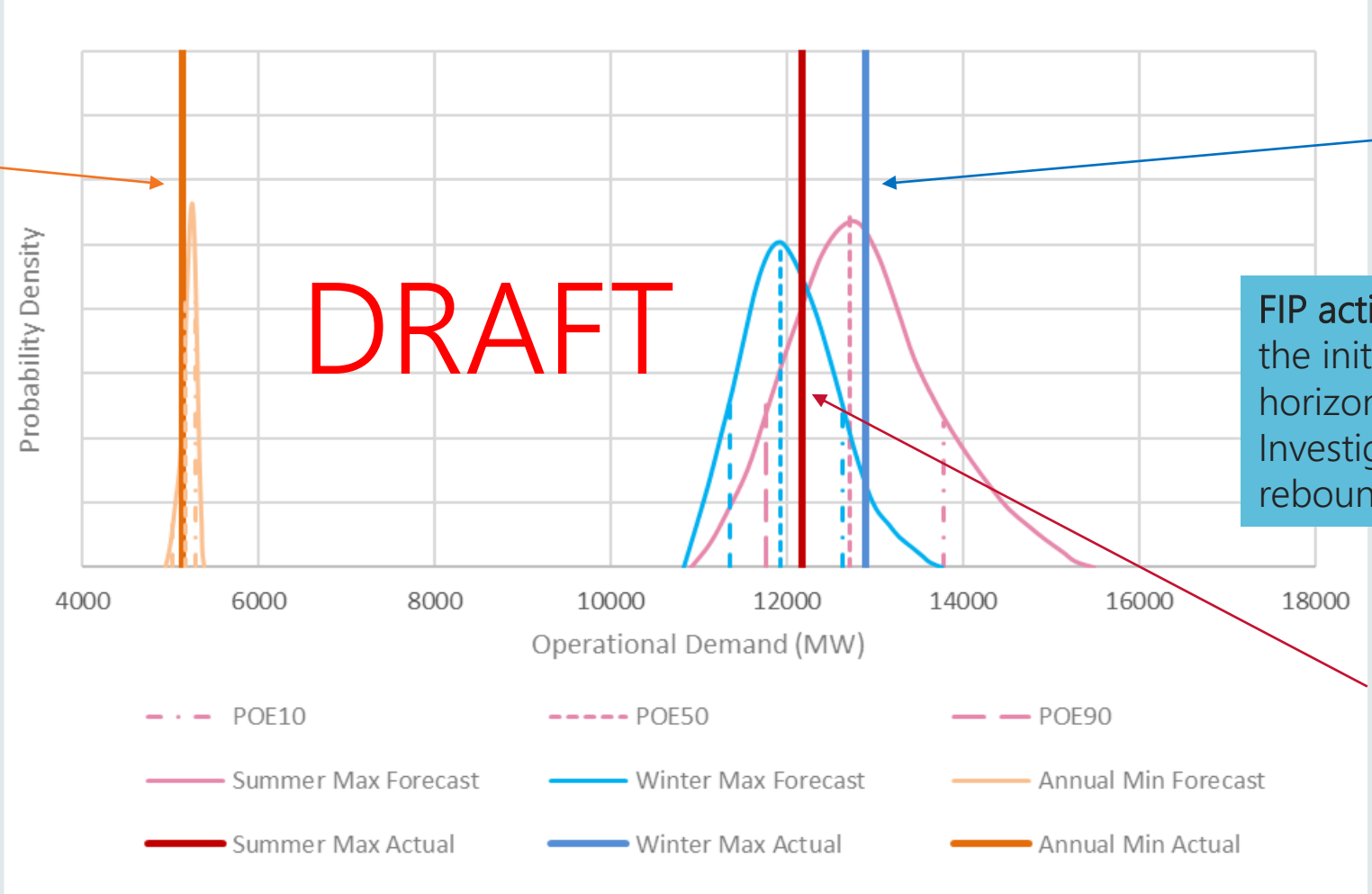
- The maximum/minimum demand forecasts are probability distributions.
- In the following, each colour represents a different forecast distribution and actual outcome.



POE – Probability Of Exceedance

New South Wales: Extreme Demand Forecasts

Transitioning to mid-day minimum this year.



Winter actual above 10% POE. Generally mild winter (warmer than average), but some significant cold snaps.

