Reliability Standard and Settings Review 2018 – Modelling Report

The Reliability Panel

13 April 2018

Notice

Ernst & Young (“we” or “EY”) has been engaged by The Reliability Panel (“you”, “Panel” or the “Client”) to provide advice and modelling assistance for the 2018 Reliability Standard and Settings Review (the “Services”) in accordance with our Letter of Appointment dated 29 June 2017 and Panel Agreement with the Australian Energy Market Commission (“AEMC”).

The enclosed report (the “Report”) sets out the modelling methodologies, key data and assumptions, modelling application and modelling outcomes of the National Electricity Market which have been designed to inform the Panel in their assessment of the appropriateness of the reliability standard and settings for the period 1 July 2020 to 1 July 2024. The Report should be read in its entirety including the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report. The report has been constructed based on information current as of 13 April 2018 (being the date of completion of this Report), and which has been provided by the Client and other stakeholders. Since this date, material events may have occurred that are not reflected in the Report.

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The methodologies described, together with the scenarios and assumptions used form the basis for the outputs produced and have been agreed upon by the Panel. The modelling is based, in part, on the assumptions stated and on information provided by AEMC, AEMO and other stakeholders engaged in this process. We do not imply, and it should not be construed that we have performed audit or due diligence procedures on any of the information provided to us. We have not independently verified, or accept any responsibility or liability for independently verifying, any such information nor do we make any representation as to the accuracy or completeness of the information. We accept no liability for any loss or damage, which may result from your reliance on any research, analyses or information so supplied.

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1 Executive Summary

1.1 Background

EY was engaged by the Reliability Panel (Panel) to provide advice and conduct modelling for the 2018 Reliability Standard and Settings Review (Review). This report describes the outcomes and insights gained through the modelling, including the methodologies undertaken by EY, in assessing the relative drivers for particular reliability settings which may apply from 1 July 2020 to 1 July 2024 (the Period).

Table 1 describes EY's tasks for this Review.

Table 1: EY's tasks for this Review

Task	Description
Task 1	**Expected unserved energy (USE):** Forecast the expected amount of USE over the Period under the current reliability settings, and assess whether the current reliability standard of 0.002% USE will be met over the Period.
Task 2	**Administered price cap (APC):** Estimate the theoretical optimal level at which the APC could be set over the Period.
Task 3	**Market price cap (MPC):** Estimate the theoretical optimal level at which the MPC could be set over the Period.
Task 4	**Cumulative price threshold (CPT):** Analyse how the level of the CPT influences the effectiveness of the theoretical optimal MPC and discuss the implications on the market from changing the CPT and MPC.

Unserved energy (USE) means the amount of customer demand that cannot be supplied in a region of the national electricity market due to a shortage of generation or interconnector capacity[1]. Events of USE would be experienced by customers as blackouts, although some types of blackouts, such as a tree falling on power lines affecting a small area, do not count as USE for the purpose of assessing the reliability standard. USE is calculated in megawatt or gigawatt hours (MWh or GWh)[2] and is typically expressed in terms of a percentage of customer demand, i.e., the reliability standard is to achieve a maximum expectation of 0.002% USE. That is, on average the risk of not being able to meet customer energy demand should be limited to 0.002% of the desirable energy consumption. The term *expected unserved energy* means a statistical expectation of a future state; an average across a range of future outcomes, weighted for probability.

Task 1 was included as part of the modelling scope for this Review for the following reasons:

- The requirements for the Review, under the National Electricity Rules, clause 3.9.3A are: "*…the Reliability Panel … (3) must have regard to the potential impact of any proposed change to a reliability setting on … (iii) the reliability of the power system.*" Understanding the expected USE for the Period under the current reliability settings is the first step toward assessing this requirement.
- To understand the most likely level of USE for the Period as a baseline, from which to devise the MPC scenarios that threaten the reliability standard (to the extent that this is necessary, where the Base Scenario delivers USE outcomes that do not threaten the reliability standard).

[1] Fact sheet available at: http://www.aemc.gov.au/getattachment/2f4045ef-9e8f-4e57-a79c-c4b7e9946b5d/Fact-sheet-reliability-standard.aspx

[2] NEM Rules, Chapter 10.

1.2 Methodology overview

EY's approach to determine the expected USE for the Period involves developing a Base Scenario and conducting detailed time-sequential half-hourly modelling of the electricity market. A number of sensitivities on the Base Scenario were also conducted to explore the impact on USE outcomes from different assumptions. All modelling assumptions were chosen by the Panel, in consultation with EY.

EY then conducted further iterative market modelling under alternative scenarios (MPC scenarios) to estimate the theoretical optimal MPC. The methodology involves producing plausible scenarios where the reliability standard is threatened; meaning that the reliability standard would be exceeded if the reliability settings such as the MPC were not set sufficiently high to incentivise new entrant investment to keep USE below 0.002%. These scenarios are devised by selecting assumptions that result in USE being above the reliability standard, in the absence of new entrant investment. The economic and technical modelling task is then to find the minimum MPC that economically incentivises sufficient new entrant investment to reduce the level of expected USE to below the reliability standard.

This methodology addresses all three principal recommendations made in the Oakley Greenwood assessment[3] that were adopted in the 2016 RSSR Guidelines[4], as well as additional suggestions made by stakeholders in July 2017 in response to questions on modelling methodology posed in the Panel's Issues Paper[5]. For details, see Section 3.5 of this report.

1.3 Differences to 2014 RSSR Review

The previous RSSR Review was conducted over 2013-14 and the final report was published in 2014. Primarily due to addressing the recommendations in the Oakley Greenwood assessment mentioned above, the key differences in the methodology for this Review to that used in the 2014 Review are as follows:

- This Review considers technology-neutral new entrant capacity, whereas the 2014 Review only assessed an Open-cycle gas turbine (OCGT) bidding at $300/MWh.
- This Review considers net revenues of existing capacity as well as new entrants in determining the theoretical optimal MPC, while the 2014 Review only assessed new entrant capacity.
- This Review assesses the theoretical optimal MPC based on plausible scenarios that threaten[6] the reliability standard, while the 2014 Review applied a more theoretical approach to the removal of capacity.
- This Review examines options for changing both the CPT and the MPC.

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[3] *Assessment of approach to modelling of Reliability Settings – Prepared for Australian Energy Market Commission*, Oakley Greenwood, Australia (September 2016).

[4] http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-reliability-standard-and-settings-guidel (1 Dec 2016).

[5] Issues Paper – Reliability Standard and Settings Review 2018, Reliability Panel AEMC (6 June 2017).

[6] By 'threaten' here, we mean that an expectation of greater than 0.002% USE could be forecast in that scenario if the MPC (and other reliability settings) are not sufficiently high. The theoretical optimal MPC is determined on a simulation with new entrant investment that achieves an expected USE at or just under 0.002% USE.

1.4 Modelling limitations

USE forecasting modelling limitations

Whilst the USE forecasts in this Review take into account many aspects of what can cause USE, the modelling has the following limitations:

- Transmission network outages, including outages of interconnectors between regions are not considered[7]. The probability of a transmission outage is very small compared to generation availability, but may have a significant impact when it occurs.
- The modelling for forecasting USE mostly considers half-hour trading intervals and does investigate five-minute dispatch in a sensitivity scenario. USE can occur due to sudden changes in residual demand and ramping limitations of thermal generators between five-minute intervals. However, we note that the majority of USE is observed due to events that occur over multiple consecutive trading intervals.
- Consideration of six historical reference years. Forecasting an expectation of USE is theoretically more accurate through modelling an increasing number of weather patterns along with their influence on demand, wind generation and solar generation. However, due to data availability, EY's modelling for this Review is limited to six historical reference years, 2010-11 to 2015-16.
- The outcomes presented are based on a set of assumptions defining several scenarios. However, there are many possible future combinations of assumptions that are not considered. In addition to this, several key assumption are based on data produced by AEMO and other third parties. EY has not verified the accuracy of this data used in the modelling.

MPC forecasting modelling limitations

The following points outline some of the more significant limitations in the outcomes for the theoretical optimal MPC.

- The methodology only considers the viability of a new entrant generator in terms of achieving an annual market revenue that exceeds their annualised costs in the years modelled in the Period. However, the market revenue forecast over the Period may not continue for the economic lifetime of the asset, due to many potential reasons, such as the introduction of a new emissions reduction policy. The methodology in this Review only addresses long-term revenue risk through the sensitivities that explore a higher WACC.
- Only two different scenarios were modelled to achieve a situation where the reliability standard is threatened. Whilst these two scenarios explore two different situations resulting in high levels of USE, both of these scenarios involve retiring high utilisation thermal generation capacity. Other situations resulting in the risk of high levels of USE may lead to different MPC outcomes.
- Given a set of assumptions for a scenario, there are several aspects of modelling the future electricity market that are uncertain, especially on the half-hourly or five-minute level. In the real market events frequently transpire that disrupt the market operation. The assumptions used for forecasting purposes broadly replicate market dynamics, however these may not capture specific market events that occur at the half-hourly or five-minute level and the response of specific generators to such events.
- The dynamic bidding methodology captures portfolio behaviour with respect to changes in running costs and market dynamics. These dynamic bidding selections do not assume any level of contracting for the portfolios and as such, do not capture any changes to bidding behaviour associated with changes in contracting levels that may arise due to an increase or decrease in the MPC. The MPC outcomes are sensitive to the market price forecast, which are directly attributable to the assumed generator portfolios and associated bidding strategies.

[7] Interconnector flow limits and their interaction with network constraint equations are taken into account. The network constraint equations used for the Base Scenario is the AEMO 2015 constraint dataset.

Additionally, any market price interactions that occur on a five-minute level are not captured in the half-hourly modelling (although this is explored in the five-minute modelling sensitivity).

- On 28 November 2017, the AEMC made a final rule to align operational dispatch and financial settlement at five minutes. This rule will reduce the time interval for financial settlement in the NEM from 30 minutes to five minutes. Five-minute settlement will commence on 1 July 2021. The majority of the modelling for this Review took place before this rule change was announced and was conducted with thirty-minute intervals. However, following the announcement EY conducted an additional scenario with five-minute modelling to quantify the potential impact of five-minute settlement on the MPC outcomes.

- There will always be uncertainty as to whether the market will respond rationally to market pricing signals and incentives.

1.5 Key outcomes and insights

Table 2 summarises the key outcomes from this Review for each of the tasks outlined in Table 1.

Table 2: Key outcomes for this Review

Task	Description
Task 1: USE	The USE forecast as modelled in the Base Scenario is very small in all regions across the Period, well below the reliability standard. The Base Scenario suggests that reliability of supply is expected to remain within the reliability standard with the current settings and current projected market development. This outlook is somewhat due to market development in response to the LRET and state based energy policy developments, very little growth in operational energy demand due to increasing uptake of behind-the-meter solar PV and domestic storage and low incentive for early retirement of existing generation based on operating cost data applied in the modelling. Sensitivity scenarios were modelled which found that key assumptions and alternative data preparation methodologies can have a significant impact on the forecast USE. However, the level of expected USE as modelled in all sensitivity scenarios is below the reliability standard throughout the Period. EY compared the USE outcomes with AEMO's modelling for the 2017 Electricity Statement of Opportunities (ESOO[8]). The difference observed in the USE outcome between the RSSR Base Scenario and AEMO ESOO modelling are not material to the modelling completed for the purpose of assessing and recommending the reliability settings (see Appendix D for further discussion on this matter).
Task 2: APC	Based on the key cost assumptions applied, six generators are estimated to have a short run marginal cost (SRMC) that exceeds the present APC setting. A further seven generators present SRMCs relatively close to the APC by the end of the Period. If generator SRMCs and loss factors were to stay the same in real terms the risk of these generators SRMCs exceeding the APC increases every year. This is because the APC is defined in nominal terms and therefore effectively declines in real terms. As such, EY considers that indexing the APC with CPI to be a reasonable change to the current APC setting. This would also bring the APC setting in line with the MPC and CPT settings in terms of the treatment of CPI. However, a decision to change the APC setting is a trade-off between several competing requirements; to limit the price risk to customers, to provide sufficient incentive for suppliers to offer their energy into the market at all times, to limit the administrative burden and cost associated with potential compensation claims or operator directions, and ultimately to maintain the integrity of the NEM operation. A demonstration of material benefits to changing the APC should be required to satisfy the last point. It does not appear that the cost base of very high SRMC suppliers has changed significantly since the previous APC determination.

[8] AEMO released the 2017 Electricity Statement of Opportunities (ESOO) in September 2017. It is available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

Task	Description
Task 3: MPC	**Scenarios and assumptions** In order to assess the reliability settings in the Period, EY modelled two MPC scenarios where the reliability standard is threatened: one in the South Australia region and the other in the Victoria region. The latter includes the assumption that the expanded Victorian Renewable Energy Target goes ahead to 2025. These two scenarios explore meeting the reliability standard in the two respective regions, where the demand profiles, capacity mix and wholesale market pricing outcomes are different. Both scenarios involve high demand, high outage rates for coal generators, and early retirement of existing thermal capacity. This combination of assumptions was chosen by EY, in consultation with the Panel, to make the scenarios as plausible as possible (i.e., rather than only having more early retirements). The Panel's Issues Paper outlines the two key aims of the MPC and CPT as being: ► To ensure investment would occur without intervention to meet the reliability standard ► Not threaten the overall integrity of the market. To this end, a high cost sensitivity was devised by the Panel as a plausible upper bound, which includes the following assumptions: ► a high gas price of $18/GJ to represent an upper-bound at the liquid-fuel price given uncertainty in low-cost natural gas supply for a low utilisation generator ► a 10% WACC to represent investment uncertainty ► Closed-cycle gas turbines (CCGTs) excluded as a candidate new entrant technology due to their inflexibility and the requirement for long-term high volume gas supply. Whilst even higher cost sensitivities were modelled, EY believes that the high cost sensitivity presented above reflects a plausible combination of cost assumptions that may occur within reasonable bounds of uncertainty. As such, EY has used the high cost sensitivity to underpin the key outcomes for the reliability settings required that provide sufficient investment signals to meet the reliability standard in the Period. These costs were applied to both MPC scenarios to explore the required reliability settings to meet the reliability settings in two different situations. **The marginal new entrant technology and scenario outcomes** Despite the relatively high gas price assumed in the high cost sensitivity, based on the modelling, EY found OCGTs to be the marginal new entrant technology to meet the reliability standard. The MPC scenario in which the reliability standard is threatened in Victoria presents the highest MPC requirement. This is due to the modelled market price outcomes, where the Victoria region has fewer high price periods compared to the modelled South Australian prices in the other MPC scenario. Fewer high price periods leads to a higher MPC being required in order for the marginal generator to recover necessary revenue from a smaller number of high price periods. **MPC and CPT outcomes** In the Victorian scenario and high cost sensitivity, EY's analysis found that a theoretical optimal MPC of $12,500/MWh is sufficient to incentivise investment in supply capacity to contain expected USE to within the reliability standard. There are a number of scenarios considering alternative new entrant costs that would require a considerably higher MPC, all other things being equal. A sensitivity scenario has been completed to model the market with five-minute dispatch and settlements to assess the potential impact on the theoretical optimal MPC calculation. In the five-minute modelling the estimated MPC was found to be $11,600/MWh for the equivalent scenario that resulted in a theoretical optimal MPC of $12,500/MWh under 30-minute modelling. This five-minute market modelling MPC outcome is on the basis that the other reliability settings are kept the same. EY notes that a decrease in the MPC will not necessarily lead to a decrease in annual average wholesale electricity market prices or costs for consumers in the long term if it leads to a change in the installed generator capacity mix. The impact of reducing the MPC from the

Task	Description
	present $14,200/MWh to $12,500/MWh was modelled with the Base scenario by keeping the installed capacity and bidding strategies the same and only changing the MPC. The impact on time-weighted annual average regional wholesale market price over the Period was estimated to be less than $0.25/MWh under all scenarios, and in most cases in the order of $0.01-0.02/MWh. As described in Section 2.6, the CPT's primary objective is to limit a market participant's risk exposure to sustained high prices. To explore the role of the CPT in the reliability setting analysis, EY explored varying the CPT to assess the relative impact on the theoretical optimal MPC. EY's analysis suggests that the efficacy of the MPC to efficiently incentivise market investment reduces if the MPC is increased while keeping the CPT the same. It follows that an alternative to reducing the MPC alone is to reduce both the MPC and CPT provided the CPT is not reduced too much in proportion to the corresponding change in the MPC. To explore this possibility, EY analysed various combinations of theoretical MPC and CPT settings to provide the Panel with alternative options to potentially changing only the MPC. For example, based on the high costs sensitivity for the Victorian scenario maintaining the current ratio of 15 between the CPT and MPC gives an outcome of both settings being able to be decreased by around 5% while still maintaining the reliability standard. This equates to an MPC in the order of $13,000/MWh and a CPT of $200,000 for the Period. Taking into account the modelling limitations listed in Section 0 and other factors that must be considered in real-world investment and project delivery decision making, EY considers these outcomes to be in line with the present MPC setting of $14,200/MWh. The theoretical optimal MPC calculation is a function of a significant number of modelling data inputs. It is an inherently probabilistic outcome based on weighting of Monte Carlo simulation of generator availability, multiple peak demand projections, multiple weather reference year data sets and portfolio Nash equilibrium bidding behaviours. There are a number of scenarios in which the theoretical optimal MPC is estimated to be significantly higher than the present MPC, including that in which the cap defender approach is applied, as was the case in previous RSSR studies. **Outcomes for other technologies** The modelling shows that while wind and solar PV technologies are relatively cheap and costs are assumed to continue to fall, they are not able to reduce USE to below the reliability standard in the MPC scenarios modelled due to their variable generation. Based on the assumptions used, battery storage was found to be able to reduce USE below the reliability standard but is still more expensive than OCGTs (and thus would require a higher MPC). There is insufficient information on the cost of implementing new demand side participation or pumped storage projects to comment on the potential for these types of projects to become a marginal source of reducing USE to within the reliability standard. These technology-options are also highly project-specific. Where CCGTs were included as a potential new entrant technology to address USE the theoretical optimal MPC was found to be $1,500/MWh in both MPC scenarios modelled. CCGTs were found to achieve their required annual revenue with an even lower MPC, but $1,500/MWh was found to be required to maintain sufficient revenues for existing OCGTs assuming nil capital cost repayments. This lower MPC may only be sufficient where the marginal generator can achieve a relatively high capacity factor and if gas fuel is available for a fixed price, at high volumes, over a long period of time. This would likely require firm access to gas pipeline capacity. However, should the presence of such conditions present a risk, the higher MPCs presented above would be required to incentivise investment in appropriate low-utilisation long-lived generation assets.
Task 4: CPT	EY explored the potential impact on settlements for an uncontracted load and various levels of contracting under alternative CPT settings. For the cases analysed EY found that the optimal level of contracting did not vary with changes in the CPT up to ±20%. Due to lack of data on market customers, EY could not quantify the relative impact on market integrity from an increase in the CPT and the MPC. The modelling suggests that maintaining near to the current ratio of 15 between CPT and MPC delivers a fair balance between limiting customer exposure to sustained high price events and sufficiently incentivising new entrant investment to maintain expected USE within the reliability standard.

Based on the quantitative modelling developed to inform the Review, EY's primary conclusions are:

- Retaining the present APC setting of $300/MWh (nominal) would appear to strike a reasonable balance between limiting price risk for customers whilst limiting the risk of need for compensation or direction to relatively few generator suppliers with an SRMC that exceeds this value.
- The calculation of the theoretical optimal MPC and CPT in combination is sensitive to a wide range of factors, many of which are uncertain. An exploration of the relationship between MPC, CPT and investment signals suggests that the current ratio of the CPT being approximately 15 times the MPC strikes a good balance between consumer protection and revenue risk for the marginal new entrant.
- There are a number of scenarios that may result in the need for a materially higher theoretical optimal MPC to sufficiently incentivise investment in supply or demand side capacity to achieve the reliability standard. Using plausible high new entrant cost assumptions, the modelling results in a minimum theoretical optimal MPC of $12,500/MWh. Allowing for the range of uncertainties explored and the modelling limitations to some degree, the present reliability settings, which include an MPC of $14,200/MWh, would provide sufficient incentives for investment to meet the reliability standard in the Period.

2 Introduction

2.1 About this report

EY was engaged by the Reliability Panel (Panel) to provide advice and conduct modelling for the 2018 Reliability Standard and Settings Review (Review). This report describes the outcomes of the Review, including the modelling methodologies undertaken by EY, in assessing particular reliability settings to apply from 1 July 2020 to 1 July 2024 (the Period).

Table 3 describes EY's tasks for this Review.

Table 3: EY's tasks for this Review

Task	Description
Task 1	**Expected unserved energy (USE):** Forecast the expected amount of USE over the Period under the current reliability settings, and assess whether the current reliability standard of 0.002% USE will be met over the Period.
Task 2	**Administered price cap (APC):** Estimate the theoretical optimal level at which the APC could be set over the Period.
Task 3	**Market price cap (MPC):** Estimate the theoretical optimal level at which the MPC could be set over the Period.
Task 4	**Cumulative price threshold (CPT):** Analyse how the level of the CPT influences the effectiveness of the theoretical optimal MPC and discuss the implications on the market from changing the CPT and the MPC.

2.2 Definition of unserved energy

Unserved energy (USE) means the amount of customer demand that cannot be supplied in a region of the NEM due to a shortage of generation or interconnector capacity. Events of unserved energy would be experienced by customers as blackouts, although some types of blackouts do not count as USE[9], including:

- ► Any outage in the transmission or distribution network including for example, a tree falling on power lines affecting a small area
- ► Security-related outages, such as due to a frequency disturbance causing power system equipment to trip.

USE is calculated in megawatt or gigawatt hours (MWh or GWh)[10] and is typically expressed in terms of a percentage of customer demand, i.e., the reliability standard is to achieve a maximum expectation of 0.002% USE. That is, on average the risk of not being able to meet customer energy demand should be limited to 0.002% of the desirable energy consumption. In this Review, EY has calculated USE in sent-out[11] terms, and therefore expressed USE as a percentage of sent-out demand, to keep the units the same.

The term *expected unserved energy* means a statistical expectation of a future state; an average across a range of future outcomes, weighted for probability. This calculation is described in more detail in Box 1 in Section 7.1. As such, an expectation of a certain level of USE does not mean that it

[9] For the official definition, see the Rules clause 3.9.3C and the summary table provided in the Panel's Issues Paper, Reliability Standard and Settings Review 2018, Reliability Panel AEMC, p. 44.

[10] NEM Rules, Chapter 10.

[11] *Sent-out generation* is the electricity supplied to the electricity network (grid), as measured at the gate of a generator. This is equal to the total generation produced by a generator minus any auxiliary power they require for their operation. *Sent-out demand* is the total electricity demand required to be supplied by large-scale generators (i.e., excluding rooftop PV) in terms of their sent-out generation (including meeting transmission and distribution system losses).

will occur – it still carries a probability as with a set of other possible USE outcomes, some higher and some lower than the expected level. In addition to this, in practice AEMO may exercise intervention mechanisms to minimise or prevent USE events happening.

2.3 Purpose of the reliability standard

The Reliability Standard is a measure of the expected amount of energy at risk of not being delivered to consumers due to a lack of available capacity. As stated in the Panel's Issues Paper:

> *The concept of a reliability standard essentially is an acknowledgement that building assets sufficient to meet all consumers' demand all of the time comes at a significant cost. A reliability standard expresses a decision about the trade-off between the level of service sought and the cost incurred to provide that level of service…*
>
> *The reliability standard is an expression of the reliability sought from the national electricity market's generation and inter-connection assets.* [12]

Currently:

> *[t]he reliability standard for generation and inter-regional transmission elements in the national electricity market is a maximum expected unserved energy (USE) in a region of 0.002% of the total energy demanded in that region for a given financial year.* [13]

Hence under the reliability standard the level of USE should not be expected to exceed 0.002% of each region's energy sent-out demand in a financial year.

2.4 Purpose of the APC

The APC is the maximum price that applies whenever the CPT is exceeded (see Section 2.6). As stated in the Panel's Issues Paper, the purpose of the APC in the NEM is to:

> *cap participants' exposure to sustained high prices, while maintaining incentives for participants to supply energy.* [14]

The APC is currently set at $300/MWh (nominal). It is set at the minimum price that allows a sufficient number of generators to recover their short-run marginal costs so as to minimise the need for compensation or direction, while limiting consumer exposure to sustained high prices. This ensures that the market continues to function with dispatch of generators meeting demand for a short period of time until the CPT is no longer exceeded.

2.5 Purpose of the MPC

The MPC defines the maximum wholesale electricity market price that can be reached in any region of the NEM (provided the CPT is not exceeded). The Panel's Issues Paper states that the role of the MPC is:

> *to limit market participants' exposure to very high prices and thereby serve to limit risk.* [15]

Furthermore in setting the level of the MPC:

> *[T]he primary principle observed is that the market price cap should not prevent the market sending efficient price signals, to support the efficient operation of and*

[12] Issues Paper – Reliability Standard and Settings Review 2018, Reliability Panel AEMC (6 June 2017), pp. 9-10
[13] National Electricity Rules (NER), cl 3.9.3C(a)
[14] Issues paper, p67
[15] Issues paper, p53

investment in electricity services over the long run. The process for setting the market price cap assumes that the reliability standard reflects the efficient level of expected unserved energy. [16]

Additionally:

The level of the market price cap also should allow the market price to create incentives for participants to manage price risk; whether it is through the purchase of contracts or even investment in generation. [17]

Setting the level of the market price cap involves making a trade-off on behalf of consumers between:

- market participants' exposure to high prices
- inefficient price signals.[18]

For the 2017-18 financial year the MPC is $14,200/MWh, and is currently set to rise in nominal terms each future financial year in line with changes in the consumer price index (CPI).

2.6 Purpose of the CPT

The CPT defines a maximum rolling-average wholesale market price over the period of 336 half-hour trading intervals (i.e., over seven consecutive days). As stated in the Panel's Issues Paper:

The cumulative price threshold is one of the settings that limit market participants' financial exposure to the wholesale spot market during prolonged periods of high prices.[19]

This refers to the CPT's primary objective: to limit the weekly market exposure of market participants. The CPT's secondary objective is to not impose so great a restriction that it compromises the ability of the other reliability settings, such as the MPC, to allow the market meet the reliability standard.

The CPT limits the total market price that can occur over a rolling seven-day equivalent period as, once the CPT is reached, an administered price period (APP) is declared and the APC becomes the maximum settlement price (in place of the MPC). The maximum settlement price can only be reset to the MPC at the end of a NEM trading day (at 4:00 AEST) and if the average wholesale market price for the previous rolling seven-day equivalent period is below the CPT.

The CPT is currently set to $212,800, which is equivalent to an average wholesale market price of $14,200/MWh over approximately 7.5 hours (15 trading intervals). The CPT is set to rise in nominal terms each future financial year in line with changes in the CPI[20].

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[16] Issues paper, p53-54
[17] Issues paper, p54
[18] Issues paper, p55
[19] Issues paper, p60.
[20] In the frequency control ancillary services (FCAS) markets an administered pricing period is declared after 2,016 five-minute dispatch intervals (or seven days), if the cumulative price in the respective FCAS market is six times the cumulative price threshold. Reviewing pricing settings in the FCAS markets is not in the scope of this Review.

3 Methodology overview

This section provides an overview of the methodologies used to determine the quantitative outcomes for modelling prepared to support the Panel's Review. It explains in turn the methodologies used to determine: the expected USE and theoretical optimal MPC, the APC and the CPT. Section 3.1 describes how time-sequential market modelling has been employed. A more detailed description of the market modelling methodology can be found later in the report (Section 7). The final section describes how the methodologies we have used for this Review address stakeholders' views and feedback.

3.1 Expected USE and theoretical optimal MPC

EY's approach to determine the expected USE for the Period involves developing a Base Scenario and conducting detailed time-sequential half-hourly modelling of the electricity market (market modelling: described in more detail in Section 7). A number of sensitivities on the Base Scenario were also conducted to explore the impact on the USE outcomes of different assumptions and to explore differences with the USE forecasts presented in the 2017 ESOO.

EY then conducted further iterative market modelling under alternative, plausible scenarios (MPC scenarios) where the expected USE could exceed 0.002% of demand, in order to estimate the theoretical optimal MPC. The methodology involves producing plausible scenarios where the reliability standard is threatened; meaning that the reliability standard would be exceeded if the reliability settings such as the MPC were not set sufficiently high to incentivise new entrant investment to keep USE below 0.002%. These scenarios are devised by selecting assumptions that result in USE being above the reliability standard. Then, the minimum MPC is found that economically incentivises sufficient new entrant investment to reduce the level of expected USE to below the reliability standard.

EY has used its in-house 2-4-C® model to conduct an extensive analysis of the expected USE and MPC. 2-4-C® is a model that replicates the function of AEMO's NEM dispatch engine (NEMDE), and is used to forecast dispatch and price outcomes for time-sequential half-hourly intervals into the future. The detailed nature of the time-sequential modelling accounts for inter-temporal constraints such as generator ramping rate limitations and fast start inflexibility profiles[21] (to the extent they may present a binding limit over half-hour intervals), storage charge/discharge cycles, and other energy limitations.

A high-level overview of the modelling methodology is outlined in Table 4 below. Each aspect of this methodology is described in more detail in the subsequent sections.

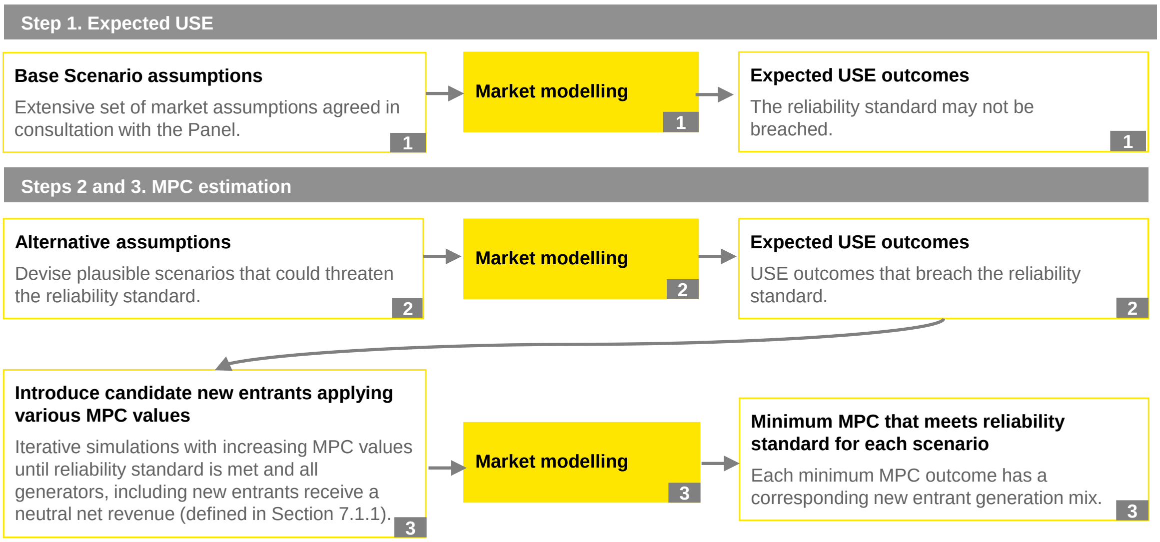
[21] All generators have limitations that define how quickly they can increase generation, especially on start up.

Table 4: Iterative modelling methodology

Step 1 **Base Scenario USE outlook**	**Conduct time-sequential half-hourly dispatch modelling to determine the expected USE for 1 July 2020 to 1 July 2024** ▶ Determine a complete set of assumptions to form a base view for the market evolution, including electricity demand, new entrant generator capacity for the LRET and retiring generator capacity ▶ Perform iterative market simulations to determine any further commercially-driven generation mix changes based on modelled wholesale market prices. Each simulation considers a range of weather patterns and generator outages ▶ Calculate the expected USE in the final simulation ▶ Calculate the expected USE in alternative simulations to explore the sensitivity to particular assumptions
Step 2 **MPC scenarios that threaten the reliability standard**	**Devise plausible scenarios where average USE threatens the reliability standard** ▶ Devise plausible alternatives to the Base assumptions to achieve an expected USE of greater than 0.002% in at least one region in the simulation ▶ Potential assumption changes include early thermal generator retirements, higher forced outage rates and high electricity demand
Step 3 **Calculate MPC required to meet reliability standard**	**For each MPC scenario devised in Step 2, determine the minimum MPC that meets the reliability standard** ▶ An extensive set of candidate new entrant generators will be assessed for their commercial incentive to be commissioned and earn revenue for different MPC levels ▶ The incentive for existing generators to stay in operation will also be assessed ▶ The new entrant capacity incentivised to achieve the reliability standard in a particular scenario could be a mix of technologies

Figure 1 represents the high-level methodology in a flow diagram. The details underlying the market modelling process represented in the yellow boxes in Figure 1 are outlined in Section 7.

Figure 1: High level flow diagram describing the modelling methodology for the expected USE and MPC



Step 1, forecasting the expected USE, involves developing a Base Scenario. The Base Scenario and its underlying assumptions reflect the most likely outcomes for the NEM as agreed with the Panel. The assumptions driving the outcomes for the Base Scenario include:

- Operational peak demand and energy consumption and associated atmospheric conditions affecting relationships between demand and wind and solar generation.
- Key policy settings, such as the LRET.
- Committed thermal generation retirements.
- The uptake of rooftop PV and electric vehicles.

- Residential and commercial (behind-the-meter) storage uptake.
- The level of demand response bidding into the market.
- Generator technology capital costs and fuel costs.

The assumptions used are provided in detail in Appendix A.

One of the main purposes of the MPC is to deliver sufficient incentive for the capacity investment (supply or demand side) required to at least meet the reliability standard. Should the reliability standard be delivered in the Base Scenario, the Base Scenario will not provide a suitable setting for analysing the appropriateness of the current MPC setting. For this reason, alternative MPC scenarios were developed to threaten the reliability standard (step 2). The assumptions devised for the MPC scenarios are described in Section 6.1.

The third step in the modelling process is to use the MPC scenarios to determine the minimum MPC that is required to incentivise investment in capacity that will address USE and ensure that any new entrants and all existing generators are also financially viable over the Period. This involves assessing the net revenue[22] of new entrant generators, calculated on an annual basis from the modelling outcomes as the difference between its wholesale market revenue and its annualised ongoing costs. A range of technologies is analysed in this step. A number of simulations will be required to determine the quantity and composition of new entrant capacity that is required to reduce USE below the standard, and at what minimum MPC.

The methodology in this study utilises a technology-neutral approach, in that a range of technologies are considered as the potential new entrant to reduce USE and potentially set the theoretical optimal MPC outcome. The technologies that are considered are as follows[23]:

- Solar PV (Fixed flat plate)
- Solar PV (Single-axis tracking)
- Solar PV (Dual-axis tracking)
- Solar Thermal
- Wind
- OCGT
- CCGT
- Large-scale storage, batteries and pumped-hydro

Since solar PV and wind technologies have a variable resource without any storage, their generation varies with that resource. For this reason, these technologies may not be able to contribute to USE to a sufficient extent to meet the reliability standard. Whilst batteries can be installed with a solar farm or wind farm to smooth out fluctuations in their generation, batteries are nevertheless a separate technology with their own capital cost. The methodology to determine the theoretical optimal MPC involves finding the marginal (lowest cost) technology that could be installed to bring USE below 0.002%. This marginal technology will be a single technology (i.e., solar PV or battery storage, but not both), regardless of whether it is installed alongside another technology or not.

The theoretical optimal MPC is determined as the lowest MPC that achieves a positive net revenue for any existing generator and new entrant investment by the end of the four years of the Period. For example, a new entrant OCGT installed in 2020-21 is required to achieve a total positive net revenue after the four years of operation. As a result, the net revenue is allowed to be negative in a particular year provided that the aggregate net revenue over all years of operation is positive.

More information regarding the technical parameters for these technologies is described in Appendix A. The source for these characteristics are from AEMO, 2016 National Transmission Network Development Plan Report (NTNDP)[24].

[22] The net revenue calculation is described in detail in Section 7.1.1.

[23] Coal and Nuclear technologies were also considered but ruled out before the modelling commenced based on very high capital costs and long lead times for construction.

[24] http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan

If information can be sourced that provides assumed implementation costs for increased demand side participation we would include increased DSP as an alternative assessed technology. However at this time such information does not appear to be available. Similarly at this time we have not been able to source reliable data on implementation costs for incremental upgrades to existing generators as an alternative capacity augmentation option.

The main outcomes of the modelling for each MPC scenario are the new entrant capacity mix that was required to address USE, as well as the minimum MPC required to ensure each of the new entrants is financially viable over the projection period. As a result, the outcomes are technology-neutral and can account for a range of plausible future scenarios, which are two of the improvements from previous reviews that have been suggested for this Review.

3.2 Market modelling iterations

A single market modelling simulation of a future year involves hundreds of time-sequential iterations of that year to capture a range of potential outcomes that may occur on the half-hourly level. Table 5 presents the parameters that are varied across these iterations and the number of each that were simulated in the scenarios. Due to the sensitivity of USE to forced outages of generators, 200 Monte Carlo iterations of forced outage profiles were simulated in the Base Scenario and associated sensitivities to achieve close to a converged result[25]. For the MPC scenarios, which are based on simulations near approximately 0.002% USE, EY considered 25 Monte Carlo iterations to be sufficient. This choice is partly due to computational limitations, but also can be justified as the MPC outcomes are based on an amount of USE being near to, but less than 0.002%, rather than exactly 0.002%.

Table 5: Parameters varied across the iterations that make up one market modelling simulation

Parameter	Description	Number of iterations	
		Base Scenario and sensitivities	MPC scenarios
Peak demand	To capture the impact on USE and wholesale market pricing from moderate and high peak demands, EY models both the 50% POE[26] and 10% POE peak demand forecast by AEMO. See Section 7.2.1 for more details.	2	2
Historical reference years	Future half-hourly demand, wind and solar PV generation is modelled based on several historical reference years to capture a variety of Australian weather patterns. See Section 7.2.1 for more details.	6	6
Forced outages	Each generator has a probability of experiencing a forced (unplanned) outage at any one time. Monte Carlo simulations of forced outages assign full and partial forced outages to each generating unit based on the assumed probabilities.	200 (Base Scenario) 100 (sensitivities)	25
TOTAL	Parameter iterations are multiplicative	2400 (Base Scenario) 1200 (sensitivities)	300

[25] The margin of error in USE modelling with respect to the number of Monte Carlo iterations of forced outages is discussed in EY's 2016 MTPASA review report to AEMO (available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Market-Management-System-MMS/Projected-Assessment-of-System-Adequacy)

[26] The 50% probability of exceedence (POE) peak demand forecast is expected to be exceeded for one half hour once in every 2 years. The 10% POE peak demand forecast is expected to be exceeded for one half hour once in every 10 years.

The time-sequential market modelling process employed by EY is described in detail in Section 7.

3.3 Reviewing the APC

As described earlier, the APC is set such that it is the minimum price that allows a sufficient number of generators to recover their short-run marginal costs so as to minimise the need for compensation or direction, while limiting consumer exposure to sustained high prices. In the event that a generator is dispatched with an SRMC higher than the APC, and the APC is applied, there is a mechanism available for that generator to apply for compensation. EY considers it reasonable that a few generators may apply for compensation in particular circumstances, as this would be a lower overall cost to consumers than having a higher APC at which all generators are paid and consumers pay.

To review the APC in the Period, EY analysed the number of generators in the NEM that may possibly apply for compensation if dispatched during an APC event, in each year of the Period, using the current settings for the APC. This involves estimating the SRMC for a selection of generators that could reasonably exceed the APC. The candidate generators for this assessment were selected based on the following criteria:

- Any generator that could use liquid (diesel) fuel. These generators are assessed using a moderate liquid fuel price, based on the most recent available liquid fuel price in the market.
- Any low utilisation gas-fuelled generator, with a typical historical capacity factor of less than 2%. Due to its low utilisation, these generators are unlikely to be able to secure long-term contracts for gas supply and may need to pay a high spot price for gas during APC-priced periods. As an upper bound for this gas price, a moderate liquid fuel price is used.

The SRMC is calculated using the following equation.

$$SRMC\left(\frac{\$}{MWh}\right) = Fuel\ cost\left(\frac{\$}{GJ}\right) \times efficiency\left(\frac{GJ}{MWh}\right) + VOM\left(\frac{\$}{MWh}\right) \tag{1}$$

where

VOM is the variable operational and maintenance cost.

The minimum required wholesale price to allow a generator to receive at least its SRMC might also consider the loss factor(s) for the generator. We include this consideration for incumbent generators however acknowledge that loss factor allocation is a risk factor that generator investment should take into account.

3.4 Assessing the impact of changing the CPT

The CPT is set to limit the maximum amount that a market-exposed retailer or customer will pay over any particular contiguous seven days. The CPT limits the price outcomes that the market might otherwise deliver in any particular week (where the supply-demand balance is extremely tight). In effect, it means that generators' revenue is less than that which would otherwise be earned in this period, through the imposition of the APC. A change in the CPT may affect the optimal contracting position that a retailer or customer would seek to manage their risk.

There is an inherent link between the MPC and the CPT. The MPC places an upper bound on the price risk exposure of uncontracted electricity purchases for each trading interval. The CPT adds a time limit (i.e., one week) to that level of exposure.

As per its primary objective, as described in Section 2.6, the theoretical optimal CPT in the NEM would depend on the level of market exposure of the relevant retailers/customers as determined by how heavily they are contracted. It also depends on their available options for additional contracts if the CPT were altered. There is little data available on this, making an assessment of the theoretical optimal CPT very difficult. Instead of directly estimating the theoretical optimal CPT, EY's approach is to assess the CPT level in this Review by investigating different CPT levels in the modelling and analysing the associated value of contracting to a hypothetical customer with a 1 MW flat load. From the modelling outcomes in each scenario, EY assessed the impact of different CPT levels on:

- The variance in and maximum value of a 1 MW customer's weekly settlement, and
- The theoretical optimal MPC.

The intention is to determine the impact different CPT levels would have on the cash flows and contracting decisions that a customer might make. The modelling outcomes forecast potential changes in the level of contracting incentivised in the market, as a result of changing the CPT. Thus, the CPT also impacts the returns from the market to a supplier, which affects new entrant generator investment. The intention is to draw conclusions on the sensitivity of the above outcomes to the CPT level to inform the Panel in its decision making process regarding the CPT setting.

As mentioned above, the theoretical optimal MPC depends on the CPT setting. As described in Section 2.6, the secondary objective of the CPT is to not inhibit the efficiency of the other reliability settings in meeting the reliability standard. Where this has been found to be a potential issue in the modelling outcomes, EY has explored potential combinations of the CPT and theoretical optimal MPC to explore the possibility of changing both settings.

3.5 Methodology features addressing stakeholder feedback

In 2016, Oakley Greenwood conducted an assessment[27] of the methodologies employed in previous Reviews and made three principal recommendations, which were adopted in the 2016 RSSR Guidelines. The methodology for this Review addresses these three principal recommendations, plus additional suggestions made by stakeholders in July 2017 in response to questions on modelling methodology posed in the Panel's Issues Paper[28].

