Forecast Improvement Plan 2020

February 2021

Final

Important notice

PURPOSE

AEMO presented a Forecast Improvement Plan in the 2020 Forecast Accuracy Report, in accordance with clause 3.13.3A(h)(2) of the National Electricity Rules. The Plan provided information on the forecasting improvements that AEMO would be prioritising for implementation ahead of the 2021 Electricity Statement of Opportunities (ESOO) for the National Electricity Market (NEM). AEMO consulted on the Plan in accordance with the Interim Reliability Forecast Guidelines. This final Forecast Improvement Plan takes into account the feedback obtained in that consultation process.

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VERSION CONTROL

Version	Release date	Changes
1	2 December 2020	Initial publication of proposed plan within the 2020 Forecast Accuracy Report
2	12 February 2021	Final publication of Forecast Improvement Plan

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1. Introduction

In accordance with National Electricity Rules (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 to be material to its reliability forecasts. Additionally, AEMO must publish information on improvements that will apply to the next Electricity Statement of Opportunities (ESOO) for the National Electricity Market (NEM). The objective of this transparency is to build confidence in the forecasts produced.

This final Forecast Improvement Plan presents the forecasting improvement initiatives AEMO has prioritised for implementation ahead of the 2021 ESOO for the NEM. It takes into account the consultation feedback obtained in the consultation of the proposed Forecast Improvement Plan, which was presented in the 2020 Forecast Accuracy Report (FAR).

The 2020 FAR, the received submissions, and the submission response documents are all available on AEMO's website[1].

1.1 Identifying forecast Improvement opportunities

AEMO acknowledges the importance of forecast accuracy to industry decision-making.

The purpose of the annual FAR is to provide transparency around forecast accuracy, including where the largest discrepancy between forecasts and observed actuals are found, and the areas where AEMO accordingly has identified opportunities to improve its forecasts.

The process has three key steps:

1. **Monitor** – track performance of key forecasts and their input drivers against actuals.
2. **Evaluate** – for any major differences, seek to understand whether the reason behind the discrepancy is due to forecast input deviations (actual inputs differed from forecast inputs) or a forecast model error (the model incorrectly translates input into consumption or maximum/minimum demand).
3. **Action** – seek to improve input data quality or forecast model formulation where issues have been identified, prioritising actions based on materiality and time/cost to correct.

This Forecast Improvement Plan focuses on the third point, outlining AEMO's prioritised actions to improve forecast accuracy as result of the review undertaken in the 2020 FAR and taking into account stakeholder feedback in the subsequent consultation.

1.2 Drivers for forecast improvements

It should be noted that not all forecast improvements stem from the actions required following the forecast accuracy assessment. It is only one of three drivers for changes to the forecasting models and processes:

1. **Forecast accuracy improvements** – minor updates to forecasting models, data or assumptions to address forecast accuracy issues found. While the Forecast Accuracy Report is prepared annually, forecast performance is tracked more regularly by AEMO and may drive other minor improvements to how inputs are sourced or models are calibrated within the yearly cycle.
2. **Evolution of energy system** – over time, electricity consumption and demand change in response to structural changes of Australia's economy, such as the emergence of a new sector (for example the development of Liquified Natural Gas (LNG) export facilities supported by electrical loads associated with

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

coal seam gas (CSG) operations), or consumer technological changes (such as electric vehicles or battery storage systems). These developments may impact the total energy consumed across a year by consumers or the daily demand profile of energy consumption, or both. The demand forecasting process continually evolves to account for these changes, in particular for the longer-term forecasting and planning processes.

3. **Regulatory requirements** – changes to rules and regulations can cause changes to how forecasts are produced, or what needs to be forecast. The Retailer Reliability Obligation (RRO) required a number of changes to AEMO's forecasting process. Similarly, the Actionable ISP will increase the focus on intra-regional transmission requirements over previous AEMO planning publications, causing a need for a higher spatial resolution to assess intra-regional power system needs.

This 2020 Forecast Improvement Plan focuses on initiatives to improve the forecast accuracy following the assessment undertaken in the 2020 FAR.

1.3 Overview of document

The key observations of the performance of the 2019 forecasts as presented in the 2020 FAR are summarised in Section 2.