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

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

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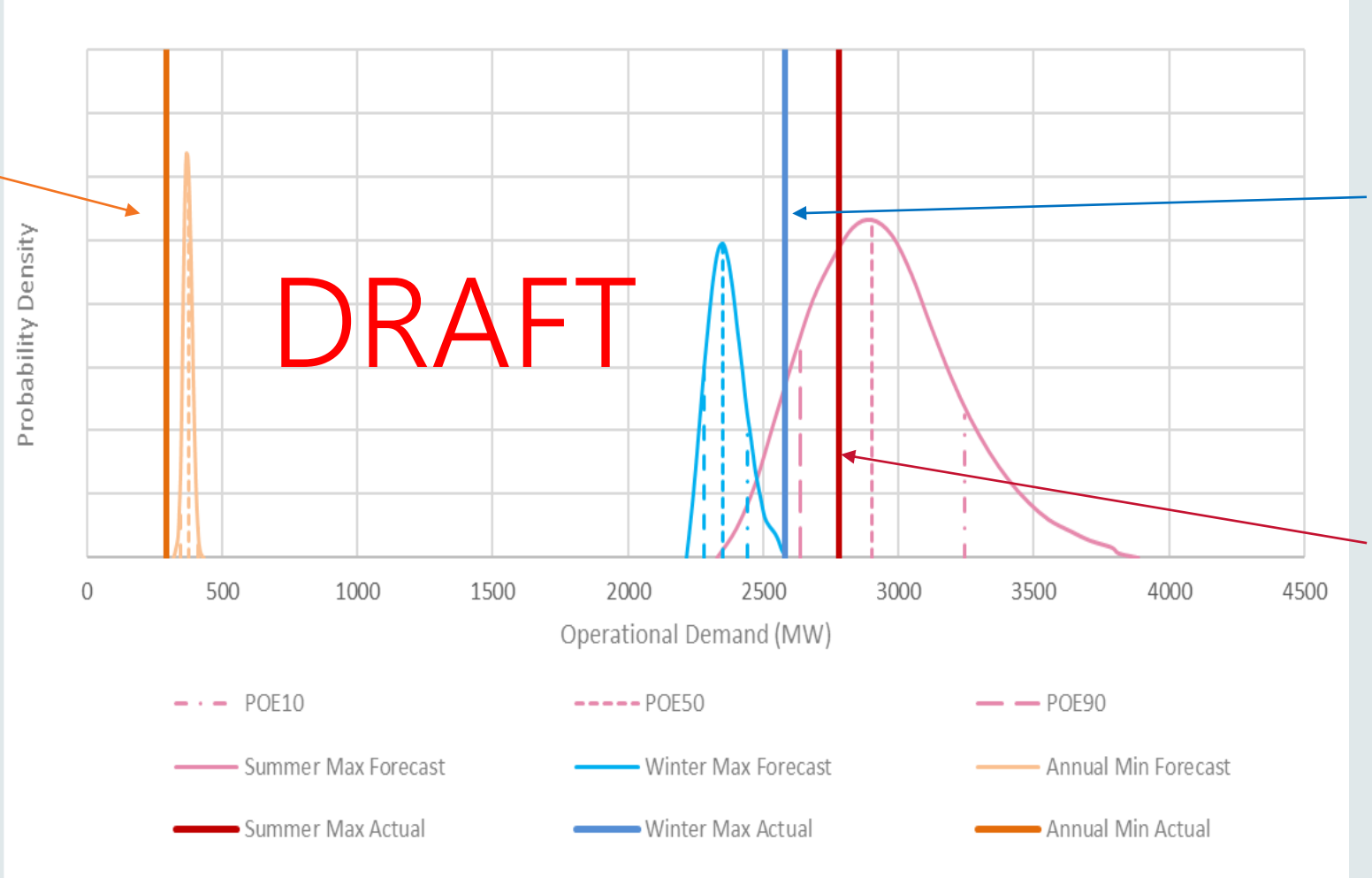
South Australia: Extreme Demand Forecasts

Significant impact from under forecast of PV capacity

FIP action: Continue to monitor uptake of distributed PV against forecast

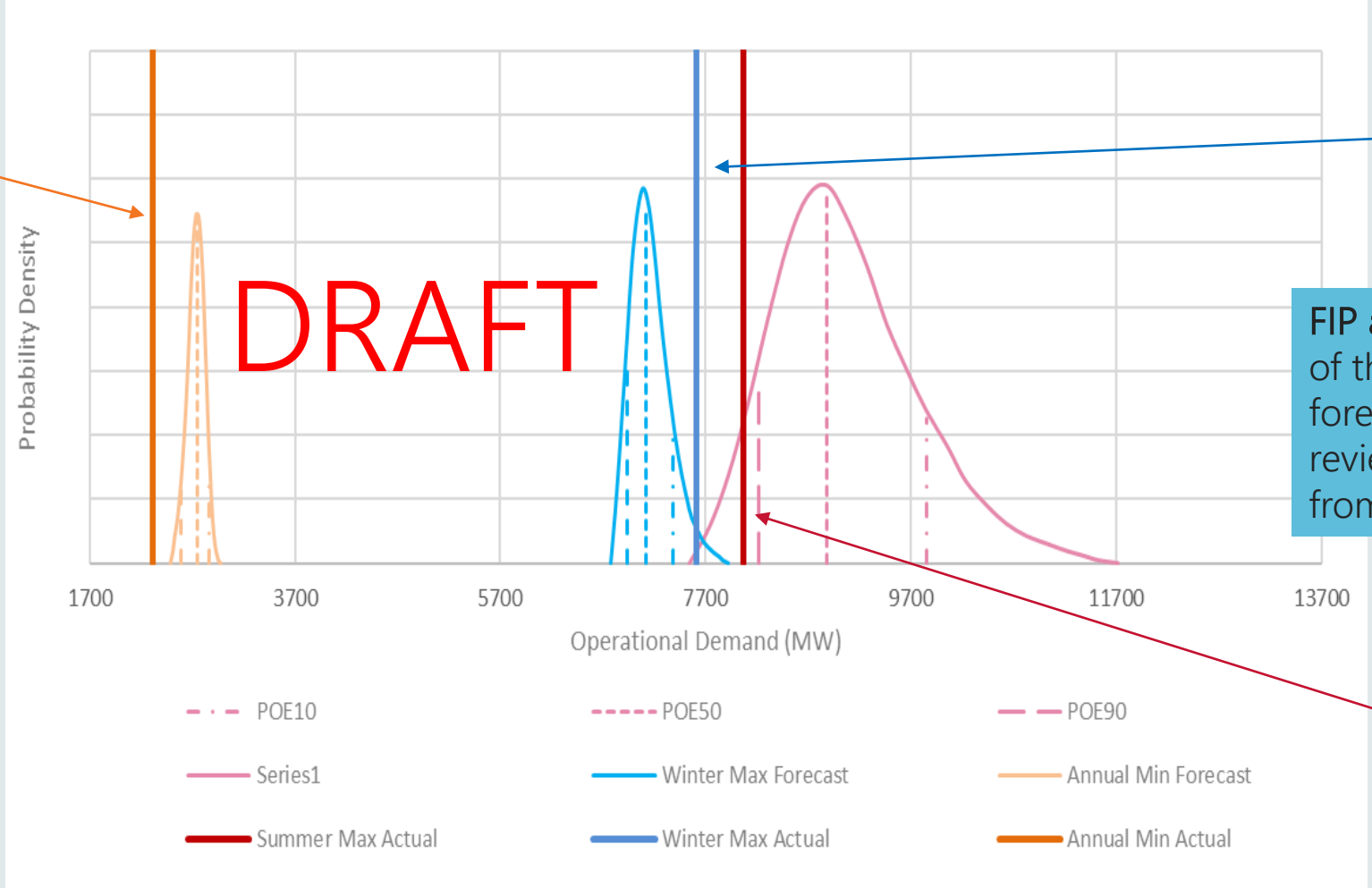


Winter actual above 10% POE. Cold snap resulted in record low daily maximum temperatures that day. The distribution of the initial year of the forecast horizon requires review.

