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Thursday, 21 January 2021

Ms Nicola Falcon
General Manager Forecasting
Australian Energy Market Operator
PO Box 2008
Melbourne, Victoria, 3001

Dear Ms Falcon

RE: AEMO Draft Forecasting Approach - Electricity Demand Forecasting Methodology Consultation

ERM Power Retail Pty Ltd (ERM Power) welcomes the opportunity to respond to the Australian Energy Market Operator's (AEMO) Draft Forecasting Approach - Electricity Demand Forecasting Methodology (the Methodology) Consultation.

About ERM Power

ERM Power (ERM) is a subsidiary of Shell Energy Australia Pty Ltd (Shell Energy). ERM is one of Australia's leading commercial and industrial electricity retailers, providing large businesses with end to end energy management, from electricity retailing to integrated solutions that improve energy productivity. Market-leading customer satisfaction has fuelled ERM Power's growth, and today the Company is the second largest electricity provider to commercial businesses and industrials in Australia by load[1]. ERM also operates 662 megawatts of low emission, gas-fired peaking power stations in Western Australia and Queensland, supporting the industry's transition to renewables.

http://www.ermpower.com.au
https://www.shell.com.au/business-customers/shell-energy-australia.html

2020 Forecast Accuracy Report

ERM Power acknowledges the ongoing work by AEMO to attempt to improve the veracity of the demand forecasting methodology in the areas of annual consumption and maximum and minimum demand outcomes. However, we remain concerned that AEMO maintains an overly conservative methodology with regards to the forecasting of regional maximum demand outcomes. This is highlighted by historical outcomes vs forecasts, in particular for the Victorian region. In December 2019[2] new temperature records were set at numerous weather stations in the Victoria region, however actual operational demand fell well below the 10% POE[3] forecast for the month of December. Similarly, in January 2020 when daily maximum temperature outcomes during the last week of January were well above historical 95th percentile outcomes and very close to historical maximums at numerous weather stations in the Victorian region, adjusted demand remained below AEMO's Summer and January monthly10% POE forecasts[4].

[1] Based on ERM Power analysis of latest published information.
[2] These new temperature records were set prior the week ending 18 December where high demand usage would be reasonably expected.
[3] Possibility of Exceedance – the probability that the actual demand outcome will exceed the forecast value
[4] Demand in AEMO's 2020 Forecast Accuracy Report (FAR) was adjusted following automated loss of load following a non-credible contingency event and activation of RERT contracts. The FAR also contained other non-verifiable adjustments.

We also note that in the history of the National Electricity Market (NEM), actual maximum demand in the Victorian region, following any required adjustments for defined load interruption, has not exceeded the market operators 10% POE demand forecast, yet demand has fallen below the 90% POE forecast for 25% of years.

In addition, we are also concerned with what we consider are reactive responses by AEMO, where actual demand outcomes, whilst remaining within the range of outcomes derived from the forecasting process, result in recalibration of baseline data and the 50 and 10% POE benchmarks. AEMO's regional maximum demand forecasts are derived from a set of 3,000 synthetic weather years, these potential weather outcomes which include for a wide range of weather variability is used to calculate a range of potential summer and winter maximum daily demand outcomes ranging from 0 to 100% POE. As set out in the Methodology, significant tail values exist in the distribution of outcomes between the 0 to 10 and 90 to 100% POE values.[5] We consider that it is entirely possible and also that it should be expected, that at some point in time actual demand could exceed a 5% POE (1 in 20 years) or even a 2% POE, (1 in 50 years) outcome which following an actual occurrence should not automatically justify significant adjustment to the 10% POE forecasts. We believe that more detailed analysis and consultation on prevailing factors that led to the 10% POE forecast being exceeded is warranted when such an event occurs, prior to any decision by AEMO to make significant adjustments to baseline and 50 and 10% POE benchmark data. This has not been the case to date, with significant adjustments made with what we believe has been inadequate consultation.