Section 3 then presents the priority improvement initiatives that have been included in AEMO's 2020 Forecast Improvement Plan.

Consistent with the Interim Reliability Forecast Guidelines[2], the minor improvements proposed in this Forecast Improvement Plan was consulted on using a single stage short-form consultation. More material changes to the Forecasting Approach, for example due to regulatory changes, will use the forecasting best practice consultation procedures. Improvements driven by changes to the ISP Methodology are accordingly consulted on using that process separately to the Forecast Improvement Plan. The ISP Methodology[3] consultation started 1 February 2021.

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

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

2. ESOO 2019 forecasts – summary of findings

While most forecast models have performed well, some of the inputs and assumptions have impacted forecast accuracy. The issues driving proposed improvements in this year's Forecast Improvement Plan are summarised below:

- Distributed photovoltaic (PV) installations were above the 2019-20 forecast in all regions, resulting in over-forecasting of operational consumption and in particular minimum demand in most cases.
- Actual economic activity was significantly lower than forecast, due to the impacts of domestic and international measures to minimise the spread of COVID-19 from late March 2020 onwards, which significantly reduced economic activity.
  - The impact on consumption is relatively smaller. While some business electricity consumption was reduced, residential consumption typically increased, and the net impact for the last quarter of the financial year was minor.
  - AEMO has limited ability to see impacts from COVID-19 separately from other potential drivers.
- On the supply side:
  - Outage rates on inter-regional transmission elements were higher than assumed, primarily due to the reclassification of credible contingencies due to bushfires near Victoria to New South Wales transmission elements, and other asset failure events.
  - Wind generation in Victoria saw higher than expected de-rating during hot summer days, where wind generation dropped while wind remained strong. The forecast wind traces used in the 2019 ESOO did not have explicit consideration for this effect, and over-estimated wind farm output during high temperature events as a result.

In addition, a number of observations on forecast variance have been noted, where the issue is expected to have been resolved with improvements already implemented in the 2020 ESOO, such as those identified in the 2019 Forecast improvement Plan initiatives. These observations include:

- Demand Side Participation (DSP) aligned well with forecast in most regions, but in both New South Wales and Victoria the DSP responses were under-estimated. The DSP methodology has subsequently been revised and implemented for the 2020 ESOO forecast following consultation on DSP methodology in the first half of 2020.
- New generation installations were aligned with forecast for most regions, however Victoria observed delays against provided timing. For summer 2019-20, there was 1,241 megawatts (MW) less installed capacity than expected in Victoria. While further delays have been observed in 2020-21, no further changes to this forecasting process are proposed at this time. Instead, AEMO is working with industry to reduce likelihood of future generator connection delays.
- Generator forced outage rates for coal-fired generators continued to deteriorate but were mostly aligned with assumptions, except for New South Wales black coal-fired generators, which performed worse than expected. An updated methodology used in the 2020 ESOO now uses participant and consultant forecasts of forced outage rates to better capture trends in performance and maintenance.

For reference, Appendix A1 lists the improvements presented in the 2019 Forecast Improvement Plan along with a summary of implementation status of each of these initiative, and any other improvements implemented for the 2020 ESOO.

3. Forecast improvement priorities for 2021

For its 2020 Forecast Improvement Plan~~FIP,~~ AEMO's ~~pproposes the following p~~riority improvement initiatives, guided by the observations in the 2020 FAR listed in Section 2, ~~for its 2020 Forecast Improvement Plan:~~are:

1. Improve PV forecasts to minimise adverse impacts on consumption, demand, reliability and system security outcomes.
2. Gain increased visibility and understanding of consumption drivers and trends through data analytics to improve forecast accuracy and improve the ability to explain forecast variance, for example due to COVID-19, from the insights.
3. ~~Better~~ Improve representation of the forecast distribution of monthly maximum demand outcomes.
4. Build~~ing~~ improved understanding of emerging technologies, such as batteries and electric vehicles (EVs).

~~4.~~5. Develop improved wind generation traces accounting for temperature cut-offs.

~~5.~~6. Improve modelling of inter-regional transmission element outage risk.

These are explained in the following sections.

3.1 PV forecast improvements

For the 2020 ESOO, AEMO has already implemented a number of changes to the PV forecasting process.