Summer outcome below 50% POE, driven by the mild Summer (La Nina).

Victoria: Extreme Demand Forecasts

Significant impact from under forecast of PV capacity combined with "perfect" minimum demand weather on Christmas day.



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

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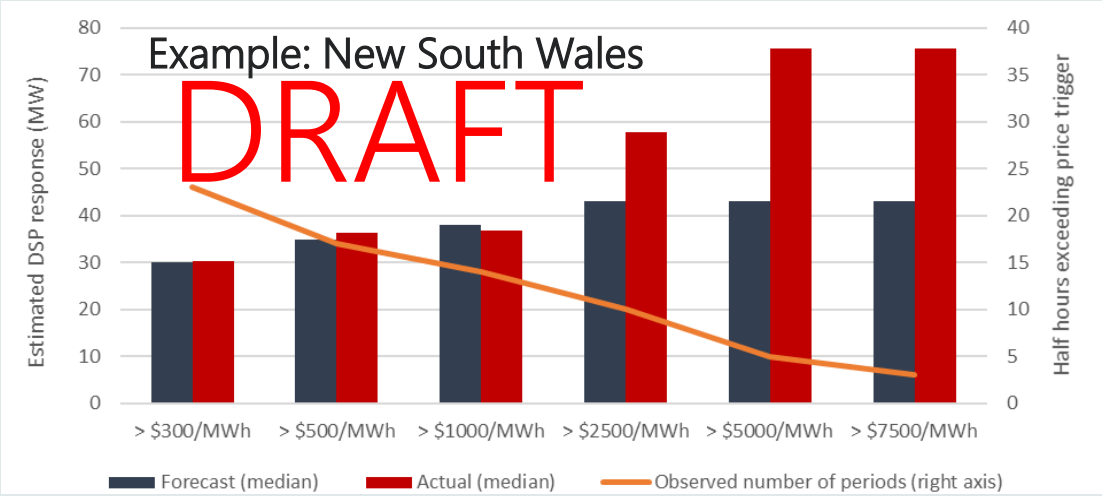
Demand Side Participation

DSP forecasting errors are generally small in magnitude compared to all other forecasting.

Median observed price-driven DSP against forecast:

- New South Wales: The forecast was well aligned for lower price triggers, however there were too few observations (<10 half hours) to reliably estimate high price DSP.
- Queensland: The forecast was well aligned for lower price triggers, however there were too few observations to reliably estimate higher prices*.
- South Australia: Observed DSP was well under the forecast across all price levels. Issues with 2020 forecast baselines identified.
- Tasmania: Observed DSP above forecast for prices with observations. Could be driven by Basslink outages driving automatic rather than voluntary DSP.
- Victoria: Too few high price points for any validation.

*Excludes impacts following Callide incident



FIP action: Monitor DSP in Queensland and South Australia and in all regions for changes following WDR and 5MS in general.

Reliability-driven DSP:

- Only Queensland reached conditions consistent with reliability DSP, with New South Wales being close
- New South Wales had good alignment with forecast reliability DSP.
- For Queensland, DSP could not be separated from automatic load shedding following the Callide incident. After this event, DSP appears to have increased.

Installed generation capacity over-forecast in several regions

Region	Forecast Installed Capacity (MW) by February 2021	Actual Operating Capacity (MW) by February 2021	Difference
New South Wales	18,634	17,858	-4%
Queensland	14,877	14,626	-2%
South Australia	5,665	5,665	0%
Tasmania	2,839	2,921	+3%
Victoria	13,962	12,817	-9%

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Participant-provided full commercial use dates proved too optimistic in Victoria, New South Wales and Queensland, with a combined 2,000 MW of variable renewable energy projects forecast to operate in Feb 2021 but actually unavailable.

FIP action: Continue to monitor trends in project completion

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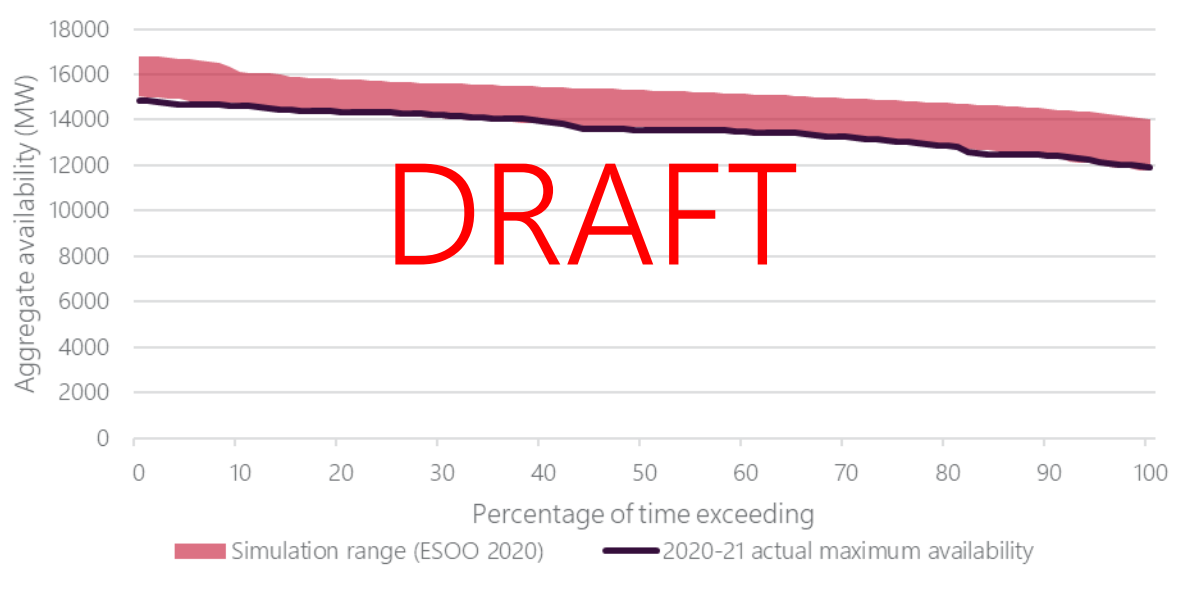
Summer supply availability benefited from mild weather, but NSW and QLD results were driven by coal and hydro outages

New South Wales supply availability for the top 10 hottest days



Summer 2020-21 was a mild year, absent of high temperature days considered in participant provided Summer Peak ratings.