We recommend that AEMO provide additional transparency in the regional forecast maximum demand values as an appendix in the FAR, by including in tabular form the full range (0 to 100% POE) of regional forecast maximum demand values derived from their modelling process. This should be displayed in at least 21 blocks, each of 5 percentile increments.

We also urge AEMO to seek assistance from the regulators with respect to using performance data provided by participants to the Essential Services Commission (ESC) and the AER on a quarterly basis[6]. Some of this data, such as monthly feed in tariff customer numbers by jurisdiction, monthly smart meter installation by metering type and number of customers with smart meters by tariff type (controlled load, time of use) may be useful as a reference source for trend analysis.

We hope that AEMO will consider the issues raised in this submission as ERM Power seeks to work with AEMO to improve its forecasting methodology. Following are more detailed comments based on the defined sections of the Methodology.

Section 2 – Business annual consumption

ERM Power agrees with AEMO definition of Large Industrial Loads (LIL's) and the LIL subsectors proposed for the NEM and the West Australia Electricity Market (WEM). However, we are concerned that insufficient differentiation and therefore analysis is occurring in the commercial, light industrial and larger sized enterprise space which consume in the 2 to 10 MW half hourly demand range. Loads in this range would have a very different consumption pattern and potentially be less sensitive to prevailing weather outcomes to other smaller commercial and industrial enterprises which consume in the 100 KW to 2 MW demand range. We recommend that AEMO request assistance from Distribution Network Services Providers (DNSP) to improve the granularity of load classification on a National Market Identifier (NMI) on the basis of differentiation of network tariff structure to better identify business consumption types.

5 Figure 17 - Draft Forecasting Approach - Electricity Demand Forecasting Methodology pp49

6 Retailers must supply market performance data quarterly in accordance with the AER's Performance Reporting Procedure and Guidelines and the ESC's Compliance and Performance Reporting Guideline.

We support AEMO's interview process with LIL's and note that not all LIL's are interviewed, however, whilst AEMO indicate which loads to be identified may be determined by the level of deviation between forecast and actual consumption outcomes, it is unclear from the methodology that this is a discussion point during the interview process. We recommend that discussions regarding deviations between forecast and actual consumption are included as a clear discussion point in the methodology.[7]

We note that AEMO may include new LIL's in its forecast, however the Methodology fails to detail the criteria benchmarks that must be met prior to their inclusion in the NEM. We recommend that the Methodology include clear criteria similar to the commitment criteria used for new supply side or transmission resources for the inclusion of new LIL's as well as commercial, industrial and larger sized medium enterprise space which are forecast to consume in the 2 to 10 MW range. We note that the Methodology already includes clear criteria for inclusion as a future load in the WEM forecast.

We note the methodology contains no criteria for classification as a small and medium enterprise (SME). We understand that industry convention would classify SME and as a non-residential connection point consuming less than 100 MWh per annum or an average load of 11.5 KW. As discussed above, we consider that more detailed analysis of half hourly and annual consumption patterns in the 100 KW to 10 MW NMI demand range should be developed.

We also note that in this load group, AEMO applies seasonality factors in developing load forecasts, it is unclear how this differentiates between loads that have a seasonality component and loads that do not. In addition, these seasonality factors are developed based on region wide impacts where some SME loads may have greater and more time period defined seasonal impacts than others. As an example, SME loads in holiday resort areas would have very high seasonality impacts whereas SME loads in a metropolitan location may not.

The Methodology indicates that for SME loads to reflect the uncertainty of forecast outcomes in the first forecast years, AEMO applies a dispersion around its central scenario, similar to a simulated random walk with a deterministic drift term. This approach results in approximately 2-3% difference from the Central trajectory in the first forecast year (for the highest and lowest demand scenarios), growing to 4-5% difference in the second forecast year and a 5-7% difference in the third forecast year. However, the FAR contains no details with respect to the accuracy of SME consumption to forecast, so absent this level of detail its unclear if this level of uncertainty adjustment is justified. We recommend that AEMO provide improved analysis of consumption and actual demand outcomes for SME to justify this level of dispersion.