This forecast attempted to better capture the range of rooftop PV and PV non-scheduled generation (PVNSG) uptake uncertainty by selecting a broader spread of uptake projections from the two distributed energy resources (DER) consultants. However, post model adjustments for COVID-19 made in April 2020 may have been too broadly applied across the scenarios, with early indications being that the actual impact of COVID-19 on rooftop PV uptake is significantly less than suggested by the initial fall in rooftop PV sales lead data, used to support the consultant's post model adjustments to the rooftop PV forecasts.

Another of the 2020 improvements was the use of a trend-based forecast in the short term by one of the consultants, although this may have missed an acceleration in PV installations by applying a trend over too long a time period, and without up-to-date installation data to capture most recent trends.

Preliminary investigation into the 2020 PV forecast performance (to be covered in detail in the 2021 Forecast Accuracy Report) shows more work is needed, in particular:

- Improved visibility of installed capacity by using the newly developed DER Register either for validation or as a primary data source, reducing the potential lag time that exists with the current Clean Energy Regulator (CER) data stream. From 1 March 2020, network service providers (NSPs)[4] are required to supply data to AEMO on every relevant generator or battery device connected to its network within 20 business days of the DER device being connected to the grid and capable of generating.
- Increased analysis and consideration of short-term installation trends, particularly if the trend has exhibited non-linear features.
- Review of the normalised PV generation profiles used to ensure the forecast generation per MW of installed PV capacity is within expectation when used to offset the consumption forecast as well as at time of maximum and minimum demand.

[4] In some regions this is done directly by the installers, but with data entries being validated by the network service providers.

These refinements are scheduled for the 2021 ESOO forecast.

3.2 Improved visibility and understanding of consumption drivers and trends

To improve its understanding of consumption and demand drivers and trends, AEMO plans to analyse smart meter data to improve the split of residential and business consumption consumers. Overall, this will:

- Help verify the models for residential and business consumption and have them based on the last year of estimated actuals rather than AER data that is currently used, and may be 18 months old. This should improve model performance and validation.
- Improve the ability to explain forecast differences by increasing the understanding of sectoral or spatial trends, such as COVID-19 impacts that may differ across NEM regions.
- Improve understanding of variability of large industrial loads at time of minimum demand events.

3.3 Improved visibility of forecast maximum demand within a year

The comparison of observed monthly maximum demand and the maximum demand of the traces used in the ESOO and Medium Term Projected Assessment of System Adequacy (MT PASA) in the FAR showed examples where the actual value fell outside the range spanned by the reference years used, typically during shoulder seasons[5]. This is because the shoulder months in the traces reflect the last nine years of *actual* outcomes rather than the *forecast* range of outcomes. If in the last nine years, there has not been a very hot period in October in a particular region, but longer-term climate series show it is possible, the forecast maximum demand for October for that region would be higher than any of the maximum demand values in the traces.

The traces based on historical reference years are scaled to meet summer and winter maximum demand forecast values, which are most relevant when assessing supply scarcity risks. Monthly maximums in shoulder months are not targeted in the same way as they generally do not drive unserved energy outcomes. This limits the distortion to the daily demand profiles, which otherwise could have unrealistic ramping events. Further, if monthly demand in every trace was scaled to a 50% Probability of exceedance (POE) or 10% POE maximum demand outcome, this could lead to overestimation of annual consumption.

However, for other purposes, such as generator outage scheduling based on MT PASA outcomes, the traces may not fully capture the distribution of maximum demand outcomes during the shoulder months when plant maintenance often occurs. AEMO will explore ways to better capture the range of maximum monthly demand outcomes across the sample of traces used, while still preserving annual consumption forecasts and minimising demand profile shape distortion. As part of this improvement initiative, the approach used to develop the 10% POE daily peak load, and the most probable daily peak load forecasts published as a stand-alone component of the MT PASA process will be reviewed.

3.4 Improved understanding of emerging technologies

For mature technologies, historical datasets exist that help build forecast models and validate the forecast outcomes. Emerging technologies, which may become widespread but have yet to see any large-scale uptake, cannot be based on history. Such technologies include battery storage and EVs.

To improve the understanding of consumer uptake of these technologies, AEMO has a number of initiatives to build knowledge that can help form assumptions and sense check the forecasting results.