Consistent with the mild year, availability in South Australia, Tasmania and Victoria was right at the top of the simulated range.

New South Wales and Queensland availability was right at the bottom or below of the simulated range, driven by higher than forecast coal and hydro outage rates during the top 10 hottest days.

FIP action: Continue to monitor trends in forced outage rates

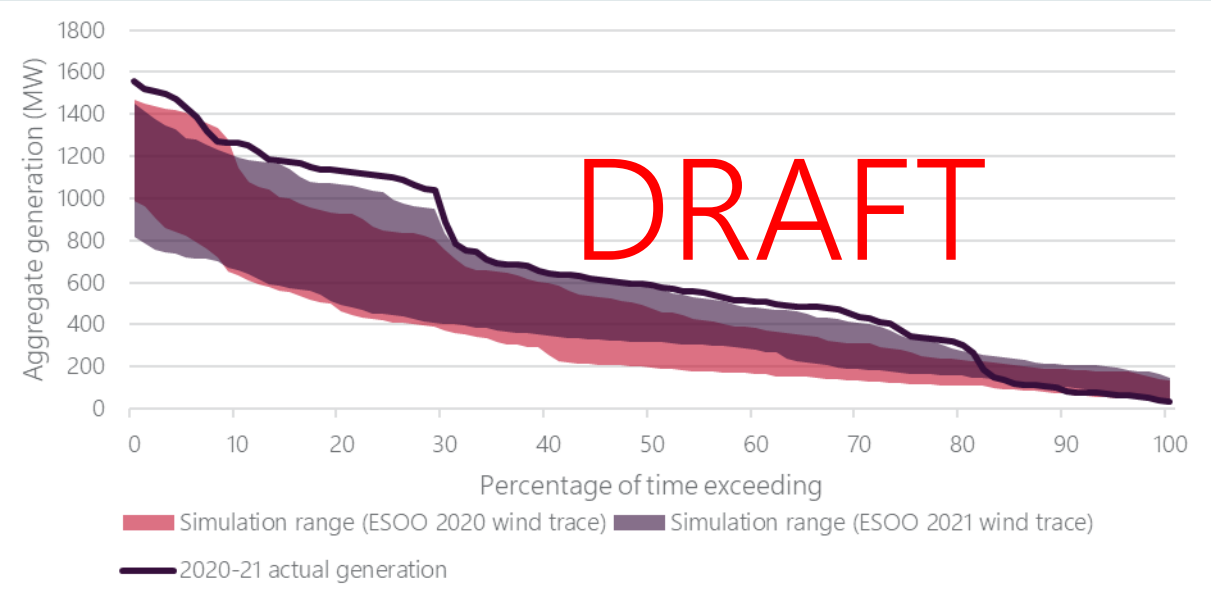
New wind traces introduced as part of the 2020 FIP better reflect observed wind supply availability

New wind traces were implemented for the 2021 ESOO that better capture observed wind generator dynamics including high wind and high temperature cut-offs.

The 2021 FAR compares accuracy against both the 2020 and 2021 method.

In South Australia, where impacts of commissioning delays were not present, actual availability exceeded both simulated ranges, as expected given the mild temperatures observed.

South Australia wind supply generation for the top 10 hottest days



FIP action: Review the number of reference years modelled in the ESOO to better account for impacts of the growing share of weather-dependent generation.

2021 Forecast Improvement Plan

The Forecast Improvement Plan guides AEMO's ongoing technical improvements

Recap

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

Stakeholder feedback and external reviews

Proposed Forecast Improvement Plan overview - research

RESEARCH

Forecast Accuracy issue	Forecasting Improvement Plan	Details
Limited ability to support sectorial level insights and inform future scenarios at sectorial level (slide 5)	Research ANZSIC mapping of consumption	Research the possibilities of mapping of broader groups of customers to specific ANZSIC sectors.
Risk of maximum and minimum demand forecast errors if not accounting for behavioural change (slide 10)	Research PV rebound effect on consumption and demand	Investigate the impacts of behavioural change in consumption for customers with rooftop PV installed and its impact (if any) on consumption and max/min demand

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Proposed Forecast Improvement Plan overview - monitor

MONITOR

Forecast Accuracy issue	Forecasting Improvement Plan	Details
Opportunity to track uptake and uplift forecasts of electric vehicles (EVs) and batteries (slide 5)	Monitor data availability of emerging technologies Escalate as required	Monitor availability of data sources for uptake and use of emerging technologies, such as EVs and batteries. Investigate application of new data sources into forecasts as the data sources emerge.
Risk of PV uptake and generation per unit forecast errors can impact overall forecast performance (slide 8)	Monitor distributed PV forecast Escalate as required	Continue to monitor uptake of distributed PV against forecast to ensure current performance is maintained.
Variation in generator project completion dates results in inaccurate supply availability (slide 14)	Monitor generator completion dates Escalate as required	Monitor trends in project completion against dates provided to AEMO's Generation Information page.
Potential for differences between provided and observed forced outage rates can impact forecast reliability outcomes (Slide 15)	Monitor forced outage rates Escalate as required	Continue to monitor trends in actual forced outage rates against those reported to AEMO by participants.
Potential change to demand side participation following introduction of Wholesale Demand Response (WDR) and 5-minute settlement (5MS) (slide 13)	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 and 5MS.

Proposed Forecast Improvement Plan overview - review, and improve

	Forecast Accuracy issue	Forecasting Improvement Plan	Details
REVIEW	Significant auxiliary load forecast error provides an opportunity to improve as-generated consumption and demand forecasts (slide 6)	Review Auxiliary load forecast	Review the suitability of the auxiliary load forecast used to convert between as-generated and sent out operational consumption and demand.
REVIEW	Observed extremes in several cases fall outside the forecast distribution (slide 10)	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.
IMPROVE	Opportunity to improve demand traces –as presented at previous FRGs (slide 16 and 22)	Improve demand trace inputs, shape and quantity	Review the number of 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 sectorial level insights and inform future scenarios at sectorial level (slide 5)	Improve visibility of sectorial consumption	Continue to expand on individual consumption drivers within LIL and broader sectorial consumption. Informed by research project on ANZSIC code mapping.