The Methodology indicates that for the long term causal model AEMO currently uses Gross State Product (GSP), ("*a measurement of the economic output of a state being the sum of all value added by industries within the state*"[8]), as one of the factors for forecasting growth in SME consumption. However, AEMO may switch between GSP and other economic measurement series on the basis of what "*gives the best fit with consumption and is reasonably expected to explain the changes observed*".[9] The Methodology provides no details of how this is analysed or the criteria for selecting the most appropriate measurement series. The methodology implies that the measurement series to be applied will be selected based on AEMO's judgement at the time. We recommend the Methodology set out clear criteria for selection of the measurement series. We also note that the coefficients based on this data are calculated on the basis of a time series of "*t* "years, with no defined time period for "*t* "or criteria for its determination defined in the Methodology. We recommend that at least the criteria for selection of the appropriate time period for "*t"* be contained in the Methodology.

[7] Step 4 – Conduct detailed interviews – Draft Forecasting Approach - Electricity Demand Forecasting Methodology pp17
[8] Draft Forecasting Approach - Electricity Demand Forecasting Methodology pp 22
[9] Draft Forecasting Approach - Electricity Demand Forecasting Methodology pp 22

The Methodology indicates that with regards to price elasticity, AEMO applies a unidirectional assumption in that higher prices will drive lower consumption but lower prices "*will have an immaterial impact on potential energy consumption*"[10]. However, this is somewhat contradicted in the next section of the Methodology – Adjustments to energy efficiency where AEMO indicates "*Applying a discount factor to the adjusted energy efficiency forecasts, to reflect the potential increase in consumption that may result from lower electricity bills (knows as the "rebound" or "take back" effect and the potential non-realisation of expected savings from policy measures.*"[11] We are also concerned that the Methodology fails to clearly detail how "*demand destruction*" is adequately considered in the model. Our observation is that once SME or commercial and light industrial (C&I) departs due to high price outcomes, it is many years, if ever, before an alternative consumption source makes up for the load which has exited. We recommend AEMO provide additional clarity in these areas of the Methodology to remove any contradictory interpretation.

Section 3 - Residential annual consumption

The Methodology indicates that AEMO analyse daily and monthly consumption to determine a value for daily average consumption by estimating the daily (monthly) underlying consumption per residential connection by dividing by the total number of connections. A regression model is then used to calculate the daily (monthly) average consumption split between baseload, cooling and heating load. In the model all connections are considered to be equal and no analysis of the type of residential housing stock is defined to determine more granular values for different types of housing such as high density apartments, medium density units or detached housing. In predicting future consumption, the model relies solely on the forecast number of new and existing connection points. Should the shares of individual types of future residential connections deviate from the current shares, then considerable time may elapse prior to the model applying a degree of self correction to the defined values for baseload, heating and cooling consumption.

In considering the potential for inaccuracy to enter the modelling process due to this, we note that the Australian Energy Regulator (AER) both through the Energy Made Easy website[12] and through energy retailers, provide details of daily average consumption for residential consumers based of number of occupants per residence. According to the Energy Made Easy website a 2-occupant residence in metropolitan NSW is estimated to consume on average 14.8 KWh per day with a range of 15.2 KWh per day in Summer and 16.8 KWh in Winter. A 5-occupant residence in metropolitan NSW is estimated to consume on average 19.7 KWh per day with a range of 19.9 KWh per day in Summer and 22.6 KWh in Winter. On the basis that a detached house would generally have a higher number of occupants that a high density apartment or medium density unit, this would suggest that a detached house on average consumes 35% more electricity than a high density apartment or medium density unit. A 5-occupant residence in metropolitan NSW with a swimming pool is estimated to consume on average 30.9 KWh per day with a range of 33.2 KWh per day in Summer and 33.8 KWh in Winter, double that of a 2-occupant residence.