The methodology for this Review ensures:

- **The MPC level is assessed on plausible, realistic market situations.** In theory, the optimal MPC level is the minimum value that incentivises sufficient investment in the NEM to avoid exceeding the reliability standard. As such, this value can only be properly tested in a situation where the market achieves an expected level of USE that is very close to, but does not exceed the reliability standard. The 2010 and 2014 Reviews were conducted when there was a significant amount of over-supply of capacity in the NEM, making the occurrence of any USE very unlikely. The methodology used in the 2010 and 2014 reviews involved removing a significant quantity of capacity from the market in all regions to achieve situations where the reliability standard is threatened in all regions simultaneously. The expected USE outcomes from the Base Scenario in this 2018 Review is unlikely to threaten the reliability standard since the assumptions include meeting the large-scale renewable energy target (LRET) and only one coal fired power station retirement. However, plausible alternative MPC scenarios have been developed in consultation with the Panel, where the reliability standard could be exceeded in the Period[29]. These scenarios involve assuming unanticipated early retirements of existing generators, high demand projections, and higher FORs for coal generators.

- **This Review incorporates analysis of all existing and candidate new entrant generators under scenarios where alternative MPCs are employed**. The 2010 and 2014 Reviews only assessed the MPC level on its ability to stimulate investment in a new entrant OCGT. The modelling undertaken for this Review explicitly considers potential retirement and new entrant

[27] *Assessment of approach to modelling of Reliability Settings – Prepared for Australian Energy Market Commission*, Oakley Greenwood, Australia (September 2016).
[28] Issues Paper – Reliability Standard and Settings Review 2018, Reliability Panel AEMC (6 June 2017).
[29] These scenarios will therefore be used to test what is the minimum MPC level required to meet the reliability standard, which may be lower or higher than the current MPC setting.

development options available from all known new entrant technologies based on a generalised profitability assessment.

- **The MPC is assessed on its ability to incentivise investment in a range of new entrant capacity technologies, not solely OCGT units**. Since the 2014 Review there has been a rapid reduction in costs of a number of generator technologies. As such, wind, solar PV and large-scale storage, among others, are now strong potential candidates for market investment and contributing to reducing USE[30]. In this Review, EY considers a range of new entrant technologies as well as the potential retirement of any of the existing generators, for impacts on reliability. The modelling incorporates a fixed amount of DSP in accordance with AEMO's projected levels. The most recent information available on market driven DSP appears to be from AEMO's 2014 review of the value of customer reliability. At the time of preparing the modelling for this Review there was insufficient data available to consider additional levels of DSP as a marginal new entrant technology to meet the reliability standard. It would be desirable to see this information become available for future reviews.

- **Extensive, detailed time-sequential modelling of renewable generation**. The 1 July 2020 to 1 July 2024 period assessed in the 2018 Review has the highest penetration of wind and solar PV capacity yet seen in the NEM. On devising the methodology for this Review, EY anticipated that USE periods may occur in the modelling during periods of high **residual demand**[31], rather than purely high demand periods as has historically been the case. As with the previous two reviews in 2010 and 2014, the 2018 Review incorporates locational half-hourly modelling of each individual large-scale wind and solar PV generator in the NEM as well as half-hourly rooftop PV generation. The 2018 Review also captures a wide range of realistic interactions between half-hourly wind generation, solar generation and demand by basing the forecast on the weather patterns that occurred over six historical years (see discussion in Section 7.2.1).

- **High cost sensitivity investigated for impact on the theoretical optimal MPC**. Some stakeholder feedback suggested that investment costs in a high-risk electricity market be considered in the modelling. Accordingly, EY has included this consideration by modelling a High costs sensitivity that incorporates a higher weighted average cost of capital for new entrant technologies among other higher costs.

[30] At the same time the non-controllable variability in renewable generation (without storage) has raised some concern regarding decreased system reliability. The impact of increasing penetration of renewable technologies on reliability for the Period is examined in this Review.

[31] Residual demand: The demand required to be met by large-scale scheduled generation. This is calculated by taking the total customer electricity consumption and netting off rooftop PV and large-scale wind and solar PV generation, as well as the net effect of behind-the-meter battery storage and electric vehicle charging load.

4 APC outcomes

This section presents an analysis of the relative number of generators and proportion of generation capacity that may be impacted by the APC setting as well as a qualitative assessment of the relative impacts of changes in the APC setting on suppliers and consumers.

4.1 Generator short-run marginal cost assessment

As described in Section 2.4, the APC is set as the minimum price that allows a sufficient number of generators to recover their short-run marginal costs so as to minimise the need for compensation, while limiting consumer exposure to sustained high prices. In other words, the APC should be sufficiently high such that a sufficient number of generators would be dispatched at that price to meet demand in the market.

Section 3.3 describes the methodology to review the APC being to assess the SRMC of a selection of candidate generators and determine how many of these require a wholesale market price above the APC in each year of the Period, based on the current market settings for the APC.

In this study, the APC is kept consistent with today's nominal value of $300/MWh. As our market projections are in real terms, with a base of 1 July 2017, we de-escalate the value such that it can be applied in real terms. Using and assumed CPI of 2.5%, the adjusted APC values are displayed in Table 6 below.

Table 6: APC in the Period

	2020-21	2021-22	2022-23	2023-24
APC (June 2017 $/MWh)	278	271	264	258

The key technical parameters used for calculating the wholesale price required for a generator to receive their SRMC are fuel cost, marginal loss factor (MLF), thermal efficiency and variable operation and maintenance (VOM) costs. The minimum price is calculated as the SRMC divided by the associated MLF. This is because the price received by a generator is the wholesale market price multiplied by the MLF.

The assumed diesel fuel price used for SRMC calculations for this APC analysis is based on Australia's Institute of Petroleum's published average diesel wholesale price[32]. Subtracting the diesel excise[33], the total net wholesale price is $0.715/litre. This is the equivalent of $18.06/GJ based on an assumed energy content of 39.6[34] MJ/litre. As agreed with the Panel, this has been rounded to $18/GJ and kept constant in real terms. Whilst the cost of liquid fuel will continue to be variable due to exposure to international oil market pricing, over the long term the price of liquid fuel has not materially changed since the last Review.

The MLFs used for each generator are the latest published MLFs[35] while the other values used are obtained from AEMO's 2016 NTNDP. As discussed in the APC review methodology in Section 3.3, 19 gas generators in the NEM were selected due to having a low typical capacity factor. The MLFs, efficiency and VOM used for the nineteen candidate generators are displayed below in Table 7.

[32] http://www.aip.com.au/pricing/facts/Weekly_Diesel_Prices_Report.htm
[33] https://www.ato.gov.au/Business/Excise-and-excise-equivalent-goods/Fuel-excise/Excise-rates-for-fuel/
[34] http://w.astro.berkeley.edu/~wright/fuel_energy.html
[35] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries

Table 7: Key technical parameters used for each candidate generator

Generator	Technology	VOM ($/MWh sent-out)	Heat rate (GJ/MWh sent-out)	Published MLF (2017-18)
Jeeralang B	OCGT	10.66	15.7	0.9830
Jeeralang A	OCGT	10.66	15.7	0.9830
Valley Power	OCGT	10.66	15.0	0.9801
Hallett	OCGT	10.66	15.0	0.9820
Somerton	OCGT	10.66	15.0	0.9968
Snuggery	OCGT	10.66	13.8	0.9318
Dry Creek	OCGT	10.66	13.8	1.0019
Port Stanvac 1	Recip. Engine	11.15	13.8	1.0047
Angaston	Recip. Engine	11.15	13.8	1.0121
Barcaldine	OCGT	10.66	12.9	0.9507
Port Lincoln	OCGT	10.66	13.8	1.0158
Mackay	OCGT	10.66	12.9	0.9577
Hunter Valley	OCGT	10.66	12.9	0.9582
Mintaro	OCGT	10.66	12.9	0.9941
Bell Bay Three	OCGT	10.66	12.4	1.0001
Mt Stuart	OCGT	10.66	12.0	0.9964
Laverton North	OCGT	10.66	11.8	1.0081
Colongra GT	OCGT	8.51	11.3	0.9831
Lonsdale	Recip. Engine	10.66	9.5	1.0047

The SRMC and minimum price outcomes are shown below in Table 8 with highlighting to demonstrate when the minimum price is clearly above the APC (strong yellow) or very close to the APC (pale yellow).

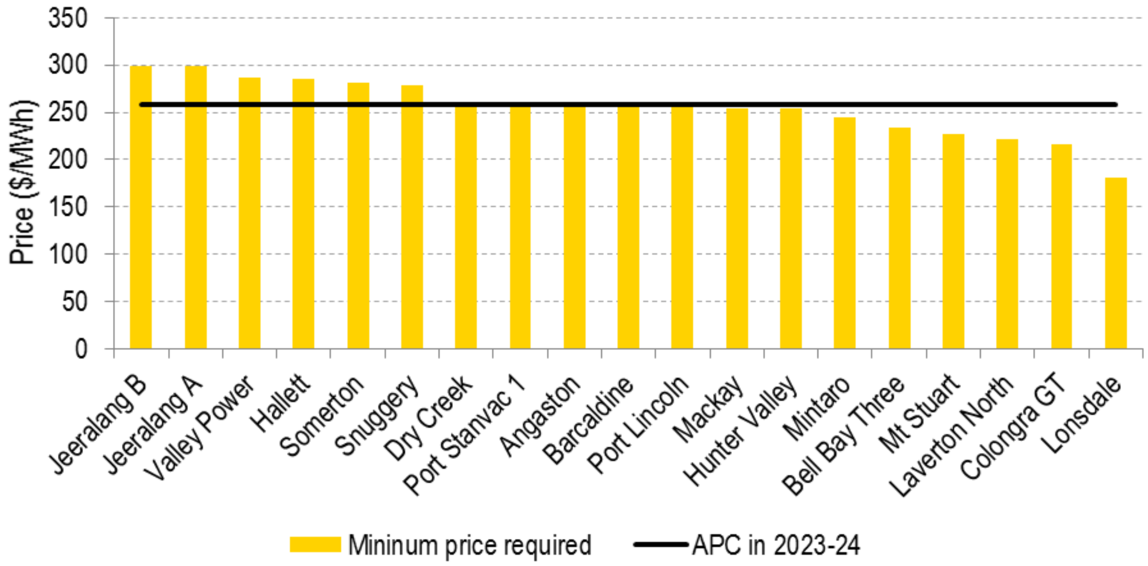
The table shows how progressively more generators require a price that is close to or exceeds the APC throughout the Period. This is an outcome of all assumptions being held constant in real terms, while the present APC is defined as nominal and thus declines in real terms. Based on the assumptions used, six of the 19 candidate generators will require a market price higher than the present APC throughout most of the Period. A further seven generators will require a market price very close to the APC by 2023-24. Hence, if any assumption turned out to be slightly different, such as the fuel price or inflation, these seven generators could require a price higher or lower than the APC.

Table 8: SRMC and minimum price outcomes

Generator	SRMC ($/MWh)	2020-21	2021-22	2022-23	2023-24
		APC ($/MWh)			
		278	271	264	258
		Minimum price ($/MWh)			
Jeeralang B	293	298	298	298	298
Jeeralang A	293	298	298	298	298
Valley Power	281	286	286	286	286
Hallett	281	286	286	286	286
Somerton	281	282	282	282	282
Snuggery	259	278	278	278	278
Dry Creek	259	259	259	259	259
Port Stanvac 1	260	258	258	258	258
Angaston	260	256	256	256	256
Barcaldine	243	255	255	255	255
Port Lincoln	259	255	255	255	255
Mackay	243	254	254	254	254
Hunter Valley	243	253	253	253	253
Mintaro	243	244	244	244	244
Bell Bay Three	234	234	234	234	234
Mt Stuart	227	227	227	227	227
Laverton North	223	221	221	221	221
Colongra GT	212	216	216	216	216
Lonsdale	182	181	181	181	181

Figure 2 illustrates the minimum price required from each generator against the APC in 2023-24.

Figure 2: The APC in 2023-24 versus the minimum required price for each generator



To capture the APC in real terms for the modelling, EY adopted an APC of $270/MWh throughout the RSSR Period. This was assumed on the basis that it is approximately the average and also the value in the middle year of the RSSR Period in the modelling.

4.2 Impact on suppliers and consumers

The APC is primarily intended to protect consumers against protracted periods of high market price events. The Panel's Issues Paper notes that there have only been five administered price periods in the energy market since inception of the NEM. In the modelling for the Base Scenario, out of 200 Monte Carlo iterations x 6 reference years, the CPT is exceeded and an administered pricing period is activated twice in Victoria in 2020-21, once in New South Wales (NSW) in 2023-24, once in Victoria in 2023-24 and never in the other two years of the Period. All of these events occur in the 10% POE demand simulations. Under normal market conditions, the CPT has a very low probability of being exceeded and therefore the application of the APC is highly unlikely.

However, in a market environment in which the reliability standard is at risk of being exceeded, the potential for extended periods of high market prices and therefore application of APC may considerably increase. From the modelling conducted in the MPC scenarios, the regions with 0.002% USE have a weighted-average of around 15 trading intervals per year in which the price is capped at the APC during an administered pricing period. If the MPC is increased or decreased (but the CPT kept the same), the number of APC-capped periods also increases or decreases, respectively.

As outlined in Section 4.1, there are approximately six generators that may be eligible for a compensation claim if they generate during an APP (with the potential for seven more by 2023-24). Such compensation is based on only the extent to which the APC prevents a generator from receiving at least its SRMC from the wholesale market. However, all customer demand is exposed to the wholesale electricity market price. As such, the potential amount of compensation claimed will always be considerably less than the additional amount paid to the market if the APC was increased to cover the SRMC of all generators.

While an administered pricing period is generally likely to be triggered in one region, the APC can be applied to neighbouring regions if they are exporting electricity into the region where the APP is applied. However, to consider one region as an example, we consider Victoria as three of the six generators with the highest SRMCs are in Victoria: Jeeralang A, Jeeralang B and Valley Power. Their total capacity is 678 MW. Suppose that:

- Victoria experiences 15 APC-capped trading intervals in 2023-24 (or 7.5 hours)

- The APC is $258/MWh
- The price required to meet the SRMC for Jeeralang A and B is $298/MWh, and for Valley Power is $286/MWh
    - Then, Jeeralang A and B can claim $40/MWh compensation, while Valley Power can claim $28/MWh compensation
- All three generators mentioned above are fully dispatched in every APC-capped trading interval
- All three generators are eligible to claim compensation for every APC-capped trading interval.
- The average Victorian demand met for the 15 APC-capped trading intervals is 9000 MW
    - This means that 678 / 9000 = 7.5% of dispatched capacity can claim compensation.

The total amount of compensation expected for the year in Victoria is about $180,000. If the APC were increased by $40/MWh, the additional amount paid to the market would be 9000 MW x $40/MWh x 7.5 hours = $2.7m. This is about 15 times the compensation value that it avoids.

However, in addition to the compensation claim value itself, there are additional costs for the administration of the claims. A decision to change the APC setting is a trade-off between several competing requirements; to limit the price risk to customers, to provide sufficient incentive for suppliers to offer their energy into the market at all times, to limit the administrative burden and cost associated with potential compensation claims or operator directions, and ultimately to maintain the integrity of the NEM operation.

4.3 Conclusion

The APC is currently set at $300/MWh in nominal terms. A change in the APC would impact customer costs for around 15 trading intervals in a market which is approaching the reliability standard (far fewer under typical market conditions). If generator SRMCs were to remain steady in real terms in the future, it is inevitable that more and more generators would be eligible to claim compensation from periods where the price is capped at the APC. EY considers that indexing the APC with CPI to be a reasonable change to the current APC setting. This would also bring the APC setting in line with the MPC and CPT settings in terms of the treatment of CPI.

However, any increase in the APC will increase costs to customers. Whilst the fuel price is assumed to be constant in real terms for the SRMC analysis in Section 4.1, there is significant uncertainty in the future fuel price and thus in the future SRMCs of generators. Retaining the current APC setting is unlikely to lead to many additional generators being eligible for compensation for the Period, and would continue to limit customer exposure to extended high price periods, whilst not compromising the integrity of the NEM in relation to sufficient incentive to offer generation into the market. It does not appear that the cost base of very high SRMC suppliers has changed significantly since the previous APC determination.

5 Forecasting USE – Base Scenario and sensitivities

This section presents the USE outcomes for the Base Scenario and the sensitivities modelled. Firstly, Section 5.1 gives an overview of the assumptions used in the Base Scenario and the sensitivities. Along with the overall expected levels of USE, the outcomes presented in subsequent sections include the generation mix outcomes and an in-depth analysis of when USE occurs in the model. Modelling limitations specifically with respect to USE outcomes are presented in Section 5.5. Finally, in relation to the Base Scenario, EY's USE outcomes are compared with the outcomes from AEMO's model used in the 2017 ESOO in Appendix D.

5.1 Base Scenario rationale

The first step of this modelling task is to forecast the expected amount of USE over the Period under the current reliability settings and to assess the likelihood that the current reliability standard of 0.002% USE will be met over the Period. This task was included as part of the modelling scope for this Review for the following reasons:

- The requirements for the Review, under the NEM rules, clause 3.9.3A are: "…*the Reliability Panel … (3) must have regard to the potential impact of any proposed change to a reliability setting on … (iii) the reliability of the power system.*" Understanding the expected USE for the Period under the current reliability settings is the first step toward assessing this requirement.
- To understand the most likely level of USE for the Period as a baseline, from which to devise the MPC scenarios that threaten the reliability standard (to the extent that this is necessary, where the Base Scenario delivers USE outcomes that do not threaten the reliability standard).

The purpose of the Base Scenario is to forecast the expected USE in the Period, in a scenario with a reasonably likely evolution of the NEM, based on publicly available data wherever possible. Hence, the formulation of the Base Scenario assumption settings needs to consider the most likely outcome from the volume of information and market intelligence available at this time. It involves:

- Formulating underlying assumptions to reflect a reasonably likely state of the NEM at the beginning of the review Period.
- Utilising a modelling approach that reflects (as far as possible) the operation of the wholesale market and how rational commercial decisions are made about new generation capacity / retirement of existing capacity.

The Panel recognises[36] that it is conducting this review a time of significant change and uncertainty:

> *[w]e are currently facing transformational change of the energy system, the energy market and the policy environment, as well as uncertainty regarding the drivers and patterns of investment. Many of these trends and developments are likely to affect the national electricity market over the period of interest for this review.*

The Panel highlighted four market trends of particular relevance for the review and the modeling project, being the continued retirement of thermal generation; an increasing penetration of renewable intermittent generation, the emergence of new technologies, and the increased coupling of gas and electricity prices. Although the review Period is only three years into the future, due to the uncertainty around market trends the modeling applied sensitivity analyses on the Base Scenario, whilst aiming to reflect the best information available today.

The Base Scenario assumptions were chosen in consultation with the Panel by applying the following principles:

- **Adopt only those market policy settings that have a high certainty of being implemented**. For instance, in regards to emission reduction targets, this meant that the full LRET was

[36] Reliability Panel AEMC Issues Paper, Reliability Standard and Settings Review 2018, 6 June 2017 (p26)

included in the Base Scenario and the 2020 VRET as a contribution to the LRET. At the time the assumptions were formulated and considered by the Panel in early August 2017, while the Victorian Government had announced its policy intention, the Bill for introduction of the full VRET to 2025 had not been introduced to the Victorian Parliament[37]. (Note that a 2025 VRET was incorporated in one of the scenarios for estimating the theoretical optimal MPC). The Finkel review's recommended Clean Energy Target was not incorporated in the Base Scenario for the same reason. The Australian Government's proposed National Energy Guarantee was announced during the modelling period for this review and as such was not incorporated in the modelling assumptions.

- **Use recognised, publicly available data sources as far as possible, and where appropriate.** The most recent data published by AEMO as part of their planning studies has been a primary data source for the Base Scenario. One key exception is adjustments to large-scale wind and solar PV capital costs based on observations of recent market developments and announcements[38].
- **Adopt neutral forecasts in relation to demand and energy consumption.** The energy and peak demand forecast published in the 2017 ESOO's Neutral scenario are adopted in the Base Scenario for electricity consumption, rooftop PV, domestic storage and electric vehicle uptake. The Strong growth forecast has been applied in a sensitivity analysis and alternative MPC scenarios.

The generation capacity forecasts in the Base Scenario reflects capacity that is currently in place; committed capacity retirements; capacity driven by current government policy; and capacity that is determined to enter or retire from the market on the basis of rational commercial investment decisions.

As outlined earlier, EY's 2-4-C® model replicates the function of AEMO's NEM dispatch engine (NEMDE), and forecasts dispatch and price outcomes for time-sequential half-hourly intervals into the future. After the assumptions are set, an initial time-sequential half-hourly market simulation is conducted over the review Period. The annual net revenue of each generator is assessed. The model determines if any new generation would enter the market (or existing plant would retire) based on commercial drivers for net revenue outcomes, within a tolerance range of ±$2/MWh, to determine the final generation capacity development expectation throughout the review Period.

5.2 Base Scenario assumptions overview

Table 9 presents an overview of the market assumptions used in the Base Scenario. Each of these assumptions are described in more detail in Appendix A.

Table 9: Overview of key assumptions

Assumption	Description	Source
Assumptions affecting demand / energy consumption		
Electricity consumption	Annual forecasts of energy and seasonal peak demand by NEM region	AEMO, 2017 ESOO Neutral scenario
Rooftop PV	Annual energy forecast from rooftop PV generation	AEMO, 2017 ESOO Neutral scenario
Electric vehicles and behind-the-meter storage	Annual energy forecast for electric vehicles and behind-the-meter battery storage	AEMO, 2017 ESOO Neutral scenario

[37] The Renewable Energy (Jobs and Investment) Bill 2017 was introduced to the Victorian Legislative Assembly on 23 August 2017 and passed on 21 September 2017. https://www.energy.vic.gov.au/__data/assets/pdf_file/0022/80509/VRET-fact-sheet-Bill.pdf, accessed 26 September 2017.

[38] The 2016 NTNDP capital costs are used directly in the High costs sensitivities, as introduced for the MPC Scenarios in Section 6.1.1.

Assumption	Description	Source
Demand-side participation	DSP has a significant role in preventing unserved energy	AEMO, 2017 ESOO
Assumptions regarding market policies		
Drivers of large-scale renewable capacity	The present legislated LRET target of 33,000 GWh is met by 2020, plus additional drivers from GreenPower and state Government renewable energy auctions.	Present legislated LRET target and additional drivers.
Emissions reduction	No explicit or implicit policy to reduce emissions from the electricity sector (aside from the LRET).	As agreed in consultation with the Panel.
Assumptions affecting generation supply		
Non-renewable generator developments	The committed and likely changes to generator capacity, including large-scale storage, are taken into account.	Based on public announcements, and agreed in consultation with the Panel.
Outage rates - generators	Outages are in two categories: Forced outage rates depict the probability of different types of generators experiencing an unplanned full or partial outage. Planned outages are specified as an average number of days a generator is unavailable due to planned maintenance every year.	AEMO, 2017 ESOO
Fuel prices	The price for natural gas and coal is a key influence on market prices, influencing the short-run costs and bidding strategies of thermal generators.	AEMO, 2016 NTNDP
Network constraint equations	AEMO publishes a data set of network constraint equations annually. These are used to constrain generation at particular times to ensure the system is operated in a secure state with respect to transmission network limitations.	AEMO 2015 constraints data set (see Section 7.2.8 for further explanation)
Technology capital costs	Capital costs for new entrant generators of different types are used to assess the economic viability for new capacity.	AEMO, 2016 NTNDP, except: Adjustments for large-scale wind and solar PV CSIRO/Jacobs Neutral trajectory (from 2016 AEMO NEFR) for large-scale storage
Technology parameters	These parameters include heat rates, economic lifetime, annual energy expectations (wind and solar) and loss factors	AEMO, 2016 NTNDP EY annual energy expectations Loss factors for 2017-18 from AEMO
WACC	The WACC is used to evaluate the annualised repayments of capital costs for each generator. 8% pre-tax real was used.	IPART Review of Regulated Retail prices, adjusted by EY in consultation with the Panel

5.2.1 Base Scenario sensitivities

Two sensitivities to the Base Scenario were simulated to explore the impact of different assumptions on the USE forecast. Table 10 lists the sensitivities modelled, including which assumptions are different to the Base Scenario for each and the motivation for exploring the impact of those assumptions.

Table 10: Base Scenario sensitivities

Sensitivity	Assumptions that differ from Base Scenario	Motivation
Base w High Demand	Uses AEMO's high demand scenario (from the 2017 ESOO Strong scenario).	Explores the impact of high demand and to compare with AEMO's modelled high demand in the 2017 ESOO report.
Base w High Demand and EY FORs	Uses AEMO's high demand scenario (from the 2017 ESOO Strong scenario) and EY's upper bound of full FORs[39] for existing coal generators.	To explore the impact of EY's upper bound FORs in isolation to other assumptions.

5.3 Base Scenario outcomes

5.3.1 Capacity mix

With the assumed new renewable capacity installed to meet the LRET and the Base Scenario assumptions, no large-scale new entrant generators were found to be economically viable in the modelling during the Period (though the installed capacity of rooftop solar PV continues to grow as per the ESOO Neutral scenario). Figure 3 shows the installed capacity outcomes in the Base Scenario over the Period, distributed by generator type and by region. As indicated on the chart, the only changes in capacity during the Period are from the assumed retirement of Liddell coal power station on 1 July 2022 and increases in rooftop PV capacity.

[39] For more details see Appendix A.10.

Figure 3: Installed capacity by type and region in the Base Scenario[40]

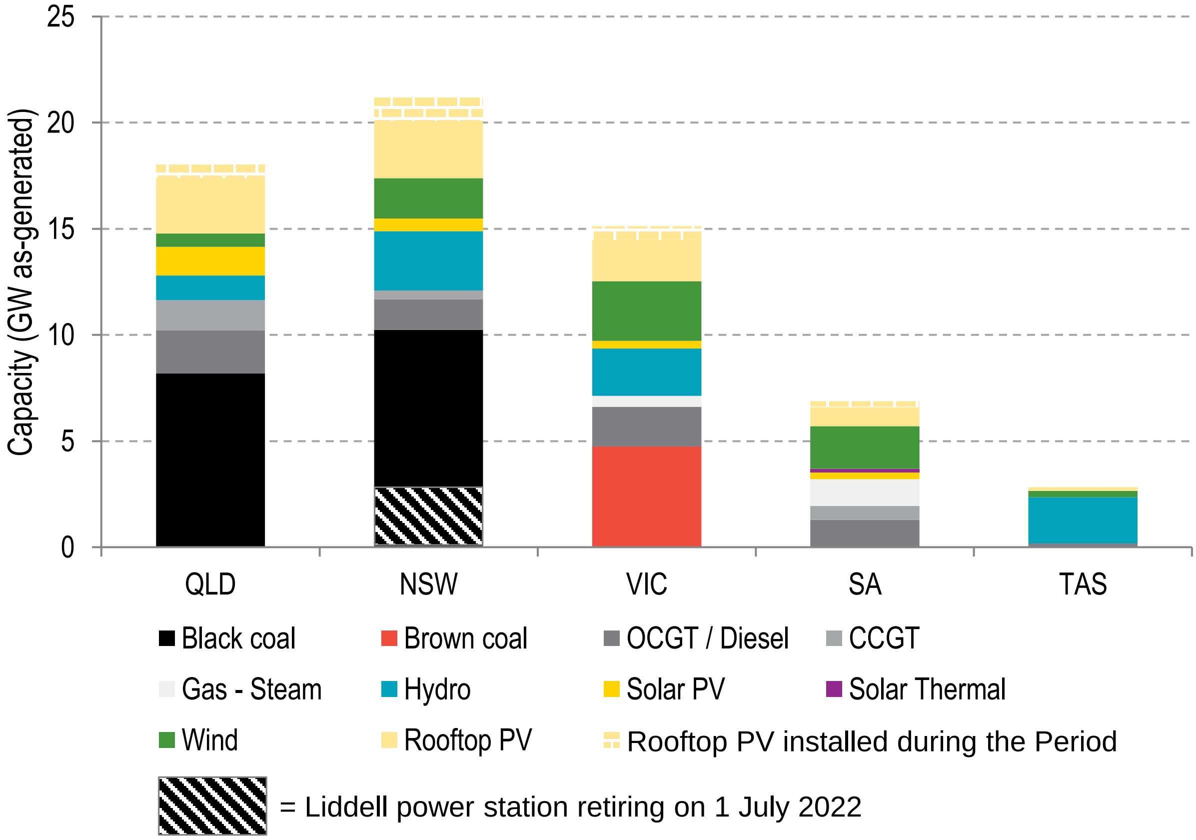


Table 11 shows the percentage share of overall installed capacity for each technology type modelled in the Base Scenario for 2017-18, 2020-21 and 2023-24. The percentages are calculated for the whole NEM and include rooftop PV. The percentage share of coal, gas and hydro technologies all decrease from 2017-18 to 2020-21 as additional wind and solar capacity is installed to meet the LRET and rooftop PV uptake. Black coal's percentage share of overall capacity decreases further in 2023-24 following the assumed retirement of Liddell, while rooftop PV is assumed to continue to increase.

Table 11: Percentage of total NEM installed capacity by technology in the Base Scenario

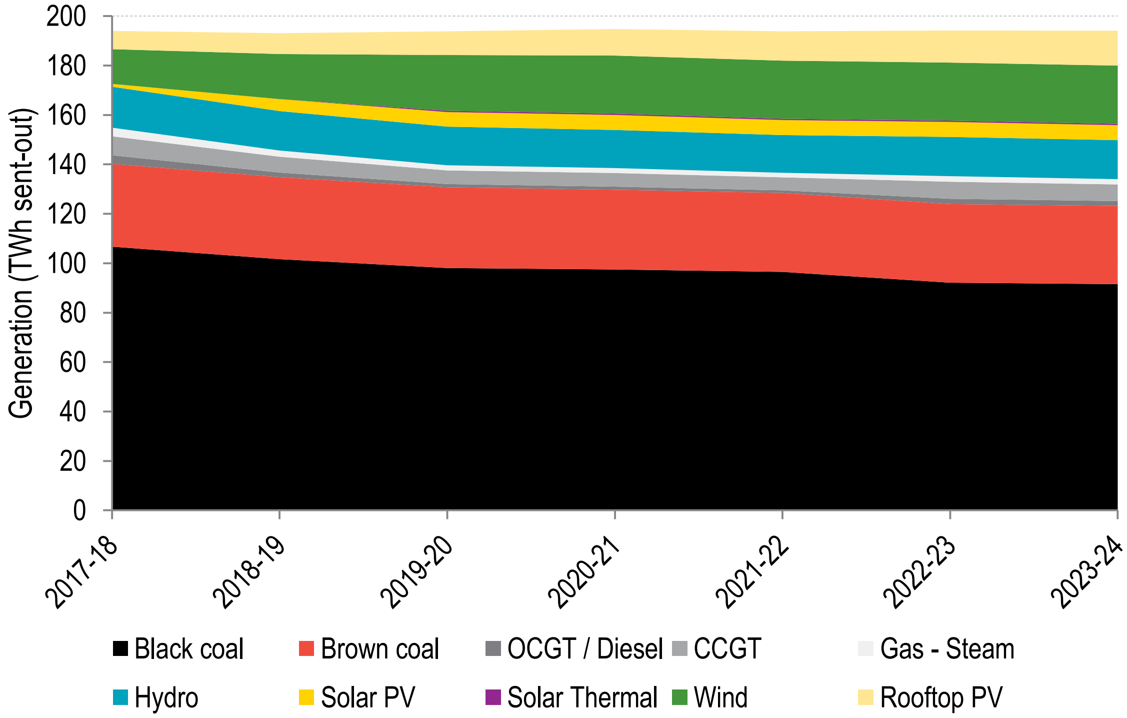
Technology	2017-18	2020-21	2023-24
Black coal	35%	30%	26%
Brown coal	9%	8%	8%
OCGT / Diesel	12%	11%	11%
CCGT	5%	4%	4%
Gas - Steam	3%	3%	3%
Hydro	16%	14%	13%
Solar PV	1%	4%	4%
Wind	9%	13%	12%
Rooftop PV	10%	14%	18%

40 All technologies in the chart are for large-scale generators, except for rooftop PV.

5.3.2 Generation mix

Figure 4 shows the annual generation outcomes across the NEM for the Base Scenario. That is, the modelled forecast of actual generation as opposed to the installed capacity by technology type (presented in the previous section). The relatively flat total generation at around 194 TWh sent-out highlights how the consumption forecast is very stable for this scenario. Over the seven years shown from the present financial year until the end of the Period, the generation from renewable sources is modelled to increase from about 20% in 2017-18 to 31% in 2023-24. The majority of this additional renewable generation is balanced with reduced black coal generation, which is initially due to reduced production levels from existing black coal capacity and then in 2022-23 further reduced due to the assumed retirement of Liddell power station. The initial reduced production levels from coal generators is due to cost competitiveness with the additional new entrant renewable capacity installed to meet the LRET.

Figure 4: NEM generation by technology in the Base Scenario



5.3.3 Expected USE outcomes

Using the Base Scenario assumptions, EY forecasts only a very small amount of USE in the Period. Figure 5 shows the expected USE outcomes in the Base Scenario from 2017-18 to 2023-24. With the reliability standard shown on the chart, the USE outcomes in the Period are so small, they are generally not visible on the chart.

Figure 5: Expected USE outcomes for the Base Scenario from 2017-18 to 2023-24

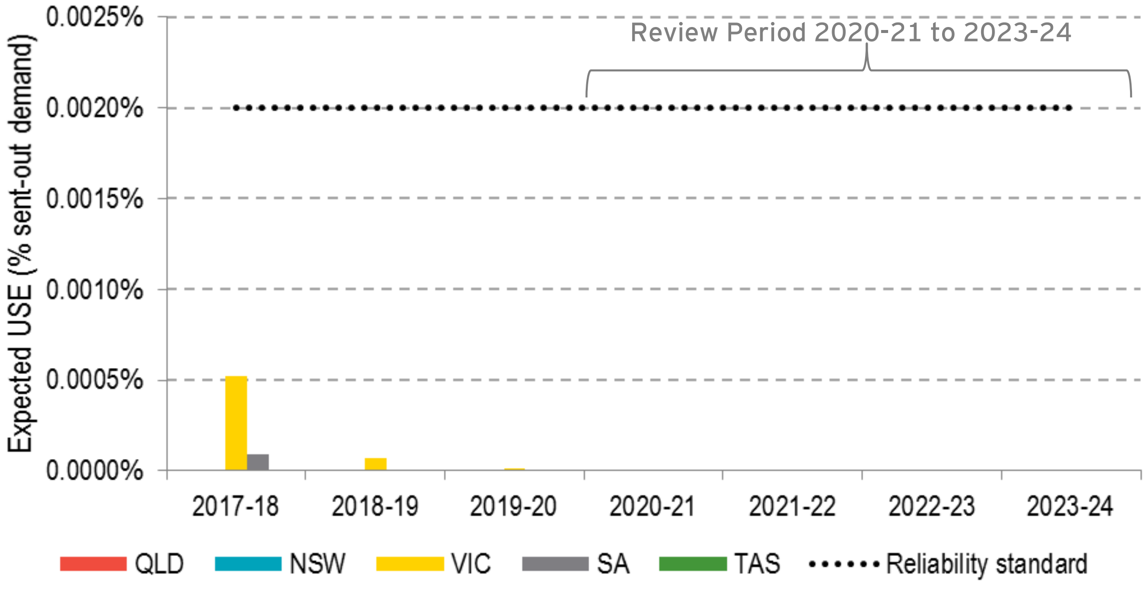
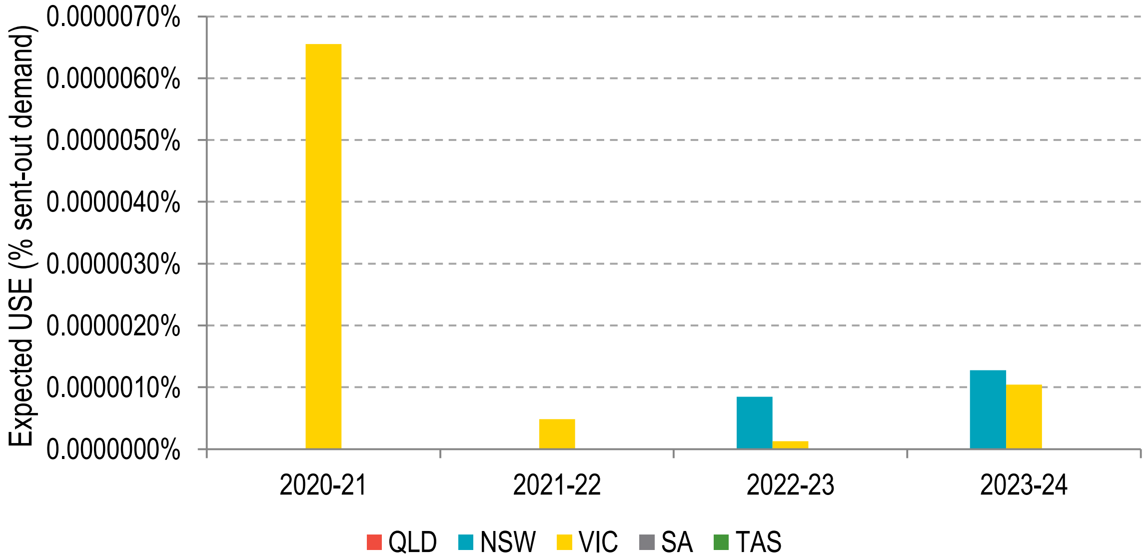


Figure 6 shows the USE outcomes for the Base Scenario in the Period only, with the y-axis scale reaching only around 1/300th of the reliability standard[41]. The chart shows some small amounts of USE forecast in Victoria in 2020-21, that diminishes in the subsequent three years as well as a small amount of USE in NSW after Liddell retires. No USE is forecast in QLD, SA or Tasmania in any year. The USE outcomes are analysed in more detail in the following section.

Figure 6: Expected USE outcomes for the Base Scenario in the Period (expanded vertical scale)*



* Note that y-axis scale shows up to approximately 1/300th of the reliability standard of 0.002%.

5.3.4 Probability of USE in the Base Scenario

Table 5 in Section 3.1 describes the nature of the 2,400 simulations made for every future year in the Base Scenario. With 17,520 half-hours in 2020-21, the total number of half-hours modelled is just over 42 million. As shown in Figure 49, there are only 33 half-hours in which *any* USE occurs in Victoria in the forecast out of the 42 million modelled. Out of the 2,400 simulations of 2020-21,

[41] As described in Box 1 in Section 7.2, the overall expected USE outcome is calculated as a weighted-average over the simulations, with a weighting of 0.3 on the 10% POE peak demand profiles and 0.7 on the 50% POE peak demand profiles.

USE occurred in just 16, and 14 of those were 10% POE peak demand profiles. Furthermore, the 10% POE peak demands are assigned a weighting of 0.3 relative to 0.7 on the 50% POE peak demands, which is less than half. It can be calculated then, that if all the assumptions for the Base Scenario were to eventuate up to 1 July 2021, the probability of **any USE occurring** at all in Victoria in 2020-21 is **0.5%, or one chance in 200**.

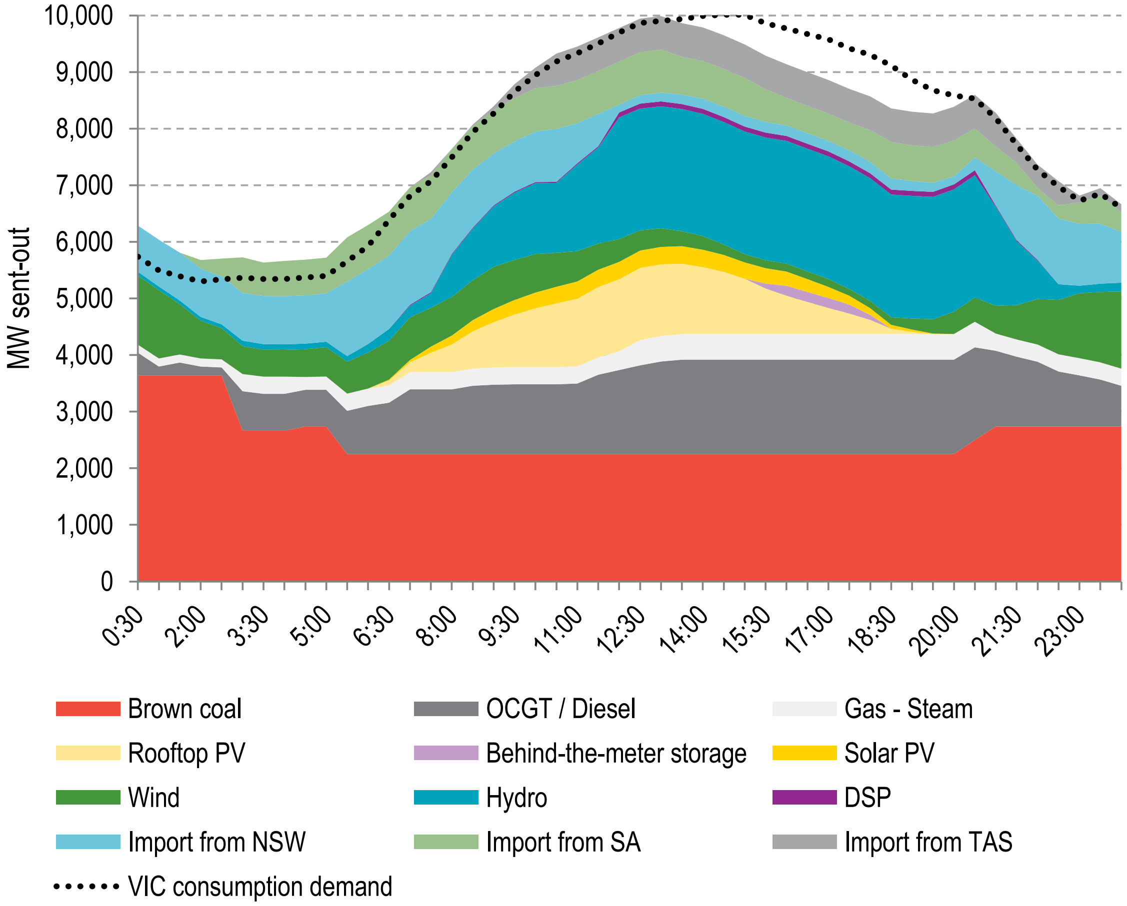
As well as the probability of any USE occurring, the probability of USE being above the reliability standard can also be calculated from the Base Scenario outcomes. Of all of the simulations for 2020-21 in the Base Scenario, 59% of the USE in Victoria occurred on a single modelled day (Thursday, 14 January 2021), based on reference year 2013-14[42]. EY simulated this day 200 times with the 10% POE peak demand profile, each with different random Monte Carlo forced outage patterns (using the FORs assumed in the Base Scenario – see Appendix A.10 for more details). USE was forecast to occur in 3 of those 200 simulations. On two of those occasions the amount of USE was over 0.002% for the year. This means that, based on the modelling outcomes of the Base Scenario and taking into account that 10% POE peak demand simulations have a 0.3 weighting relative to 0.7 for the 50% POE peak demands, the probability of **USE being above the reliability standard** in Victoria in 2020-21 is **0.1%, or one chance in 1000.** In addition to this, in practice AEMO may exercise intervention mechanisms to minimise or prevent USE events happening, if at all possible.

5.3.5 USE modelling case study: 14 January 2021 in Victoria

Figure 7 shows the modelling outcomes for each half-hour of 14 January 2021 in Victoria, being the day that the highest USE is observed in the Base Scenario simulation. Victoria in 2020-21 was chosen for this case study as it was the region and year with the most USE in the Base Scenario. The chart shows Victorian dispatched generation by type, plus imports of electricity from the neighbouring regions of SA, NSW and Tasmania.

[42] This particular modelled day is based on the weather on Thursday 16 January 2014. EY applies a day-shifting algorithm for each future modelled year to ensure that the days of the week are always consistent.