Demand Trace redevelopment – process has commenced with discussion on target outcomes

Recap

Improve

What characteristics are we seeking from current and future demand traces?

- Account for demand generated from weather patterns
  - Both current and future weather patterns
  - Use many more weather years (and corresponding demand traces) in reliability forecasts
- Account for temporal demand drivers (day of week, time of day, trend)
  - As affected by new technologies, electrification, etc.

Incorporation of correlation between demand, renewable generation and time. Also, spatially between neighbouring regions.

Intuitive and accessible

Traces should allow for:

- Calculation of unserved energy in the subsequent market modelling, allowing:
  - Assessment of whether reliability standard is met
  - Identification of problematic timing of generator or network outages
- Minimum demand analysis, especially for system security assessment
- Identification of scenario-specific future generation and transmission expansion requirements
  - Assessment of timing and economics of network investments
- What-if studies, such as:
  - High inverter based instantaneous penetration (mainland NEM) – frequency and duration
  - Ramping events
  - Low coincident renewable generation events such as wind droughts

Will trace approach deliver?

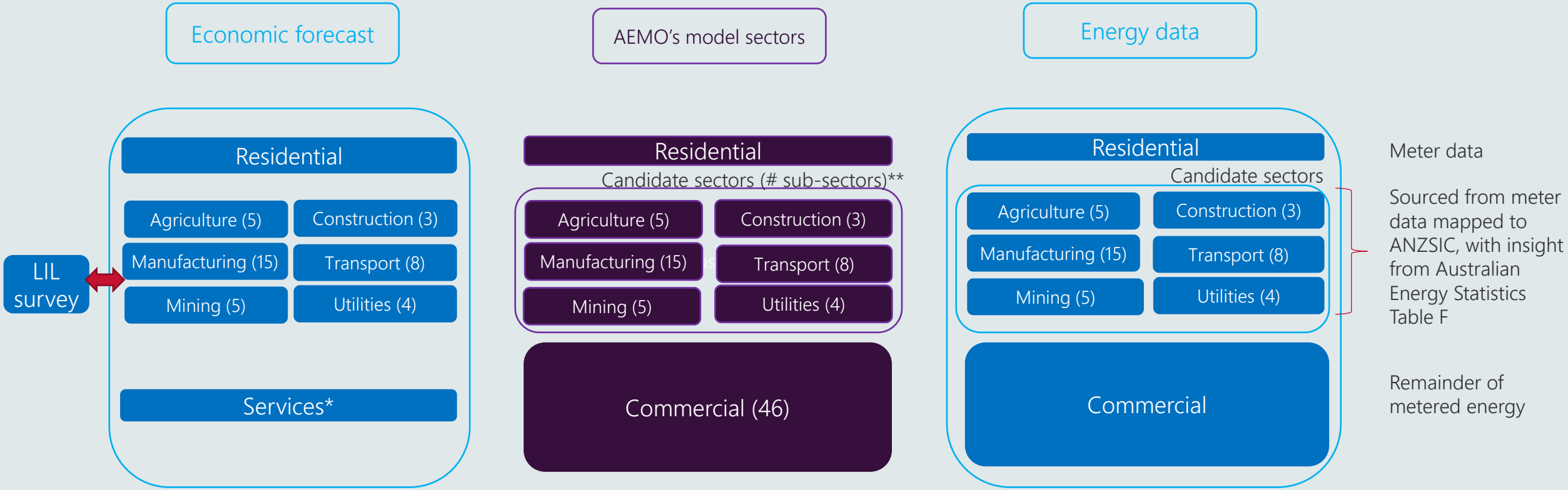
✓ or ✗

Visibility of sectorial consumption – align of energy and economic data to improve granularity in key sectors

Improve

Recap

Redevelopment of energy data sources allows finer-grain modelling of key energy use sectors



* Services encompasses ANZSIC divisions F, G, H, J, K, L, M, N, O, P, Q, R, S

** These sub-sectors may be modelled individually where appropriate (e.g. coal mining, food and beverage manufacturing, steel manufacturing etc.)

Discussion

Purpose: summarise the draft 2021 Forecasting Accuracy Report (FAR) results, and discuss forecasting challenges that motivate the Forecast Improvement Plan (FIP). 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?

Appendix

NEM regional consumption higher than forecast during COVID19 in mainland states

Negative % error: Forecast lower than actual
Positive % error: Forecast higher than actual