This data suggests that the type of future residential connections may have a meaningful impact on the level of energy consumption in the NEM and WEM. We recommend that AEMO further consider the need for greater granularity in its analysis of residential connection points with regards to baseload, heating and cooling loads both for annual consumption and half-hourly demand values. AEMO may be able to request assistance from DNSPs to segment consumption on the basis of network tariff structure at a NMI level or alternatively as discussed previously in the submission performance data[13] already supplied by retailers on a quarterly basis .

[10] Draft Forecasting Approach - Electricity Demand Forecasting Methodology pp 22

[11] Draft Forecasting Approach - Electricity Demand Forecasting Methodology pp 23

[12] https://www.energymadeeasy.gov.au/benchmark

[13] S2.9a and b of the AER's Performance and Reporting Guideline requires this information to be supplied to the AER quarterly. Similarly, The ESC's Compliance and Performance Guideline, indicator B021 is required to be supplied by retailers quarterly.

We note the Methodology includes adjustment for take up of new electrical appliances, however, whilst the Methodology is clear for new connections, the Methodology contains no detail regarding the replacement of old with new appliances for existing connections. A replacement new appliance whilst larger than the replaced appliance may have higher energy efficiency and may potentially use less energy than the replaced appliance. We recommend AEMO detail in the Methodology how variance in energy consumption is calculated for replacement as opposed to new appliance uptake.

The Methodology applies factors for what is referred to as the "rooftop solar PV rebound effect". This is based on AEMO's assumption that households with installed rooftop PV are likely to increase consumption due to lower electricity bills and less behavioural diligence to reduce energy consumption. Further, the Methodology indicates that "*The PV rebound effect is allocated proportionally to base load, heating load, and cooling load per connection.*"[14] In ERM Power's view, whilst it is reasonable that base load could potentially be impacted by this rebound effect, it is less clear that heating and cooling load would be significantly impacted. In addition, the Methodology sets out little actual detail regarding how the apportioning of this rebound effect to the base load, heating load, and cooling load categories is applied or AEMO's process for determining these. We recommend that additional details be provided in the Methodology setting out the process for how the level of "rooftop solar PV rebound effect" is calculated and the apportioning of this to base load, heating load, and cooling load per connection.

We note that the Methodology apples similar adjustment factors for the impacts of price sensitivity and energy efficiency price rebound reductions as that applied to SME loads. Similar to our previous comments with regards to SME load in these areas, we recommend AEMO provide additional detail and clarity in these areas of the Methodology to remove any contradictory interpretation. In addition we note the Methodology applies these rebound savings equally to base load, heating load, and cooling load per connection without considering the impact that tariff structures may have on this as well as changes in consumer disposable income, where consumers may focus on energy usage outcomes under higher usage conditions with reduced energy efficiency reductions during heating or cooling periods.

We consider it's questionable if consumers having made the decision to adjust set points for cooling or heating appliances will adjust these again when observable cost savings have been demonstrated. We recommend AEMO consider further analysis in this area.

We recommend that in considering the uptake of electric vehicles for residential recharging, that additional work be undertaken and consulted on with interested stakeholders on the potential impact of changes to residential tariff structures.

Section 5 – Maximum and minimum demand

In ERM Power's opinion, from a reliability forecasting perspective, the calculation of forecast maximum demand outcomes has the greatest potential to result in unwarranted additional costs to consumers.

Unlike the methodology for calculation of annual consumption where components of business and residential load are segregated and calculated individually before being combined to create the individual regional and market wide consumption forecasts, the methodology for calculation of minimum and maximum demand extracts only LIL half hourly historical demand outcomes and combines all other loads to develop the half hourly traces of base load, cooling load and heating load. In the methodology all connection points for commercial, light industrial, SME and residential load are considered to have the same average values and respond the same in terms of increased demand for meeting heating and cooling load to the forecast synthetic weather outcomes.