Figure 7: Modelling outcomes for one iteration of 14 January 2021 in Victoria – Base Scenario



The chart shows that USE is modelled to occur between 13:30 to 20:30 (1.30pm – 8.30pm). Notably, this period is during the highest demand of the day, but it continues past the peak demand to the evening as the amount of solar generation reduces to zero. Outages and availability of wind and solar generation limit the available capacity and in response, hydro, storage, and DSP make significant contributions to meeting demand. Note that only the interconnector imports are shown. In the periods in the chart where the total generation plus imports is greater than consumption, Victoria is exporting the excess generation to the regions not showing energy imports in the chart. Notably, during the period of USE, the following events coincide:

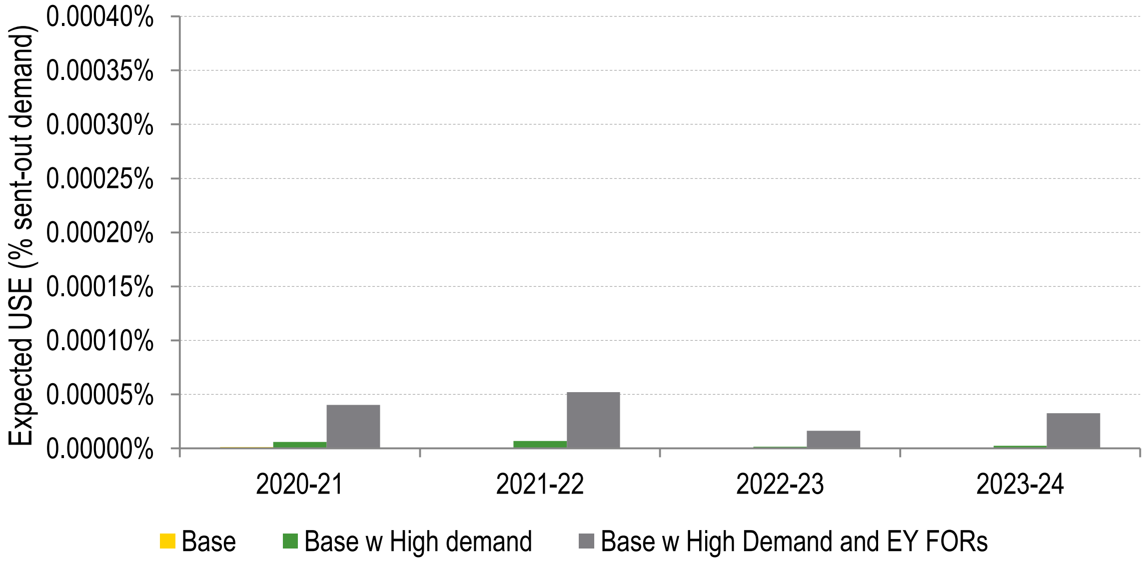
- Only 2.25 GW of 4.7 GW brown coal (46%) was available due to the randomly simulated outages
- Only ~0.14 GW of the 2.8 GW wind capacity (5%) was generating due to the weather data for this day
- An interconnector constraint prevented Victoria importing more than ~190 MW from NSW (10%), due to the increase in generation from Murray power station competing for the same transmission capacity. This illustrates the importance of the nature of network limitations captured through the implementation of constraint equations in the modelling, and similarly in real world events.

5.4 Base Scenario sensitivity outcomes

As discussed in Section 5.3.1, no new entrant large-scale capacity was found to be economically viable in the Base Scenario, aside from the new capacity assumed to be built to meet the LRET and the assumed rooftop PV uptake. To explore the impact of the assumptions varied in isolation, the results for the Base Scenario sensitivities are presented for the same generator capacity mix as the Base Scenario. That is, no new entrant generators are installed in the sensitivities as with the Base Scenario, even if there is an economic signal for new entrants in the sensitivities.

Figure 8 shows the USE outcomes for Victoria in the Base Scenario and the two sensitivities, with the y-axis scale being up to one fifth of the reliability standard of 0.002%. While some of the sensitivities produce much higher USE compared to the Base Scenario, the levels are still less than 2.5% of the reliability standard.

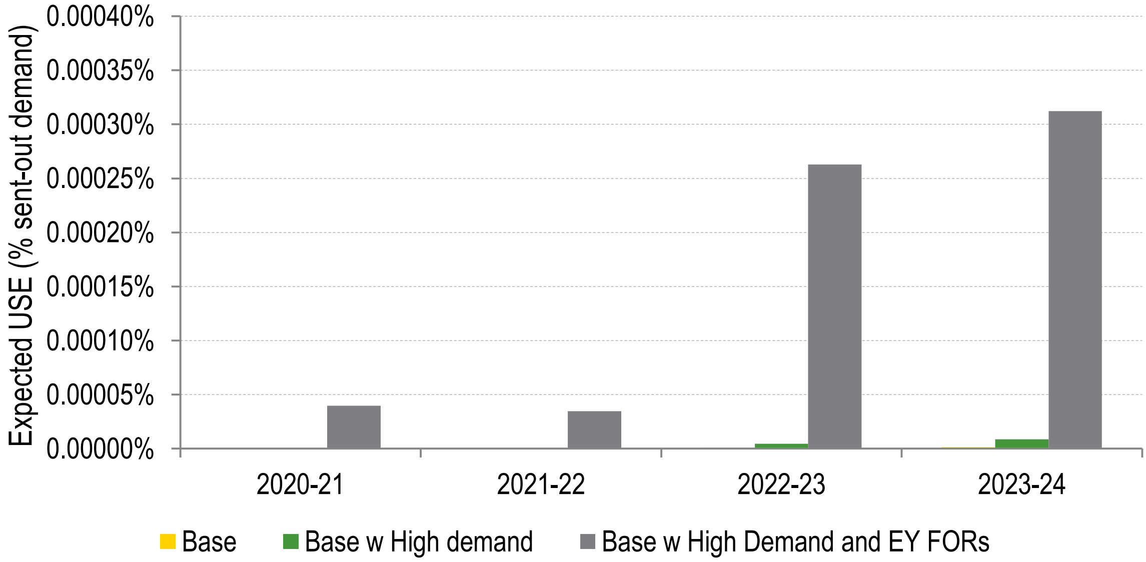
Figure 8: Expected USE outcomes* in Victoria for the Base Scenario sensitivities



* Note that y-axis scale shows up to one fifth of the reliability standard of 0.002%.

Figure 9 shows the USE outcomes for NSW in the Base Scenario and the two sensitivities, with the same y-axis scale as the previous chart.

Figure 9: Expected USE outcomes* in NSW for the Base Scenario sensitivities



* Note that y-axis scale shows up to one fifth of the reliability standard of 0.002%.

The sensitivity with high demand only (Base w High demand) increases USE across the regions and years. The ESOO Dispersed sensitivity does not exhibit any significant differences in USE outcomes. Changing the full FORs to EY's upper bound values in addition to High demand (Base w High Demand and EY FORs) makes a much bigger difference. In this sensitivity, the USE forecast in Victoria for this sensitivity is around 2.5% of the reliability standard and in NSW is around 15% of the reliability standard from 2022-23 after Liddell is assumed to retire.

The USE outcomes for Queensland (QLD) and South Australia (SA) are either zero or negligible over the Period for all the sensitivities modelled. This is due to the combination of demand, installed capacity and other assumptions modelled affecting the USE outcomes for these regions.

Whilst the sensitivities modelled have found some assumptions can have a significant impact on the forecast USE, the levels of USE in all sensitivities are far below the reliability standard throughout the Period.

5.5 Limitations to the USE forecasting

Whilst the USE forecasts in this Review take into account many aspects of what can cause USE, the modelling has the following limitations:

- Transmission network outages, including outages in interconnectors between regions are not considered[43]. The probability of a transmission outage is very small compared to generation availability, but often has a significant impact when it occurs.
- It only considers half-hour trading intervals. USE can occur due to sudden changes in residual demand and ramping limitations of thermal generators between five-minute intervals. However, five-minute issues are typically resolved quickly and the majority of USE in energy terms is from events that occur over multiple consecutive trading intervals.
- Consideration of more than six historical reference years. USE forecasting is generally more accurate, the more realistic types of weather patterns are modelled along with their influence on demand, wind generation and solar generation. However, due to data availability, EY's modelling for this Review is limited to six years, 2010-11 to 2015-16. With the wind data available for 2016-17 at the time of the modelling, some analysis of the differences in the 2016-17 year compared to the six years modelled is provided in the following section.

5.5.1 Analysis of wind resource by reference year

EY's half-hourly wind generation modelling is based on location-specific historical wind resource data. The data source is hourly wind speed forecast data from a series of Australian Bureau of Meteorology (BoM) Numerical Weather Prediction models on a ~12 km grid across Australia. The hourly wind speed data has been collected by EY since early 2010, but the equivalent data is not available prior to that. EY was not able to model the 2016-17 reference year on the same basis as the previous six reference years for this Review as the solar resource data was not yet available from the BoM at the time of the modelling. Because of these reasons, EY's market modelling for this Review is based on the reference years 2010-11 to 2015-16.

To explore the wind resource in the 2016-17 year and compare that to the six years modelled, EY made an analysis of the total wind generation installed in 2020-21 in the Base Scenario. Figure 10 shows the lowest 9% of total NEM wind generation values for each reference year, sorted from highest to lowest (duration curve). The 2016-17 year stands out from the other years with the highest number of half-hours with relatively low wind generation. For example 8% of trading intervals in 2016-17 have modelled total NEM wind generation less than 10% of installed capacity. The other six reference years range from 5% to 7% of trading intervals.

[43] Interconnector flow limits and their interaction with network constraint equations are taken into account. The network constraint equations used for the Base Scenario is the AEMO 2015 constraint dataset.

Figure 10: Duration curve of lowest 9% of total modelled NEM wind generation in 2020-21 by reference year - Base Scenario

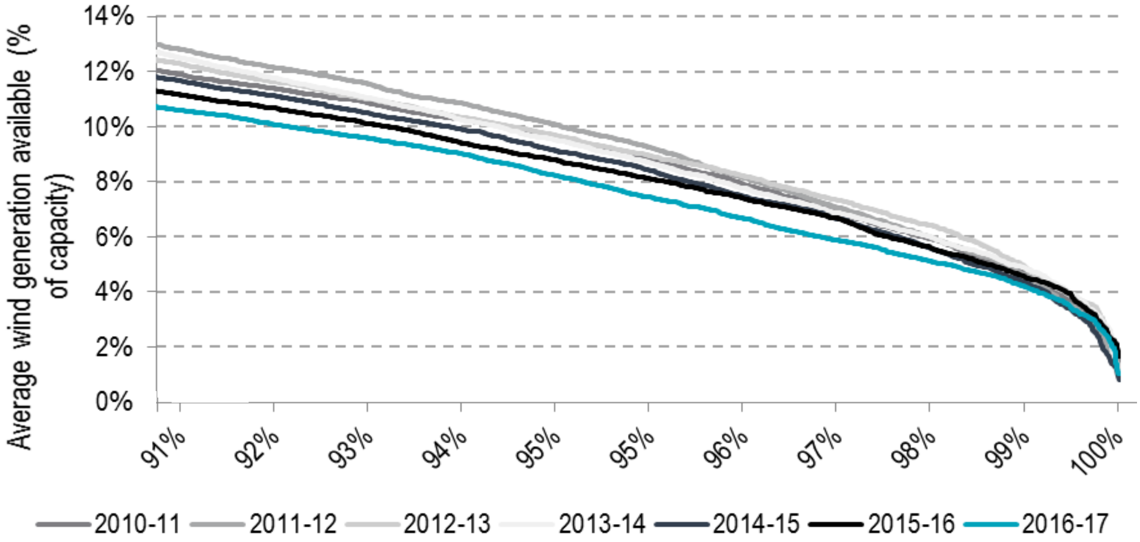


Figure 11 shows the average monthly modelled NEM wind generation in 2020-21, by reference year. The results show that the 2016-17 reference stands out in June, with the lowest monthly average wind generation compared to any other month and reference year. This is in agreement with observed wind data for June 2017 and the month has been coined 'the calming'[44]. However, as shown in Appendix A, all the USE forecast occurs in the warmer months of December to March so if 2016-17 were modelled, the low wind generation in June may not contribute to any additional USE in the forecast.

Figure 11: Average monthly total modelled NEM wind generation in 2020-21 by reference year - Base Scenario

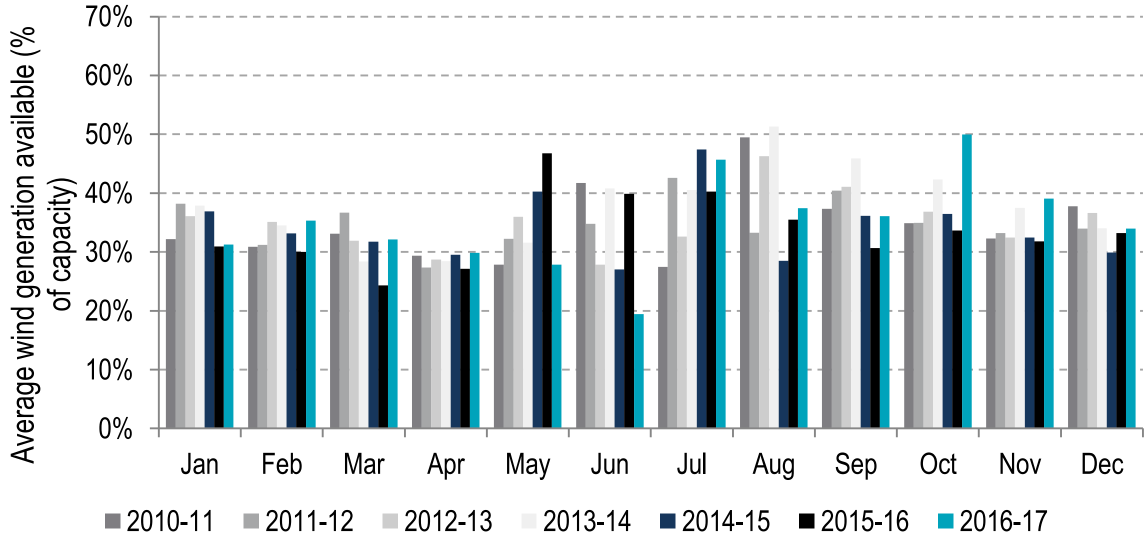
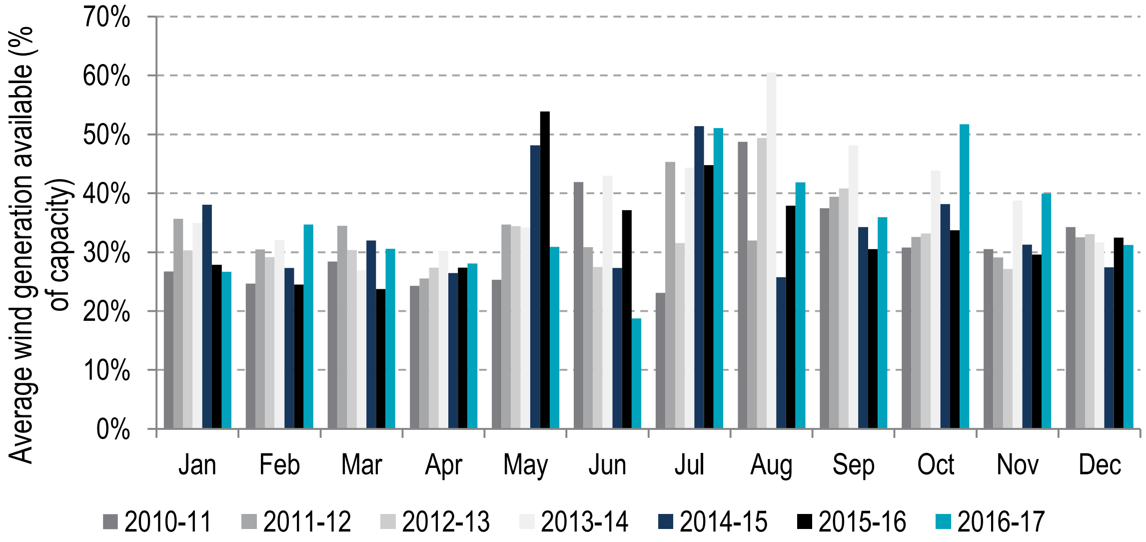


Figure 12 shows the average total monthly wind generation in 2020-21 for Victorian wind farms only.

[44] Example source: http://www.theaustralian.com.au/business/mining-energy/lack-of-wind-blows-out-south-australia-power-costs/news-story/4ba33127cece152d31ffe202cbe09ab4

Figure 12: Average monthly total modelled Victorian wind generation in 2020-21 by reference year – Base Scenario



As shown in Appendix A, the majority of the USE forecast in Victoria in 2020-21 is in February and is based on the 2011-12 reference year. However, Figure 12 shows that in the month of February, the 2011-12 reference year is one of the highest in terms of the average modelled Victorian wind generation. This indicates that low average wind generation is not a reliable indicator of USE risk. While the analysis in the section provides some insight into the variability in the wind generation modelled by EY, it also shows that very little can be understood about USE risk without actually modelling all aspects of the supply-demand balance. It is therefore unknown how much of a difference including 2016-17 would make to the USE forecast. Nevertheless, Figure 54 in Appendix A shows that there is a large variation in USE by reference year and indicates that including a seventh year could materially alter the overall average expectation of USE.

5.6 Conclusion

The primary purpose of the modelling conducted for this section is to determine whether the reliability standard is likely to be met in the Period under the current reliability settings.

The USE forecast in the Base Scenario is very small in all regions across the RSSR Period, well below the reliability standard.

EY analysed the distribution of USE in the Base Scenario and found that the USE is primarily concentrated in summer months, the late afternoon/early evenings and in the simulations based on the 2013-14 reference year. This is a consequence of higher temperatures impacting the availability of generators in conjunction with the higher demand periods in the late afternoons in summer and falling solar generation at that time of day (see Appendix A for details).

To help understand the impact of some assumptions on expected USE, two Base sensitivities were modelled exploring the impact of high demand and higher outage rates for coal generators (see Appendix A.10). The only sensitivity that produces materially higher USE than the Base Scenario used both high demand and EY's upper-bound outage rates for coal generators. However, expected USE with these assumptions remains well below the level of the reliability standard.

To understand the differences between the USE outcomes in the 2017 ESOO and EY's modelling in this Report, AEMO and EY collaborated and conducted additional comparison scenarios. The outcomes of this analysis to date is presented in Appendix D.

6 MPC scenarios

This section describes the MPC scenarios devised to threaten the reliability standard and the outcomes for the theoretical optimal MPC. The sections describe the following:

- Section 6.1 - overview of the scenarios and the assumptions used in the sensitivities.
- Section 6.2 - outcomes for the theoretical optimal MPC for each scenario and sensitivity, keeping the CPT and APC at their present levels.
- Section 6.3 – outcomes for the theoretical optimal MPC under different APC and CPT settings.
- Section 6.4 - findings on the impact of different CPT settings on the contract market.
- Section 6.5 - capacity mix outcomes in each MPC scenario.
- Section 6.6 - USE outcomes before and after introducing the new entrant capacity and the marginal generator to meet the reliability standard.
- Section 6.7 – impact of five-minute settlement on the theoretical optimal MPC
- Section 6.8 - general impact of changing the reliability settings on different aspects of the market as per the Panel's criteria.
- Section 6.9 - primary limitations of the modelling.
- Section 6.10 - the overall outcomes.

6.1 Scenario overview

To estimate the theoretical optimal MPC for the Period, EY undertook the following steps:

1. **Devised two plausible scenarios** (MPC scenarios) as alternatives to the Base Scenario in which the expected USE would exceed the reliability standard without a sufficiently high MPC. The scenarios are devised to explore meeting the reliability standard in two different regions, where the demand profiles, capacity mix and pricing outcomes are different.
2. For each scenario, **model several sensitivities** exploring the impact of higher new entrant capital costs, WACC, gas prices, reduced economic lifetimes, and different bidding strategies for the marginal new entrant OCGT, along with variations to the APC and CPT.
3. For each of these scenarios and sensitivities, **estimate the minimum MPC that** would be required to economically incentivise a level of capacity that meets the reliability standard. This involves gradually increasing the MPC starting with a low value, such as $1,000/MWh and installing economically viable new entrant capacity until the forecast USE is less than 0.002% in all years of the Period.

Table 12 outlines the assumptions made for the two MPC scenarios to achieve a USE outcome greater than 0.002% (step 1 above).

Table 12: Overview of MPC scenarios

Scenario	Region in which USE is threatened	Assumptions differing from the Base Scenario
MPC Scenario 1	South Australia	► AEMO high demand forecast[45] ► EY's coal outage rates[46] ► Early retirement of 1,040 MW of thermal capacity in SA
MPC Scenario 2	Victoria	► AEMO high demand forecast ► EY's coal outage rates ► VRET 5150 MW scheme[47] ► Early retirement of 2,600 MW of thermal capacity in Victoria

The two MPC Scenarios explore the reliability standard being threatened in SA and Victoria, respectively. These regions were chosen primarily on consideration of plausibility - these are the two regions where the most plausible scenarios could be devised to threaten the reliability standard. This is mainly due to the thermal power stations in these regions being older than in other regions and are hence more likely to retire earlier than currently expected.

In addition to the objective of plausibility, EY agreed in consultation with the Panel that the second scenario would explore a rapid uptake of renewable capacity. The theory is to test the MPC under a scenario where the shape of residual demand is significantly different. This results in USE occurring at different times and potentially requires a different new entrant mix to meet the reliability standard. Victoria is chosen for MPC Scenario 2 as it is a region that is expected to have a very high concentration of renewable capacity within the Period due to the relatively advanced VRET policy development. It is also worthwhile testing the MPC for a different region in each scenario for similar reasons.

EY also conducted modelling to explore the MPC required to meet the reliability standard in the NSW region. Using the same Strong demand and outage rates in the other MPC scenarios, as well as the assumed retirement of Liddell power station, EY's modelling found that NSW would require a further 1,300 MW of NSW coal capacity to be retired to exceed the reliability standard in NSW. The MPC outcomes from this case are discussed as a sensitivity to the outcomes for the other MPC scenarios in Section 6.2.

In simulation trials for designing the scenarios, EY also explored threatening the reliability standard in QLD for MPC Scenario 1 as a scenario exploring relatively low penetration of renewable capacity. However, EY found that achieving high USE in QLD was less plausible than in SA or Victoria due to:

- The necessary removal of the equivalent of 1.5 existing QLD coal power stations (2,580 MW or a third of QLD's coal capacity) and these power stations are among the newest in the NEM
- The coal capacity removal resulted in economic signals for more than 2 GW of new entrant wind and solar PV capacity with a very low MPC. As a result, the capacity mix in QLD becomes very different to today.

[45] From Strong scenario in AEMO's 2017 ESOO. This includes higher demand, rooftop PV, EV and behind-the-meter battery uptake compared to the Neutral scenario (as used in the Base Scenario in this Review). For details, see Appendix A.
[46] EY analysed historical availability of NEM coal generators to estimate an upper bound for their forced outage rates. For details, see Appendix A.10.
[47] Involves 700 MW of renewable capacity in addition to the LRET installed in Victoria in each year in the Period (https://www.energy.vic.gov.au/renewable-energy/victorias-renewable-energy-targets).

6.1.1 Base costs and High costs assumptions

This section explains the assumptions underpinning the MPC Scenarios; both the assumptions used in the two Base cost MPC scenarios (SA and Victoria) and those used for the various sensitivities that were conducted on them.

Rationale and overview

The two foundational MPC Scenarios (SA and Victoria) utilise a set of base costs. Several higher cost sensitivities were then assessed on each of the foundational MPC scenarios, to explore an upper range of cost assumptions to estimate how high the MPC would need to be if those high costs assumptions turn out to be closer to reality for the Period. Table 13 summarises the different assumptions used in the Base costs and each of the High costs sensitivities for the MPC outcomes. The Base costs are used in the Base Scenario as well as both MPC Scenarios. The High costs sensitivities are only used for the MPC Scenarios. The high cost sensitivities are based on a core set of different assumptions that pertain to higher costs for generators.

Table 13: Assumptions that differ between the MPC Base costs scenario and the four High costs sensitivities

Assumption	MPC Scenarios				
	Base cost sensitivity	High cost sensitivities^			
		High	Cap defender	12% WACC	Half lifetime
WACC (pre-tax real)	8%	10%	10%	12%	10%
Economic lifetime for OCGTs	30	30	30	30	15
Bidding strategy of marginal OCGT*	SRMC	SRMC	$270/MWh#	SRMC	SRMC
Capital costs** – wind and solar PV	EY market research	2016 NTNDP			
Capital costs** - Storage	CSIRO/Jacobs Neutral	CSIRO/Jacobs Strong			
Gas fuel price	2016 NTNDP	$18/GJ			
Include CCGTs as potential new entrant	Yes	No			

* This is equivalent to the cap defender strategy employed in the 2014 Review.
** The same capital costs for OCGTs and CCGTs were used in the Base and High costs sensitivities as these are considered stable and more certain for the Period than with the other technologies.
# As described above the nominal $300/MWh APC is estimated to be $270/MWh in real terms for the purpose of the modelling. This estimate is equally applied to the $300/MWh cap contract on the basis that this standard contract is also effectively nominal.
^ As well as higher costs, the High cost sensitivities exclude CCGTs as a potential new entrant technology. The reasons for this are described below in this section.

Additional sensitivities to those shown in the table were also conducted involving varying the APC and CPT. The details and reasoning for these sensitivities are described in Section 6.3.

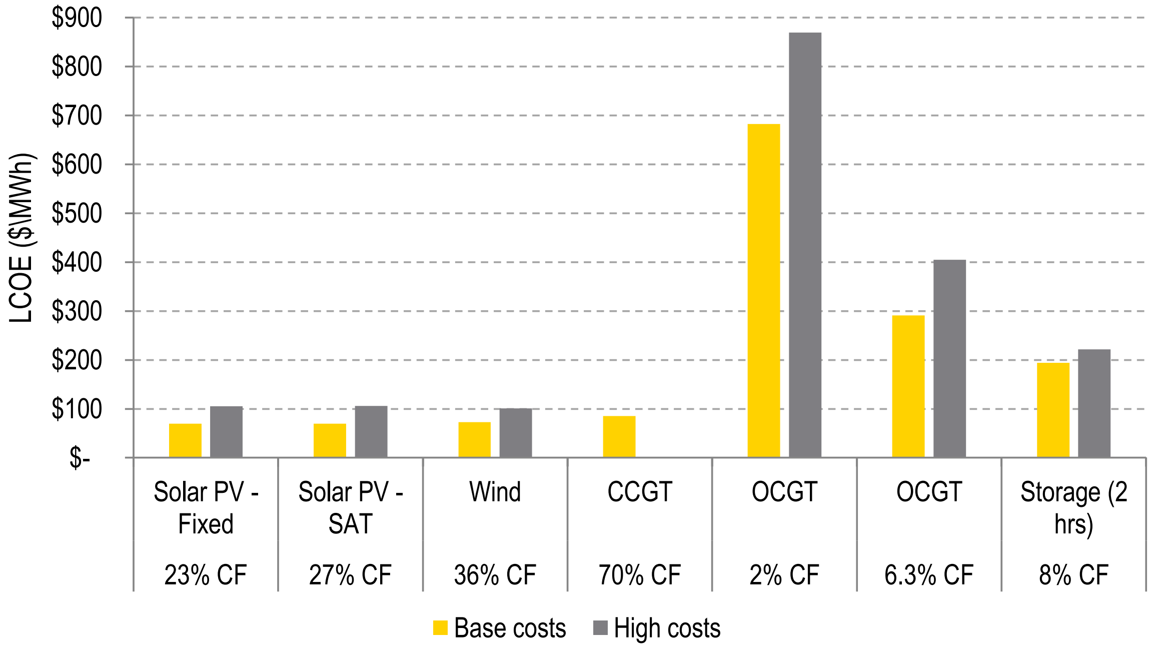
Overall high costs used for different generator technologies

The details regarding the capital cost and gas fuel price trajectories used are provided in Appendix A.7 and Appendix A.9, respectively. However, the comparative overall costs of the different technologies can be more easily assessed by comparing their levelised cost of energy

(LCOE). The LCOE describes the total annualised costs of a generator technology, based on assumptions of economic lifetime, WACC and capacity factor[48]. The LCOE is expressed in $/MWh and depicts the average price the generator technology requires for each MWh of its generation over a given year in order to make a net positive return.

Figure 13 shows the LCOEs for the key contending generator technologies[49], based on assumed achieved capacity factors. Two capacity factors are shown for OCGTs as the capacity factor for an OCGT can vary greatly depending on how it bids into the market, reflecting its contracting position and also how often wholesale market prices are very high. The 6.3% figure represents the capacity factor achieved by the marginal new entrant SRMC-bidding OCGT in MPC Scenario 2, while for the APC-bidding OCGT it is 2%.

Figure 13: LCOEs for key technologies using the Base costs and High costs assumptions (SAT = single-axis tracking)[50]



The chart shows solar PV (both fixed plate and single-axis tracking) to have the lowest LCOE at around $70/MWh based on the Base cost assumptions[51]. The LCOE for wind is a little higher at $73/MWh, while CCGTs have a LCOE of $85/MWh. The LCOEs for OCGTs and storage are much higher. However, a lower LCOE does not necessarily make a technology more economically viable than another. Depending on the market dynamics, some technologies will be able to earn more market revenue than others. Furthermore, whilst solar PV and wind technologies have a comparatively low LCOE compared to OCGTs (at the assumed capacity factors), they will not necessarily be the marginal technology to set the MPC if they are unable to reduce USE below the reliability standard, due to not having enough generation available during periods of USE.

In the case of storage, the LCOE shown is relative to its discharge energy in MWh, where 8% represents the capacity factor achieved given it is operated with a full cycle of charging and

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[48] A generator's capacity factor for a given year is defined as its average generation output divided by its AC rated capacity, i.e., if it produced at its rated capacity for the entire year it would have a capacity factor of 100%. However, 100% is usually not achievable due to outages, and in the case of renewable energy also due to their energy resource not being fully available at all times.

[49] Due to high capital costs, solar thermal, solar PV dual-axis tracking, coal and nuclear technologies were found to not be in contention.

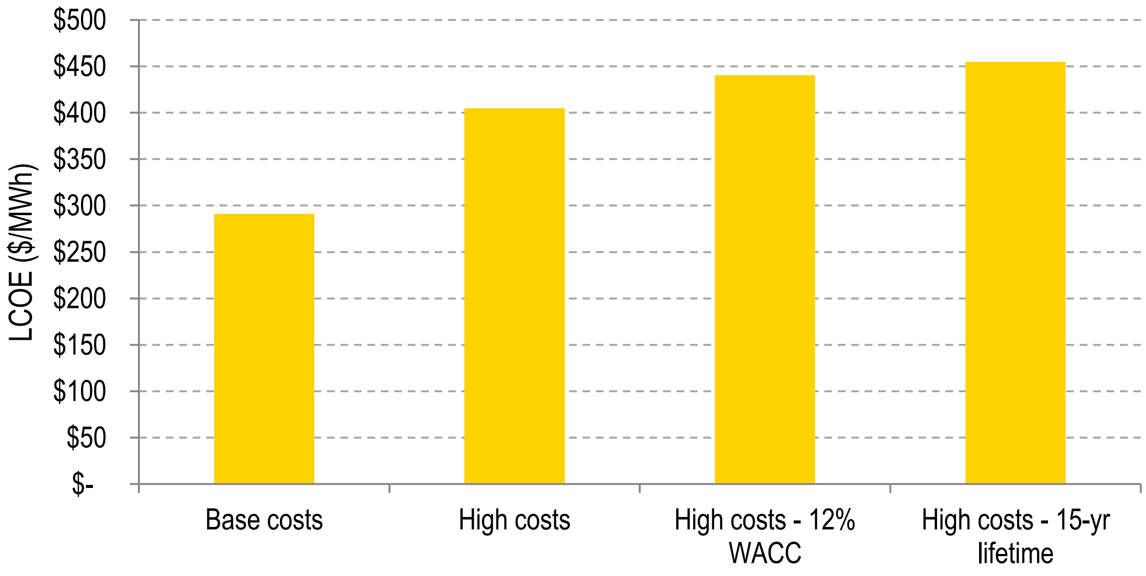
[50] The cost associated with OCGTs securing gas on a more irregular basis than CCGTs due to low usage volumes is incorporated with a $2/GJ uplift on OCGT gas prices. However, there is some uncertainty around the magnitude associated with these costs.

[51] The LCOE of CCGTs is not shown in the High cost case since CCGTs are ruled out in that sensitivity.

discharging each day. The storage LCOE takes into account an estimate for its cost of charging. This cost is estimated to be $92/MWh as this was found to be a consistent charging-weighted average price of electricity for a reasonably optimal charging profile in the MPC Scenarios with 0.002% USE. This charging cost can be considered equivalent to the fuel cost of the gas generators, which are also taken into account in the presented LCOEs. Like solar and wind generation, storage is also limited in when it can generate to earn the market revenue it needs recover its LCOE. Storage is limited in a different way to renewables, where the storage operator has some control over when to charge and discharge the battery, but this requires good day-ahead forecasts of market prices to optimise the revenue potential.

While OCGTs have the highest LCOEs of the technologies presented, they are the most flexible in that they are able to generate up to their rated capacity at almost any time, subject to outages. For this reason OCGTs can most easily capture high prices when they generate compared to the other technologies presented. Figure 14 compares the LCOEs for an OCGT based on the sensitivities modelled. Reducing the economic lifetime from 30 years to 15 years has a slightly bigger impact on the LCOE compared to increasing the WACC from 10% to 12%.

Figure 14: Comparative LCOEs for an OCGT in the sensitivities with a 6.3% capacity factor



CCGTs not considered in High cost sensitivities

Based on the assumptions and the economic outcomes in the modelling, CCGTs were found to be the most competitive new entrant technology in the MPC scenarios. CCGTs could be installed with a positive net revenue and reduce USE to below the reliability standard with an MPC as low as $300/MWh. These CCGTs achieve a 70% capacity factor in the modelling. This outcome is likely to be a direct result of the reliability standard being threatened with early retirements of baseload capacity. This leads to wholesale market prices being above the long-run marginal cost of a CCGT at most times in the year – not just when USE occurs.

However, these modelling outcomes are based on the assumptions chosen and the economic outcomes that arise. The modelling does not consider other reasons why CCGTs may not be a viable marginal new entrant. The Panel has considered these reasons in consultation with EY, such as:

- Various reasons why CCGTs have not performed well in the NEM, including:
  - The risk of not being able to operate at the required consistently high capacity factors over the lifetime of the asset, with the future threats of high renewable energy penetration and emissions reduction targets
  - The difficulty in securing gas volumes required for high utilisation at the gas prices assumed in the modelling, for the economic lifetime of the asset

    - The risk of lower market prices occurring over the economic lifetime of the asset, and
    - Reduced flexibility compared with OCGT and reciprocating engine technology, including higher minimum load to extract maximum operating efficiency and higher cycling costs.
- Alternative scenarios to threaten the reliability standard could be devised by retiring OCGT capacity, which may not favour CCGTs.

To explore the MPC outcomes without CCGTs as an option, CCGTs were simply ruled out as a potential technology in the High cost sensitivities.

6.1.2 Sensitivity with five-minute settlement

EY conducted a sensitivity to estimate the potential impact of moving to five-minute settlement on the theoretical optimal reliability settings. This sensitivity was conducted with the same assumptions as MPC Scenario 2, High costs.

Given that the five-minute settlement rule change is to commence on 1 July 2021, and that 2021-22 was the price-setting year for MPC Scenario 2, EY only modelled 2021-22 to explore the sensitivity to the settings with five-minute settlement.

The approach and methodology for the required modelling with five-minute settlement is presented in Section 7.3, and the outcomes are presented in Section 6.7.

6.2 MPC outcomes with present settings for CPT and APC

This section outlines the MPC outcomes for the MPC scenarios with base costs and the high cost sensitivities, using the current settings for the CPT and APC. The section provides:

- an overview of the MPC outcomes
- an explanation of the key MPC outcomes, including the causes of the different outcomes between the two MPC scenarios
- analysis on the pricing outcomes to explain the impact of the CPT on the MPC outcomes.

Table 14 presents the theoretical optimal MPC outcomes, as modelled to be required to meet the reliability standard in each respective scenario and sensitivity presented in Table 13. These results are based on keeping the CPT and APC at the present values of $212,800 and $270/MWh, respectively.

Base costs

For each of the Base costs sensitivities modelled, a mix of new entrant wind, solar PV and CCGT capacity was found to be economically viable as a result of the scenario assumptions (including the early retirement of thermal capacity). The resulting capacity mix by region is shown in Section 6.3. However, the modelling outcomes showed CCGT units to be the most economic new entrant technologies that were also capable of reducing USE below the reliability standard. This CCGT capacity was found to be economically viable with an MPC as low as $300/MWh. However, EY’s analysis also indicates that a higher MPC of $1,500/MWh is required to maintain positive net revenues for some existing OCGT generators in the MPC scenario simulations with expected USE near 0.002%. The theoretical optimal MPC for the Base costs sensitivities is therefore determined to be $1,500/MWh.

Table 14: MPC outcomes, with the present settings for the CPT ($212,800) and APC ($270)

MPC scenario	Sensitivity		Theoretical optimal MPC ($/MWh)	Marginal new entrant technology (achieved capacity factor)
MPC Scenario 1 (SA)	Base costs		$1,500	CCGT (70%)
	High costs	High	$8,900	OCGT (3.5%)
		Cap defender	$9,000	OCGT (2.1%)
		12% WACC	$21,000	OCGT (3.5%)
		Half lifetime	>$50,000	OCGT (3.5%)
MPC Scenario 2 (Victoria)	Base costs		$1,500	CCGT (70%)
	High costs	High	$12,500	OCGT (6.3%)
		Cap defender	$21,000	OCGT (2.0%)
		12% WACC	$37,000	OCGT (6.3%)
		Half lifetime	>$50,000	OCGT (6.3%)

High cost sensitivities

With the assumptions used in the High costs sensitivities, and CCGTs ruled out, no new entrant wind or solar PV capacity was found to be economically viable. Instead, OCGT units were found to be the most economic new entrant capacity and this technology was also found to be capable of reducing the expected USE below the reliability standard.

In all cases, MPC Scenario 1 produces lower MPC outcomes than MPC Scenario 2. This is due to the wholesale market prices in MPC Scenario 1 being high (>$1,000/MWh) more frequently than in MPC Scenario 2, in combination with a lower marginal loss factor being assumed for the Victorian new entrant OCGTs (based on their likely locations). This is explained more in the following subsection.

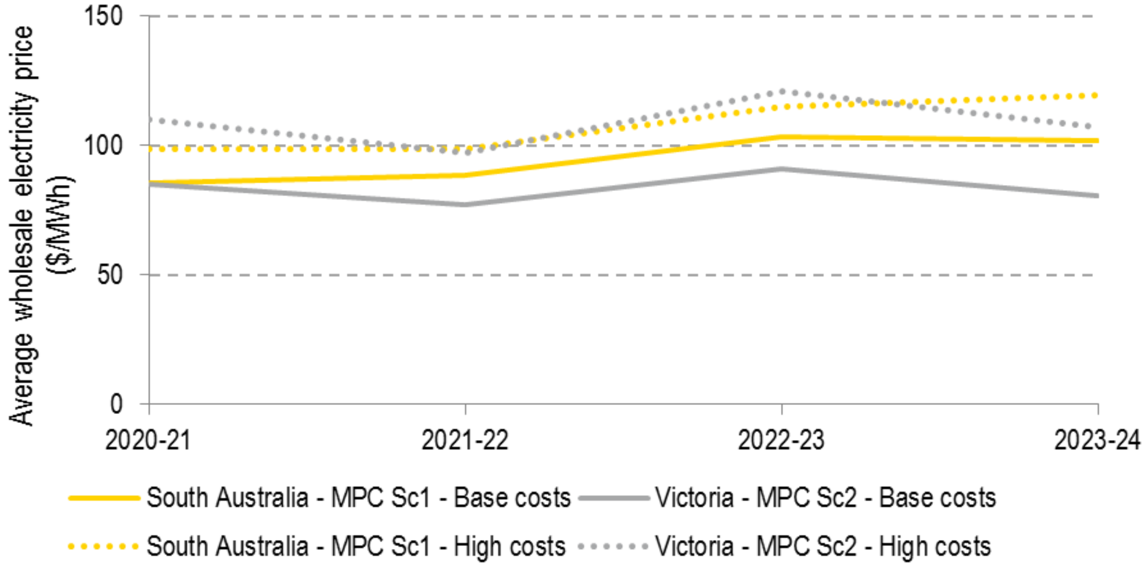
The cap defender sensitivities were found to require a higher MPC relative to the High cost market bidding sensitivity. The cap defender uplift in the theoretical optimal MPC is relatively lower in MPC Scenario 1 compared to MPC Scenario 2. This result in MPC Scenario 1 is despite the OCGT achieving a significantly lower capacity factor (and thus requiring a much higher average price for each MWh of its generation to recover the fixed costs, as demonstrated in Figure 13). This outcome is due to the Nash-equilibrium dynamic bidding selections being more sensitive to the bid of the new entrant OCGT in SA compared to Victoria in combination with there being a higher number of modelled trading intervals with prices between $190/MWh and $270/MWh in Victoria in MPC Scenario 2 compared with SA in MPC Scenario 1. This is explained more in the following subsection.

As described earlier, EY also conducted some modelling of the case of threatening the reliability standard in NSW. This was only conducted with the High cost sensitivity assumptions to explore if NSW would require a higher MPC than Victoria in MPC Scenario 2. However, the modelling shows that partly due to comparative lower amounts of wind and solar capacity in NSW, NSW requires a lower MPC than both SA and Victoria to meet the reliability standard in the cases modelled. As such, MPC Scenarios 1 and 2 are the more critical to analyse for this Review.

Explaining the MPC outcomes

Figure 15 presents the average wholesale pricing outcomes across the modelled scenarios for the Base and High costs sensitivities. Each price series incorporates the theoretical optimal MPC established for the respective scenario and the current CPT level of $212,800 with an APC of $270/MWh.

Figure 15: Annual average wholesale electricity price outcomes for the MPC scenarios (showing the Base and High cost outcomes)



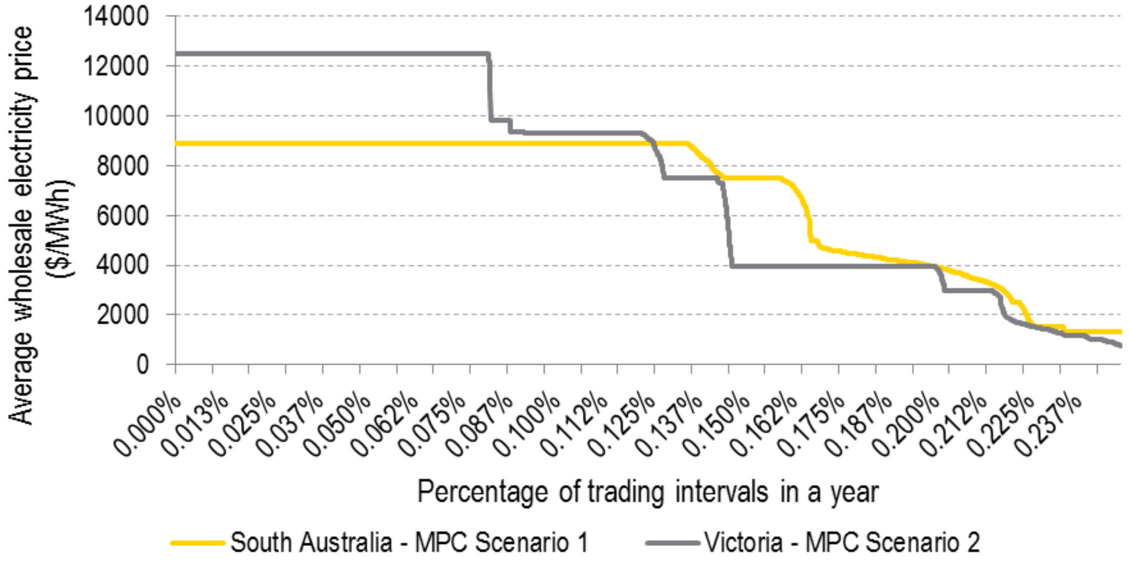
The wholesale market price outcomes for the Base cost sensitivities in the MPC scenarios are consistent with the marginal generator being CCGTs. Average wholesale prices are around the LCOE of CCGTs (as shown in Figure 13) or higher, which is largely due to the thermal capacity being retired early.