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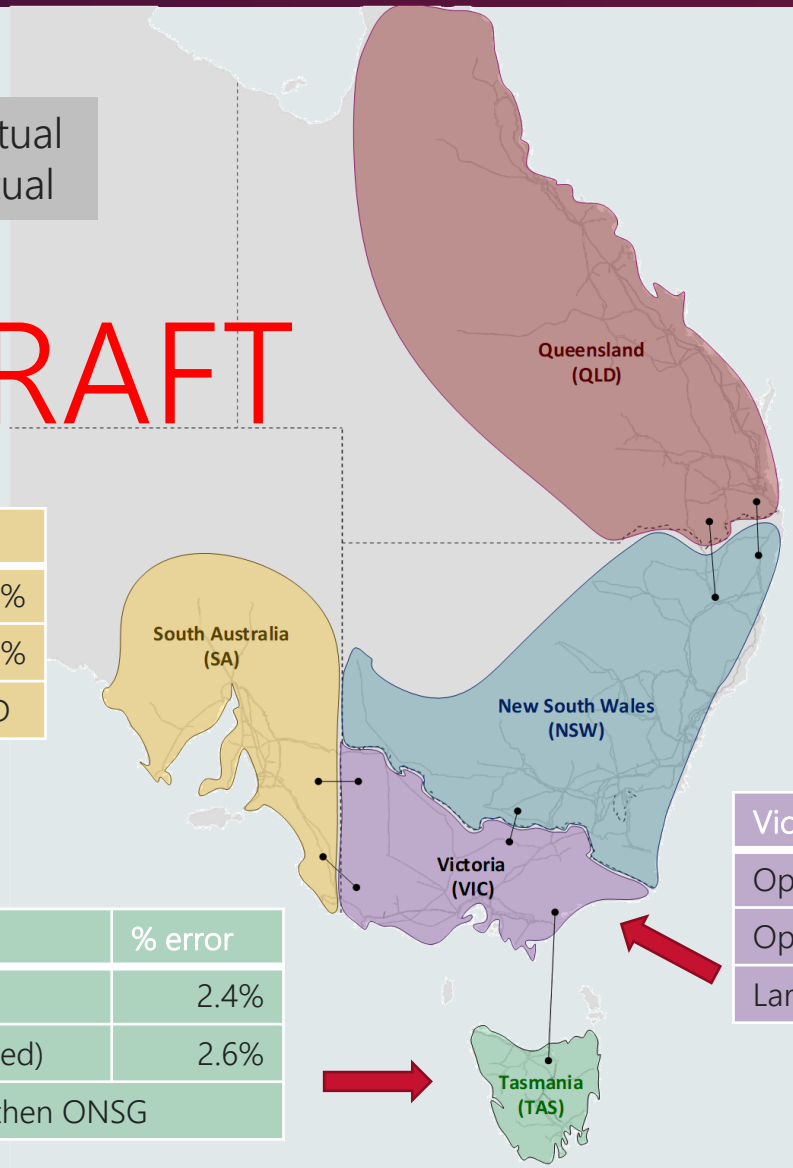

Queensland	% error
Operational (sent out)	-2.4%
Operational (as-generated)	-0.1%
Largest differences: Aux load, then LNG	

South Australia	% error
Operational (sent out)	-0.3%
Operational (as-generated)	-0.1%
Largest differences: PVNSG, then losses and CDD	

New South Wales	% error
Operational (sent out)	-1.0%
Operational (as-generated)	-0.8%
Largest differences: LIL, then CDD	

Victoria	% error
Operational (sent out)	-1.6%
Operational (as-generated)	-0.4%
Largest differences: Aux load, then losses and PV	

Tasmania	% error
Operational (sent out)	2.4%
Operational (as-generated)	2.6%
Largest differences: LIL then ONSG	

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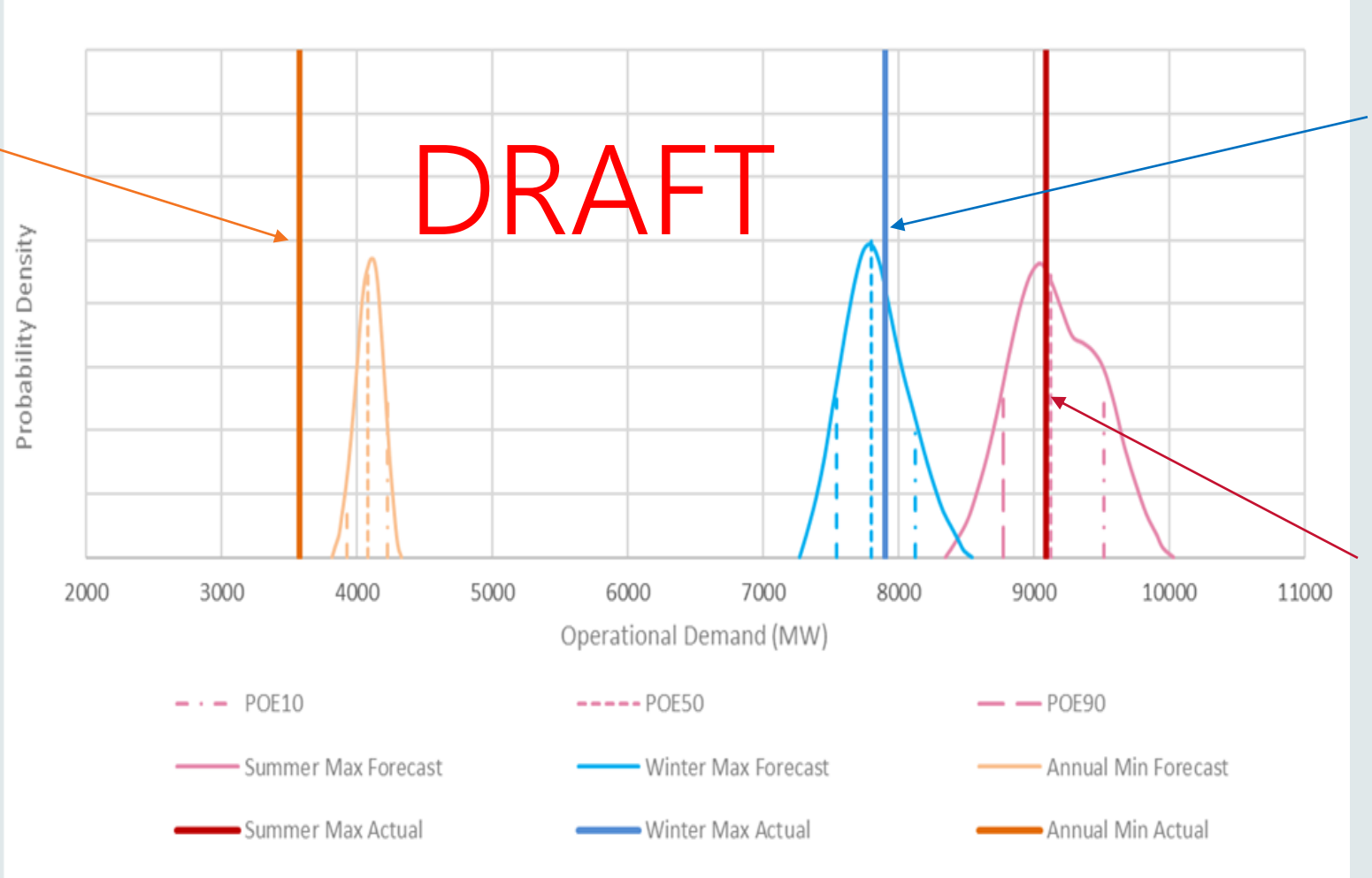
Queensland: Extreme Demand Forecasts