For batteries, AEMO is working with distribution NSPs (DNSPs) to improve knowledge of existing battery storage installations in the DER Register, and working with CSIRO through the NEAR program[6] to develop

[5] This refers to months that do not fall within the defined summer or winter periods.

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

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.

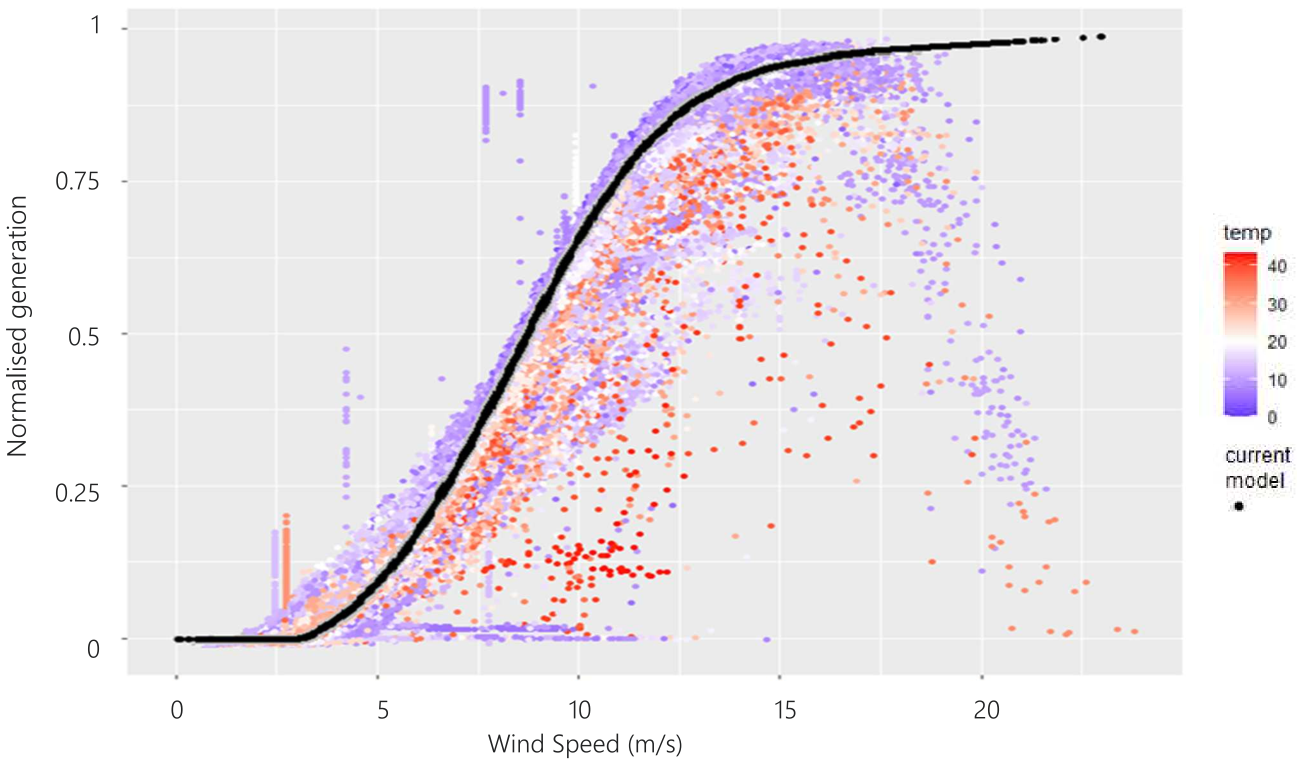
For EVs, AEMO has been leading the EV Data Availability Taskforce under the Distributed Energy Integration Program (DEIP) Electric Vehicle Grid Integration Working Group[7]. Its initial work, to be published soon, identifies EV data needs from an energy sector perspective, including registration data and the installation of charging infrastructure, alongside potential collection mechanisms and delivery options for this data.

~~3.4~~3.5 Wind generation trace development

AEMO's current process for wind generation traces is to use historical weather readings, filling gaps and missing values, and applying an empirical wind turbine power curve to convert wind speed and other weather variables into energy generated.