The results presented indicate that a much higher MPC is required to restore the reliability standard in Victoria (MPC Scenario 2) compared to SA (MPC Scenario 1) after the assumed retirements have been made in each scenario. The following reasons contribute to this outcome:

- The removal of thermal capacity from SA in MPC Scenario 1 results in the frequency of wholesale market prices above $270/MWh being greater than the equivalent outcome in Victoria for MPC Scenario 2. This is shown in more detail with the figure below.
- The assumed MLF for the new entrant OCGTs in Victoria is 0.96 due to their likely location being in the Latrobe Valley, while the MLF assumed for new entrant OCGTs in SA is 1 since they are likely to be installed near Adelaide.

Figure 16 below shows the top 0.24% of wholesale market price outcomes in 2020-21 for SA and Victoria in MPC Scenarios 1 and 2, respectively, again from the 10% POE demands only. In both scenarios the theoretical optimal MPC for the High costs sensitivity is used (as presented in Table 14).

Figure 16: Top 0.24% of price duration curves for 2020-21 in the MPC scenarios, High costs (10% POE demands only)



The figure shows that for MPC Scenario 1 there is a similar number of trading intervals with prices greater than $9,000/MWh in SA as there are for Victoria in MPC Scenario 2. However, in SA the percentage of trading intervals in the 10% POE demand-years modelled with prices $7,500/MWh or higher is approximately 0.17%, whilst in Victoria the number of trading intervals in which prices exceed $7,500/MWh is approximately 0.15%. The difference in the volume of high-priced trading intervals has an impact on the required MPC, resulting in a higher MPC being required in MPC Scenario 2. Since the marginal SA OCGT can receive $7,500/MWh more frequently than the equivalent OCGT in Victoria it does not need as high an MPC to recover its annualised fixed costs. The OCGT's market revenue in the two scenarios can be approximated by the areas under the two curves in Figure 16[52].

Some reasons why the price outcomes for SA have more frequent very high prices >$7,500/MWh include:

- The SA Government-funded new 250 MW OCGT peaking generator[53] is to be installed for reliability purposes only and is modelled as bidding at the MPC. This capacity can thus set the price at the MPC without USE occurring, increasing the number of MPC-priced periods for a scenario with 0.002% USE. As a result of this, more thermal capacity is removed in SA to threaten the reliability standard than would otherwise have been the case without this OCGT.
- SA also has comparatively more existing peaking OCGT capacity compared to Victoria, which leads to more high-priced periods in the modelling outcomes based on their bidding strategies.

Figure 17 and Figure 18 compare price duration curves from MPC Scenario 1 and MPC Scenario 2, respectively to explain the differences in the high costs (SRMC bidding) and cap defender outcomes presented in Table 14. A single iteration for the 10% POE peak demand is shown as a demonstrative sample from the full data set. The charts focus on the price range $190/MWh - $300/MWh, which is where the price duration curves differ between the SMRC ($190/MWh) bidding and cap defender ($270/MWh bidding) sensitivities. In both sensitivities, the prices are only shown where the OCGT would be dispatched (if available), which for the cap defender sensitivity is only for prices greater

[52] The actual market revenue depends on when the OCGTs generate, as well as being adjusted by the assumed loss factors and including the outcomes in the 50% POE demands. Overall, these market revenues are approximately equal for the two scenarios with the MPC outcomes shown in the chart.

[53] EY notes that the likelihood of this peaking generator being built is less clear since the South Australian Liberal Party won the state election on 17 March 2018. Its exclusion may put upward pressure of the MPC outcomes for MPC Scenario 1 for the reasons outlined in this section. Source: http://www.abc.net.au/news/2017-11-28/sa-liberals-foreshadow-inquiry-into-power-plant-purchase/9200740

than $270/MWh. Both charts have the y-axis starting from $190/MWh, approximately the SRMC of the new entrant OCGTs, so that the area under the curves is indicative of the additional revenue above the SRMC that the OCGT earns in each case. It is this additional revenue that contributes to covering the fixed costs, including capital cost repayments that ultimately contribute to the theoretical optimal MPC calculation. The charts are also shown with the same scaling on the x-axis to allow direct comparison of the magnitude of this additional revenue.

Figure 17: Price duration curve for SA prices between $190/MWh and $300/MWh for a single 10% POE peak demand iteration with the 2014-15 reference year in 2020-21 – MPC Scenario 1

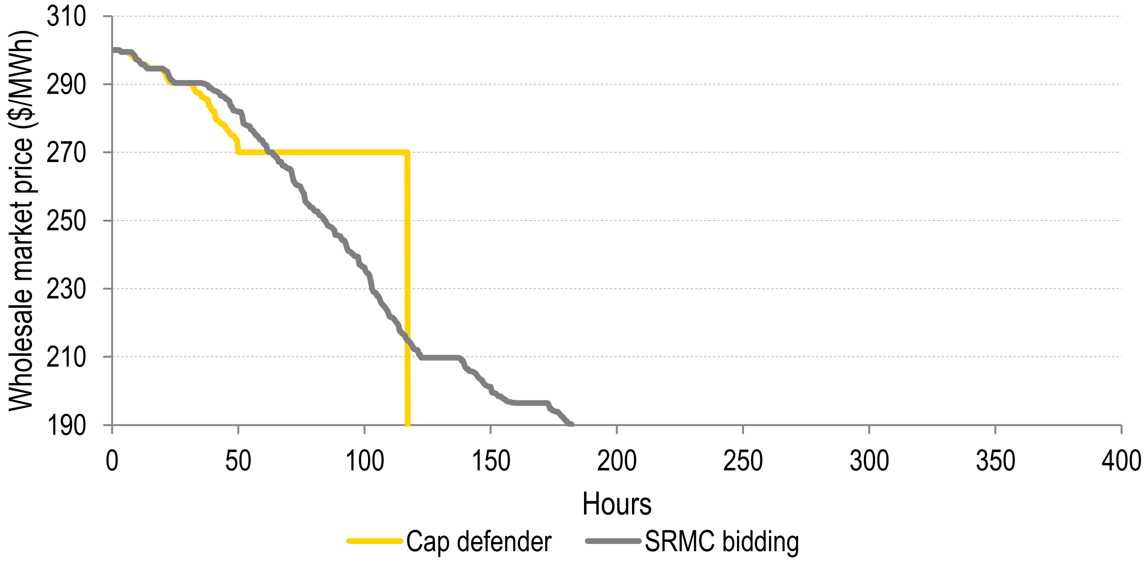
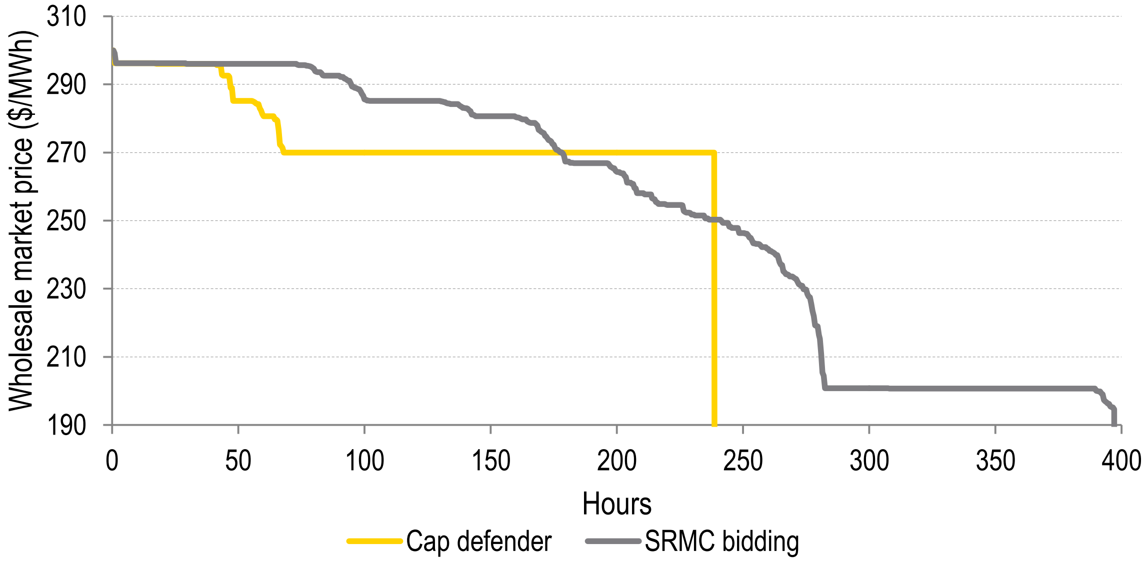


Figure 18: Price duration curve for Victorian prices between $190/MWh and $300/MWh for a single iteration with the 2014-15 reference year in 2020-21 – MPC Scenario 2



In Figure 17 the area under the two curves is similar, indicating a similar amount of additional revenue for the new entrant OCGT. This is congruent with the outcome of a similar theoretical optimal MPC in the SRMC bidding (High costs) and cap defender sensitivities in MPC Scenario 1.

In contrast, Figure 18 shows that the area under the curve is much greater in the SRMC bidding sensitivity compared to the cap defender approach, which is consistent with the result of a much higher theoretical optimal MPC in the cap defender sensitivity in MPC Scenario 2.

In both scenarios the incidence of trading intervals with prices at $270/MWh or greater is higher in the cap defender sensitivity. This is due to the Nash-equilibrium dynamic bid strategy selections. With the OCGT bidding higher in the cap defender sensitivities, portfolios of generators are able to achieve a higher net revenue by offering capacity in higher price bands in some circumstances, including where the OCGT becomes the marginal unit and sets the price at $270/MWh. There are also outcomes where the Nash-equilibrium selections lead to prices that are lower with the cap defender bidding strategy compared to SMRC bidding. However, in MPC Scenario 1 the occurrences of higher prices from bidding differences counteracts the loss in additional revenue for the OCGT from trading intervals of lower prices and for trading intervals where the price is between $190/MWh and $270/MWh (and the OCGT bidding at $270/MWh does not get dispatched). In MPC Scenario 2 this is not the case, with a net loss of additional revenue from the cap defender bidding strategy.

The above analysis illustrates the sensitivity of the theoretical optimal MPC calculation to the trading strategy or the marginal new entrant, level of competition in the market and resulting market prices and market revenue available to the marginal new entrant. In broad terms, a capacity mix with a higher proportion of high cost generation may lead to higher market prices and therefore a lower MPC requirement. Conversely, a market or market regions with a relatively higher proportion of low cost generation may lead to lower market revenue opportunities for the marginal new entrant, and therefore the need for a relatively higher MPC.

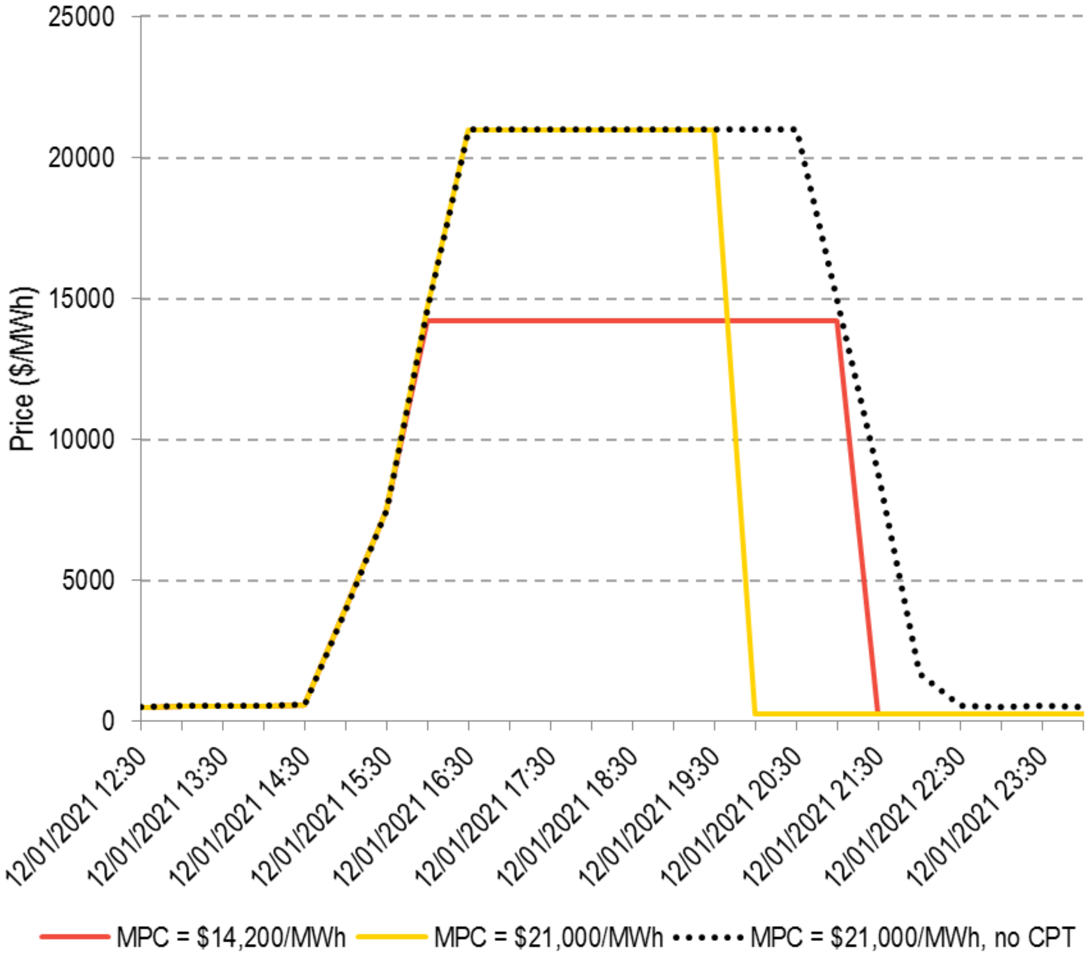
Impact of the CPT on the MPC outcomes

As shown in Figure 14, the 12% WACC and 15-year economic lifetime sensitivities increase the LCOE of an OCGT (with a 6.3% capacity factor) by $36/MWh and $50/MWh, respectively. Whilst this appears relatively small compared to the overall LCOE, which is greater than $400/MWh, this increase in LCOE has a marked impact on the required MPC. This is due to two compounding reasons:

- Out of all periods when the marginal OCGT is generating, there are relatively few with the price at the MPC.
- As the MPC is increased, the CPT is triggered more frequently, resulting in some former MPC periods being capped at the APC instead of the MPC. This reduces the number of periods priced at the MPC.

Figure 19 shows the market price outcomes for Victoria for a single 12-hour period modelled in MPC Scenario 2, under different reliability settings. The pricing outcomes are shown for the cases of the present reliability settings (with the MPC at $14,200/MWh), changing the MPC to $21,000/MWh (as per the MPC outcome for the High cost, Cap defender sensitivity presented in Table 14) and compares these to the case where the CPT is set sufficiently high such that it is not exceeded to trigger an administered pricing period.

Figure 19: Price outcomes for Victoria in a single 12-hour period modelled in MPC Scenario 2, under different reliability settings



The chart shows that when the MPC is increased from $14,200/MWh to $21,000/MWh the CPT is triggered four trading intervals earlier resulting in the price being set at $270/MWh instead of the MPC. In other words, the number of MPC-priced periods is reduced from 11 to 7 during this particular 12-hour period. As a result, the average price received by the marginal OCGT during this particular 12-hour period is only marginally higher in the case with the higher MPC. The average price for three cases is as follows, highlighting the impact of the CPT in this particular 12-hour period:

- Case MPC = $14,200/MWh: **$7,168/MWh** average price.
- Case MPC = $21,000/MWh: **$7,431/MWh** average price.
- Case MPC = $21,000/MWh, no CPT: **$10,224/MWh** average price.

Figure 20 shows the impact of increasing the MPC on the number of MPC-priced periods over all 10% POE demands modelled[54]. The impact on South Australian prices in MPC Scenario 1 and on Victorian prices in MPC Scenario 2 are both shown.

[54] There are 150 years of half-hourly outcomes simulated using 10% POE demands, and 150 years of 50% POE demands. These 150 years are based all combinations of six historical reference years and 25 Monte Carlo iterations of forced outage profiles.

Figure 20: Number of MPC-priced periods in SA for MPC Scenario 1 and Victoria for MPC Scenario 2 (with present settings for the CPT and APC, and for 10% POE demands only)

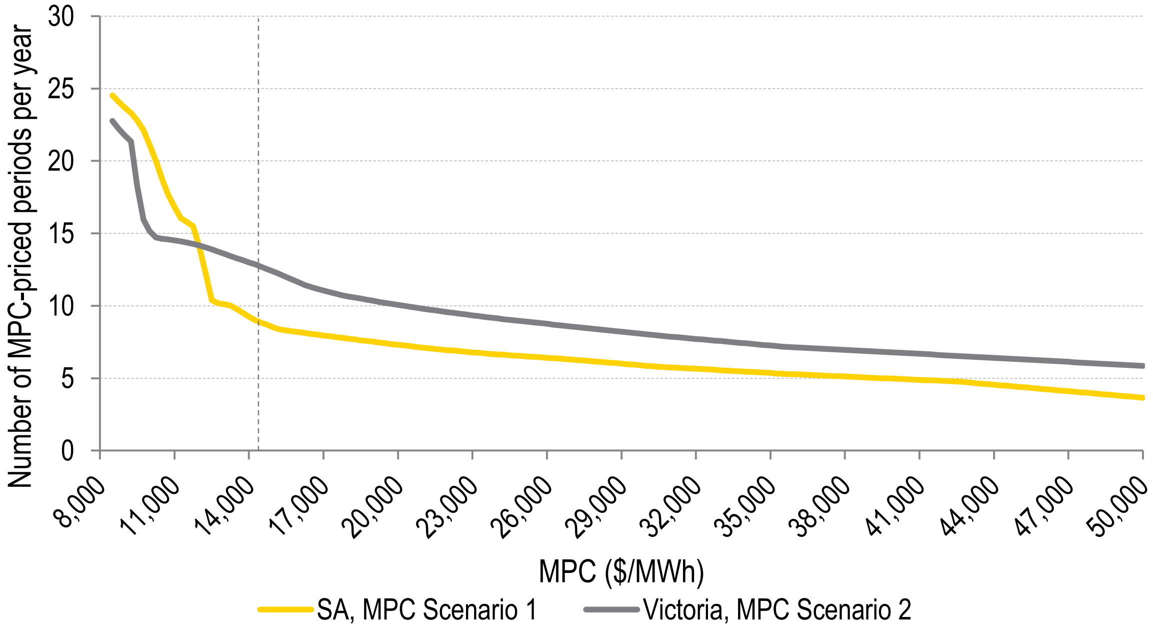


Figure 20 shows that with the present reliability settings (as indicated by the vertical dotted line), including an MPC of $14,200/MWh, the number of MPC-priced periods per year with 0.002% USE is modelled to be around 9 in SA and 12.5 in Victoria. As the MPC is increased beyond this, the number of MPC-priced periods steadily declines due to the CPT being triggered more and more frequently.

If the MPC is decreased, both regions show some sharp increases in the number of MPC-priced periods. This is due to the pricing outcomes based on the bidding strategies modelled by EY, where prices are set between $8,000/MWh and $12,500/MWh. The high-priced periods become capped at the MPC if the MPC is reduced low enough, giving the sharp increases in the number of MPC-priced periods shown in the chart.

SA has more prices in the $8,000/MWh to $12,500/MWh range than Victoria in the modelling; so much so that the region with the highest number of MPC-priced periods switches from Victoria to SA when the MPC is reduced below $12,000/MWh.

The decline in MPC-priced periods with an increasing MPC implies that the MPC becomes less and less efficient at providing a sufficient market signal for investment. The implications of this analysis is that the MPC could be reduced if the CPT (or APC) were increased and that instead of a single large increase in the MPC, there might be an outcome where both the CPT and MPC are increased that is more efficient, and less disruptive to the market overall. The theoretical optimal MPC is analysed for different CPT and APC settings in Section 6.3.

6.3 MPC outcomes with varied APC and CPT settings

The theoretical optimal MPC values presented for the scenarios and sensitivities in Section 6.2 are all based on the maintaining the current settings for the APC and CPT. Both the APC and CPT have different primary objectives to the MPC, as described in Section 2. However, for some of the sensitivities the theoretical optimal MPC was found to be much higher than the current MPC, and rather than changing only the MPC, there might be a better compromise where two or three of the reliability settings could be changed by smaller amounts to achieve the reliability objective, but with a lower impact to the market overall.

To explore the relative options, EY analysed the theoretical optimal MPC for different combinations of the APC and CPT.

6.3.1 APC sensitivities

Table 15 shows the optimal theoretical MPC found for each High cost sensitivity with the APC set to $400/MWh, compared to the current setting of $270/MWh.

Table 15: Optimal theoretical MPCs for each High cost sensitivity with two different APCs

MPC scenario	APC	High	Cap defender	12% WACC	Half lifetime
MPC Scenario 1 (SA)	$270/MWh	$8,900	$9,000	$21,000	>$50,000
	$400/MWh	$8,600	$8,700	$19,000	$50,000
MPC Scenario 2 (Victoria)	$270/MWh	$12,500	$21,000	$37,000	>$50,000
	$400/MWh	$12,000	$20,000	$32,000	>$50,000

The results show that with an MPC around $9,000/MWh increasing the APC to $400/MWh results in decreasing the necessary MPC by only around $300/MWh. However, at higher MPCs the same increase in APC can reduce the required MPC by a larger amount. This is because the CPT is triggered more with a higher MPC (keeping the CPT constant) and as a results there are more periods with the price capped at the APC.

6.3.2 CPT sensitivities

Rather than increasing the APC, Table 16 presents the theoretical optimal MPCs found by increasing the CPT by incremental amounts. In each sensitivity, EY analysed increasing the CPT in increments of 5% of the current setting to provide the Panel a set of alternative combinations for the CPT and MPC to achieve the 0.002% USE reliability objective. EY explored up to a 25% increase in the CPT. In each sensitivity EY only explored increasing CPTs up to the point where the theoretical optimal MPC is found near the current setting, as increasing the CPT beyond this would only decrease the MPC further.

Table 16: Exploring reductions in the theoretical optimal MPCs for each High cost sensitivity with increased CPTs if the MPC is higher than the current setting of $14,200/MWh

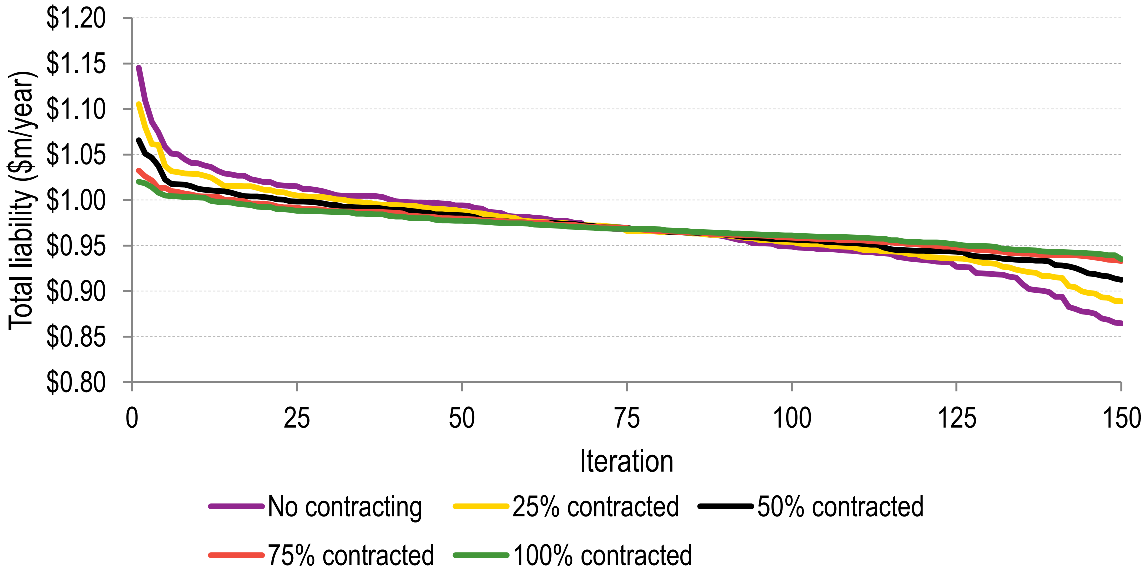
MPC scenario	CPT	Theoretical optimal MPC, with different CPTs			
		High	Cap defender	12% WACC	Half lifetime
MPC Scenario 1 (SA retirements)	Current ($212,800)	$8,900	$9,000	$21,000	>$50,000
	+5%			$17,000	$37,000
	+10%			$15,000	$30,000
	+15%			$14,000	$24,000
	+20%				$22,000
	+25%				$19,000
MPC Scenario 2 (Victoria retirements)	Current ($212,800)	$12,500	$21,000	$37,000	>$50,000
	+5%		$19,000	$30,000	$47,000
	+10%		$17,000	$26,000	$37,000
	+15%		$16,000	$23,000	$33,000
	+20%		$15,000	$21,000	$30,000
	+25%		$14,000	$20,000	$27,000

The results shows that the value of the CPT can have a material impact on the MPC required to achieve the reliability standard, especially for very high MPCs, where the CPT can be triggered more often. For example, with an MPC of $21,000/MWh in MPC Scenario 1, 12% WACC sensitivity, a 5% increase in the CPT from the current level decreases the required MPC by $4,000/MWh, while increasing a further 5% only decreases the MPC by $2,000/MWh and there are further diminishing returns for higher CPTs. Even larger MPC reductions can be realised for a 5% CPT increase in the sensitivities where the MPC is around $40,000-$50,000/MWh.

6.3.3 Impact of CPT on the demand for contracting

This section explores the potential impact on the optimal level of contracting for electricity customers from changing the CPT. Figure 21 presents the net payments/liability by iteration for a 1 MW load after sorting from the highest net liability to the lowest net liability. As with the generator contracting chart (Figure 23), the results are presented for 150 weighted-average results over the equivalent 10% POE and 50% POE cases for each iteration, i.e., each point on the chart represents a pair of 10% POE and 50% POE outcomes.

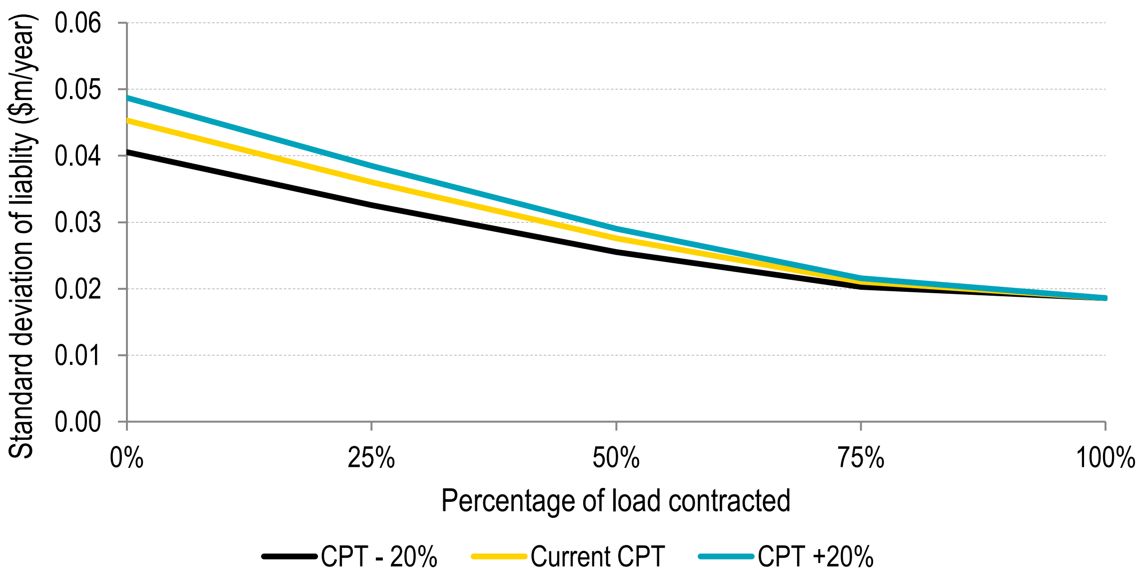
Figure 21: Duration of total net liability by iteration for a 1 MW load with different levels of contracting - MPC Scenario 2, High costs (MPC: $12,500/MWh), 2020-21



The chart shows that the variation in potential liabilities is reduced as the level of contracting increases.

Figure 22 shows the standard deviation of values presented in Figure 21, which is based on the current CPT setting, and compares this to the standard deviations under alternative CPT settings (but keeping the MPC the same at $12,500/MWh).

Figure 22: Standard deviation of liabilities over all iterations for a 1 MW load with different CPTs, MPC Scenario 2, 2020-21



The contracting analysis above shows that the volatility risk with no contracting increases with a higher CPT, but this volatility can be managed to the same level with 100% contracting regardless of the CPT.

6.4 Impact of contracting for OCGTs

For modelling purposes, it is assumed that cap contracts are always valued at the fair price. That is, the cap contract price in this modelling is set such that it equals the weighted average contract settlement over all iterations. Given the methodology used in this report considers the weighted average revenue obtained by the new entrant over all iterations, a cap contract sold at fair value is expected to have an average net payoff of $0 (i.e., the contract value is expected to equal the average contract settlement). Therefore, the level of contracting employed by a potential new entrant is not considered when assessing the economic viability of new entrants, which in turn leads to our estimate of the theoretical optimal MPC using our methodology.

The potential variation in the annual wholesale market revenue a generator might receive can be analysed from EY's modelling from the outcomes for each iteration. This also allows an assessment of the impact of different levels of contracting for a generator in minimising the variation in their potential annual revenues. EY analysed the net revenue outcomes for the new entrant Victorian OCGT (SRMC bidding) in 2020-21 for MPC Scenario 2 across the iterations modelled and applied different levels of contracting with $270/MWh cap contracts (equivalent to $300 cap contracts in nominal terms) valued at the overall fair value. As defined in Section 7.1.1, a generator's net revenue is defined as:

$$\text{Net revenue} = \text{pool revenue} - \text{O\&M costs} - \text{annualised capital cost repayments} - \text{fuel costs} \qquad (2)$$

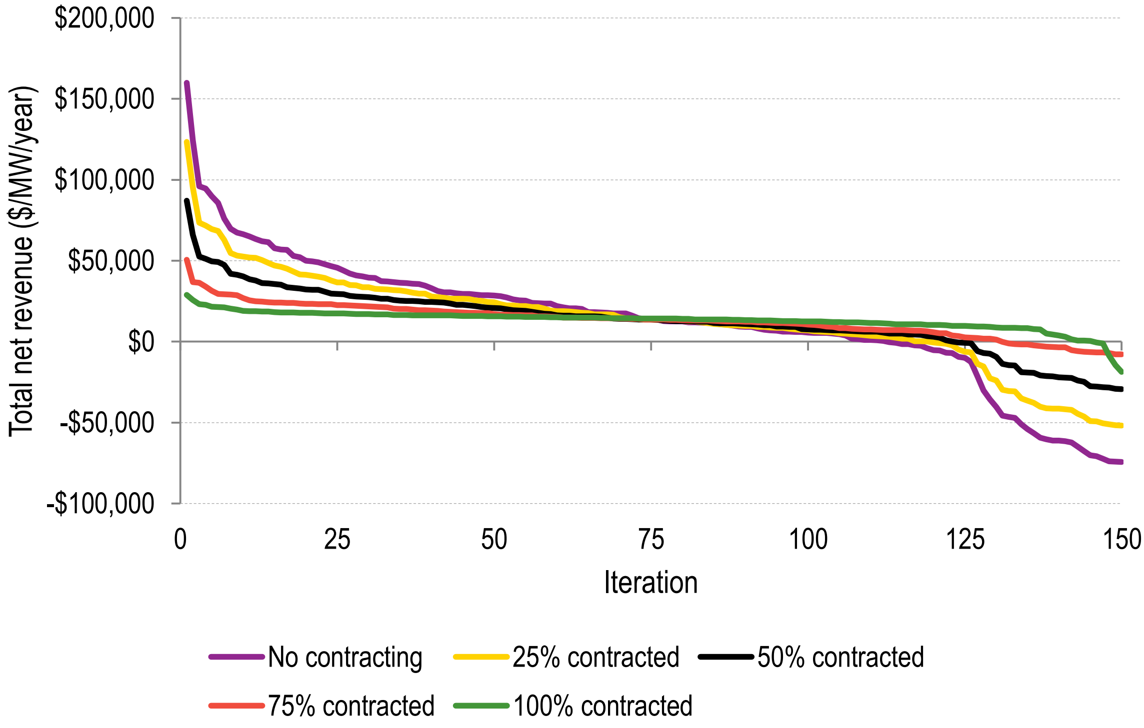
but in this case the calculation includes adding on the contract value and subtracting the contract settlements[55].

Figure 36 presents the net revenue outcomes by iteration (normalised for 1 MW capacity) after sorting from the highest net revenue to the lowest net revenue. The results are presented for 150 weighted-average results over the equivalent[56] 10% POE and 50% POE cases for each iteration, i.e., each point on the chart represents a pair of 10% POE and 50% POE outcomes.

[55] A $270/MWh ($300/MWh nominal) cap contract provides a generator with a fixed payment at the contract value (in this case the fair value) for every trading interval in the year and in return, whenever the wholesale market price is above $270/MWh the generator pays the off-taker the difference between the wholesale market price and $270/MWh. This contract cap can be made for any percentage of the capacity of the generator.

[56] They have the same forced outage profiles.

Figure 23: Duration of total net revenue by iteration for the marginal new entrant OCGT normalised to 1 MW capacity with different levels of contracting - MPC Scenario 2, High costs (MPC: $12,500/MWh), SRMC bidding in Victoria, 2020-21

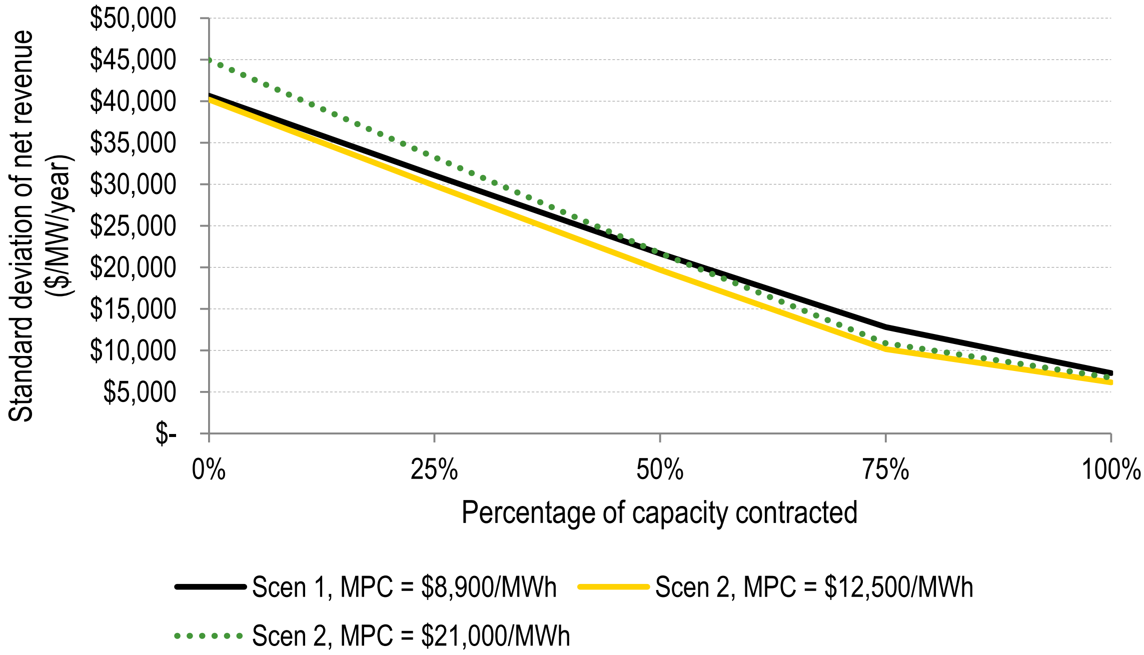


The figure shows that contracting 100% of capacity is the most effective strategy shown to minimise the volatility of total net revenue over the iterations modelled. It also demonstrates how contracting 75% of capacity exposes a unit to some upside risk but minimises some higher downside risks with 100% contracting relating to availability of the generator and the incidence of high and extreme market pricing events.

The negative net revenues in Figure 23 represent iterations where the expected outcome (based on the forced outage profile) is for the OCGT to earn less revenue from the market and contract settlements than its annualised costs. The figure shows that the chance of a negative net revenue is very small with 100% contracting. The expected net revenue is about $15,000 rather than zero because the average net revenue received over all iterations for the installed OCGT in the forecast is $23/MWh in 2020-21 (this balances with a negative net revenue earned in 2021-22).

Figure 24 summarises the curves in Figure 23 with the standard deviation of each curve, and compares this to the values that would be derived from MPC Scenario 1, High sensitivity with an MPC of $8,900/MWh. The MPC Scenario 2 cap defender sensitivity with an MPC of $21,000/MWh is also shown for comparison. The chart shows that in all three cases the level of volatility in the net revenue received by generators in the market decreases with increasing levels of contracting up to 100% of capacity being contracted. The level of the MPC does not change this outcome, in the three cases presented.

Figure 24: Volatility in total net return against contracting position for new entrant OCGT (SRMC bidding) in both MPC Scenarios, plus the cap defender sensitivity in MPC Scenario 2 ($21,000/MWh)



As with a load, contracting at 100% of capacity is shown minimise the risk of volatility for a generator compared to lower levels of contracting. However, in the real world there may be other factors affecting an OCGT's availability for dispatch not modelled, which may lead to a smaller contracting amount being optimal.

6.5 Capacity mix outcomes for the MPC scenarios

Figure 25 and Figure 26 shows the new entrant capacity found to be economically viable by region in MPC Scenario 1 and MPC Scenario 2, respectively, using the Base costs, relative to the existing capacity and retired capacity.

All the new entrant renewable capacity modelled to be economically viable in the Base cost sensitivity of MPC Scenario 1 is installed between 2020-21 and 2022-23. The new 150 MW of CCGT capacity is installed in 2020-21. For the High costs sensitivity of MPC Scenario 1, the new entrant capacity consists solely of 150 MW of OCGT generation installed in 2020-21.

For MPC Scenario 2 with Base costs, new entrant wind and solar PV capacity is found to be economically viable in NSW and SA from 2020-21, but not in Victoria due to the VRET capacity installed in this scenario (the cumulative VRET capacity installed is presented in Figure 27). All the new entrant capacity installed outside of Victoria enters the market in 2020-21. 250 MW of CCGT capacity is installed in Victoria in 2020-21 and an additional 150 MW is installed from 2022-23. For the High cost sensitivity of MPC Scenario 2, no new entrant capacity is forecast to enter the market outside of Victoria. Within Victoria, 280 MW of OCGT capacity is installed in 2020-21 and an additional 120 MW of OCGT in 2022-23.