Significant impact from under-forecast of PV capacity

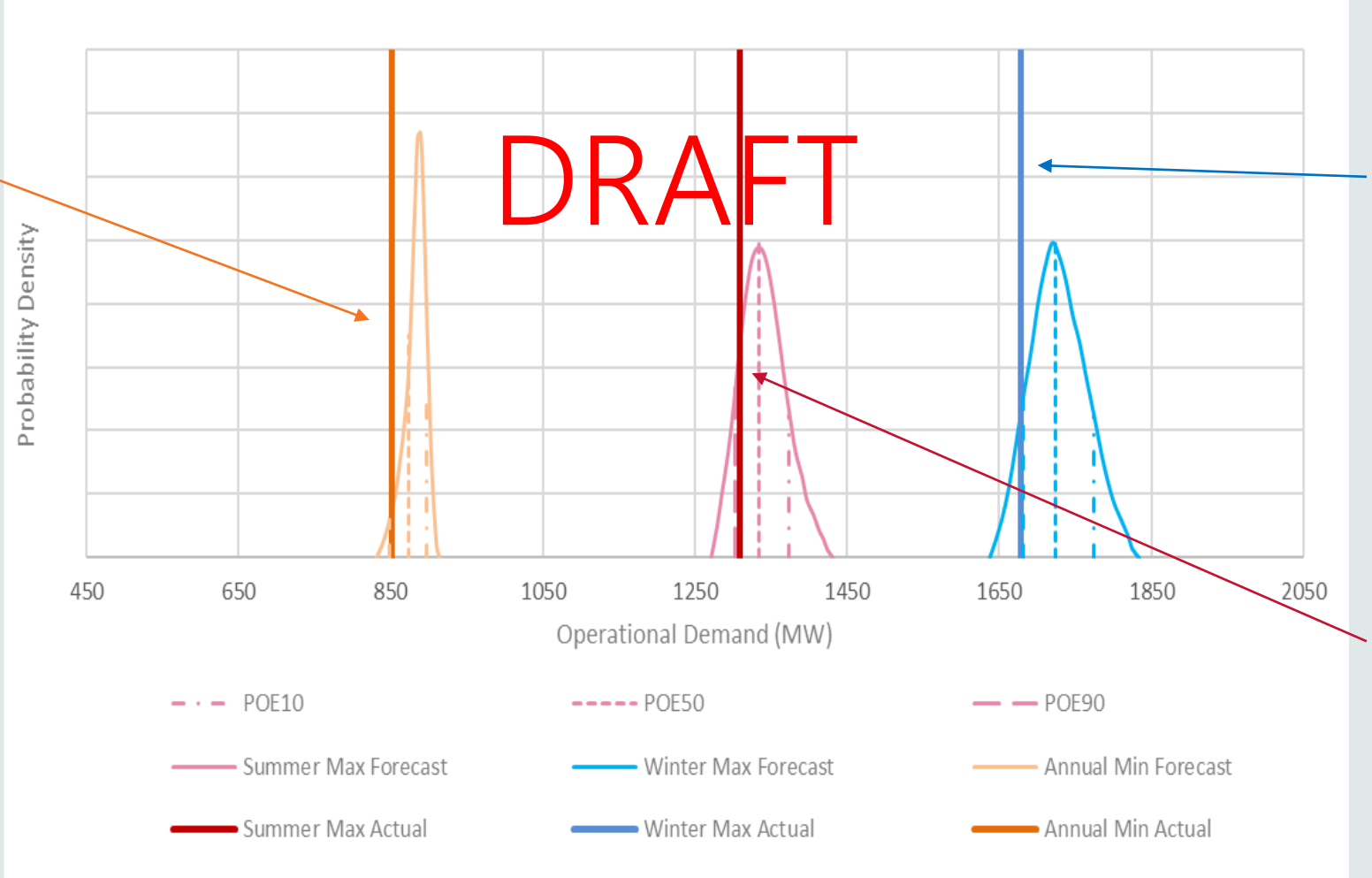


Winter actual just above 50% POE. This is well aligned with forecast drivers.

Summer outcome was near median. Temperature weaker than normal, but humidity higher.

Tasmania: Extreme Demand Forecasts

Outcome near 90% POE. Partly explained by a partial outage of an LIL*



Winter actual at 90% POE. LIL was in the low end of the expected range. Combined with a Sunday outcome, this mostly explains the low outcome.

Summer outcome just at 90% POE, driven by the very mild Summer (La Nina). The maximum was driven by a mild cold snap. LIL was lower than the median for a 50% POE as well, suggesting a low outcome is appropriate.

*Note that this was the minimum excluding minimum demand events caused by automatic load shedding

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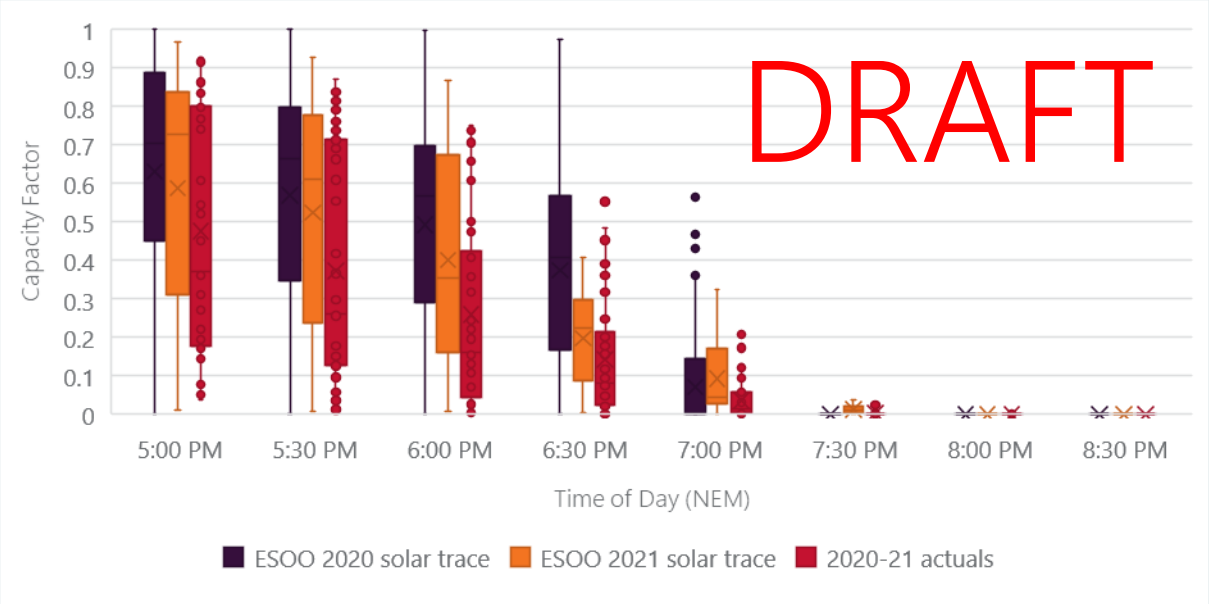
Traces for large scale solar using adjusted technical parameters better reflect observed solar availability