[14] Draft Forecasting Approach - Electricity Demand Forecasting Methodology pp 31

We consider that improvements in the accuracy of forecasts of future maximum demand outcomes may be available through better segregation of the different types of demands at individual connection points or NMI's. Improvements could be achieved by AEMO seeking the assistance of DNSPs to provide network tariff application information to help classify the type of load at each individual NMI. This would require a one-off allocation of demand type to each connection point which would potentially remain valid for a sustained period.

When considering the factors derived from the EDA assessment process as set out in Table 6,[15] which move forward to the half hourly demand model, it's unclear if AEMO in their assessment included a more granular day of the week for working weekdays assessment as it can be readily observed that both Mondays and Fridays have different demand patterns to Tuesdays, Wednesdays and Thursdays across all months and seasons. We recommend that AEMO consider if a further granular breakdown of working weekdays is warranted.

With regards to the simulation of the base year[16], the Methodology indicates there is a degree of interaction between the GEV model and the half hourly model, in particular, the transition over future forecast years from purely GEV to purely half hour model forecasts, however, no detail regarding the transition process is provided. We recommend AEMO provide further detail in this area.

The methodology indicates that "*Historical weather events are simulated to develop a weather distribution to normalise demand then stochastic volatility is applied*."[17] Stochastic volatility is normally applied when it has clearly been determined that volatility may vary over time. In addition, there are multiple methods for applying stochastic volatility and the method used in not set out in the Methodology. It is unclear to ERM Power given the significant array of weather sensitive input assumptions already applied in the model, which are already varied over time, why an additional stochastic volatility factor is required. We recommend AEMO provide more detail in the Methodology as to why its inclusion is required, given the other existing weather sensitive input assumptions, and which stochastic volatility model is used.

Similarly, we note the Methodology indicates that additional adjustment factors are applied that represents random normally distributed changes in demand not explained by the model demand drivers from both the half hourly and GEV model. We recommend AEMO provide more detail in the Methodology as to why their inclusion is required.

The Methodology indicates that the synthetic weather years are developed using the last 20 years of historical weather data. In this process, historical weather data is broken down into 26 fortnightly weather blocks, these blocks are then randomly selected to create the synthetic weather year outcomes. It's unclear to ERM Power how this would ensure the historically observed normal pattern of rolling within season of weather outcomes are maintain across the entire 3,000 simulated synthetic weather years. We recommend that AEMO provide additional detail regarding this in the Methodology. We also note that all 20 historical years are warmed to meet a view of possible future climate conditions, its unclear to us how this will maintain the natural range of historical outcomes if all years are warmed to achieve a common view of future climate forecasts. We consider these years should maintain the normal spread of reasonably possible weather outcomes as opposed to a central forecast view of future outcomes.

The Methodology then indicates that "*The half-hourly forecast process grows half-hourly demand by economic conditions such as price and GSP, demographic conditions such as connections growth, and technological conditions such as EV uptake <u>to derive an annual growth index</u>.*", and further, "*The forecast year-on-year change is applied <u>to each of the 17,520 half-hours</u> for each simulation in the half-hourly model and to each forecast year. The process <u>grows half-hourly underlying demand</u> by annual or seasonal growth indices such as population growth, economic factors and price.*"[18]

[15] Draft Forecasting Approach - Electricity Demand Forecasting Methodology pp 46
[16] Section 5.4 Draft Forecasting Approach - Electricity Demand Forecasting Methodology pp 47
[17] Draft Forecasting Approach - Electricity Demand Forecasting Methodology pp 47
[18] Draft Forecasting Approach - Electricity Demand Forecasting Methodology pp 48

It is unclear to us how this process would allow for structured charging, and potentially discharging of electric vehicles when an annual growth index is applied to all half hours. We recommend that AEMO considered if individual growth index values should be applied to different half hour periods.