Figure 25: Existing, retired and new entrant capacity over the Period for MPC Scenario 1 – Base costs

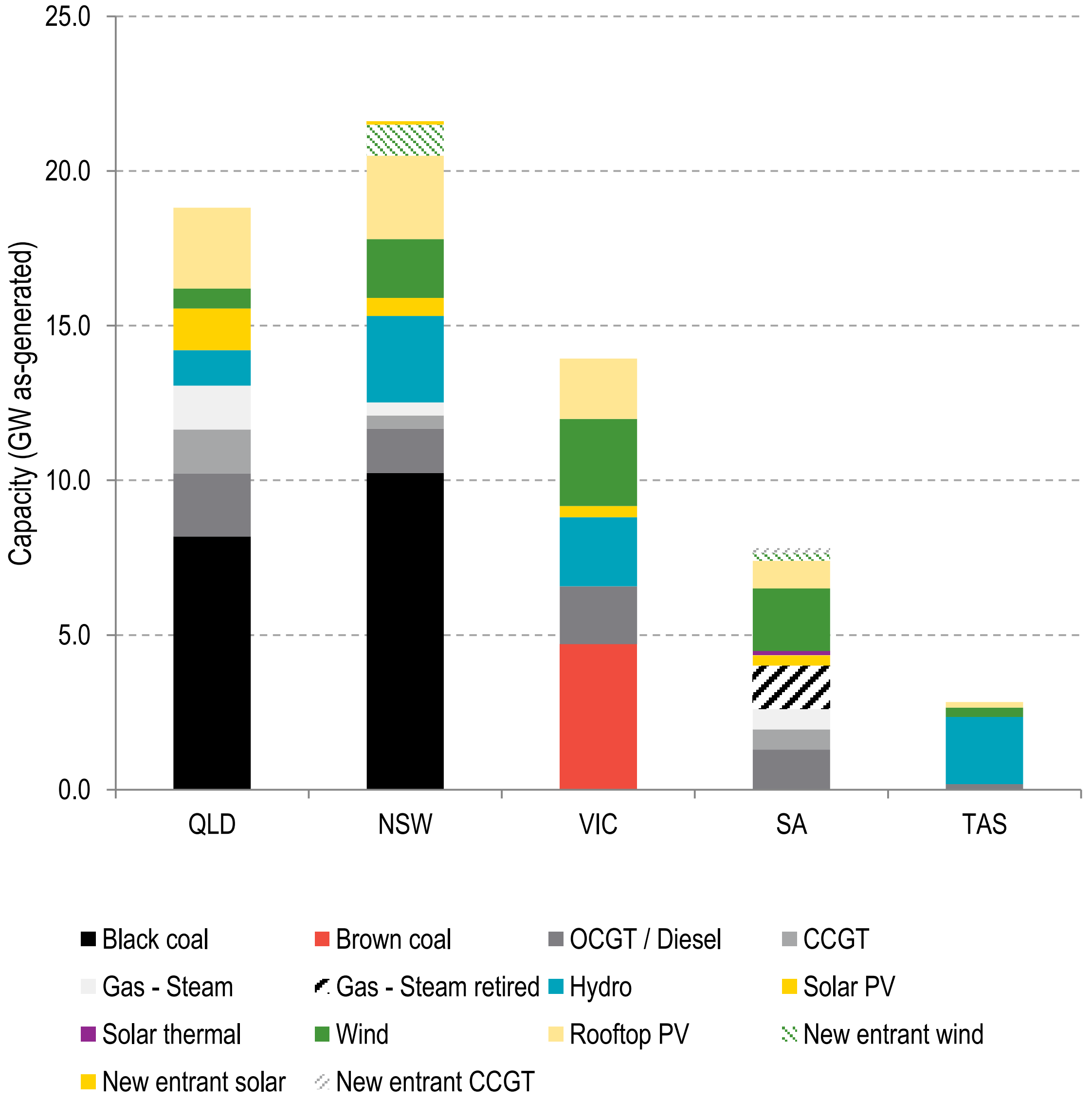


Figure 26: Existing, retired and new entrant capacity over the Period for MPC Scenario 2 – Base costs

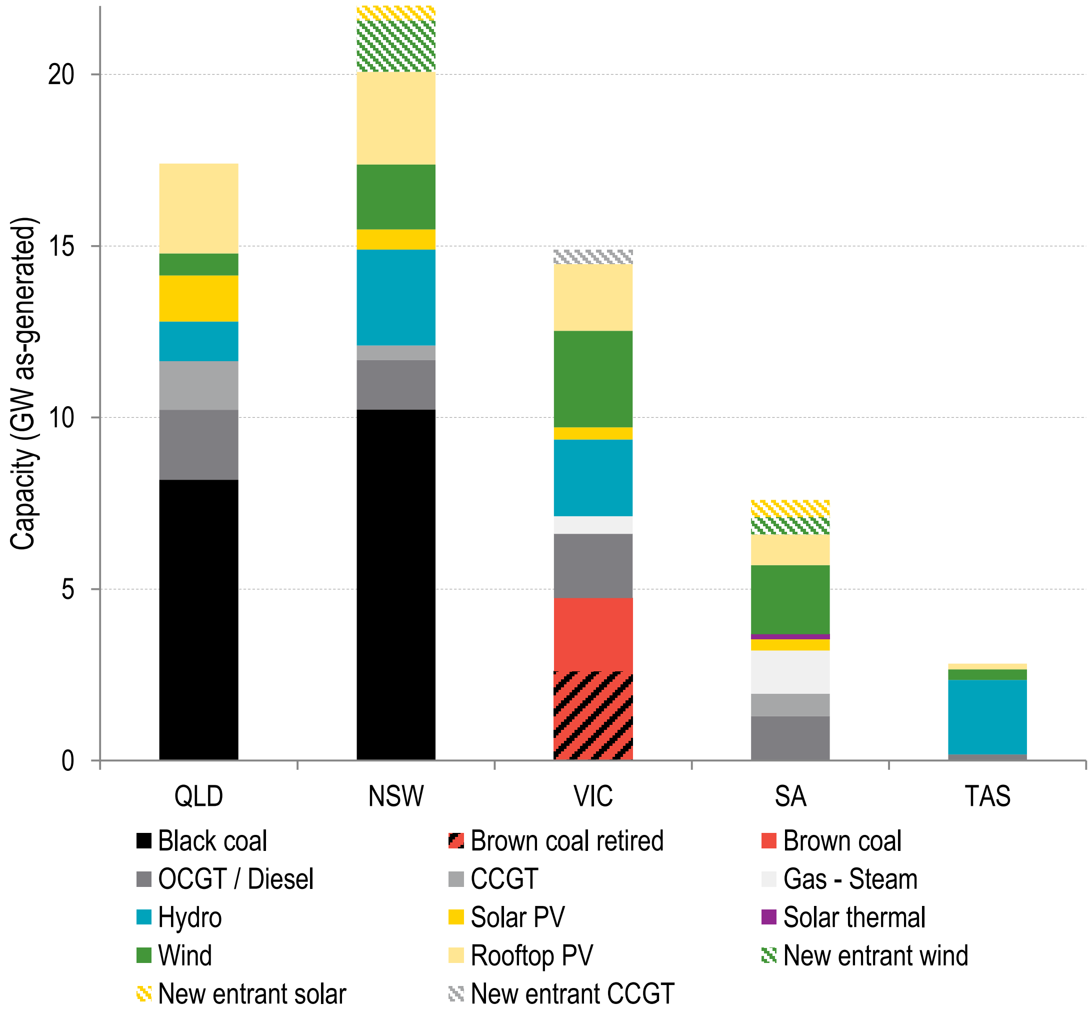
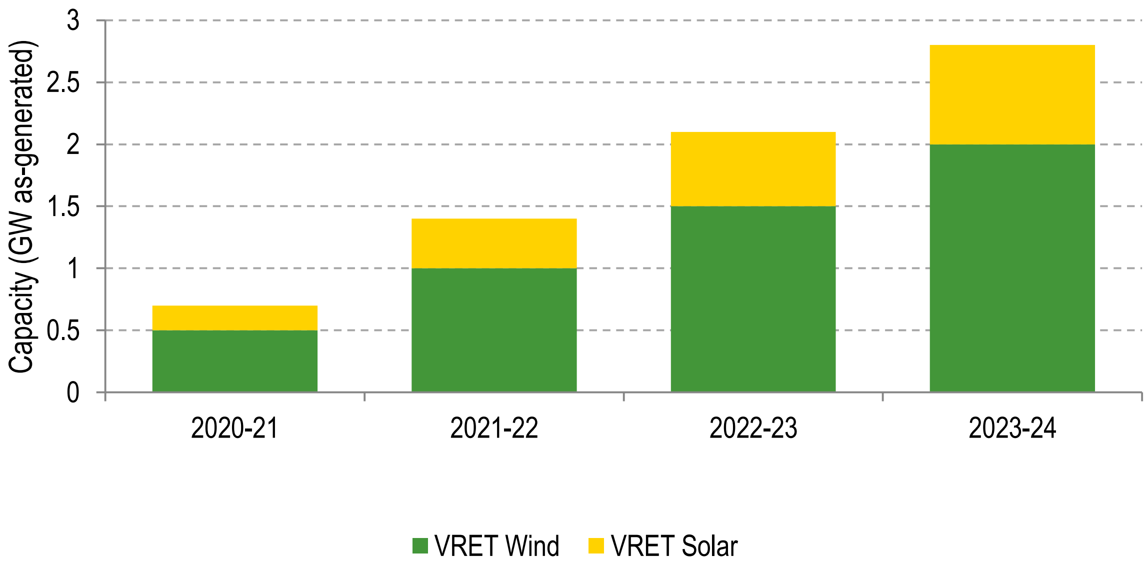


Figure 27: Cumulative new entrant capacity installed to meet the VRET - MPC Scenario 2



While large-scale storage would potentially be capable of reducing USE, with the cost assumptions used, large-scale storage was found to not be able to compete with gas generators in being the marginal generator for setting the theoretical optimal MPC. Using storage for contribution to USE while maximising wholesale market revenue would be difficult to manage in the actual market – it would involve forecasting USE events a few hours ahead to ensure that the storage unit had some charge to be able to fully contribute to those events.

6.6 USE outcomes

As described in the methodology, each MPC scenario is designed to induce USE above the reliability standard of 0.002%. Then, new entrant capacity is installed on an economic basis for the lowest MPC that reduces USE back below 0.002%. Figure 28 and Figure 29 illustrate this process by showing the level of expected USE before and after new entrants are installed in the High cost sensitivities for MPC Scenario 1 and 2, respectively.

Figure 28: Expected USE in SA – MPC Scenario 1 - High costs sensitivity

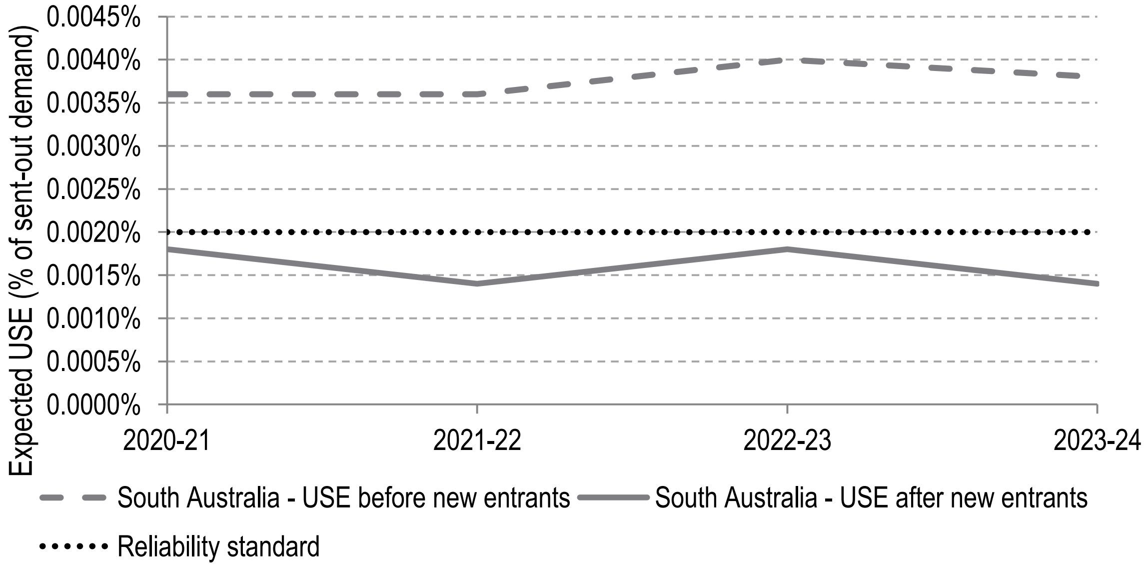
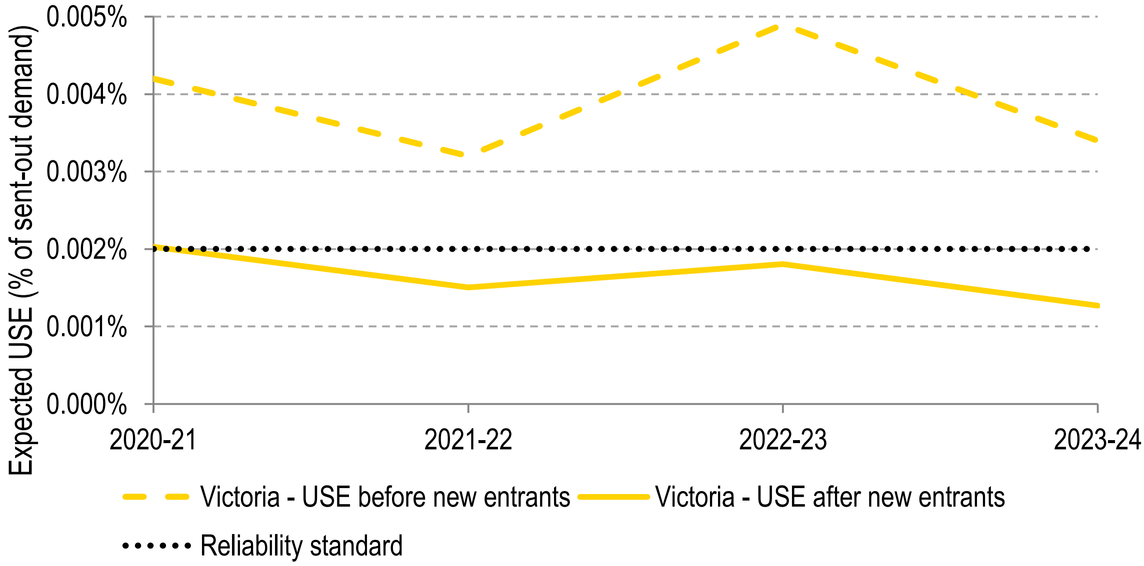


Figure 29: Expected USE in Victoria - MPC Scenario 2 - High costs sensitivity



6.7 MPC outcomes with five-minute settlement

This section outlines the MPC outcomes for MPC Scenario 2, High costs with the five-minute settlement rule change, as introduced in Section 6.1.2. The section provides:

- An overview of the MPC outcomes, including impact of different CPTs
- An explanation of the key MPC outcomes, including the causes of the different outcomes between 30-minute and five-minute settlement in the modelling.

Table 17 presents the theoretical optimal MPC outcomes comparing the 30-minute and five-minute modelling, for different CPT levels. These results are based on keeping the APC at the present value of $270/MWh.

Table 17: MPC outcomes for MPC Scenario 2, High costs, for different CPTs, comparing the 30-minute and five-minute modelling

MPC scenario	CPT	Theoretical optimal MPC, with different CPTs	
		30-minute modelling	Five-minute modelling
MPC Scenario 2 (Victoria retirements)	-10%	**$15,000**	$13,000
	-5%	**$13,000**	$12,100
	Current ($212,800)	**$12,500**	$11,600

The results show that the theoretical optimal MPC in the five-minute modelling is lower than in the 30-minute modelling, but still relatively close to the present MPC at $14,200/MWh. The five-minute modelling produced a very similar overall expected amount of unserved energy (USE) to the 30-minute modelling in MPC Scenario 2. Consistent with this, the five-minute modelling also resulted in a similar number of hours with prices at the MPC. However, due in part to the interactions of generator bidding and ramp rate limitations, the five-minute modelling resulted in a higher incidence of prices between $200/MWh and $250/MWh compared to the 30-minute modelling. These periods provide the new entrant OCGT with higher market revenue compared with the 30-minute modelling, putting downward pressure on the theoretical optimal MPC.

Comparing five-minute and 30-minute demand

The 30-minute demand values modelled by EY are an average of five-minute demands as published by AEMO. Figure 30 shows a typical day of demand in Victoria using historical data, comparing the five-minute demand to the thirty-minute average demand, while Figure 31 shows the difference between those values every five minutes. As demonstrated in Figure 31, the difference in the five-minute demand from the representative 30-minute demand varies greatly and is up to 150 MW or more on a few occasions in this one sample day. This gives an indication of the level of differences in five-minute modelling versus 30-minute modelling. Differences in large-scale wind and solar generation are in addition to the demand differences.

Figure 30: Historical operational Victorian demand 5th of January 2015[57]

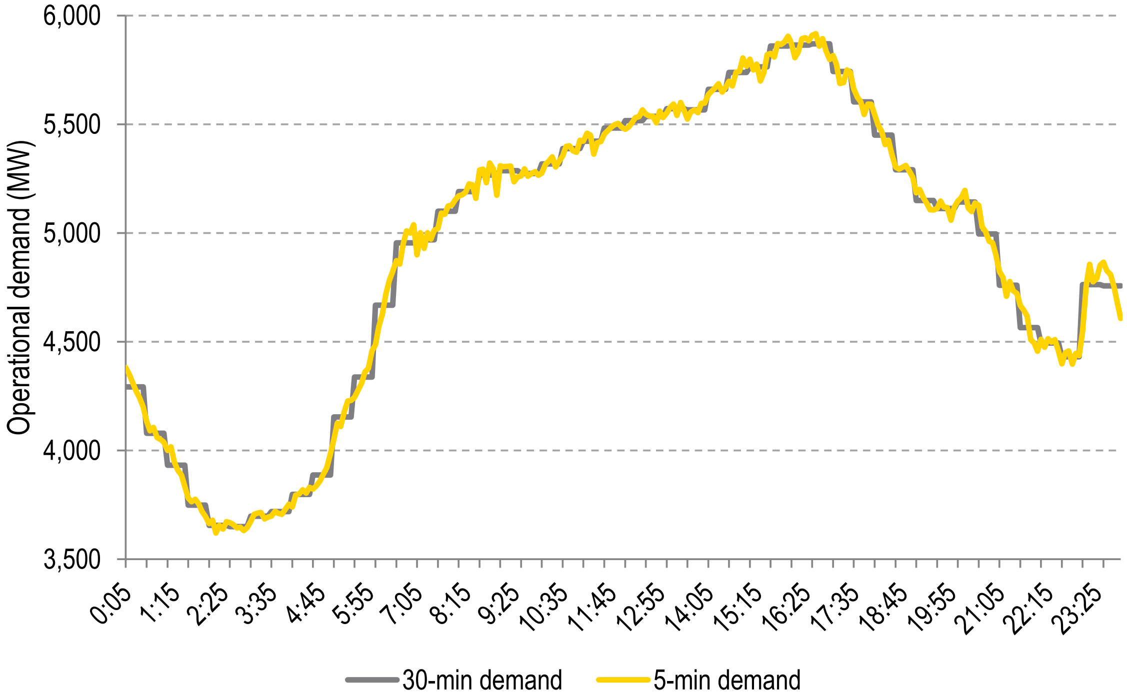


Figure 31: Difference between historical five-minute demand and 30-minute demand on a five-minute basis, 5th of January 2015

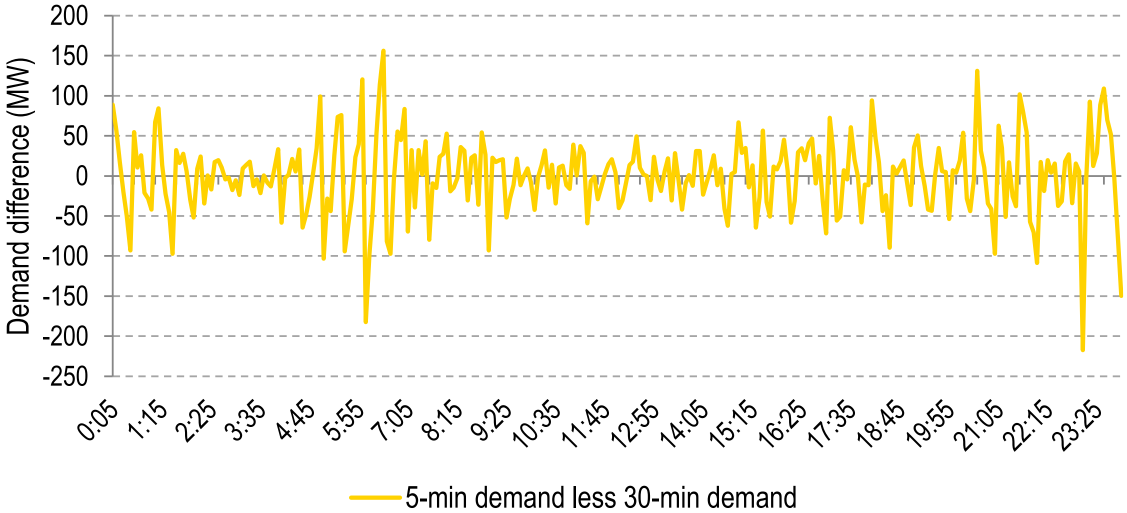
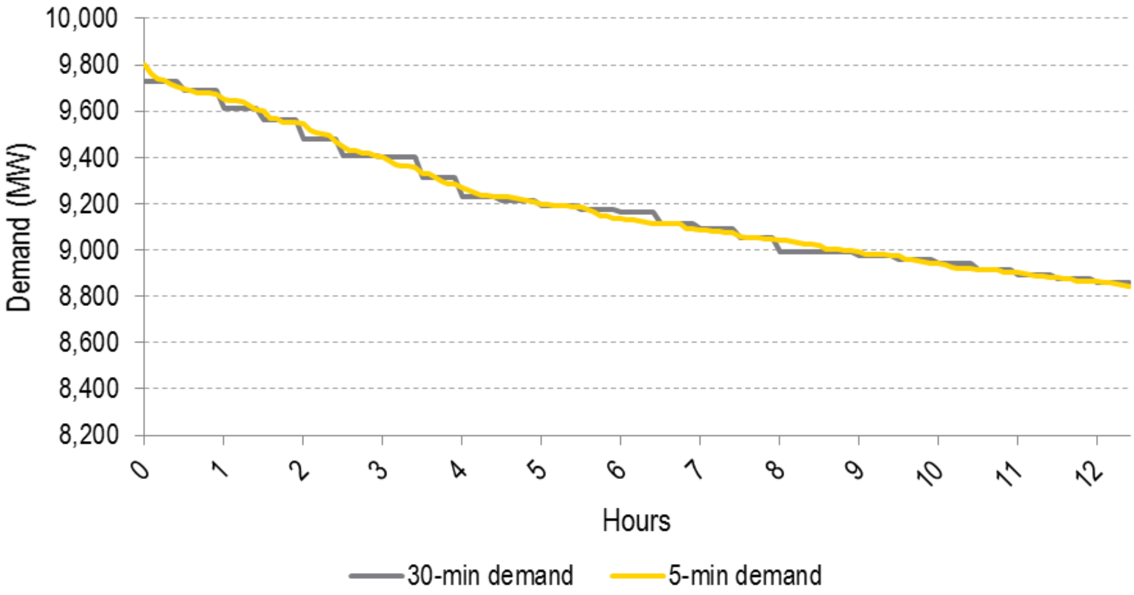


Figure 32 shows the highest 12.5 hours (150 five-minute intervals) operational demand in Victoria modelled for 2021-22. The diagram shows that EY's five-minute modelling methodology has produced a similar duration curve with a slightly higher peak, as intended.

[57] Source: AEMO market data

Figure 32: Highest 12.5 hours of modelled 30-minute and five-minute demand



Explaining the MPC outcomes

Figure 33, Figure 34 and Figure 35 show the price duration curve outcomes comparing the 30-minute and five-minute modelling, for all prices greater than the SRMC of the marginal new entrant OCGT ($190/MWh). Only the outcomes for the 2014-15 reference year, with 10% POE peak demand are shown as a demonstrative example. The duration curves are split into the three charts for clarity. Figure 33 shows the hours of MPC, and indicates a similar level of USE in the two modelled scenarios.

Figure 33: Highest 7 hours of modelled Victorian prices from the 2014-15 reference year, 10% POE peak demand, comparing the 30-minute and 5-minute scenarios

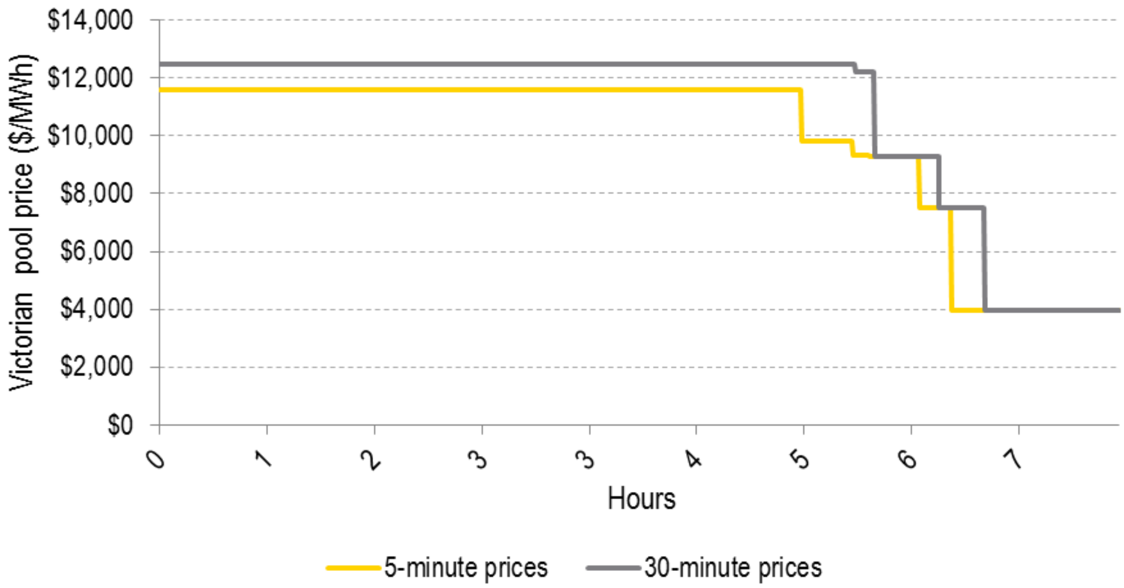


Figure 34: From the 7th highest hour to the 10th hour of highest prices in Victoria from the 2014-15 reference year from the 30-minute and 5-minute modelling

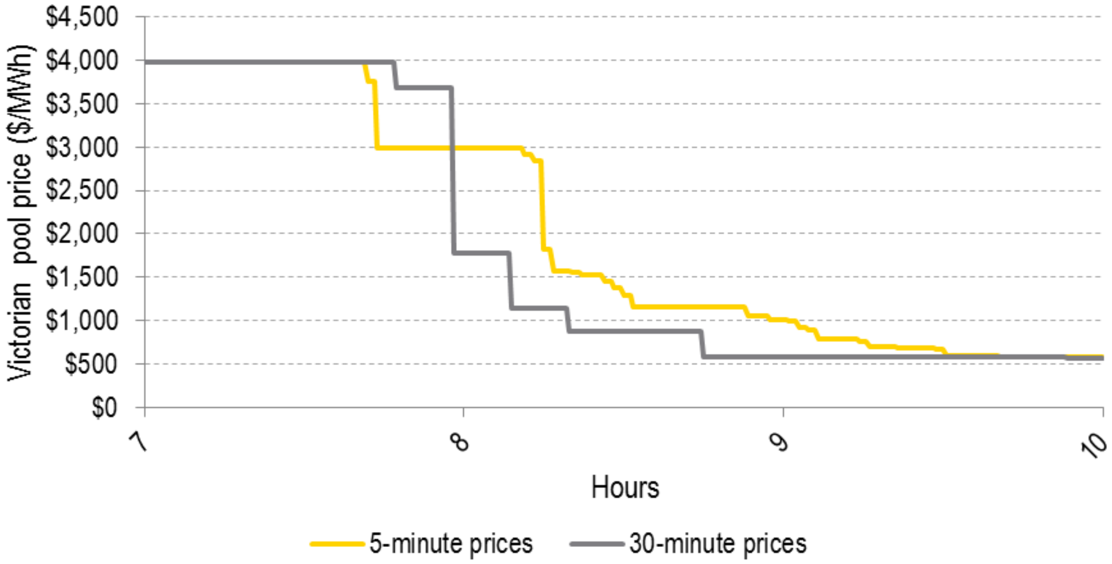
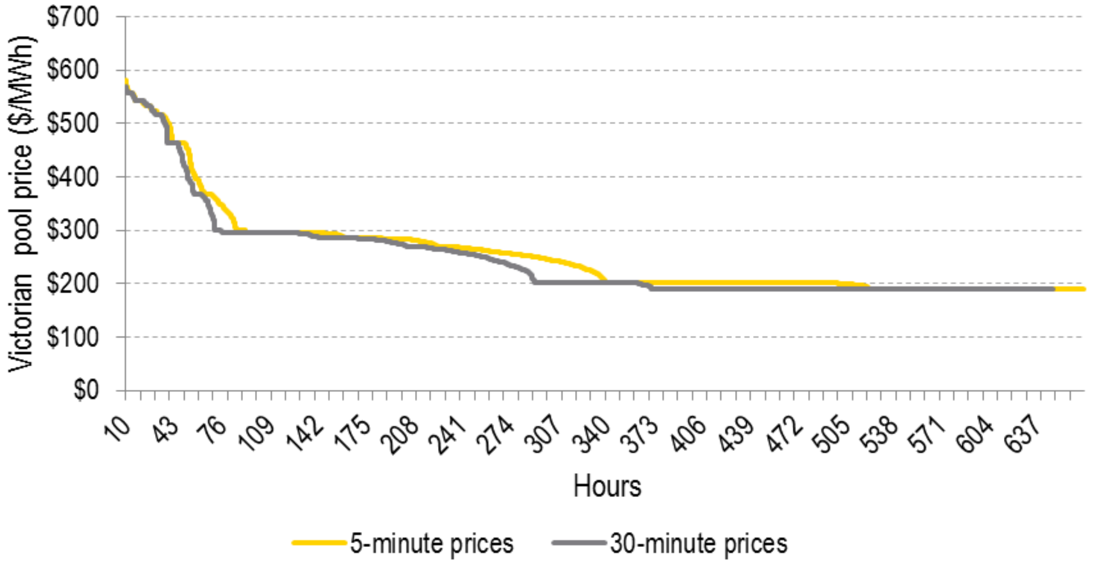


Figure 35: From the 10th hour to $190/MWh for prices in Victoria from the 2014-15 reference year from the 30-minute and five-minute scenarios



The price duration curves displayed above show that the wholesale market modelling delivers very similar market price outcomes between the 30-minute and five-minute trading interval modelling. Considering the scale differences between the charts, the five-minute scenario results in tens more hours of higher prices between $190/MWh and $500/MWh as well as higher prices between $500/MWh and $3,000/MWh.

Limitations

Whilst there is a substantial amount of detail covered in the 30-minute and five-minute modelling, there are many uncertainties in the assumptions used and limitations in the modelling approach. One of the most important aspects in the modelling that influences the reliability setting outcomes is the wholesale market pricing outcomes. Just focussing on this aspect, the following lists some of the uncertainties and limitations in the price outcomes.

- ► The portfolios of generators and the level of contracting is not known for the RSSR period. Assumptions around these have an influence on pricing outcomes.

- In the dynamic bidding process, three fixed bidding strategies are used for each generator in each region. Whilst these strategies have been designed to cover a wide range of bidding behaviour, within the bounds of the operational limits of each power station, there are infinite bidding strategies that could be used in reality.
- The dynamic bidding approach selects the Nash-equilibrium bidding strategy for each portfolio for a modelling period (30 minutes or five minutes) based on the conditions of that period only. In reality, it is likely that forward-looking projections (to 30 minutes ahead or longer) would be taken into account in selecting the best bidding strategy.

Along with the above limitations, based on the 2016 NTNDP data set, EY has only used Frame OCGTs for the new entrant OCGT technology. More flexible OCGT technologies, such as aero-derivative and reciprocating engines may have a comparative advantage with five-minute settlement compared to 30-minute settlement. However, these technologies have a higher capital cost, offset partly by a higher efficiency, making it uncertain as to whether they would require a higher or lower MPC than Frame OCGTs.

Conclusions

The outcomes presented show that moving to five-minute settlement may not make a substantial impact on the theoretical optimal reliability settings within the bounds of uncertainty associated with the assumptions and modelling limitations.

6.8 Assessment of impacts relating to Panel's criteria

6.8.1 General impact of a change in the reliability settings

Table 18 provides a general qualitative assessment of the potential impacts on the market from changing each of the reliability settings, as per the Panel's assessment criteria.

Table 18: Market parameters influence on market dynamics

	MPC	CPT	APC
Spot price	An increase in the MPC is likely to result in an increase in the volatility of prices and the annual average price.	The CPT has a positive correlation with the annual average spot price. A higher CPT means that imposition of an APC will be less frequent, likely increasing the annual average spot price.	The APC has a positive correlation with the annual average spot price. A higher APC means that when the CPT is exceeded a higher APC will be imposed, resulting in a higher settlement at that time.
NEM investment	An increase in the MPC increases the financial incentive for more generation and demand-side response investment.	With an increase in the CPT, there is a subsequent increase in the financial incentive for more supply-side investment. However, a higher CPT may increase prudential requirements and increase customer exposure, increasing barriers to entry.	Increasing the APC would incentivise NEM generation investment through higher average market prices, however may increase risk to customers presenting a barrier to entry.
System reliability	A higher MPC tends to incentivise more supply, and potentially increased demand side participation. Both of these would improve system reliability.	All else being equal an increase in CPT delivers potential for higher market prices and incentives for additional capacity, improving system reliability	A higher APC would tend to improve the economic performance of a generator, incentivising additional capacity, thus improving system reliability.
Market participants	An increase in the MPC would impact uncontracted participants through increased price risk. To a point, a higher MPC may stimulate contracting liquidity between market participants. However, an extreme MPC may reduce propensity to contract resulting in increased market risk.	The CPT will influence market participant risk exposure and may influence prudential settings.	A higher APC may increase customer price risk, potentially influencing contracting markets (cap contract strike price for example).

EY notes that a decrease in the MPC will not necessarily lead to a decrease in annual average wholesale electricity market prices or costs for consumers in the long term if it leads to a change in the installed generator capacity mix. The impact of reducing the MPC from the present \$14,200/MWh to \$12,500/MWh was modelled for the Base scenarios by keeping the installed capacity the same and only changing the MPC. The impact on time-weighted annual average regional wholesale market price over the Period was estimated to be less than \$0.25/MWh under all scenarios, and in most cases in the order of \$0.01-0.02/MWh.

6.8.2 Implications from changing the MPC versus the CPT

The MPC outcomes presented in Sections 6.3.2 and 6.7 include a range of options for varying the MPC in isolation of the other reliability settings, as well as options to vary both the MPC and CPT.

In the case of a decrease in the MPC, market price volatility may initially decrease making settlements less risky. This may lead to a reduction in contracting, which would increase market exposure for generators and encourage them to bid more strategically to increase prices when the price is below the MPC. While the net impact on average prices may be increased or decreased, the market price for periods of USE would be reduced, giving a weaker market signal for a marginal new entrant to be installed to maintain the reliability standard. If this leads to a new entrant project being delayed or deferred indefinitely, the impact of decreasing the MPC may lead to higher average wholesale market prices.

In the case of a large increase in the MPC, this may increase market price volatility (as distinct from generally high market prices). A more volatile market is inherently more risky as the opportunity to extract value is derived from shorter periods of time. The risk of not generating in the short period of time in which significant value is received from the market also makes contracting a higher risk position as the generator has fewer opportunities to recover contract settlements from generating during high price periods. For this reason anecdotal evidence suggests that above a threshold, highly volatile markets result in a reduction in propensity for suppliers to contract as the risk of failing to physically hedge the contractual position becomes too high.

Rather than a large increase in the MPC, another option is a moderate increase in both the MPC and CPT. The purpose of the CPT is described as the setting that limits participants' financial exposure to the wholesale spot market during prolonged periods of high prices[58]. The CPT is therefore intended to protect electricity consumers from exposure to high wholesale spot market prices. The CPT may also influence the propensity for contracting between retailers and generators. If the CPT is very low, the financial exposure to the spot market would be commensurately low and therefore the need to secure risk management instruments would be lessened. Conversely, if the CPT is relatively high then risk of exposure to prolonged high prices increases, driving an increase in propensity to contract.

Increasing the CPT will increase the consumer risk to prolonged high prices but allow for a reduced MPC as presented in Section 6.3.2. However, there are secondary considerations relating to increasing the CPT from its current setting. A material matter is the setting of prudential requirements for market customers. Increasing the CPT may lead to a call for increasing credit support under the participant prudential settings. This may place customers under financial pressure, increase barriers to entry and reduce efficiency in the market.

On balance the quantitative and qualitative assessment of the CPT setting suggests that:

- Keeping the CPT the same would maintain the current financial risk levels of an uncontracted load to prolonged high market prices, but the modelling outcomes in some sensitivities suggest a material increase in the MPC requirement, increasing the risk of market price volatility.
- Increasing the CPT would soften the need for an increase in the MPC and, if the ratio between the CPT and MPC is kept the same, market price volatility would also be expected to stay at similar levels. However increasing the CPT could trigger an increase in credit support placing a financial burden on market customers.
- Reducing the CPT would increase the risk to marginal generators of not being able to achieve required returns from the wholesale market. A very low CPT may reduce risk to customers reducing the propensity to contract. In combination these factors may result in insufficient incentive for investment in the marginal capacity required to achieve the reliability standard.

[58] Reliability Panel AEMC Issues Paper, Reliability Standard and Settings Review 2018, 6 June 2017

6.9 Limitations to forecasting the theoretical optimal MPC

6.9.1 Long-term generator profitability assessment

New entrant generator investment decisions are typically made based on a market assessment over the economic lifetime of the generator. EY has analysed the economic lifetime revenue for the Base Scenario for a wide range of capacity development options as outlined above. For this Review a full economic lifetime assessment of new entrant capacity options is out of scope in all other scenarios, but also deemed unnecessary for the following reasons:

- New entrant renewable projects built up to 2020 are driven by the LRET where the available additional subsidy mitigates the development risk at least to the period ending the year 2030, reducing the need to determine their long-term economic viability.
- New entrant generator technologies installed in the Period largely based on MPC revenue are assessed based on their annualised net revenue. Since this Review has only determined the MPC for the four years in the Period, the MPC and associated revenue of these new entrants in future years was not up for assessment and was assumed to continue in a similar fashion to that modelled in the Period. Thus if a new entrant makes a return on investment during its years of operation in the Period, it was assumed to continue to make a return in future years, subject to the uncertainty around the MPC and other market dynamics in those later years.

In addition to the above, EY's generator profitability assessment was based on the modelled commercial signals only, and does not explicitly take into account the impact of uncertainty in investment decisions (such as due to the present uncertainty surrounding emissions reduction policies in the NEM). However, uncertainty was captured through the choice of the weighted-average cost of capital (WACC), which is a key assumption that impacts on the annualised repayments on capital costs modelled in EY's generator profitability assessment/net revenue.

6.9.2 Portfolio behaviour limitations

For this Review, EY's modelling methodology was underpinned by generator bidding profiles based only on wholesale market operations and outcomes. Specifically, the bidding profiles were based on observed historical behaviour in the wholesale market, which implicitly captures portfolio revenue-maximising behaviour and the impact of contracting positions.

A large number of additional assumptions have been made in order to implement dynamic bidding. Dynamic bidding involves making many assumptions based on available data to allow the Nash equilibrium to find reasonable solutions for how bidding could occur in the market. The MPC scenarios, in particular, feature significant changes to capacity and explore USE levels near 0.002%, which is a very different situation to recent history in the NEM. In order to capture likely changes in bidding strategies in the modelling and how those strategies might change between half-hours, EY has employed a dynamic bidding approach. This approach is very similar to what was applied in the 2014 Review.

To capture different portfolio behaviour, a series of bidding strategies were utilised. These strategies attempt to capture portfolio behaviour with respect to changes in running costs and market dynamics. The limitations associated with this methodology are that without transparency regarding actual portfolio strategies and respective contracting positions, it is difficult to forecast market portfolio behaviours.

Furthermore, the dynamic bidding approach selects the Nash-equilibrium bidding strategy for each portfolio for a modelling period (30 minutes or five minutes) based on the conditions of that period only. In reality, it is likely that forward-looking projections (to 30 minutes ahead or longer) would be taken into account in selecting the best bidding strategy.

6.9.3 Forecasting the electricity market

Given a set of assumptions for a scenario, there are several aspects of modelling the future electricity market that are uncertain. Any assumption that directly influences the economic performance of any unit in the modelling, existing or prospective, has potential to influence the MPC. These include fuel cost, capital cost, WACC, plant parameters etc. As the economic performance of a generator may be better or worse based on these assumptions, it may subsequently alter the required MPC to financially incentivise the achievement of the reliability standard.

6.9.4 Policy changes

This Review is taking place at a time when the AEMC is undertaking several rule-change assessments and other changes are being considered in the market, such as the National Energy Guarantee (NEG).

The present proposed design of the NEG includes applying a mechanism to meet a reliability requirement that "builds on existing NEM and financial market arrangements that facilitate investment in capacity"[59]. On the basis that the present reliability framework will continue functioning as it currently does, including a current reliability standard of 0.002%, implementation of the NEG would not alter the theoretical optimal MPC outcomes if applied to any of the scenarios modelled in this Review.

6.10 Conclusion

A number of inferences can be made from the results presented for the MPC scenarios:

- Under the modelled scenarios and technical assumptions, in the high cost sensitivity it has been found that OCGT (or potentially reciprocating engines with a similar cost) is the marginal technology to meet the reliability standard.
- The modelling shows that while wind and solar PV technologies energy is relatively low cost and costs are continuing to fall, they are not able to reduce USE to below the reliability standard in the MPC scenarios modelled due to their variable generation. Based on the assumptions used, battery storage was found to be able to reduce USE below the reliability standard but is still more expensive than OCGTs (and thus would require a higher MPC). There is insufficient information on the cost of implementing new demand side participation or pumped storage projects to comment on the potential for these types of projects to become a marginal source of reducing USE to within the reliability standard. These technology-options are also highly project-specific and may not be modelled in a generalised way to meet the reliability standard.
- Assuming a secure supply of gas and long term energy off-take expectations, CCGT units are very economic options for addressing USE associated with base load retirements.
- In the modelling conducted for the Period, Victoria requires a higher MPC than SA to maintain the reliability standard across all sensitivities. This is due to the pricing outcomes from the bidding strategies employed in the modelling, where SA has more prices between $7,500/MWh and the MPC than Victoria.
- From all the MPC scenarios and sensitivities modelled that excluded CCGTs as an option, the highest theoretical optimal MPC is found to be in excess of $50,000/MWh, if the CPT is kept the same.
- Discounting the most extreme sensitivities with very high cost and very low cost assumptions, a theoretical optimal MPC in the order of $12,500/MWh or higher would appear to be sufficient to incentivise marginal entrant capacity to achieve the reliability standard.

[59] Energy Security Board National Energy Guarantee -Consultation Paper: http://www.coagenergycouncil.gov.au/publications/energy-security-board-national-energy-guarantee-consultation-paper

- Taking into account the modelling limitations listed in Section 0 and other factors that must be considered in real-world investment and project delivery decision making, EY considers these outcomes to be in line with the present MPC setting of $14,200/MWh. The theoretical optimal MPC calculation is a function of a significant number of modelling data inputs. It is an inherently probabilistic outcome based on weighting of Monte Carlo simulation of generator availability, multiple peak demand projections, multiple weather reference year data sets and portfolio Nash equilibrium bidding behaviours. There are a number of scenarios in which the theoretical optimal MPC is estimated to be significantly higher than the present MPC, including that in which the cap defender approach is applied, as was the case in previous RSSR studies.
- EY notes that a decrease in the MPC will not necessarily lead to a decrease in annual average wholesale electricity market prices or costs for consumers in the long term if it leads to a change in the installed generator capacity mix. The impact of reducing the MPC from the present $14,200/MWh to $12,500/MWh was modelled for the Base scenarios by keeping the installed capacity the same and only changing the MPC. The impact on time-weighted annual average regional wholesale market price over the Period was estimated to be less than $0.25/MWh under all scenarios, and in most cases in the order of $0.01-0.02/MWh.
- Keeping the CPT the same, increasing the APC only has a moderate impact on reducing the theoretical optimal MPC, depending on the magnitude of the MPC.
- Whilst even higher cost sensitivities were modelled, EY believes that the high cost sensitivity modelled reflects a plausible combination of cost assumptions that may occur within reasonable bounds of uncertainty. The modelling suggests that the present MPC settings are adequate to incentivise investment in new entrant capacity to meet the reliability standard.

7 Detailed methodology for the market modelling

This section describes the detailed methodology to be applied in this Review for modelling and forecasting the NEM. Section 7.1 describes how the evolution of the NEM is forecast using several iterations of market simulations. Section 7.2 describes the methodology employed for each market simulation. Section 7.3 describes the methodology employed to investigate the potential impacts on the reliability standards of moving to five minute dispatch and settlements. The descriptions include the reasoning behind the approach taken for each part.

7.1 Forecasting the electricity market – an iterative approach

The term "market modelling" in this Report refers to the process of forecasting the expected generation mix and wholesale prices in the electricity market, as an outcome of selected input assumptions. The market modelling procedure employed by EY involves running many market simulations with the 2-4-C® model to arrive at a final set of outcomes. The process involves the following steps:

1. **Determine a set of input assumptions.** These assumptions include policy drivers such as the LRET, the reliability settings and other market rules as well as an electricity demand forecast, generator costs and technical parameters and many others as described in Section 7.2.

2. **Set up an initial market simulation.** Using all the assumptions, conduct an initial time-sequential half-hourly market simulation over the Period. Assess the annual net revenues of each generator using the method of calculating net revenue described below, and determine if any new entrants or retirements would be commercially driven for net revenue outcomes outside a tolerance range.

3. **Iterative modelling to achieve final simulation.** Adjust the new entrants and retirements; re-simulate several times until all generators have a net revenue within a specified tolerance. EY considers that when wind and solar PV generators reach their project lifetime, the sites are likely to be upgraded to new wind and solar PV generators. As such EY does not consider retirements of wind and solar PV generators in this iterative process.