An example empirical power curve shown in relation to observed wind farm output is available in Figure 1.

Figure 1 Current wind generation model with scatter plot of wind speed and temperature



This empirical power curve is increasingly used rather than historical wind generation measurements, as wind farms connect to regions physically distant from existing wind farms. The empirical power curves do not currently capture the effects of high wind and high temperature cut-outs. In the example case shown below, wind speeds over 19 metres a second are associated with reduced output, and a similar effect can be seen with temperatures over 35°C.

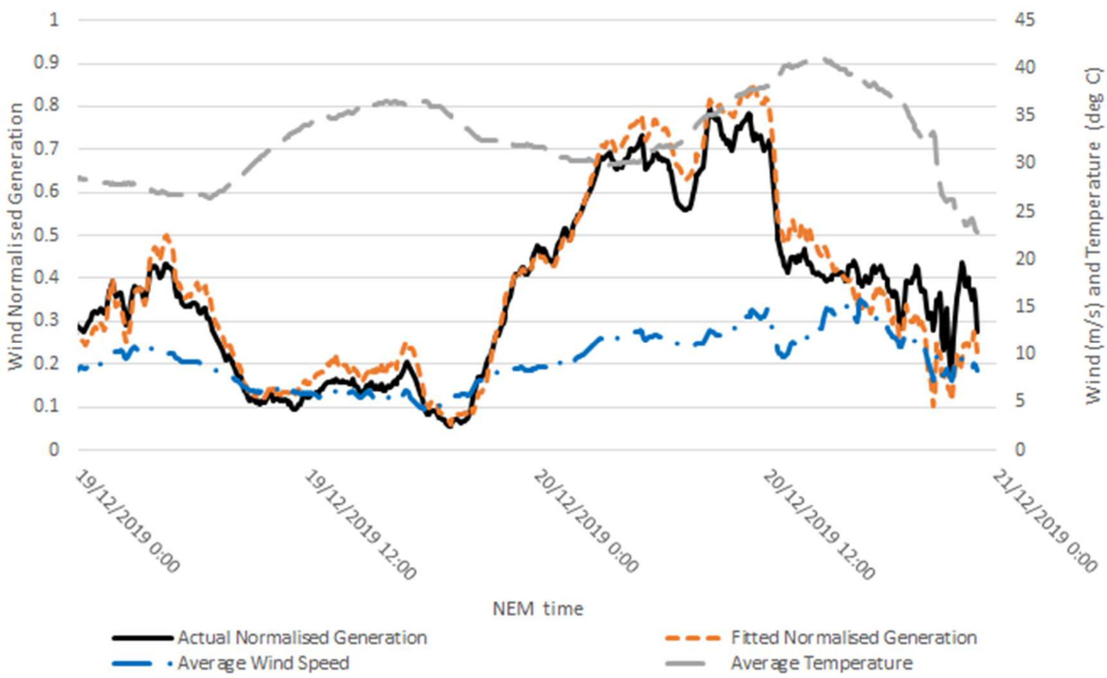
High temperature cut-outs were observed in the 2020 summer and resulted in an unexpected reduction in supply availability. Recent analysis suggests that wind generation output during annual high temperature

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

events may reduce more often due to climate change[8]. As installed wind capacity increases across the NEM, improved consideration of the relationship between wind generation and high temperature is important.

AEMO intends to develop and implement a new wind generation model that will produce more realistic traces in the presence of high temperatures or wind speeds. Figure 2 shows a potential trace from a prototype model, demonstrating realistic wind farm output driven entirely by meteorological inputs.

Figure 2 Prototype wind generation model on high temperature day



This improvement will result in better wind traces in current application and will build increased capability to explore weather and power system outcomes beyond those observed in the history. Such capability is required to comprehensively model the impacts of climate change.