New solar traces were implemented for the 2021 ESOO that subtly changed the simulation of solar generation using the existing methodology.

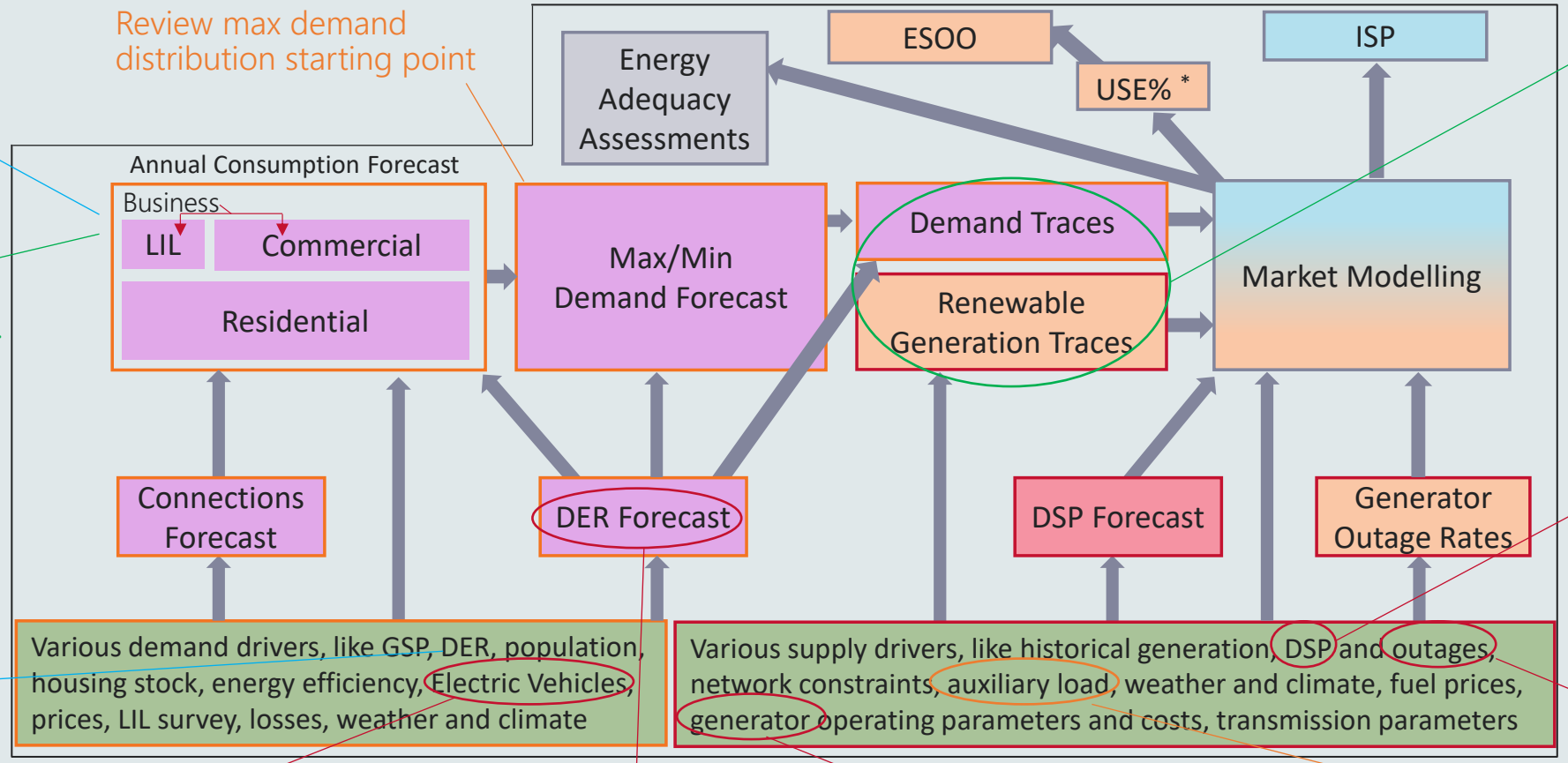
The 2021 FAR compares accuracy against both the 2020 and 2021 traces.

In Victoria, solar traces have been compared across time of day, showing better alignment between 2020-21 actuals with the updated solar trace, than with the previous.

Example: Victoria solar trace comparison for the top 10 hottest days by time of day



Proposed Forecast Improvement Plan overview - research, monitor, review, and improve



Research ANZSIC application

Review max demand distribution starting point

Improve visibility of sectorial consumption trends:

- LIL mapping (incl. NSG interaction)
- Residential/ business split sampling uplift

Demand Trace redevelopment - Improve demand traces inputs (EV, electrification), shape and quantity

Monitor DSP in light of 5MS and WDR.

Research PV rebound (growth in max demand)

Monitor FOR

Monitor emerging technologies: Data availability for EV, Batteries, Fuel Switching and hydrogen.

Monitor PV forecast, including supply chain

Monitor extent of commissioning delays (mainly QLD, NSW and VIC)

Review auxiliary load forecast

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