7.1.1 Calculating a generator's net revenue

All capacity developments made within the market modelling procedure are determined by assessments of the net-revenue of generators modelled within 2-4-C®. A generator's net revenue is calculated for any particular year using the equation (3) below.

$$\text{Net revenue} = \text{pool revenue} - \text{O\&M costs} - \text{annualised capital cost repayments} - \text{fuel costs} \quad (3)$$

where

Pool revenue is the total annual wholesale market revenue earned over each trading interval in the year. In the modelling, this is the sum-product of the modelled dispatched generation and the wholesale market price over all trading intervals, multiplied by an assumed loss factor for the generator. In the case of large-scale storage, the pool revenue is the difference between the revenue earned during discharge (generation) and the cost of the electricity during charging.

O&M costs is the total fixed and variable operation and maintenance costs. Variable operational costs may include an emissions cost associated with an emission reduction policy.

Annualised capital cost repayments is the annualised capital cost of the generator, taking into account the assumed economic life and weighted average cost of capital (WACC) for the generator.

Fuel costs is the total cost of the fuel used in the generator's modelled production of electrical energy throughout the year. The fuel cost is always zero for wind, solar PV and large-scale storage.

The net revenue equation is in line with the calculation performed in the 2014 Review in that the revenue earned in all trading intervals is considered in determining the commercial viability of a generator, rather than just MPC periods. It does not consider other potential revenue sources (other than pool revenue), unless an emission reduction policy is assumed that provides additional revenue (or costs) to particular generators. The major sources of generator revenue that are excluded are listed below, with the reasoning for each.

- **Large-scale generation certificates (LGCs).** With the present capital costs of large-scale wind and solar PV power stations, and the pipeline of projects under development, EY believes the LRET will be met on time[60]. Based on the announced status of various renewable projects, EY will develop an LRET new entrant list in consultation with the Panel.

- **Ancillary services**. There are several ancillary service markets in which generators can participate and earn revenue. One of the more significant of these is the Frequency Control Ancillary Services (FCAS) market, where generators can offer services to ramp up or down generation from a set point to manage the supply-demand balance. The revenue generators currently earn for providing ancillary services is small compared to revenue from electricity sales. In 2015, the total value of FCAS in the NEM was $112 million, being 1.4 per cent of the $8.3 billion traded on the energy market in the NEM. The 2018 Review tasks are focussed on the reliability settings in the NEM. These settings are primarily driven by outcomes in the energy market due to its relative size. For this reason the interaction between the energy and ancillary markets are not considered for this Review.

Assessing a generator's net revenue is conducted differently depending on whether they are existing or a new entrant:

- **Existing generators**: There is no publically available data for an existing generator's capital cost repayments and in many cases the capital cost might be already paid off. As such EY assess the year-on-year net revenue of existing generators in the modelling assuming no capital cost repayments are required, and retires them on a commercial basis if the net revenue is negative (and persists with negative revenue in subsequent years).

- **New entrant generators**: In EY's long-term modelling (to 2030 and beyond) commercially driven new entrant decisions are based on the net present value (NPV) of a generator's net revenue over its assumed economic lifetime. This will be conducted for the Base Scenario to capture the influence of the long-term assumptions on new entrants in the Period. However, since the scope for the 2018 Review is only to assess the Period from 1 July 2020 to 1 July 2024 and due to the uncertainty of the MPC in subsequent years, in the alternative scenarios EY will base new entrant decisions on the annual net revenue expectation within the Period only.

7.2 Market simulations

The market simulations are conducted using EY's in-house market dispatch modelling software, 2-4-C®. Figure 36 shows a flow diagram depicting the input assumptions and data processing used for the market simulations in this Review.

[60] However, as described earlier in this Report, failure to meet the LRET may still be considered as an alternative scenario.

Figure 36: Data flow diagram for the market simulations

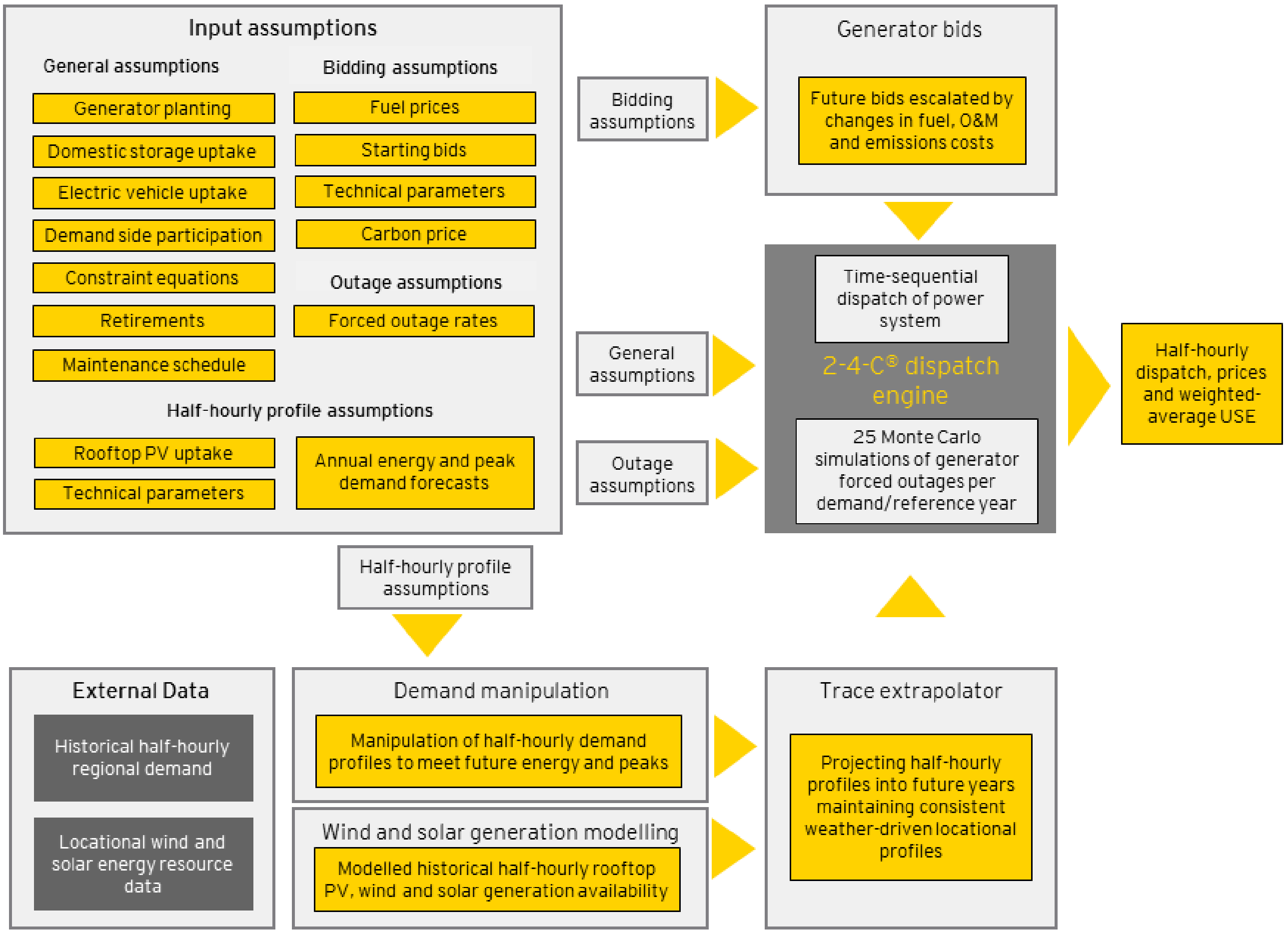
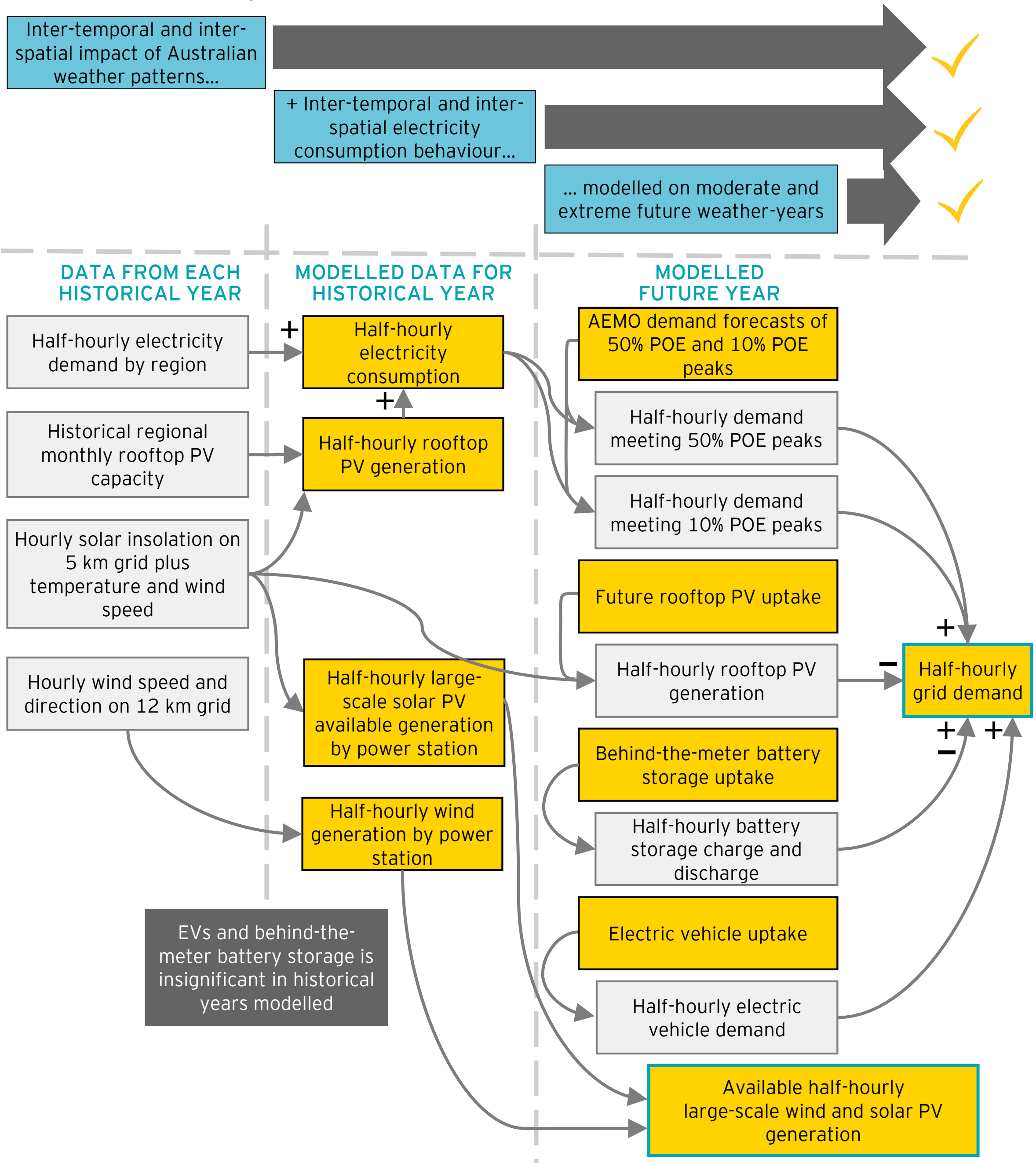


Figure 36 shows that conducting a market simulation involves establishing a large set of input assumptions. The key input assumptions and EY's methodology to modelling them in a market simulation are described in the following sections. The first of these, Section 7.2.1, describes the methodology and philosophy behind forecasting the electricity market on a half-hourly basis. Some of the input assumptions are processed in models external to the dispatch software, 2-4-C®, to determine the quantities to be used directly in the dispatch modelling. One of these determines the bids for each generator, for which the methodology is described in more detail in Section 7.2.6. An overview of 2-4-C® itself is provided in Box 2.

7.2.1 Forward-looking half-hourly modelling

EY's approach to forward-looking half-hourly modelling is to base all the inter-temporal and inter-spatial patterns in electricity demand, wind and solar energy on the weather resources and consumption behaviour in one or more historical years (reference years). Figure 37 depicts EY's methodology to modelling future half-hourly electricity demand, rooftop PV generation and large-scale wind and solar PV available generation, in terms of the data used.

Figure 37: Flow diagram showing EY's use of an historical year of electricity and atmospheric conditions data to make a half-hourly forecast



The top section of Figure 37 also highlights the philosophy behind what features in the historical half-hourly data are projected forward, and what features are modified to capture future conditions. These are described in more detail as follows:

- The historically observed **inter-temporal and inter-spatial impact of weather patterns** are maintained in the forecast. Historical hourly locational wind and solar resource data is used by EY to model half-hourly[61] generation from rooftop PV, large-scale solar PV[62] and wind generation. All the correlated interactions between wind and solar generation at different sites are projected forward consistently, maintaining the impact of actual Australian weather

[61] Hourly historical resource data is interpolated to half-hourly data.
[62] The same applies to solar thermal generation.

patterns. The available half-hourly large-scale wind and solar PV generation profiles are bid[63] into the market to meet grid demand in the 2-4-C® dispatch modelling. These may not be fully dispatched in case of binding network constraints or being the marginal generator and setting the price, with the volume above the marginal price being curtailed.

- **Inter-temporal and inter-spatial (regional) electricity consumption behaviour** is maintained in the forecast. Historical half-hourly grid demand is obtained from AEMO and added to EY's historical modelled rooftop PV to produce the historical electricity consumption. By projecting consumption forward instead of grid demand, EY maintains the underlying half-hourly consumer behaviour while specifically capturing the future impact of increasing rooftop PV generation in changing the half-hour to half-hour shape of grid demand during each day. EY also separately models behind-the-meter storage profiles and electric vehicle charging profiles to capture their impact on the shape of grid demand.

- The historical year(s) used in the modelling consist of various types of weather, which may or may not be considered typical or average. With respect to demand, the historical electricity consumption is processed to convert it into two types of weather-years for each future year modelled. One could be considered a **moderate year**, which uses AEMO's 50% POE peak demand forecast[64], while the other is considered a year with more **extreme weather**, using AEMO 10% POE peak demand[65].

- Overall, the half-hourly modelling methodology ensures that the underlying weather patterns and atmospheric conditions are projected in the forecast capturing a consistent impact on demand, wind and solar PV generation. For example, a heat wave weather pattern that occurred in the historical reference year is maintained in the forecast for each future year. The forecast is developed in the context of a moderate or extreme weather year from a demand perspective. The availability of renewable generation which is assumed to be operational within the Period is a function of the atmospheric conditions specific to each plant location and as would have been experienced across the whole NEM during the same weather event.

The number of individual iterations used in the Base Scenario, sensitivities and the MPC scenarios in this Review are provided in Table 5 in Section 5.2. All simulated iterations of half-hourly results are collated with a weighted-average of 0.7 on the 50% POE iterations and 0.3 on the 10% POE iterations. The reasoning behind this weighting is discussed in Box 1.

To capture a wide range of weather patterns and their impacts on electricity demand and locational wind and solar generation EY will use six reference years (as mentioned above) as the historical financial years from 2010-11 to 2015-16 for this Review. In general, the more reference years modelled, the more different types of weather patterns can be captured. However, the six years used for this Review were selected based on the following combination of reasons:

- The satellite-derived solar insolation data for the most recent financial year, 2016-17, is not yet available from the BoM, and is typically not available until around December for the previous financial year
- Use of recent years captures more representative half-hour to half-hour electricity consumption behaviour for the future years modelled
- The data quality available to model wind generation prior to 2010-11 is significantly poorer than for the years selected
- The feasible limit of the amount of computational effort required in this Review, and
- EY's recent study for AEMO's 2016 review of the Medium Term Projection of System Adequacy (MTPASA)[66] concluded a minimum of five reference years is required.

[63] EY's bidding methodology is described in Section 7.2.6.
[64] The 50% POE peak demand forecast is expected to be exceeded for one half hour once in every 2 years.
[65] The 10% POE peak demand forecast is expected to be exceeded for one half hour once in every 10 years.
[66] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Market-Management-System-MMS/Projected-Assessment-of-System-Adequacy

Box 1: Reasoning behind weightings used to collate 50% POE and 10% POE demand outcomes

The potential for unserved energy is probabilistic. Various combinations of prevailing customer demand, availability of conventional and intermittent generation, energy storage devices, demand side participation and transmission network capability and availability will influence the potential for unserved energy. The Reliability Standard is presently defined as:

> *The reliability standard for generation and inter-regional transmission elements in the national electricity market is a maximum expected unserved energy in a region of 0.002% of the total energy demanded in that region for a given financial year.*

The interpretation of the definition is of particular importance in determining an appropriate modelling approach. The focus of the interpretation is on the term *expected*. The expectation of unserved energy is considered to be the weighted probability of a range of factors. In the absence of time constraints and data availability considerations the modelling would ideally apply a very wide range of key factors such as atmospheric conditions and peak demand and simply weight each event equally. Monte Carlo iterations of unplanned outage events on generation and transmission elements are each considered to be equally likely. The sample of six reference years for atmospheric conditions and 'load shape' are also considered to be equally likely for the purpose of the modelling. Ideally we would model a large number of POE peak demand conditions however the computation time would be intractable. To manage the problem size, we limit POE peak demand samples to 10% and 50% POE scenarios. In order to establish the expected USE from these samples we assume that the probability density function of the demand POE samples are normally distributed. We then seek to find the quantum of the cumulative distribution function exceeding the 90th, 50th and 10th percentile. It is found that 30.4% of the cumulative distribution is contained above the 10th percentile, 30.4% is below the 90th percentile and 39.2% between the 10th and 90th percentile. As peak demand expectation reduces the chance of unserved energy also reduces. We therefore make a conservative approximation that the unserved energy expectation is similar for all POEs below the 50% POE peak demand forecast. It then follows that we establish the expected unserved energy from the Monte Carlo simulations as follows in equation (4).

$$\begin{aligned} Expected\ USE = {} & 0.304 \times Avg\ of\ 10\%\ POE\ USE\ (6\ Ref\ Years \times 25\ Monte\ Carlo\ simulations) \\ & + 0.696 \times Avg\ of\ 50\%\ POE\ USE\ (6\ Ref\ Years \times 25\ Monte\ Carlo\ simulations) \end{aligned} \tag{4}$$

EY applies a rounded 0.3 weighting on all 10% POE outcomes and 0.7 weighting on 50% POE outcomes. While the above analysis is for USE specifically, EY applies the weightings to all outcomes (such as generator revenues and prices) for simplicity.

The methodologies to produce the forecast half-hourly demand, wind and solar profiles for the modelling are briefly described in more detail in the following sections.

7.2.2 Half-hourly locational renewable generation modelling

As described earlier, and depicted in Figure 37, EY models future half-hourly generation availability for forecast uptake of individual wind and large-scale solar PV power stations, based on historical wind and solar resource data. An overview of the methodology for wind and solar is as follows:

- **Wind**: EY's wind energy simulation tool (WEST) uses historical hourly short-term wind forecast data from the BoM on a 12 km grid across Australia to develop wind generation profiles for existing and future potential wind power stations used in the modelling. WEST manipulates the BoM wind speed data for a site and processes this through a typical wind farm power curve to target a specific available annual energy in the half-hourly profile for each power station. Existing wind farms use the historical average achieved annual energy from actual data, while all new wind farms use an assumed annual energy that varies depending on their location in the NEM.

- **Solar PV**: EY's solar energy simulation tool (SEST) uses historical hourly satellite-derived solar insolation data on a 5 km grid across Australia, obtained from the BoM, along with BoM weather station data of temperature and wind speed. The resource data from the BoM is processed using the System Advisory Model (SAM) from the National Renewable Energy Laboratory (NREL) to develop locational solar PV generation profiles. The annual energy output varies from site to site as a result of calibration to the performance of existing solar farms and the locational resource data.

7.2.3 Half-hourly demand modelling

To forecast the half-hourly demand based on a historical year, EY first constructs the historical electricity consumption profile. This is made from adding together the historical half-hourly operational demand data published by AEMO and EY's historical modelled rooftop PV generation. The historical rooftop PV is modelled with SEST using regional monthly rooftop PV capacity and annual generation published by AEMO. EY's modelled half-hourly rooftop PV generation achieves AEMO's published annual generation expectation and is based on various representative locations and installation orientations of rooftop PV systems for each NEM region.

Using AEMO's latest forecasts of annual regional electricity demand, EY's Trace Extrapolator (TEX) tool applies statistical techniques to manipulate the historical demand profile to meet future annual energy and seasonal peak demand forecasts. SEST is used to produce corresponding future rooftop PV profiles based on AEMO's forecast of rooftop PV uptake, and this is subtracted from the demand consumption to give the half-hourly operational demand for application in 2-4-C®.

Box 2: Overview of 2-4-C®

The 2-4-C® software was developed soon after the NEM inception in 1998 and is maintained entirely in-house by EY (formerly ROAM Consulting). The 2-4-C® dispatch engine is able to replicate most functions of the AEMO real-time dispatch engine (NEMDE), meaning that 2-4-C® is capable of simulating real market behaviours to the most rigorous level of detail possible in a multi-year forward-looking assessment. As with NEMDE, 2-4-C® bases dispatch decisions on the market rules, considering generator bidding patterns and availabilities to meet regional demand. The model takes into account full and partial forced outages and planned outages for each generator, half-hourly renewable energy generation availability by individual power station as well as inter- and intra-regional transmission capabilities and constraints.

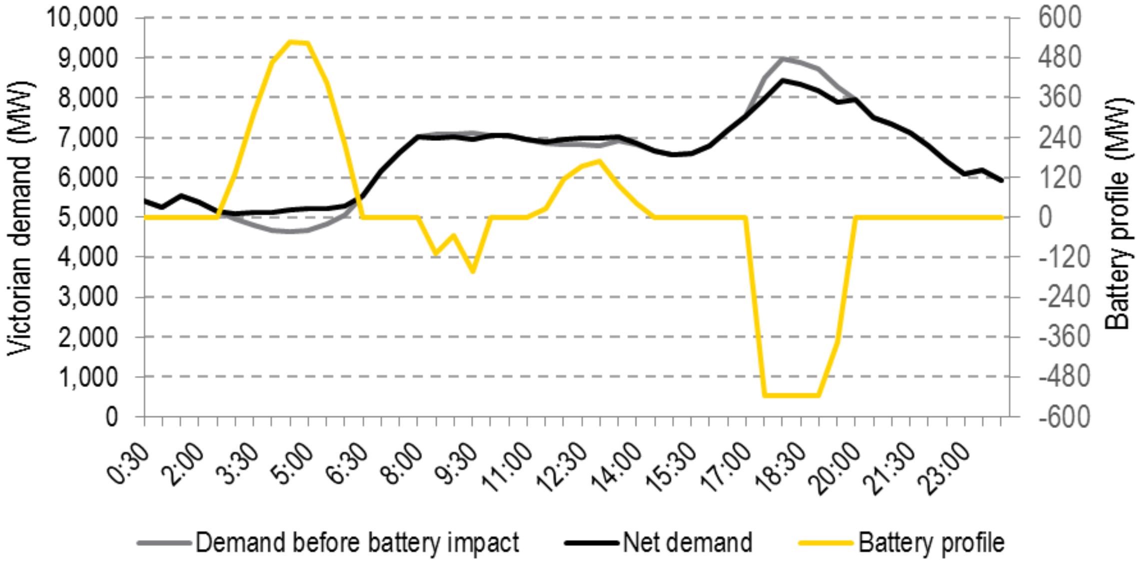
7.2.4 Behind-the-meter battery storage

EY's behind-the-meter battery storage profile tool produces a seasonal time-of-day charge and discharge profile for behind-the meter battery storage for each region. The tool aims to produce an aggregate profile that responds to peak demand usage tariffs and lower priced daytime effective tariffs due to battery owners also owning rooftop PV systems. Rather than assuming a particular retail tariff structure for future battery owners, it is assumed that the tariffs will relate to the net demand profile on the distribution network – consumption minus rooftop PV generation. As a result the tool produces a fixed time-of-day discharge profile that reduces the seasonal peak net demand and a charge profile that operates during the lowest periods of residual demand. To incorporate imperfection into the aggregated profile of the batteries, the following two factors are applied in the profile algorithm:

- Total energy charge discount factor: **85%**. To account for the likelihood that battery owners won't fully charge their batteries every day (due to faults, performance degradation, etc.), the daily charge is limited to 85% of the total installed energy capacity.
- Coincident charge/discharge discount factor: **70%**. This factor accounts for faults, coordination and the potential for different tariff signals to lead to batteries never being charged or discharged all the same time. The maximum charge or discharge is limited to 70% of the total charge/discharge capacity in MW.

Figure 38 below illustrates an example day in winter on how the aggregate battery charge and discharge cycle alters the operational demand profile.

Figure 38: Example day showing impact of behind-the-meter battery storage on operational demand in Victoria



This behind-the-meter storage profile is added/subtracted to the operational demand for 2-4-C® modelling. The amount of behind-the-meter storage modelled in each future year is provided by AEMO as part of the 2017 ESOO demand scenarios. The trajectories used are shown in Appendix A.3.

7.2.5 Electric vehicle demand

EY converts the annual energy expectation from electric vehicles (EVs) forecast by AEMO into half-hourly profiles to add to the grid demand used by 2-4-C®. Little is yet understood on when EVs will be charged in aggregate. EY has developed two alternative time-of-day EV demand profiles, one for weekdays and one for weekends. These profiles assume that overnight charging rolls off early in the morning, followed by an extended low period during the morning period of high electricity demand and commuting activity. Charging then increases again after people arrive at their destinations, and persists throughout the day before decreasing again in the afternoon when commuting activity commences again. Overnight charging commences significantly after the evening peak demand driven by time-of-use and peak demand tariff signals.

7.2.6 Bidding

In the real NEM, each generating unit bids their available capacity in up to 10 bands of quantities of capacity at different prices (price-quantity pairs). For example, a coal unit typically bids a certain proportion of its load at or near the market floor price (-$1000/MWh) to reflect the cost of restarting and incremental proportions of its capacity at positive prices to reflect their running costs, to recover fixed costs and to influence opportunistic pricing events in the market. To reflect changes in running costs and bidding strategies the bids can be changed frequently if desired. In some cases, portfolios of generators are owned by single entities and these generators are contracted in different ways to reduce the risk in wholesale market price exposure. These factors can influence the bidding strategies employed for individual generators.

Future significant changes to the capacity mix are likely to change the bidding strategies employed by generators when this changes their relative portfolio positions. The MPC scenarios, in particular, feature significant changes to capacity and explore USE levels near 0.002%, which is a very different situation to recent history in the NEM. In order to capture likely changes in bidding strategies in the modelling and how those strategies might change between half-hours, EY has employed a dynamic bidding approach. This approach is very similar to what was applied in the 2014 Review.

Dynamic bidding methodology for this Review

EY constructed bidding profiles for each individual generator based upon historical data with the objective to match recent observed market outcomes as closely as possible. This information is used to determine three separate bidding strategies as options to be employed in any modelled half-hour for each generator across the NEM. These three bidding strategies are chosen to be suitably diverse to allow realistic flexibility for entities owning portfolios of generators. Any known or assumed factors that may influence existing or new generation are taken into account in modifying the three candidate bidding profiles for each modelled future year. Such factors include water availability, changes in regulatory measures, fuel costs or fuel availability, carbon abatement policy or changes in total portfolio generation capacity where applicable.

Using a turn-based approach, the dynamic bidding methodology selects the bidding strategy that maximise the revenue for each portfolio subject to other portfolios and their strategies for each half-hour modelled. This turn-based approach iteratively determines an equilibrium in which no portfolio benefits from changing its bidding strategy. This approach accounts for the marginal cost of all generation in the portfolio and the assumed contacting position of each portfolio.The employed strategy submits a respective bid for each generator offering their capacity at up to 10 price-quantity pairs, as in the actual market.

7.2.7 Demand-side participation

Electricity consumption in the NEM has some inherent non-disclosed price response where some market-exposed consumers tend to use less power when prices are high. The impact of this is captured in AEMO's energy and peak demand forecasts modelled by EY. However, AEMO also publishes an amount of demand that is responsive to market prices, and these loads bid into the market[67]. The explicitly bidding demand side participation (DSP) data is incorporated into 2-4-C® as bidding loads as it would in the actual market. At pricing benchmarks, these loads are switched off in the model as would happen in the actual market.

7.2.8 Network constraints

Every year AEMO produces an updated data set of system-normal transmission network constraint equations for use in forward-looking market modelling studies, including AEMO's own studies. EY has used AEMO's 2015 constraint equation data set for all scenarios in this Review. The 2017 constraint equation data set was made available during the Review but without sufficient time to incorporate it into the MPC Scenario modelling. However, EY compared the two constraints sets and concluded that the impact on MPC outcomes would be minimal, as described in Appendix C.

7.3 Five-minute settlement modelling

7.3.1 Background to approach

The rule change to move from 30-minute settlement to five-minute settlement may impact the dispatch and wholesale market revenues of generators. Under 30-minute settlement generators receive revenue based on their total generation over a 30-minute trading interval and the average of the six five-minute wholesale market prices over the same interval. However, under five-minute settlement the generators will be paid for their generation in each five-minute interval at the five-minute price.

Each generator has limitations in how fast it can increase or decrease its generation (ramp rates) and in how quickly it can start up and synchronise with the grid. These limitations could impact on a generator's wholesale market revenue under five-minute settlement. Furthermore, bidding

[67] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/Key-component-consumption-forecasts/Demand-side-participation

behaviour may change under five-minute settlement causing wholesale market pricing outcomes to be different.

In order to allow direct comparability between the 30-minute and five-minute modelling outcomes, the same methodology and assumptions were applied to all parameters where possible. This includes adopting the same capacity mix and new entrant OCGTs and modelling the full set of reference years and Monte Carlo iterations to capture a similarly extensive set of market situations.

In the five-minute modelling the same generator portfolios and their associated bidding strategies are applied. As described in Section 7.2.6, EY's dynamic bidding module selects the optimal bids for each generator in a Nash-equilibrium outcome for each modelled interval. On modelling five-minute settlement, EY's dynamic bidding module will select the optimal bids every five minutes instead of every 30 minutes. Whilst the bidding strategies employed by generators under five-minute settlement could be different, the caveats in EY's bidding strategies in the 30-minute modelling, as described in Section 6.9.2, apply to same extent with five-minute modelling. As such, EY has used the same bidding strategies in the five-minute modelling.

However, some additional assumptions and revised input data are required to model five-minute settlement. These are described in the following sections. EY included modelling of generator ramp rate limitations as described in Section 7.3.2, but did not explicitly apply fast-start inflexibility profiles (FSIP). FSIP enables generators to inform AEMO on minimum operating times to manage thermal stresses from fast cycling of generators. Generators without FSIP capability need to plan ahead for starting up and bid into the market when they are synchronised and ready to generate. There is little public information available on how generators approach this planning aspect. However, the ramping limitations for each generator somewhat captures the relative limitations for how quickly generators can ramp from zero generation to full capacity. EY considers ramp rate limitations to be a reasonable approximation to the comparative abilities for each generator in the modelling outcomes for this exercise.

To explore the sensitivity to the reliability settings from five-minute settlements, EY conducted the modelling on MPC Scenario 2, where the reliability standard is threatened in Victoria, as this scenario has the highest outcomes for the reliability settings. The reliability setting outcomes are determined on the high costs sensitivity as this is considered the highest cost sensitivity with reasonable plausibility in the RSSR modelling report.

Furthermore, given that the five-minute settlement rule change is to commence on 1 July 2021, and that 2021-22 was the price-setting year[68] for MPC Scenario 2, EY only modelled 2021-22 to explore the sensitivity to the settings with five-minute settlement, while minimising simulation time.

7.3.2 Additional assumptions: generator ramp rates

Each generator has a limit to how quickly they can increase or decrease their generation output. These limitations are called ramp rates.

Whilst EY applied generator ramp rates in the 30-minute modelling, these limitations do not bind very often over the 30-minute time step modelled and have a negligible impact on the outcomes. However, with five-minute modelling ramp rate limitations are much more important to capture as accurately as possible.

The assumed ramp rates that have been collated from the public data as published by AEMO and applied in the modelling are provided in Appendix A.13. EY analyse the generator bid offers for each

[68] In the following year the Liddell power station retires and as a result the MPC required is lower in the final two years of the Period.

dispatch interval, which include ramp rate parameters. The applied ramp rates that have been collated from the data are representative of each generators recent observed behaviour[69].

Renewable generator ramp rates are set sufficiently high such that they are able to capture the respective changes in availability dictated by their resource data.

To model these five-minute variations, EY translated all half-hourly profiles to five-minute profiles. The methodology used for each of these is described in the following subsections.

7.3.3 Five-minute electricity demand

As described in Figure 37 in Section 7.2.1, EY's forecast half-hourly electricity demand is based on historical half-hourly demand and modelled half-hourly rooftop PV, behind-the-meter battery storage and EVs.

Historical five-minute electricity demand is available from AEMO, with the same source as the half-hourly demand data.

EY translates the other three components of demand from 30-minute to five-minute profiles using a form of linear interpolation that ensures that the average of the six five-minute values across a 30-minute interval is equal to the 30-minute value. EY considers a smooth linear interpolation to be sufficient for these three data elements since they are all regional aggregations of many distributed energy resources (e.g., thousands of rooftop PV systems). EY considers it unlikely that these will vary in five-minute intervals in a coordinated manner and as such would not exhibit any significant variation in aggregate on the five-minute level.

Using the historical five-minute demand data and interpolated five-minute rooftop PV, EY creates the forecast five-minute demand based on the 30-minute demand forecast. The procedure is as follows:

- Produce the 30-minute forecast demand profiles with the same methodology as the 30-minute modelling[70].
- For each forecast 30-minute demand value, calculate the scaling factor between this forecast value and the equivalent original historical 30-minute demand. For example, is the forecast demand for 12:00 on 28th February 2021 is 10% higher than the equivalent historical demand value at 12:00, than the scaling factor for this 30-minute interval is 1.1.
- Apply the calculated scaling factors to each historical five-minute demand value in the equivalent 30-minute interval. Using the same example, the six five-minute historical demands for the 30-minute historical interval are multiplied by 1.1 to produce the forecast five-minute demands for 11:35, 11:40, 11:45, 11:50, 11:55 and 12:00 on 28th February 2021.

This methodology ensures that the five-minute demand profiles are consistent with the 30-minute demand profiles, and that the average of each set of six forecast five-minute forecast demands is equal to the forecast 30-minute demand for the same interval. EY notes that peak in the five-minute demand profiles will likely be higher than the equivalent 30-minute demand profiles, just as the five-minute peak would have been higher than the 30-minute peak historically.

7.3.4 Five-minute locational renewable generation modelling

As described in Section 7.2.2, EY models every individual large-scale wind and solar generator resource availability in each modelled interval. As each wind farm and solar farm tends to cover a

[69] It is noted that generators may alter their ramp rate offer for commercial reasons. The collation process is essentially taking the modal observed ramp rate offer which is generally assumed to be representative of the physically realisable ramp rate of each generator.

[70] AEMO's peak demand forecasts are based on 30-minute average demands, making it appropriate to apply these to demand forecasting with 30-minute demand profiles.

relatively small area[71], variations in large-scale wind and solar farm production levels may be significant over a five-minute period due to moving wind patterns and solar irradiance patterns such as cloud cover. However, the data from the BoM used to develop dispatch profiles for large-scale wind and solar generators is measured and recorded at an hourly resolution. Thirty-minute profiles have been developed using linear interpolation between the hourly data points. It is important to capture five-minute variations in large-scale wind and solar PV generation due to the significant capacity installed and the nature of flexibility limitations of the power system over five minute intervals. Linear interpolation does not adequately capture variations in renewable resource for five-minute modelling of large-scale wind and solar generation.

Historical five-minute generation data is available in AEMO market data for each existing large scale wind and solar farm in the NEM. EY has combined this data with the locational hourly resource data from the BoM to produce five-minute dispatch profiles for each modelled wind and solar farm. Essentially, a range of observed five-minute historical dispatch profiles are randomly selected to fill in the five-minute time steps between hourly generation data points constructed from the BoM data. Each five-minute profile is selected based on having a similar starting and ending dispatch level from hour to hour. This methodology selects a plausible five-minute dispatch profile, which avoids unrealistic discontinuities at the beginning or end of an hour where the modelled hourly generation data is joined to five-minute data from historical actual generation.

Based on market data EY has observed that some existing wind farms have greater five-minute variability than others, which is largely due to their location. To increase the plausibility of the modelled five-minute profiles further, each existing wind and solar farm utilises its own historical five-minute profile data sets. All other wind and solar farms use a reference wind or solar farm that is considered to have typical variability and a large amount of data, as well as a similar size to the wind or solar farm being modelled. In general, the characteristics of five-minute variability would depend on the size of the wind or solar farm due to having a larger geographical spread of wind turbines or solar panels. Table 19 lists the wind and solar farms used as a reference for five-minute dispatch variability for modelled new entrant wind and solar farms.

Table 19: Representative wind and solar farms used to develop five-minute generation profiles for future wind and solar farms, respectively

Capacity bin (MW)	Wind	Solar
0 to 30	Cullerin Range wind farm	Royalla solar farm
30 to 150	Hallett 2 wind farm	Broken Hill solar farm
150+	Macarthur wind farm	Broken Hill solar farm

The methodology is as follows:

► **Create a collection of historical five-minute profiles across an hour**. Develop a collection of five-minute profiles across an hour using five-minute AEMO generation data for existing wind and solar farms. The collection is stored for each individual generator using the available data, after manually removing extended periods of curtailment and non-typical availability. The profiles are also normalised to vary between 0 and 1, where 1 represents the capacity of the generator.

  Each profile in each collection is then categorised depending on their starting dispatch value and ending dispatch value. These categories have been determined based on analysing the collection of profiles and considering the relative number of sample profiles that would be allocated to each category. This resulted in slightly different categories being used for wind than for solar. For wind generators, ten starting and ending values were established, giving 100

[71] Say, a few square kilometres.

total categories (representing all combinations of starting and ending values across the hour, 0-10%, 10-20%, and so on). For solar generators, seven starting/ending values were used, giving a total of 49 categories.

- **Convert hourly generation profiles to five-minute profiles.** For each wind or solar farm, loop through each pair of consecutive hourly modelled generation values. Select a random historical normalised five-minute generation profile across an hour and multiply it by the wind or solar farm's capacity. This profile is to be obtained from the appropriate category, based on the following conditions:
  - If the wind or solar farm is existing, use the collection from its own historical generation. Otherwise use the relevant collection for a generator of a similar size.
  - The selected profile must have a starting and ending value that fall into the same categories as the starting and ending hourly modelled generation values.

7.4 Differences in the methodology to the 2014 Review

The previous RSSR Review was conducted over 2013-14 and the final report was published in 2014. Primarily due to addressing the recommendations in the Oakley Greenwood assessment mentioned above, the key differences in the methodology for this Review and that used in the 2014 Review are as follows:

- This Review considers technology-neutral new entrant capacity, whereas the 2014 Review only assessed an OCGT bidding at $300/MWh.
- This Review considers net revenues of existing capacity as well as new entrants in determining the theoretical optimal MPC, while the 2014 Review only assessed new entrant capacity.
- This Review assesses the theoretical optimal MPC on plausible scenarios that threaten the reliability standard, while the 2014 Review used scenarios with arbitrary removal of capacity.

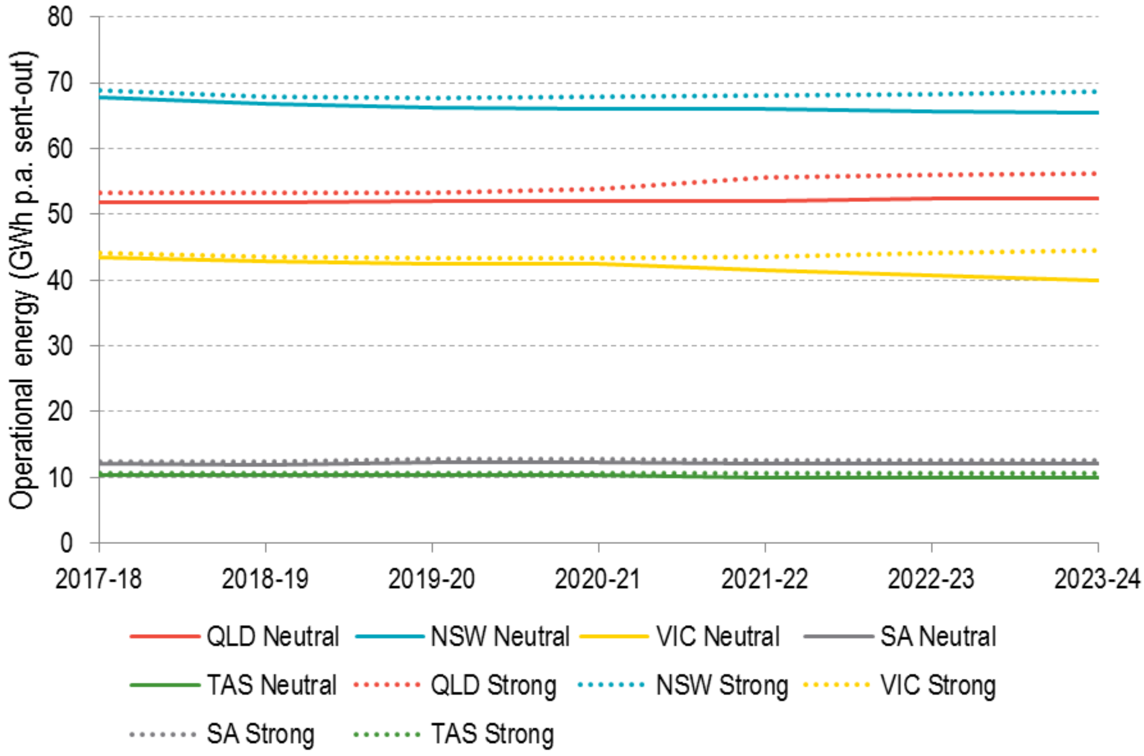
In addition, this Review included modelling of a five-minute settlement market to estimate the impact of this on the theoretical optimal reliability settings.

Appendix A Modelling assumptions

A.1 Demand and energy consumption

One of the primary considerations when forecasting the electricity market is the future demand for electricity, which is usually forecast in terms of annual energy consumption and seasonal peak demands. EY has used the 2017 ESOO[72] as the source of electricity demand and energy projections. Figure 39 shows the annual energy projections by region for AEMO's Neutral and Strong (High demand) scenarios as used for this Report. These trajectories are for operational sent-out demand, equivalent to consumption minus rooftop PV. The forecasts for both scenarios and all regions are fairly flat implying that rooftop PV generation is offsetting any increase in consumption.