~~3.5~~3.6 Inter-regional transmission elements forced outage rate model

The AEMO current process for forced outage rates on inter-regional transmission elements uses available outage history for the months November to March, as per the following formula.

$$forced\ outage\ rate = \frac{\text{outage hours in sampled history}}{\text{total hours in sampled history}}$$

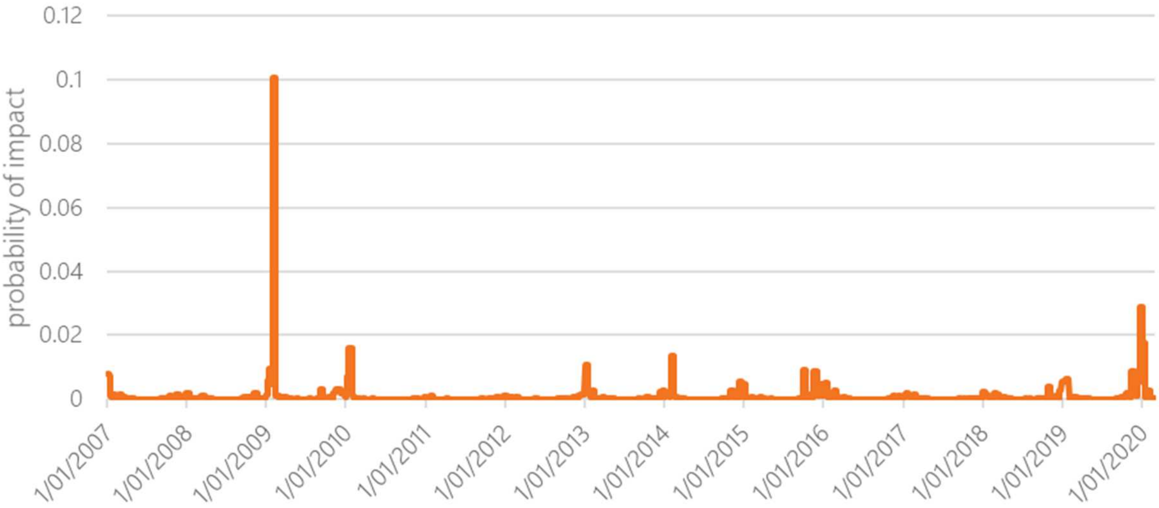
The current method is appropriate for random outages but may not adequately capture trends in frequency or timing/coincidence when the outages are driven by weather. Weather conducive for bushfires and high wind gust events is identifiable and can be used to develop forced outage simulations that better capture trends in frequency and timing. For example, bushfires are more likely to occur during periods of high temperatures that follow periods of low rainfall. Given that weather is increasingly the cause of transmission outages, as observed in 2019-20, improving the simulation of single credible contingencies is important for accurate forecasts.

[8] CSIRO, Bureau of Meteorology~~OM~~, AEMO. 2020. Electricity Sector Climate Information Project Case Study - Heat Impacts on VRE Generation Output. https://www.climatechangeinaustralia.gov.au/en/climate-projections/future-climate/esci/, based on Huang J, Jones B, Thatcher M, and Landsberg J. 2020. Temperature impacts on utility-scale solar photovoltaic and wind power generation output over Australia under RCP8.5. https://aip.scitation.org/doi/10.1063/5.0012711.

AEMO intends to develop and implement new transmission failure models, that predict failure as a function of weather, where relevant. For example, as the Victoria to New South Wales inter-regional transmission elements can be impacted by bushfire, predicting bushfire impact probability as a function of daily bushfire weather, expressed as Forest Fire Danger Index (FFDI) may improve outage rate assumptions.

Figure 3 shows the output of a prototype model that shows that the daily probability of impact attributable to bushfire is centred on high temperature periods of summer with variation in conditions year to year. The 2009 bushfire year has the highest instantaneous probability, while the 2019-20 bushfire year has reduced probabilities that are distributed over a longer time. These probabilities align with observed impacts, but also recognise that bushfire risk exists in every year, to varying degrees. In implementation, the projected outage rates will consider the increasing frequency of bushfires projected by climate change models.

Figure 3 Prototype daily transmission bushfire impact model output for Victoria – New South Wales inter-regional transmission elements



While this improvement will result in better modelling of single credible contingencies on inter-regional transmission elements in current application, it also builds capability that allows for exploration of weather and power system outcomes beyond those observed in the history. Such capability is required to comprehensively model the impacts of climate change, and will be subject to further consultation over time.

A1. Status of 2020 ESOO improvements

The 2019 Forecast Improvement Plan was published in the 2019 Forecast Accuracy Report[9]. It proposed a number of improvements planned for the 2020 ESOO. For visibility of progress, each improvement is listed below along with a summary of feedback and the implementation status.