The methodology indicates that output from non-scheduled intermittent generation (NSIG) where "*The forecast impact on maximum and minimum demand is calculated based on the different demand, technologies' historical generation at time of maximum or minimum grown proportionally with any forecast growth in installed capacity.*"[19] Given the large capacity of NSIG in the NEM it is important that the Methodology set out greater detail how output from NSIG is applied. Its unclear if output from NSIG is applied based on individual year historical weather aligned outcomes, the average output across all years or the minimum output across all years at the time of maximum and the maximum output at times of minimum demand. We recommend AEMO provide additional clarity in this area.

Section 6 – Half hourly demand traces

ERM Power is concerned that scaling of half hourly demands remains to a degree an opaque black box process and whilst the methodology sets out the process from a theoretical perspective, it does not set out any framework for independent analysis and audit of the process post completion. Recent changes to information provided to participants as part of the Medium-Term Projected Assessment of System Adequacy rule changes provides information with regards to the range of daily maximum demand outcomes post scaling to both the 50% and 10% POE forecasts. These same demand forecasts are used in the Electricity Statement of Opportunities Reliability Forecast. We note across the regions that post scaling, the maximum of the daily range of maximum daily demand outcomes for demand scaled to the 50% POE forecast for approx. 70% of days is higher than the maximum of the daily range of maximum daily demand outcomes for demand scaled to the 10% POE forecast.

Given the demand traces are scaled in a single process, it's unclear to us how a daily 50% POE forecast could be higher that the 10% POE forecast. We recommend AEMO consider further independent auditing and transparent reporting on of the final demand traces prior to use, as well as additional effective consultation with stakeholders regarding the development of this process.

Appendices

<u>Weather and Climate</u>

The Methodology indicates that "*AEMO incorporates climate change into its minimum and maximum demand forecast as well as its annual consumption forecast. For the annual consumption forecast, according to Climate Change in Australia (CCiA) data average annual temperatures are increasing by a constant rate. However, half-hourly temperatures have higher variability and may include increasing extremes*.". However, previous to this section, the Methodology indicates that trend analysis adjustments are already applied for forecast changes in climate to the heating degree days and cooling degree days values. Whilst we believe it would be reasonable to apply either one of the climate adjustment factors in isolation, its unclear if the combined application of both adjustment factors is warranted.

<u>Rooftop PV forecast</u>

The Methodology indicates that population growth will be used to calculate forecast growth in rooftop PV solar installations. We question if trend analysis of Essential Services Commission and AER's retailer supplied solar tariff data[20] would provide a more accurate value for forecasting increase in rooftop solar PV installation. We suggest that AEMO seek this data from the regulators.

[19] Draft Forecasting Approach - Electricity Demand Forecasting Methodology pp 50

[20] S2.9a and b of the AER's Performance and Reporting Guideline requires this information to be supplied to the AER quarterly. Similarly, The ESC's Compliance and Performance Guideline, indicator B021 is required to be supplied by retailers quarterly.

Energy storage systems (ESS) forecast

With regards to ESS charge/discharge profile used in minimum and maximum demand, we query AEMO's view that, "*the effect per battery at reducing the operational demand at peak times in summer is relatively small given that battery operations are targeting residential load reductions*".[21]

Whilst the effect per battery may be small, installation of 100,000, 4KW capacity BESS, (based on a Tesla Powerwall 2), could reduce system load by 400 MW at peak demand times if tariff structure reform maximised the benefit for consumers to do so. Introduction of a peak period time-of-use tariff or payments for participation in a virtual power plant (VPP) scheme may facilitate a change to the charge/discharge profile of residential and commercial ESS and we recommend this be closely monitored and considered by AEMO.

Electric vehicles (EV) forecast

When considering the forecast for EV uptake, with regards to the EV payback period factor, we recommend AEMO also include a change to registration costs based annual kilometers usage charges.

Please contact Ron Logan 0427 002 956 or rlogan@ermpower.com.au if you have any questions with regards to this submission.

Yours sincerely,

[signed]

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[21] Draft Forecasting Approach - Electricity Demand Forecasting Methodology pp 62