Figure 39: AEMO Neutral and Strong annual regional energy forecast in the NEM

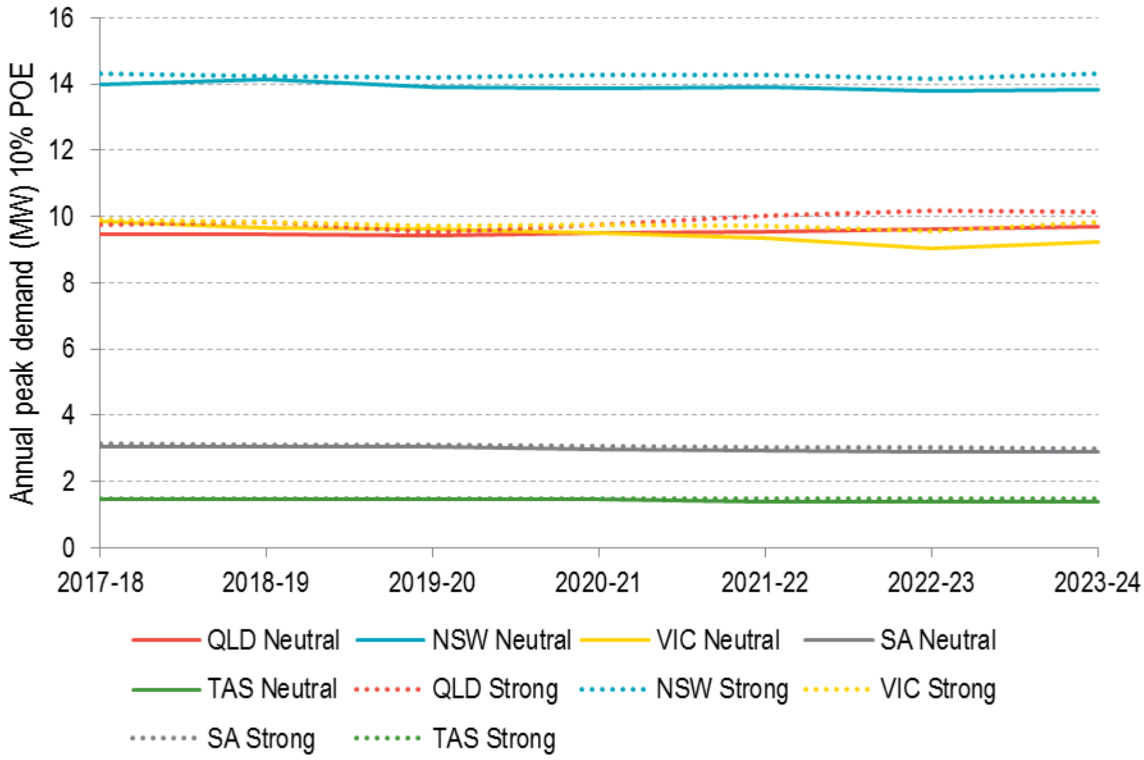


Peak demands are materially influenced by weather conditions, particularly hot temperatures in summer and cold temperatures in winter, driving cooling and heating air conditioning loads, respectively. The peak demand (and near-peak demand conditions) increases the risk of extreme price volatility as well as USE, and therefore the magnitude of the peak demand in any given year is a material factor in determining overall wholesale market revenues for generators and USE. EY has used two of AEMO's published peak demand forecasts representing a 10% probability of exceedance (POE) and an average (50% POE) peak demand level. The 50% POE peak represents a typical year, with a one in two chance of the peak demand being exceeded in at least one half hour of the year. The 10% POE peak demand represents a one in ten chance of being exceeded in at least one half hour of the year. EY simulates both targets and creates weighted-average results.

Figure 40 below shows the regional peak demand in the NEM for the 10% POE projection used in this scope of work from the Neutral and Strong economic growth scenario from the 2017 ESOO.

[72] Available at: http://forecasting.aemo.com.au/

Figure 40: AEMO Neutral and Strong annual 10% POE regional peak demand forecast in the NEM

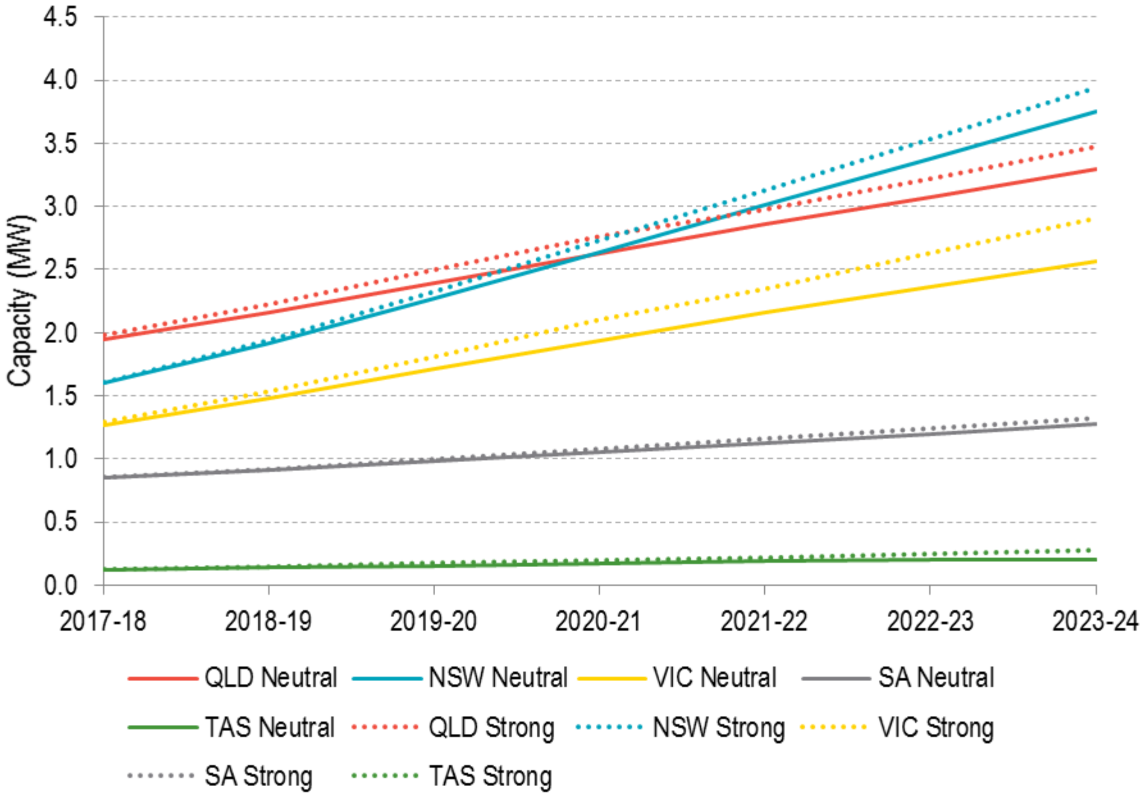


A.2 Commercial and residential rooftop PV systems

The uptake in rooftop PV systems in recent years has been rapid in all states, driven by favourable government policies and attractive payback periods. While many of the supportive government policies have now been removed (or significantly scaled back), AEMO still expects significant growth in rooftop PV uptake due to decreasing costs of PV systems and increasing (real or customer perceived) retail energy costs.

Figure 41 shows the rooftop PV trajectories used in this scenario, which is also based on the underlying conditions of AEMO's Neutral and Strong scenarios from the 2017 ESOO.

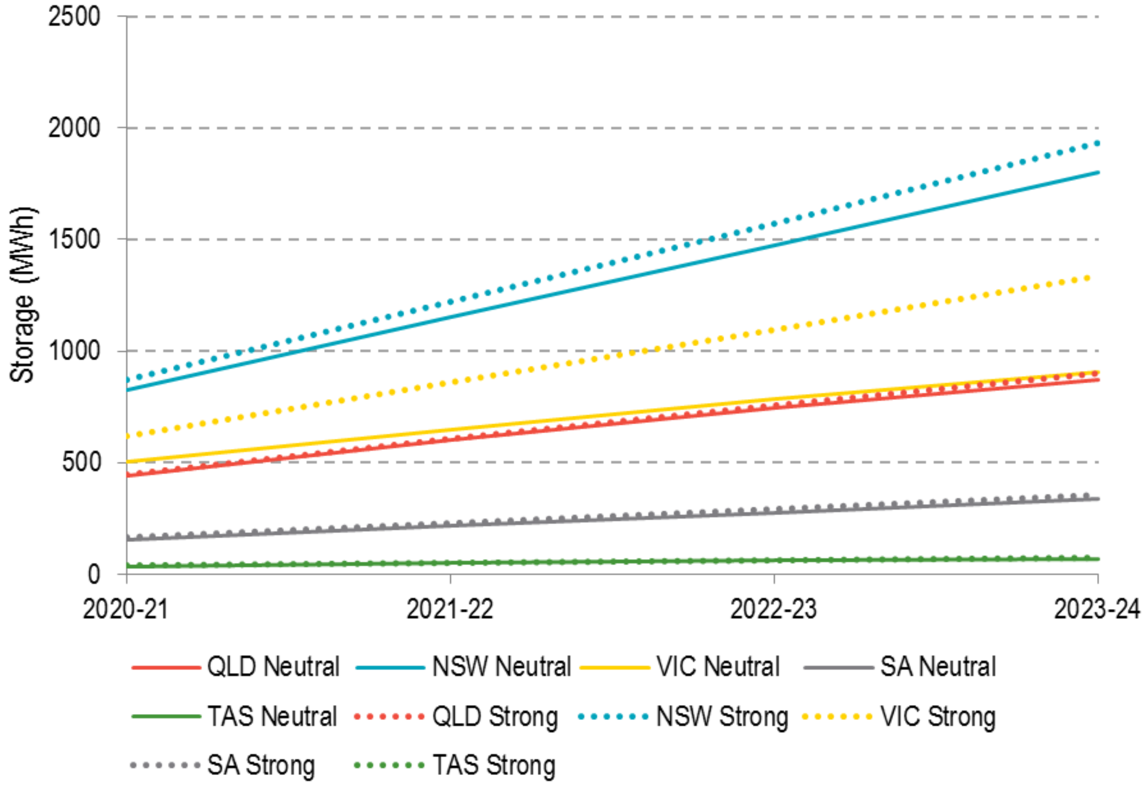
Figure 41: AEMO Neutral installed rooftop PV capacity forecast for the NEM



A.3 Behind-the-meter storage uptake

EY has adopted AEMO's behind-the-meter household and commercial battery storage uptake from the 2017 ESOO from both the Neutral and Strong scenarios where applicable. Figure 42 shows this uptake in each region and scenario for the total battery energy capacity in MWh. AEMO have assumed that the batteries have a storage size of two hours on average, meaning that the available instantaneous discharge capacity in MW is half of the energy capacity shown in the figure.

Figure 42: Behind-the-meter battery storage uptake trajectories from the 2017 ESOO



EY's storage profile tool determines the aggregate charge and discharge profile of the installed behind-the-meter battery storage capacity as largely a consistent daily profile for each season (summer and non-summer) and region. The methodology for this tool is described in Section 7.2.4.

A.4 Emissions reduction policies

The introduction of the Emissions Reduction Fund and Safeguard Mechanism from the Coalition Government are currently the key policy settings (with the renewable energy target policies) to drive decarbonisation of the electricity sector to contribute to Australia's emissions abatement targets. The Federal Opposition pre-election commitment advocated an electricity sector emissions trading scheme with linkages to international offsets (with no explicit carbon pricing agenda before 2020). Given that both major political parties appear unlikely to introduce any explicit pricing arrangements on emissions in the near term, EY considers it appropriate that carbon pricing remain repealed for this modelling.

While the Federal Government's Finkel Review[73] advised on introducing a Clean Energy Target (CET) into Australia's stationary electricity sector to reduce emissions, at the time of writing this Report the Federal Government has not made a move to adopt such a policy and instead proposed a different scheme, the National Energy Guarantee. Prior to this proposal being announced, EY agreed in consultation with the Panel not to model any new emissions reduction policy within the

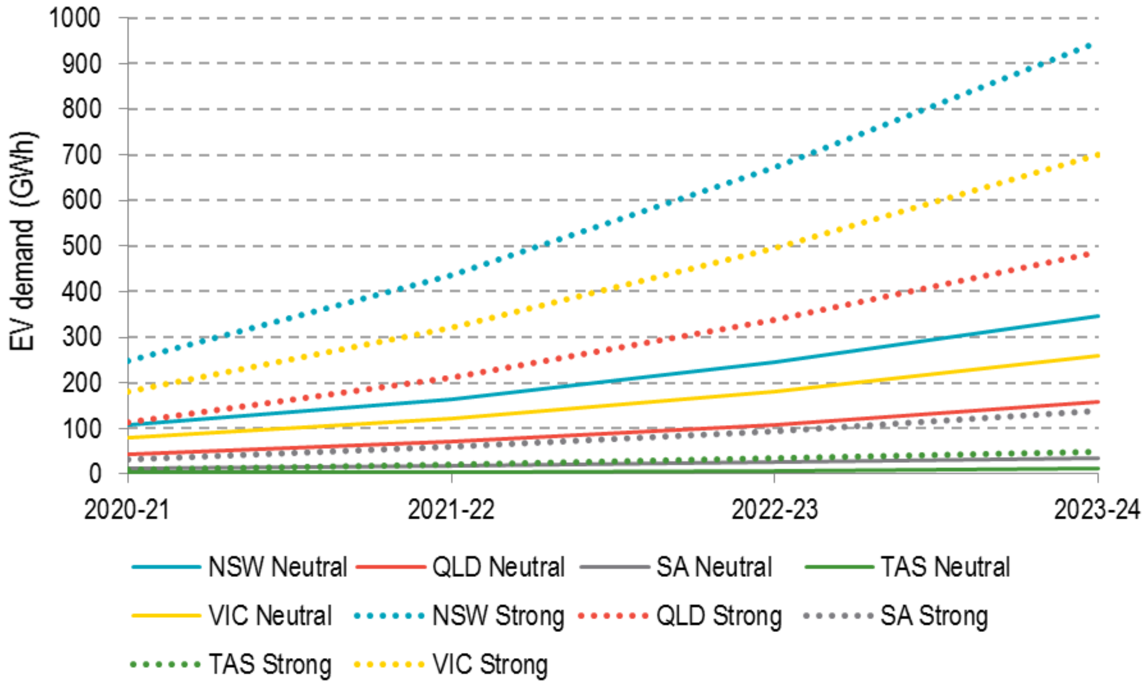
[73] http://www.environment.gov.au/energy/national-electricity-market-review

Period for the Base Scenario. To explore a high concentration of renewable capacity in one region, the expanded VRET 2025 target is adopted in MPC Scenario 2 as the only additional policy that would potentially lead to reduced emissions from the electricity sector.

A.5 Electric vehicles

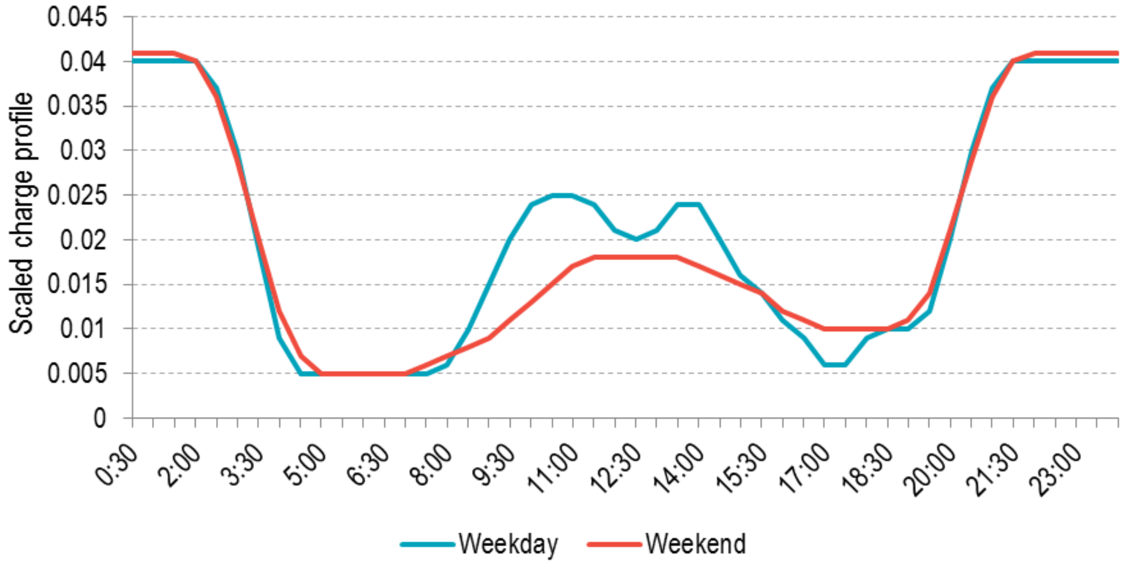
All modelled scenarios incorporate explicit modelling of an uptake of electric vehicles (EVs) as providing a new source of electrical load as consumers switch from petrol-based vehicles to those that rely on charging from the grid. The additional energy required for EVs is based on the 2017 ESOO report for the relevant scenarios. The EV uptake trajectories used are expressed in terms of additional regional energy demand as shown in Figure 43.

Figure 43: Electric vehicle energy demand trajectories from the 2017 ESOO



To include EVs in the modelling, EY has constructed two bespoke time-of-day demand profiles, one for weekdays and one for weekends, as shown in Figure 44. We assume that overnight charging rolls off early in the morning, followed by an extended low period during the morning period of high electricity demand and commuting activity. Charging then increases again after people arrive at their destinations, and persists throughout the day before decreasing again in the afternoon when commuting activity commences again. Overnight charging commences significantly after the evening peak demand driven by time-of-use and peak demand tariff signals.

Figure 44: Percentage of energy use for electric vehicles per day on time-of-day average



A.6 Thermal generation developments

As agreed in consultation with the Panel, the assumed retirement or mothballing (temporary removal from service) of thermal generation is listed in Table 20 below.

Table 20: Assumed thermal generator retirements

Power station	Region	Type	Capacity (MW)	Timing	Comments
Smithfield	NSW	CCGT	171	31/7/2017	Retirement announced (AEMO Generation Information 27/02/2017)[74]
Mackay GT	QLD	OCGT	34	1/7/2021	Retirement announced (AEMO Generation Information 27/02/2017)
Liddell	NSW	Black Coal	2,000	1/7/2022	Announced retirement (https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information)
Torrens Island A	SA	Gas - Steam	480/240	1/7/2019 (reduced capacity)	AGL plans to mothball two of the four turbines from 1/07/2019. https://www.agl.com.au/about-agl/media-centre/article-list/2017/june/agl-announces-development-of-$295m-power-station-in-sa

Table 21 shows the generator capacity assumed to return to service, as per public announcements and as agreed with the Panel.

Table 21: Assumed plant returning to service

Power station	Region	Type	Capacity	Timing	Comments
Swanbank E	QLD	CCGT	385	1/01/2018	Announced to return to full operation in first quarter of 2018: http://statements.qld.gov.au/Statement/2017/6/4/swanbank-e-power-station-fires-up-again

[74] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

Announced new thermal entrant plant and upgrades as assumed in the modelling are listed below in Table 22.

Table 22: Other assumed thermal upgrades and new entrant plant

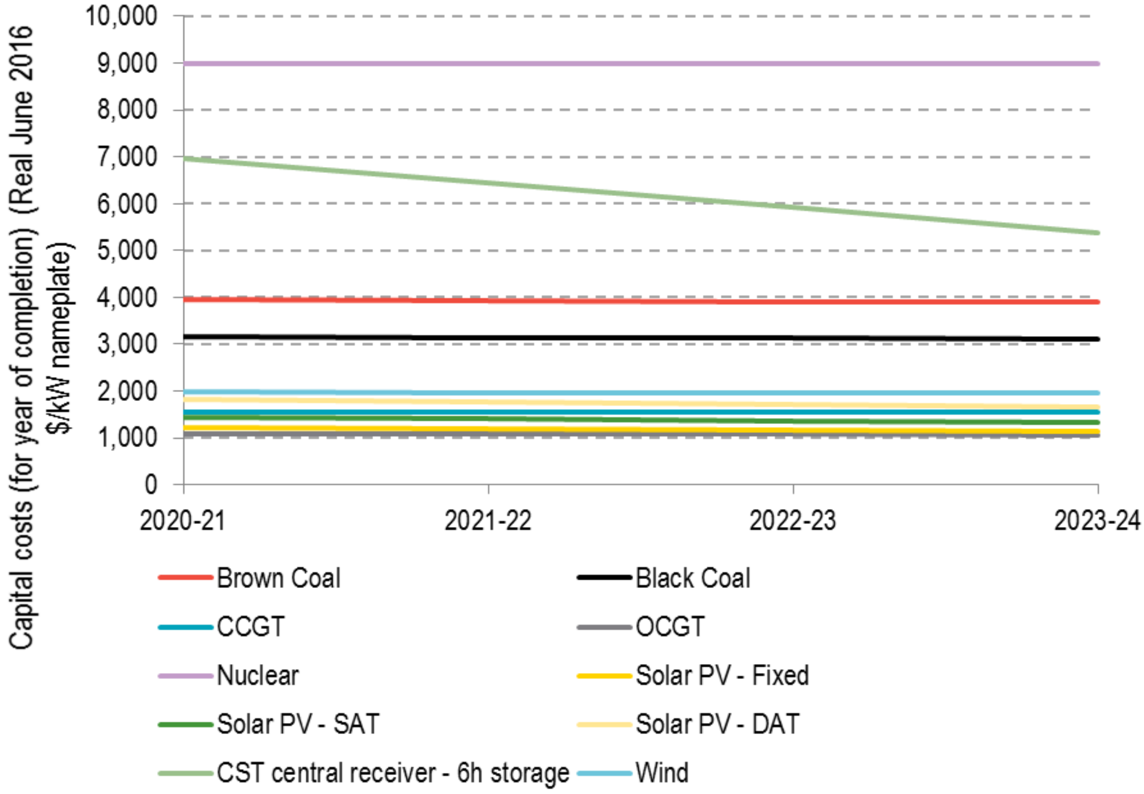
Power station	Region	Type	Capacity	Timing	Comments
SA Gov OCGT peaker	SA	OCGT extreme peaker	250 MW	1/07/2021	http://www.theaustralian.com.au/national-affairs/south-australia-energy-plan-360m-gasfired-power-plant-to-be-built/news-story/1ada5e2f160c87202a676170a62df009
Barker Inlet Power Station	SA	Compression Reciprocating Engine	210 MW	1/07/2019	Able to operate at full capacity within 5 mins of starting https://www.agl.com.au/about-agl/media-centre/article-list/2017/june/agl-announces-development-of-$295m-power-station-in-sa
Loy Yang B upgrade	VIC	Brown Coal	40/40 MW	1/7/2019 1/7/2020	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information Both units to increase in capacity by 40 MW each over two years.
Hornsdale Power Reserve battery	SA	Storage	100 MW / 129 MWh	1/01/2018	http://reneweconomy.com.au/sa-seeks-bids-for-100mw-battery-plant-to-kick-off-storage-boom-14527/ http://www.abc.net.au/news/2017-07-07/what-is-tesla-big-sa-battery-and-how-will-it-work/8688992
Vic Gov 100 MW battery	VIC	Storage	100 MW / 100 MWh	1/07/2019	http://www.premier.vic.gov.au/australias-largest-battery-to-be-built-in-victoria/
Qld Gov 100 MW battery	QLD	Storage	100 MW / 100 MWh	1/07/2019	http://statements.qld.gov.au/Statement/2017/6/5/palaszczuk-government-powers-up-an-energy-and-jobs-bonanza

A.7 New entrant capital costs

In consultation with the Panel, EY has based the new entrant capital costs on projections developed by AEMO, as published in the 2016 NTNDP report. The only exception to this is that Solar PV and wind capital costs have been reduced for the Base Scenario (and Base costs sensitivities) as agreed by the Panel. These reduced costs are based on publically available market analysis conducted by EY.

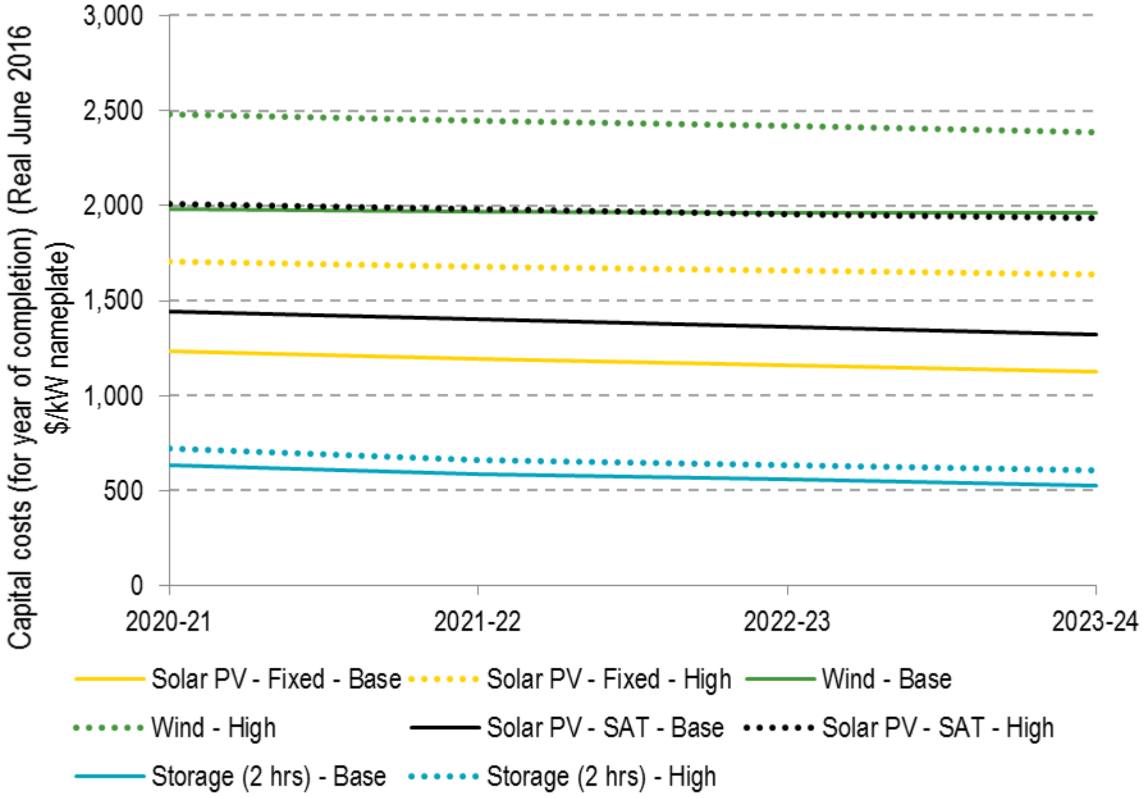
Figure 45 shows the Base costs capital cost projections for the generator technologies considered.

Figure 45: New entrant capital costs for the generator technologies considered in the modelling – Base costs



For the High costs sensitivities, alternative higher new entrant capital costs were assumed for solar PV, wind and storage. For wind and solar PV AEMO's 2016 NTNDP capital costs were used directly while the high CSIRO/Jacobs storage capital cost trajectory was used. The capital costs assumed for these technologies in the Base costs and High costs sensitivities are displayed in Figure 46.

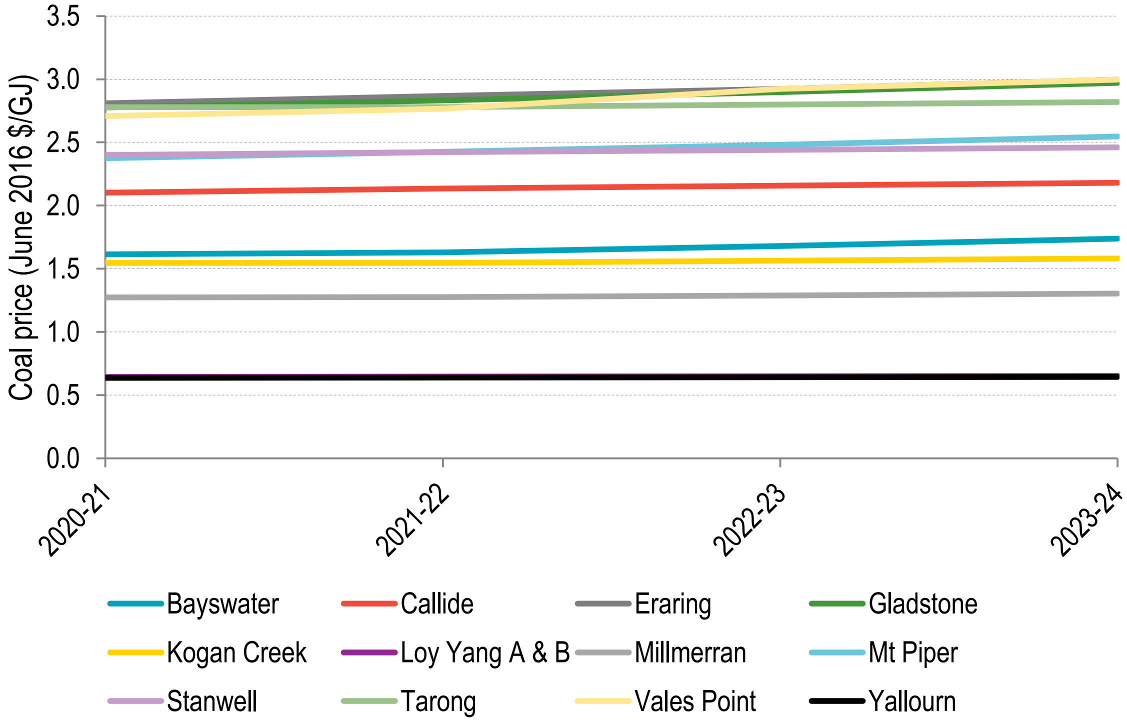
Figure 46: Base costs and High costs new entrant capital costs for wind, solar PV and storage



A.8 Coal prices

Figure 47 shows the assumed coal prices (from the 2016 NTNDP) used in the modelling for the existing coal power stations. These prices are part of the short-run marginal cost of coal generators, which influences their bidding in the model. This can have an impact on the merit order of different generators, and the wholesale market prices forecast by the model.

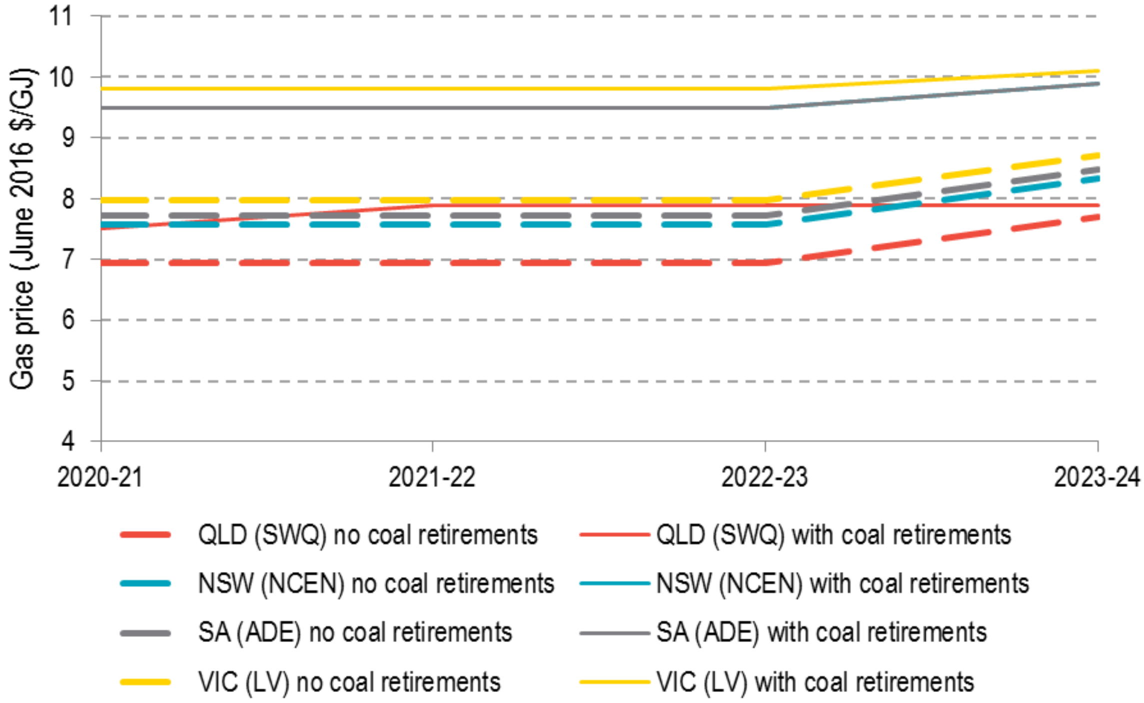
Figure 47: Coal prices for current operating power stations from AEMO's 2016 NTNDP



A.9 Gas prices

Figure 48 illustrates the gas price assumptions used in the Base costs and High costs sensitivities. The Base costs are from AEMO's 2016 NTNDP while the High costs scenario is based on the Core Energy Group coal retirements trajectory from the AEMO 2016 National Gas Forecasting Report[75].

Figure 48: Assumed new entrant CGGT* gas prices for indicative zones in each mainland region – both sensitivities.



* Gas prices assumed for OCGTs have a $2/GJ premium on these prices due to their limited ability to contract gas supply in high volumes.

These prices are part of the short-run marginal cost of gas generators, which influences their bidding in the model. This can have an impact on the merit order of different generators, and the wholesale market prices forecast by the model. EY does not consider the impacts of short-term gas contracts in our modelling, rather considering the pricing effect of long-term gas contracts for gas powered generators. As existing gas generators' current gas contracts roll off, EY expects that these generators will be forced to adopt this price trajectory for their future gas contracts.

[75] https://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report

A.10 Generator forced outage rates

As described in Section 7.2.1, EY conducts a number of Monte Carlo iterations in the market modelling to capture the impact of forced (unplanned) generator outages. Each Monte Carlo iteration assigns random outages to each generating unit, based on assumed outage statistics. Table 23 shows the outage rate statistics assumed in the Base Scenario, as supplied by AEMO from the 2017 ESOO. As shown in the table, the same outage statistics are applied for generators with the same fuel type. The nature of outages for wind and solar generators is different to large thermal generating units due to the modular nature of wind turbines or solar panels within a power station. The capacity factors modelled for wind and solar farms are based on observed and expected output of the wind and solar farms modelled, and as such implicitly include the impact of outages.

Table 23: Forced outage rates statistics as provided by AEMO from the 2017 ESOO[76]

Technology	Forced outage rate	Derating
Black coal	2.23%	100.0%
Black coal	12.61%	26.6%
Brown coal	4.05%	100.0%
Brown coal	5.60%	21.9%

AEMO's outage rates are based on outage information submitted to AEMO by the generators. AEMO then aggregated this information to assign a single rate for each generator type.

For this Report, EY made an independent analysis of full outage rates for existing coal generators using the half-hourly generator availability data published by AEMO. EY analysed the availability of coal generating units in the four warmest months, December to March, over the most recent six years. EY presumed that the percentage of time of full outages during these warmer months to provide a reasonable estimate of the forced outage rate, due to the following reasons:

- Coal generators have a high start-up cost and do not typically choose to shut down for short periods of time, and
- Due to high prices in summer, coal generators do not schedule their planned maintenance during this period.

Table 24 compares AEMO's outage rates to EY's outage rates using the above methodology. One caveat with EY's methodology is that on some occasions after a forced outage, coal generators may have chosen to keep particular units withdrawn for economic reasons. Due to this issue, EY considers the outage rates calculated from the data to be an upper bound for the true outage rate of each generator. Nonetheless, EY has applied these upper bound outage rates as a reasonable sensitivity for the MPC scenarios.

[76] EY has only recently learned from AEMO that these are the 2016 ESOO outage rates. EY is working on a scenario update using the 2017 ESOO outage rates now that AEMO has provided them.

Table 24: Comparison of full forced outage rates used in the Base and MPC scenarios

Sensitivity	Base Scenario (AEMO's rates)	MPC scenarios (EY's upper bound analysis)
Liddell	2.23%	29.5%
Gladstone 132	2.23%	23.1%
Gladstone 275	2.23%	21.7%
Mt Piper	2.23%	11.9%
Yallourn	4.05%	9.5%
Tarong North	2.23%	8.9%
Vales Pt	2.23%	8.7%
Eraring 1 & 2	2.23%	8.2%
Callide B	2.23%	7.2%
Kogan Creek	2.23%	7.2%
Eraring 3 & 4	2.23%	7.0%
Bayswater 330	2.23%	5.7%
Loy Yang A	4.05%	4.7%
Callide C	2.23%	3.4%
Millmerran	2.23%	3.2%
Bayswater 500	2.23%	3.0%
Loy Yang B	4.05%	2.8%
Tarong	2.23%	1.5%
Stanwell	2.23%	0.5%

A.11 Portfolios and contracting assumed for dynamic bidding

Table 25 provides a summary of the portfolios used by EY in modelling competition in the NEM for dynamic bidding in the model. It is assumed that new entrant generation does not belong to a particular portfolio and this generation is either bid at the generator's short-run marginal cost (in the case of wind or solar PC capacity) or for other technologies several bidding strategies are employed to determine an optimal strategy.

Table 25: Generation portfolios

Region	Portfolios
Queensland	CS Energy
	Stanwell
New South Wales	AGL
	Delta
	Origin Energy
	Energy Australia
Victoria	AGL
	Energy Australia
	Origin Energy
South Australia	AGL
	Engie
	Origin Energy

A.12 Generator ratings – summer and winter

As the temperature can materially vary from ideal operating conditions, the respective performance of generators can be materially influenced. For this reason, typically generators have a lower maximum rating in summer compared to winter. EY has adopted AEMO's summer and winter ratings for each generator, as published in AEMO's generation information[77].

A.13 Generator ramp rates

The ramp rates assumed for each generator are sourced from AEMO published historical market data[78] as described in Section 7.3.2.

NTNDP station name	Region	Technology	Ramp-up Rates (MW/min)	Ramp-down Rates (MW/min)
Bayswater 330	NSW	Black Coal	5	9
Bayswater 500	NSW	Black Coal	7	7
Eraring 1 & 2	NSW	Black Coal	5	5

[77] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information
[78] http://www.nemweb.com.au/Reports/Current/Daily_Reports/

NTNDP station name	Region	Technology	Ramp-up Rates (MW/min)	Ramp-down Rates (MW/min)
Eraring 3 & 4	NSW	Black Coal	5	5
Liddell	NSW	Black Coal	4	4
Mt Piper	NSW	Black Coal	10	10
Vales Pt	NSW	Black Coal	5	6
Smithfield	NSW	CCGT	30	30
Tallawarra	NSW	CCGT	6	6
Guthega	NSW	Hydro	5	10
Shoalhaven	NSW	Hydro	10	10
Shoalhaven Pump Lower	NSW	Hydro	12	12
Blowering	NSW	Hydro	2	2
Hume (NSW)	NSW	Hydro	10	10
Tumut3	NSW	Hydro	150	150
Tumut1	NSW	Hydro	40	20
Colongra GT	NSW	OCGT	12	12
Uranquinty	NSW	OCGT	11	11
Hunter Valley GT	NSW	OCGT	4	4
Callide B	QLD	Black Coal	4	4
Callide C	QLD	Black Coal	6	6
Gladstone 275	QLD	Black Coal	5	5
Gladstone 132	QLD	Black Coal	5	5
Kogan Creek	QLD	Black Coal	8	8
Millmerran	QLD	Black Coal	5	5
Stanwell	QLD	Black Coal	3	3
Tarong	QLD	Black Coal	4	4
Tarong North	QLD	Black Coal	4	4
Condamine	QLD	CCGT	3	3
Swanbank E	QLD	CCGT	12	12
Townsville GT	QLD	CCGT	4	5
Barron Gorge	QLD	Hydro	3	3
Kareeya	QLD	Hydro	5	5
Wivenhoe	QLD	Hydro	120	120
Barcaldine	QLD	OCGT	3	3
Braemar Stage 1	QLD	OCGT	9	9
Braemar Stage 2	QLD	OCGT	30	10
Mackay GT	QLD	OCGT	10	10
Mt Stuart GT	QLD	OCGT	9	9
Roma GT	QLD	OCGT	8	8

NTNDP station name	Region	Technology	Ramp-up Rates (MW/min)	Ramp-down Rates (MW/min)
Darling Downs GT	QLD	OCGT	10	10
Oakey GT	QLD	OCGT	30	11
Yarwun Cogen	QLD	OCGT	10	10
Hornsdale Battery Gen	SA	Battery storage	200	200
Hornsdale Battery Load	SA	Battery storage	200	200
Osborne	SA	CCGT	10	10
Pelican Point	SA	CCGT	10	20
Angaston	SA	Diesel Engine	14	14
Lonsdale	SA	Diesel Engine	15	15
Port Lincoln	SA	Diesel Engine	3	3
Port Stanvac 1	SA	Diesel Engine	15	15
Snuggery	SA	Diesel Engine	3	3
Lonsdale Generation (at Morphett Vale East 66)	SA	Diesel Engine	15	15
Torrens Island A	SA	Gas - Steam	5	5
Torrens Island B	SA	Gas - Steam	8	5
Hallett GT	SA	OCGT	12	12
Dry Creek GT	SA	OCGT	5	5
Ladbroke Grove	SA	OCGT	8	8
Mintaro GT	SA	OCGT	5	5
Quarantine	SA	OCGT	3	3
Tamar Valley CCGT	TAS	CCGT	9	9
Bastyan	TAS	Hydro	30	30
Cethana	TAS	Hydro	30	30
Devils Gate	TAS	Hydro	30	30
Fisher	TAS	Hydro	15	15
Gordon	TAS	Hydro	90	90
John Butters	TAS	Hydro	30	30
Lemonthyme	TAS	Hydro	20	20
Catagunya	TAS	Hydro	76	76
Lake Echo	TAS	Hydro	30	30
Mackintosh	TAS	Hydro	30	30
Meadowbank	TAS	Hydro	8	8
Poatina	TAS	Hydro	10	10
Reece	TAS	Hydro	10	10
Tarraleah	TAS	Hydro	30	30
Trevallyn	TAS	Hydro	40	40
Tribute	TAS	Hydro	10	10

NTNDP station name	Region	Technology	Ramp-up Rates (MW/min)	Ramp-down Rates (MW/min)
Tungatinah	TAS	Hydro	50	50
Bell Bay GT	TAS	OCGT	10	10
Tamar Valley OCGT	TAS	OCGT	10	10
Loy Yang B	VIC	Brown Coal	10	10
Loy Yang A	VIC	Brown Coal	5	5
Yallourn	VIC	Brown Coal	5	5
Newport	VIC	Gas - Steam	10	10
Dartmouth	VIC	Hydro	50	50
Eildon	VIC	Hydro	5	5
Hume (Vic)	VIC	Hydro	10	10
McKay Creek	VIC	Hydro	30	30
Murray1	VIC	Hydro	112	100
West Kiewa	VIC	Hydro	5	5
Somerton GT	VIC	OCGT	8	8
Bairnsdale	VIC	OCGT	3	3
Jeeralang A	VIC	OCGT	9	9
Jeeralang B	VIC	OCGT	6	6
Laverton North	VIC	OCGT	27	24
Mortlake Stage 1 OCGT	VIC	OCGT	13	13
Valley Power	VIC	OCGT	11	6

Appendix B USE distribution analysis

This appendix analyses the distribution of USE for the Base Scenario and MPC Scenario 2.

B.1 Base Scenario

With the very small amounts of USE forecast in the Base Scenario, this scenario presents an opportunity to analyse the nature of USE events at the fringe of it occurring (for the years modelled and the regions where it is forecast). In other words, these are the first half-hours where USE could occur; where the supply-demand balance is at its tightest.

To analyse the types of periods when USE occurs in the Base Scenario, EY investigated the two different regions with the highest levels of forecast USE in different years. As shown in Figure 6 in Section 5.3.3, these are Victoria in 2020-21 and NSW in 2023-24.

To first provide a perspective the distribution of USE forecast across all half-hours modelled, Figure 49 shows the USE outcomes in Victoria in 2020-21, sorted from highest to lowest. The chart shows the maximum amount of USE forecast in any half-hour trading interval is 757 MW, with 39 trading intervals with USE greater than 200 MW. There are 87 trading intervals in total that present with any level of USE from the simulations conducted out of the 42 million trading intervals simulated and all of these were modelled to occur in the years with a 10% POE peak demand profile.