Table 1 Proposed improvements relevant to the 2020 ESOO

Improvement	Stakeholder feedback	Status
Operational energy consumption forecast methodology Develop multi-model ensembles of energy consumption per region considering both the existing component based model and shorter-term monthly time-series models.	This proposed improvement was discussed at the January 2020 Forecasting Reference Group (FRG) meeting. Written feedback suggested broad support but requested clarity as to how time-series models would be incorporated or merged alongside component-based models to reflect customer segments or total energy consumption trends.	**Implemented**. Improvements have been implemented and demand methodology documents have been updated to provide requested clarity.
PV forecasts Use the DER Register and work more closely with the Clean Energy Regulator (CER) to ensure insights from historical installations are captured in short-term trends, possibly at more detailed spatial granularity.	This proposed improvement was discussed at the January 2020 FRG.	**Partially implemented**. The timing of the DER Register data availability precluded its use in underpinning these forecasts, however AEMO's DER forecasts considered the most up-to-date information on historical uptake from the CER, and CSIRO's forecast methodology improved to incorporate this trend. Green Energy Markets (GEM) was engaged as a second consultant to complement the forecasts provided by CSIRO.
Generator derating in response to summer heat AEMO will apply two summer capacity ratings to better capture available capacity at different temperatures.	This proposed improvement was discussed at the November 2019 and January 2020 FRG.	**Implemented.** The 2020 ESOO and Reliability Forecasting Methodology document has been updated.
Customer connection forecast methodology AEMO now has over five years of connections history for all regions, so a new connections model is being developed that incorporates greater visibility and consideration of the history and dwelling type characteristics.	This proposed improvement was discussed at the January 2020 FRG.	**Implemented**. Demand forecasting methodology document has been updated to reflect the changes to the connection model that better capture short-term trends.

[9] AEMO. 2019. Forecast Accuracy Report 2019, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/forecast_accuracy_report_2019.pdf

Forecasting portal* Publish shoulder seasonal minimums in addition to summer/winter	This proposed improvement was discussed at the January 2020 FRG.	**Implemented**. Shoulder demand forecasts are now available on the portal.
Demand side participation Include responses from peaking type non-scheduled generators in DSP forecast rather than offsets in the demand forecast.	This proposed improvement was discussed at the January 2020 FRG and reflected in the DSP methodology consultation Feb-Aug 2020.	**Implemented**. DSP methodology documents have been updated.
Auxiliary load Estimations of auxiliary load will be requested from generators directly through the Generation Information data collection process.	This proposed improvement was discussed at the January 2020 FRG.	**Implemented**. Market modelling has been updated with generator provided auxiliary rates.

* The AEMO forecasting portal can be found at http://forecasting.aemo.com.au.

In addition to the above improvements, AEMO conducted several investigations, and completed numerous minor methodological improvements including:

- Monitoring the performance of generator new entrant connections to ensure actual rates of connection match forecast.
- Implementing forward-looking forced outage rate projections (discussed in the June 2020 FRG).
- Changing how current Reliability and Emergency Reserve Trader (RERT) participation affects inclusion in DSP forecast, with voluntary responses now being reflected in the DSP forecast even for RERT participants (consulted on with industry as part of the DSP forecast methodology consultation in 2020).
- Developing a dynamic EV charge profile to reflect controlled EV charging that is optimised around minimum demand (only relevant beyond the 10-year ESOO planning horizon).
- Assessing the likely impacts of COVID-19 on consumption, maximum/minimum demand and DER investments to adjust 2020 ESOO forecast accordingly.

Abbreviations

Abbreviation	Full name
CER	Clean Energy Regulator
CSG	Coal seam gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	Distributed Energy Resources
DSP	Demand Side Participation
ESOO	Electricity Statement of Opportunities
FRG	Forecasting Reference Group
MT PASA	Medium Term Projected Assessment of System Adequacy
MW	Megawatt
NEM	National Electricity Market
NER	National Electricity Rules
POE	Probability of exceedance
PV	Photovoltaic
PVNSG	PV non-scheduled generation
RERT	Reliability and Emergency Reserve Trader
VRE	Variable renewable energy