Figure 49: All forecast USE outcomes by half-hour trading interval in Victoria in 2020-21, sorted from highest to lowest

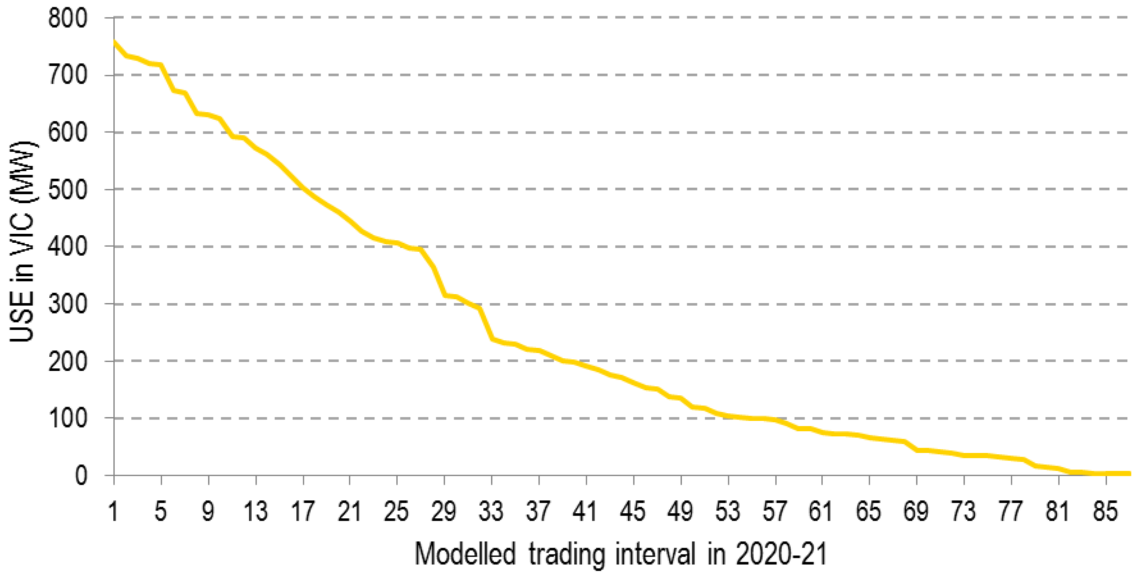


Figure 50 shows the distribution[79] of the forecast USE by month for Victoria in 2020-21. All of the forecast USE in 2020-21 occurs during the summer months with the vast majority occurring in January.

[79] The chart shows the distribution of the MWh of unserved energy forecast, which weights some half hours more than others. All the subsequent USE distribution charts in this section are on the same basis.

Figure 50: USE outcomes by month in Victoria for 2020-21 – Base Scenario

In the case of NSW in 2023-24 (see Figure 51), the forecast USE is all in February and December.

Figure 51: USE outcomes by month in NSW for 2023-24 – Base Scenario

USE is expected to be more likely in the warmer months in Victoria and NSW, due the combination of the following reasons:

- ► Victoria and NSW typically have higher peak demands due to hot weather rather than cold weather.
- ► Thermal generators are typically derated in hot weather due to technical limitations in the power station design. EY has modelled seasonal ratings for thermal generators as an explicit assumption (see Appendix A.12).

To reiterate, the USE analysed for the Base Scenario in this section is based on very small amounts of USE, far below the reliability standard, which occur at the fringe of only the tightest periods of the modelled supply-demand balance. This analysis should be interpreted in this context.

Figure 52 shows the forecast USE distribution by time of day for Victoria in 2020-21. The chart shows that this USE is concentrated in the late afternoon and early evening, with a peak around

16:30-17:00. This is the expected time of day when the demand would be at its highest. This is especially true for residual demand (consumption minus renewable generation) as the late afternoon and early evening would be associated with low or zero solar PV generation (including rooftop PV).

Figure 52: Forecast USE by time of day in Victoria, 2020-21 – Base Scenario

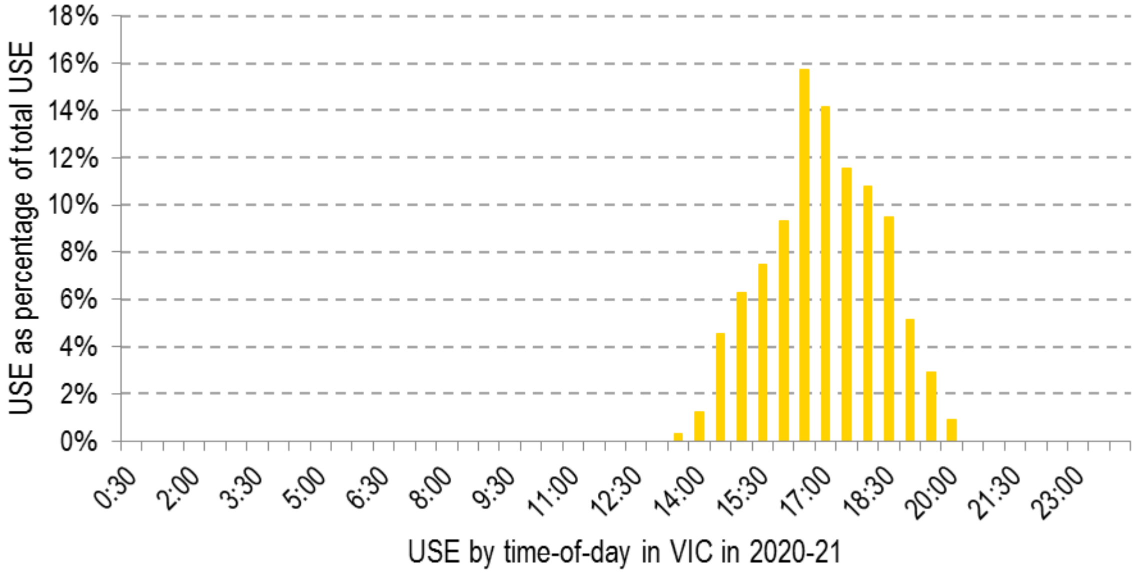


Figure 53 shows that in the case of NSW in 2023-24, the forecast USE is also distributed in the late afternoon and early evening.

Figure 53: Forecast USE by time of day in NSW, 2023-24 – Base Scenario

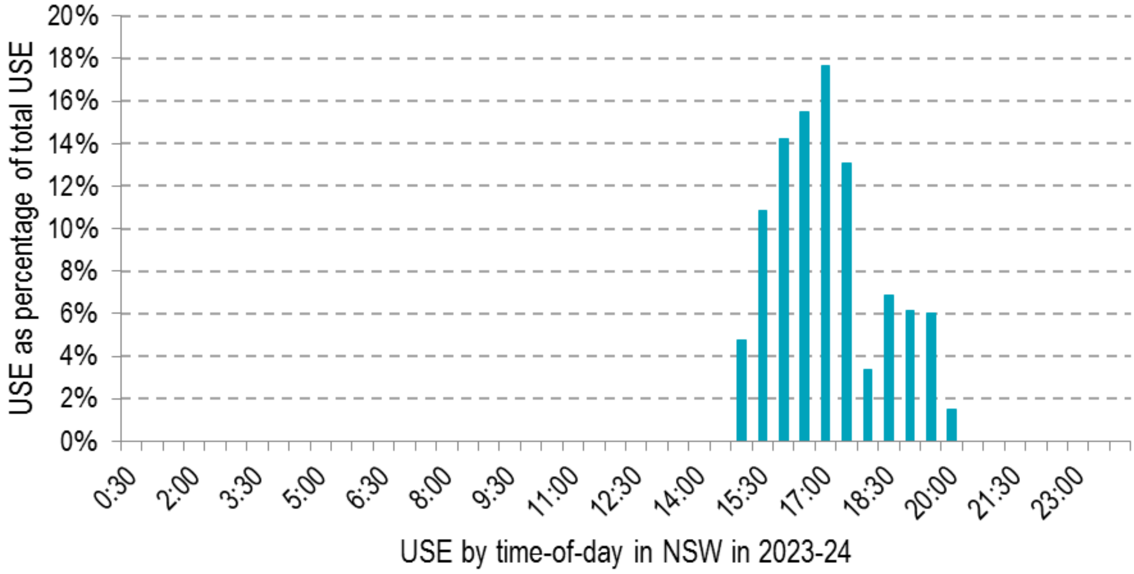


Figure 54 shows the distribution of USE (in MWh) in Victoria in 2020-21, based on the historical reference years modelled. The chart shows that almost 90% of the USE forecast occurs in the simulations based on the 2013-14 reference year, while no USE is forecast in the simulations based on the 2010-11, 2012-13 or the 2015-16 reference years. This highlights the importance of modelling as many reference years are practical when forecasting USE.

Figure 54: Forecast USE by reference year in Victoria, 2020-21 – Base Scenario

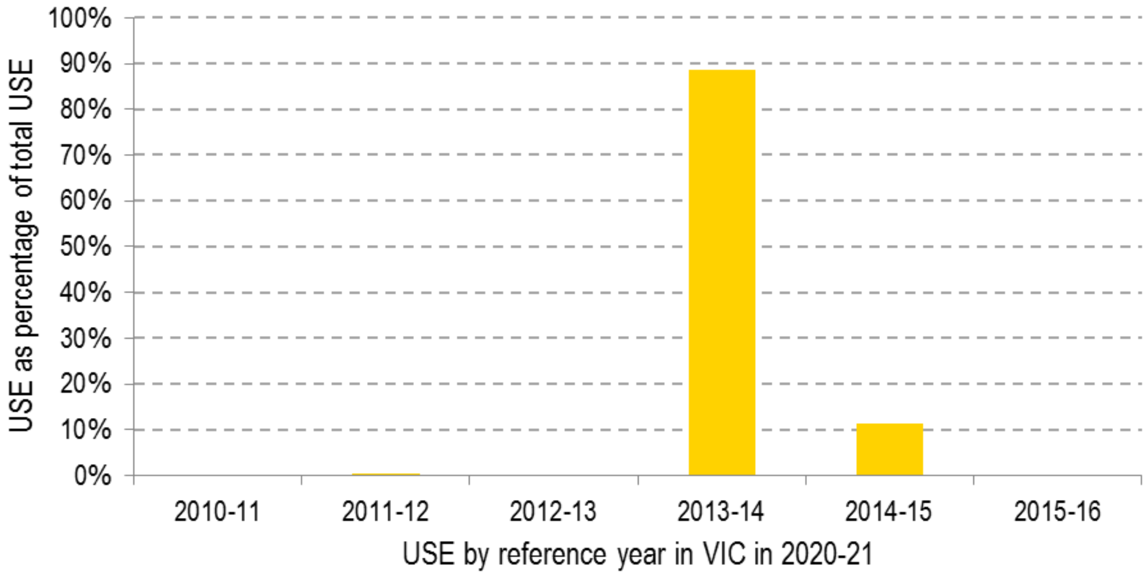
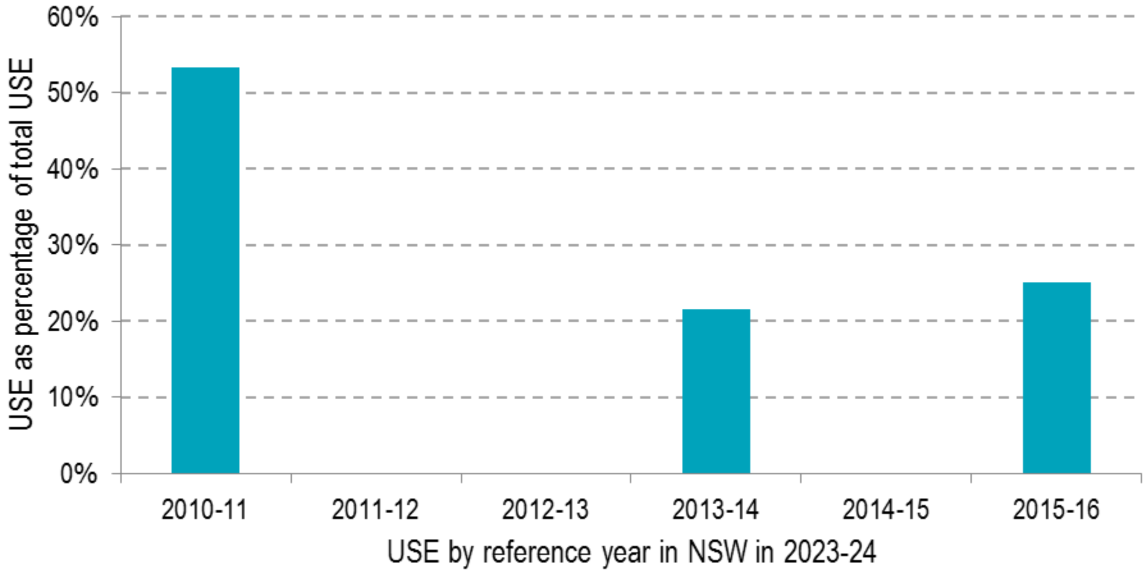


Figure 55 below shows the equivalent chart for NSW in 2023-24, where there is a different contribution from reference years to the USE outcomes.

Figure 55: Forecast USE by reference year in NSW, 2023-24 – Base Scenario



In theory, the true distribution of USE risk by month, time-of-day or reference year would be due to differences in when periods of high residual demand occur, as well as a tendency to occur in summer due to the ratings of thermal power stations being reduced during that period. However, due to the USE being in very small amounts, the distribution outcomes demonstrated in the charts above are somewhat an outcome of the random outage profiles selected over the 200 iterations. This issue is discussed further in Section B.2.

B.2 MPC Scenario 2

With close to 0.002% USE in MPC Scenario 2 in Victoria, the distribution of USE can be compared to the Base Scenario analysis presented in the previous section above, to see if the distribution changes with much greater quantity of USE. This section analyses the types of periods when USE occurs in MPC Scenario 2 for Victoria in 2020-21, as was done in the Base Scenario analysis in the previous section[80].

Figure 56 shows the distribution of forecast USE across all half-hours modelled for Victoria in 2020-21, sorted from highest to lowest. The chart shows the maximum amount of USE forecast in any half-hour trading interval is almost 2,000 MW, with over 2,000 simulated trading intervals having USE.

Figure 56: All forecast USE outcomes by half-hour trading interval in Victoria in 2020-21, sorted from highest to lowest - MPC Scenario 2

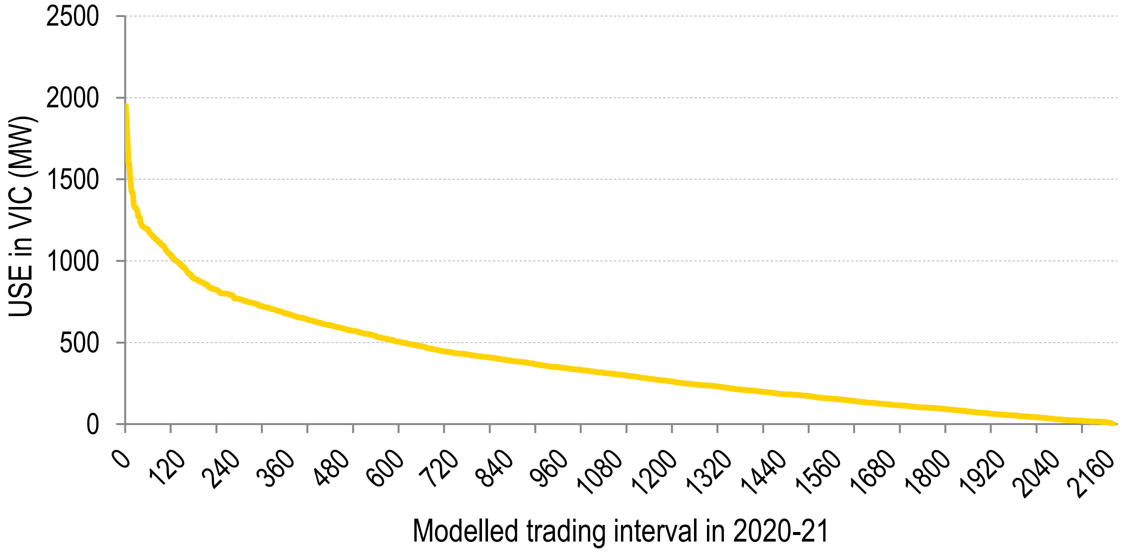
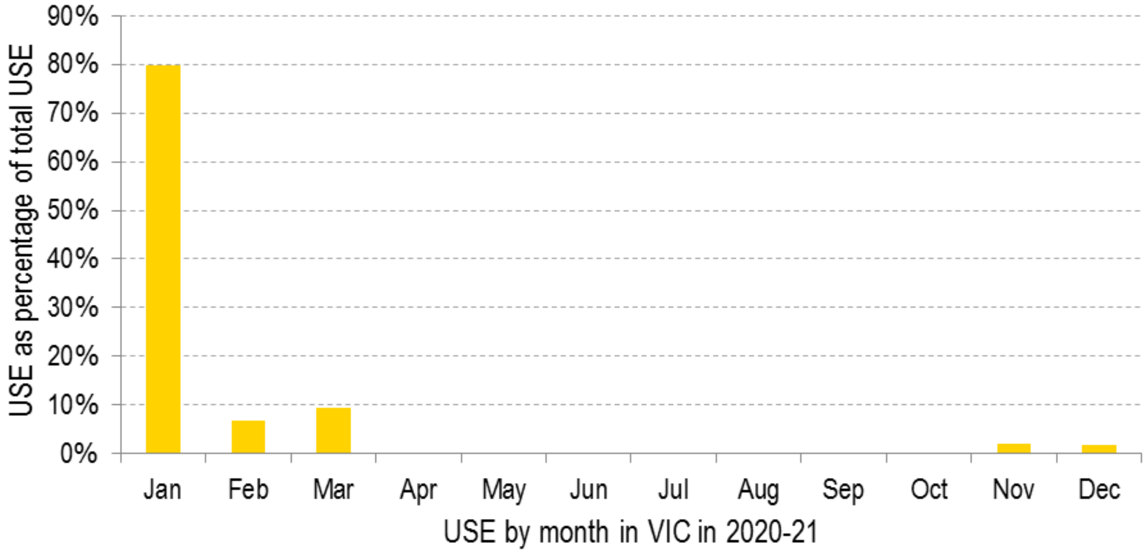


Figure 57 below shows the distribution[81] of the forecast USE by month for Victoria in 2020-21 for MPC Scenario 2. All of the forecast USE in 2020-21 occurs in the five warmest months, November to March, with the majority occurring in January.

[80] There is more USE in NSW in 2023-24 in MPC Scenario 2 as well, but it is only 30 times more at 0.00003%, still well below the reliability standard.

[81] The chart shows the distribution of the MWh of unserved energy forecast, which weights some half hours more than others. All the subsequent USE distribution charts in this section are on the same basis.

Figure 57: USE outcomes by month in Victoria for 2020-21 – MPC Scenario 2



While the warmer months remain the dominate periods for USE risk, there is a small risk in some other months of the year.

The distribution of Victorian USE in 2020-21 by time-of-day in MPC Scenario 2 is displayed below in Figure 58. The figure demonstrates that Victoria is most susceptible to USE during the afternoon to early evening. In comparison to the Base Scenario, the range of periods in which USE occurs is wider.

Figure 58: Forecast USE by time of day in Victoria, 2020-21 – MPC Scenario 2

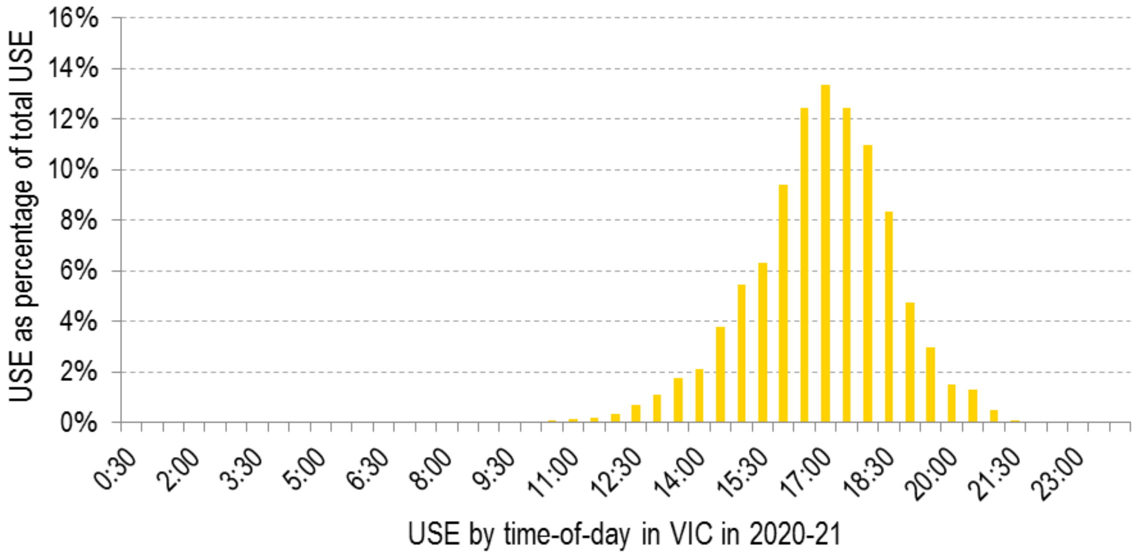


Figure 59 shows the distribution of USE in Victoria in 2020-21, based on the historical reference years modelled. The chart shows that almost 50% of the USE forecast occurs in the simulations based on the 2013-14 reference year, while no USE is forecast in the simulations based on the 2010-11 reference year. The latter is a surprising result - after removing over 2 GW of thermal capacity in Victoria, there is still no USE forecast based on the 2010-11 reference year. However, this result can explained by observing the top values of residual demand by reference year, as shown below in Figure 60. The result highlights the importance of modelling multiple reference years as there is a big variation between them in terms of USE outcomes.

The Victorian USE distribution by reference year for MPC Scenario 2 can be compared with the distribution for the very small amount of USE in the Base Scenario in Figure 54. The reference year with the largest contribution is 2013-14 in both scenarios, but in the Base Scenario this is around 90% with the other 10% being mostly from 2014-15. This is commented on below in the discussion of residual demand following Figure 60.

Figure 59: Forecast USE by reference year in Victoria, 2020-21 – MPC Scenario 2

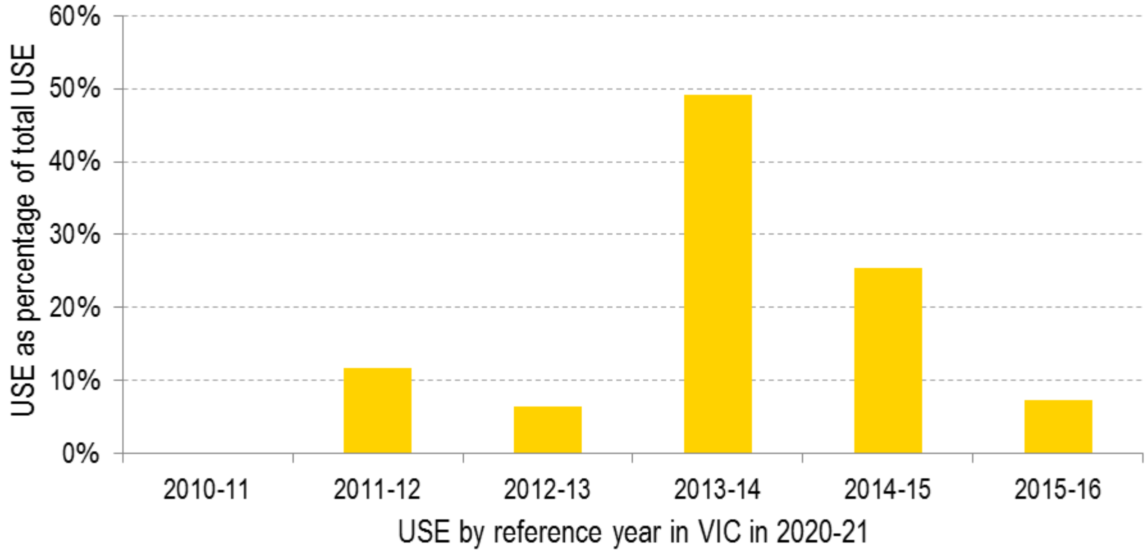
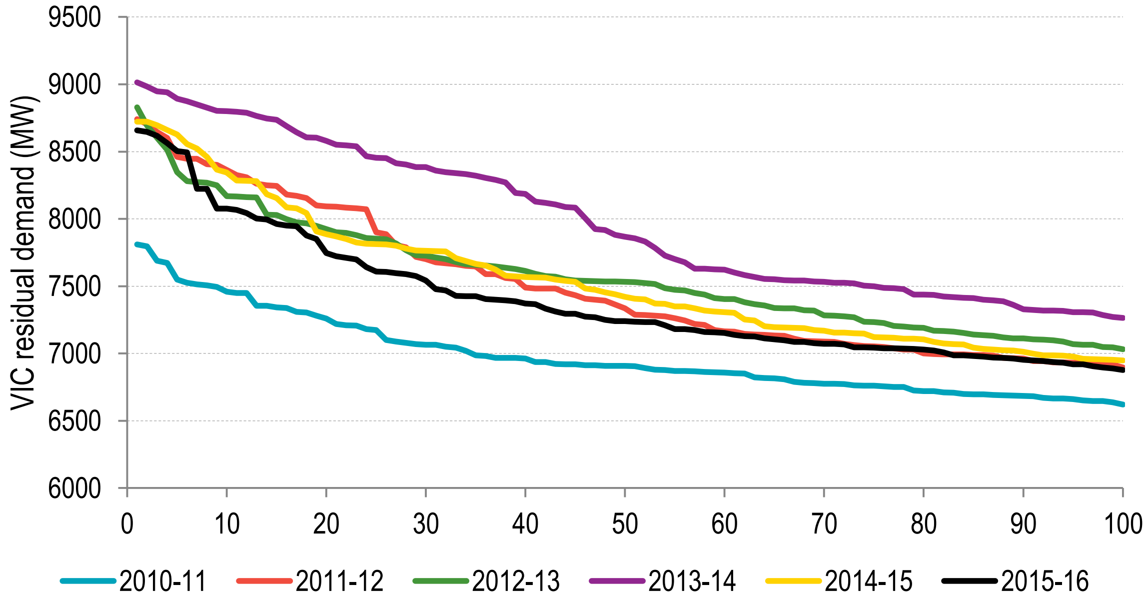


Figure 60 below shows the top 100 residual demand values for Victoria in 2020-21 by reference year, sorted from highest to lowest, for MPC Scenario 2 Base costs. The charts shows that two reference years stand out: the 2013-14 year has the highest values of residual demand of all of the reference years, while 2010-11 does not have many high values in comparison to the others. The chart is consistent with the USE outcomes shown in Figure 54 and Figure 59 and explains why 2010-11 has no USE forecast in Victoria.

Figure 60: Top 100 residual demand values for Victoria in 2020-21 by reference year – MPC Scenario 2 Base costs



The top 100 values of residual demand in Victoria in 2020-21 for the Base Scenario look very similar to the trends in Figure 60.

With the larger amounts (near 0.002%) of USE analysed in this section, the USE distribution trends are much more robust, despite only 25 Monte Carlo iterations being performed in the MPC scenarios. The extremely rare occurrence of USE in the Base Scenario means that the outcomes depend more on the modelled random outages in the Monte Carlo iterations. The 200 iterations modelled for the Base Scenario produces USE distributions relatively consistent with MPC Scenario 2 and the residual demand trends. EY found that this was not the case for 100 iterations (not shown).

Appendix C Comparison of the AEMO 2015 and 2017 constraint equation data sets

As described in Section 7.2.8, the modelling conducted for this Review used AEMO's 2015 network constraint equations data set (2015 constraints). AEMO's 2017 network constraint equations (2017 constraints) data set are an update to the 2015 constraints and feature a more extensive and complex data set. In EY's understanding, one primary difference is that the 2017 constraints take into account the retirement of the Hazelwood power station. AEMO do not publish any documentation describing the differences in constraints data sets between years.

The different formulations of the two constraint equations data sets may restrict generation and interconnector flows differently. This could lead to different modelling outcomes in terms of unserved energy (USE), pricing outcomes and ultimately revenue outcomes for the marginal new entrant generator that meets the reliability standard. This in turn could lead to different estimations of the theoretical optimal reliability settings.

This Appendix explores the potential impact of using the 2017 constraints on:

- The Base Scenario outcomes, forecasting expected USE. The results show higher USE outcomes with the 2017 constraints data set, but still at levels well below the reliability standard.
- The reliability setting outcomes in the MPC Scenarios. In our view, applying the 2017 constraints would result in similar reliability setting outcomes to the modelling applying the 2015 constraints and well within the bounds of uncertainty.

The outcomes of the analysis conducted on each of these are described in more detail below.

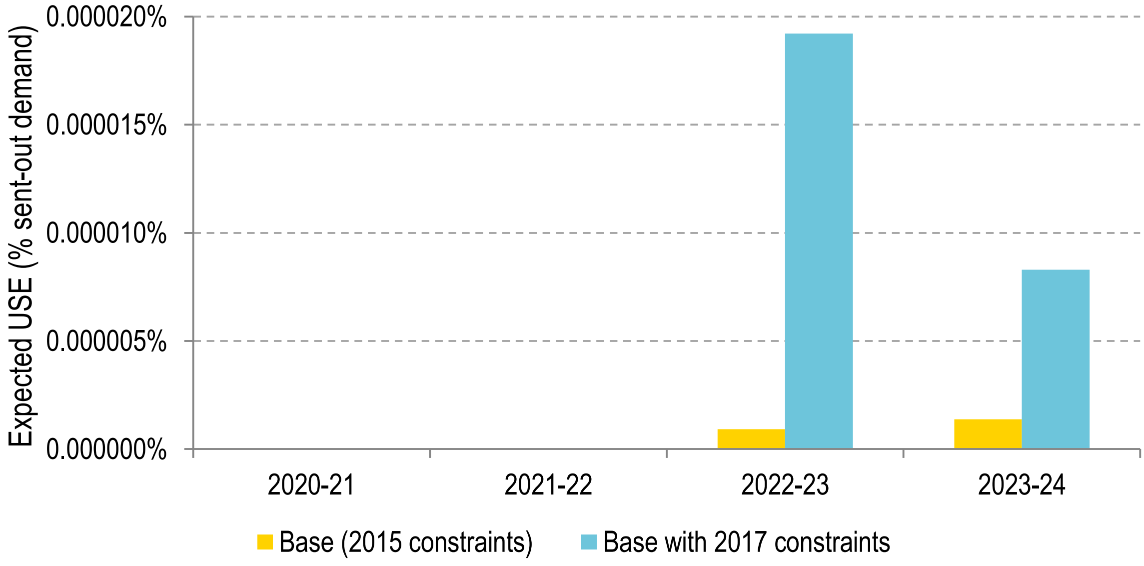
The Base Scenario – forecasting USE

EY conducted a sensitivity to the Base Scenario using the 2017 constraints, but keeping all other assumptions the same, including the same capacity mix. Figure 61 shows the outcomes for Victoria. The USE outcomes are higher with the 2017 constraints in all years except 2022-23, but are still less than 1% of the reliability standard of 0.002% USE.

Figure 61: USE outcomes in Victoria in the Base Scenario comparing the 2015 constraints and the 2017 constraints*

* Note that y-axis scale shows up to one hundredth of the reliability standard of 0.002% USE.

Figure 62: USE outcomes for New South Wales in the Base Scenario comparing the 2015 constraints and the 2017 constraints*



* Note that y-axis scale shows up to one hundredth of the reliability standard of 0.002% USE.

In summary, the 2017 constraints appears to have a more limiting impact of generation than the 2015 constraints, leading to higher USE outcomes. However, in the Base Scenario the expected USE in both cases is forecast to be less than 1% of the reliability standard or less in all years of the Period.

The MPC Scenarios – estimating the theoretical optimal reliability settings

To explore the extent of the potential impact of the 2017 constraints on the reliability settings outcomes, EY performed the first two steps in estimating the theoretical optimal reliability settings and compared the distribution of USE with each constraint equations data set. Without conducting more extensive modelling to estimate the reliability settings with the 2017 constraints, EY considers the distribution, or 'shape' of USE is an illuminating indicator of whether the 2017 constraints would produce similar reliability settings outcomes to application of the 2015 constraints in the modelling. For the marginal new entrant generator, the number of observed trading intervals with USE has a strong link to the generator's market revenue as these are the periods with the wholesale market price likely to be at the MPC. Furthermore, in a supply-demand balance situation that is resulting in the risk of 0.002% USE occurring, the expectation of high market prices supplementing market revenue for the marginal new entrant generator is similar.

EY analysed the shape of USE at the modelling stage where the new entrant OCGT is installed to bring USE to just below 0.002%. This represents the situation in which the market revenue of the OCGT is assessed to estimate the theoretical optimal reliability settings. Specifically, EY conducted the following two modelling steps with the 2017 constraints:

1. Establish a capacity mix that just breaches the reliability standard
2. Install a new entrant OCGT with a capacity that results in the expected USE being just under 0.002%.

The above steps were conducted on MPC Scenario 2 – with the reliability standard threatened in Victoria. To simplify the analysis we focused only on the 2020-21 year.

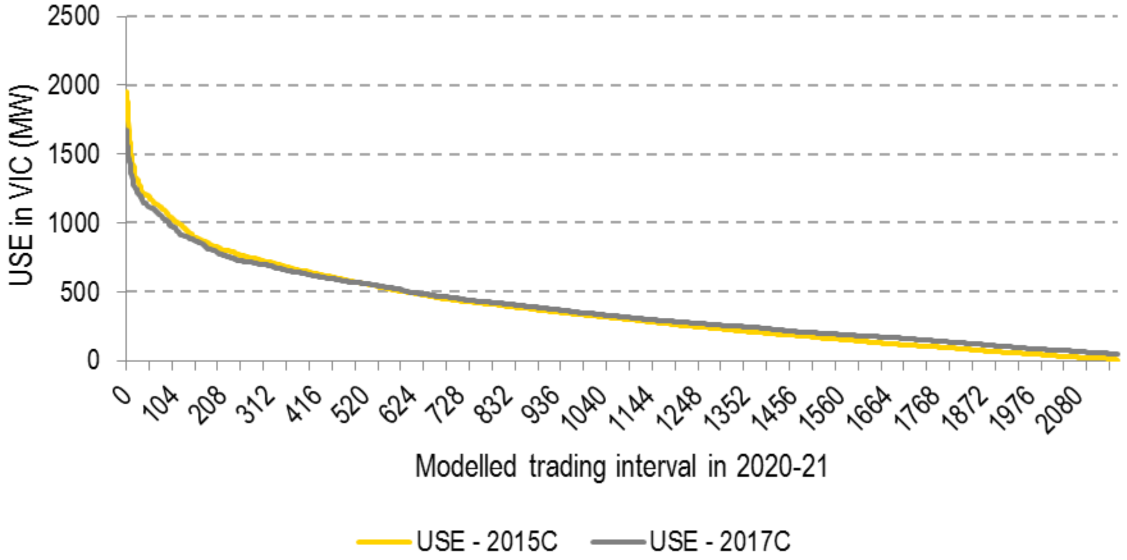
Following these steps using the 2017 constraints, we found that the 2017 constraints limit the dispatch from some generators in Victoria to a greater extent than the 2015 constraints. This is congruent with the outcomes for the Base Scenario as described in the previous section. In order to achieve a similar level of USE using the 2017 constraints, the level of generation assumed to be retired and the capacity of the marginal new entrant generator to achieve a level of USE just within the reliability standard is different. Table 1 summarises the capacity mix differences between the two constraint equations data sets.

Table 26: Capacity mix changes in 2020-21, MPC Scenario 2 with 2015 and 2017 constraints

Constraint data set	Early retirements	New entrant OCGT capacity
2015 constraints	2,600 MW of thermal capacity in Victoria	270 MW
2017 constraints	2,100 MW of thermal capacity in Victoria	350 MW

The shape of USE can be displayed as a duration curve, where the USE outcomes across all trading intervals modelled in a particular year are sorted from highest to lowest. Figure 63 shows the duration curves for USE in Victoria in 2020-21 using the 2015 and 2017 constraints. The individual USE outcomes are observations applying 25 Monte Carlo iterations of forced outage profiles, across 6 reference years, for two different demand projections, totalling 300 'simulation years' of 30-minute trading intervals[82].

Figure 63: Duration curve of USE for Victoria in 2020-21 in MPC Scenario 2 (2015C refers to 2015 constraints)



The above results indicate that the shape of Victorian USE in 2020-21 with the 2017 constraints is very similar to that with the 2015 constraints. Furthermore, the maximum USE in both scenarios has approximately the same magnitude and occurs in the identical modelled trading interval. This is a strong indication that USE is occurring at the same times with either constraint data set, which means that the new entrant OCGT is likely to receive a similar contribution to its revenue from USE periods.

It is important to acknowledge that this analysis has not explicitly assessed the potential effect on theoretical profitability of the marginal new entrant generator from wholesale market prices in all modelled trading intervals. In absence of further analysis the similarity of the USE shape presents a strong indication that the 2017 constraints would result in a similar outcome for the reliability settings to the 2015 constraints, well within the bounds of uncertainty explored in the RSSR studies.

[82] This is 25 * 6 * 2 * 300 * 17520 = 1,576,800,000 trading intervals

Appendix D Comparison with the 2017 ESOO USE forecasts

In September 2017, AEMO published the 2017 ESOO, which focuses on forecasting USE for the NEM regions for a 10-year outlook from 2017-18 to 2026-27. The USE forecasts in the ESOO scenarios were different to those forecast in the Base Scenario and sensitivities in this Review. Working with AEMO, EY has identified the reasons for the differences in USE forecasts. This appendix presents the key reasons for the differences, and compares AEMO's and EY's USE forecasts through some additional modelling scenarios.

EY used as many of the ESOO assumptions as was possible when the primary modelling was conducted for this Review. The RSSR and ESOO modelling were completed independently and as such a number of key assumptions and the preparation of modelling data are unique to each model. In particular, the rationale for assumed generator capacity development between the RSSR Base Scenario and the ESOO scenarios is different leading to differences in the generators assumed to be installed in the Period. AEMO provided EY with sufficient detail of the generator capacity development plan applied in the ESOO dispersed renewables scenario to enable EY to replicate the development plan in the EY model. The installed capacity and other assumptions were aligned to the ESOO modelling in order to isolate the reason(s) for the different USE outcomes in EY's and AEMO's modelling. EY then conducted additional sensitivities to that scenario, introducing EY's data sets one by one to isolate the contributions to the USE differential between the ESOO and the RSSR Base Scenario for this Review. We focused on the 2022-23 year of the RSSR Period, being the year following the assumed retirement of the Liddell power station in New South Wales.

In summary, AEMO's 2017 ESOO presents a higher forecast USE in NSW in 2022-23 compared to EY's modelling when applying AEMO's ESOO modelling data sets. The magnitude of this forecast difference is 43 MWh out of 348 MWh. When implementing EY's half-hourly profiles for demand, wind, solar, behind-the-meter battery storage and electric vehicles the difference increased to 328 MWh. It has been determined that the majority of the differences in USE forecasts are due to the following factors:

- EY's half-hourly modelling of wind, solar and rooftop PV uses different source data and data preparation techniques to AEMO. In particular EY use different data sets that describe the characteristics of wind generation in different regions. This difference in wind resource data means AEMO and EY have different wind generation profiles. The contribution of this assumption to the differing USE levels was approximately 25%.
- EY's modelling assumes a much greater contribution to peak demand from behind-the-meter storage which might be expected in the Period as a result of changing electricity tariff structures that reward peak demand reduction. This assumption results in lower peaks in the demand to be met by scheduled generators in the NEM, compared to AEMO. The estimated impact of this assumption for NSW in 2022-23 is approximately 63% of the difference of forecast USE levels.
- EY's dispatch modelling software differs from AEMO's and as a result, some aspects of the modelling approach are not the same. The contribution of applying alternative dispatch modelling software on the USE levels was assumed to contribute to the remaining difference, being approximately 12%.

Differing rationales for the RSSR and ESOO scenarios

As described in Section 5.1, the rationale for the Base Scenario for this Review is to develop a scenario with a reasonably likely evolution of the NEM for the Period. More specifically, the Base Scenario is designed to forecast USE for a reasonably likely capacity mix in the NEM, given current market policies, publicly available data, and an assessment of the ongoing commercial viability of existing and new entrant plant.

The three scenarios modelled for the 2017 ESOO have different objectives to the Base Scenario in this Review. The aim of the ESOO committed capacity scenario is to provide information about 'generating units for which formal commitments have been made for construction or installation'[83]. AEMO is required to model this scenario under the market Rules. This scenario does not install capacity sufficient to meet the LRET, for example.

The stated purpose of the ESOO's two renewable generation scenarios was 'to capture a broad range of possibilities that could occur in the NEM in the next 10 years'[84]. AEMO modelled one scenario with renewables development concentrated in Victoria and one scenario with renewables development spread across the NEM. The concentrated renewables installed capacity meets the LRET and includes additional renewable capacity in Victoria from 2020 to 2025 to model the full VRET target. The dispersed renewables scenario meets the LRET and includes additional renewable capacity spread across the NEM regions.

Key assumptions and their impact on USE forecasts

In addition to the scenario objectives, there are other differences between the assumptions in the Base Scenario in this Review and the ESOO scenarios.

To understand the reasons for the differences between the USE outcomes in AEMO's and EY's modelling, AEMO and EY conducted a set of additional scenarios with the assumptions being as similar as possible. While these scenarios use the ESOO dispersed renewables scenario capacity mix with the ESOO Strong scenario featuring high demand growth and technology uptake, AEMO conducted a new simulation with two major assumption changes to the ESOO:

1. **The simulations are based on the five reference years, 2011-12 to 2015-16.** AEMO's ESOO and EY's RSSR wind and solar generation and consumption demand profiles are based on different underlying datasets. 2011-12 to 2015-16 represents the period of overlap between them and allows any differences due to choice of reference years to be minimised.

2. **For each reference year, the number of Monte Carlo iterations of different generator forced outage profiles is 100.** While EY's and AEMO's Monte Carlo modelling software both produce random outage profiles that adhere to the assumed outage rates for each generator, they do not produce exactly the same specific outages for each iteration. As discussed earlier, USE outcomes can vary greatly between iterations and a large number of iterations is required to reduce error in forecasting an expected outcome, as well as reduce this source of difference in the outcomes between AEMO's and EY's modelling. One hundred was considered a reasonable number to reduce USE differences due to the forced outage profiles simulated in AEMO's and EY's modelling software to a reasonable level.

To compare with AEMO's new simulation outcomes, EY conducted three comparison scenarios. AEMO supplied EY the details for the thermal and renewable capacity mix in the ESOO Dispersed Renewables scenario as well as the half-hourly demand and renewable generation profiles modelled by AEMO for the ESOO. EY's three scenarios have the following objectives:

- One scenario is designed to be as close to AEMO's assumptions as possible, including using the 2017 network constraint equations data set and AEMO's half-hourly profiles for demand, wind and solar, which incorporates AEMO's treatment of behind-the-meter battery storage and electric vehicles.
- The other scenarios are the same as the first, except that they explore the impact of applying EY's half-hourly profiles for demand, wind, solar, behind-the-meter battery storage and electric vehicles. These scenarios explore the impact on USE from the differences in the half-hourly profiles used (which are not the same due to differences in methodologies and underlying resource data).

[83] NER clause 3.13.3(q)(2).
[84] ESOO p. 6, 7, emphasis added. Both Scenario 2 and Scenario 3 are not required by the rules.

These new scenarios focus on 2022-23, which is the year that follows the retirement of Liddell power station. This year has some of the largest USE differences between AEMO's and EY's modelling.

Table 27 summarises the assumptions used in AEMO's new scenario and EY's three comparison scenarios. Alternative data sources and data preparation techniques have been described above.

Table 27: Summary of assumptions for the ESOO comparison scenarios

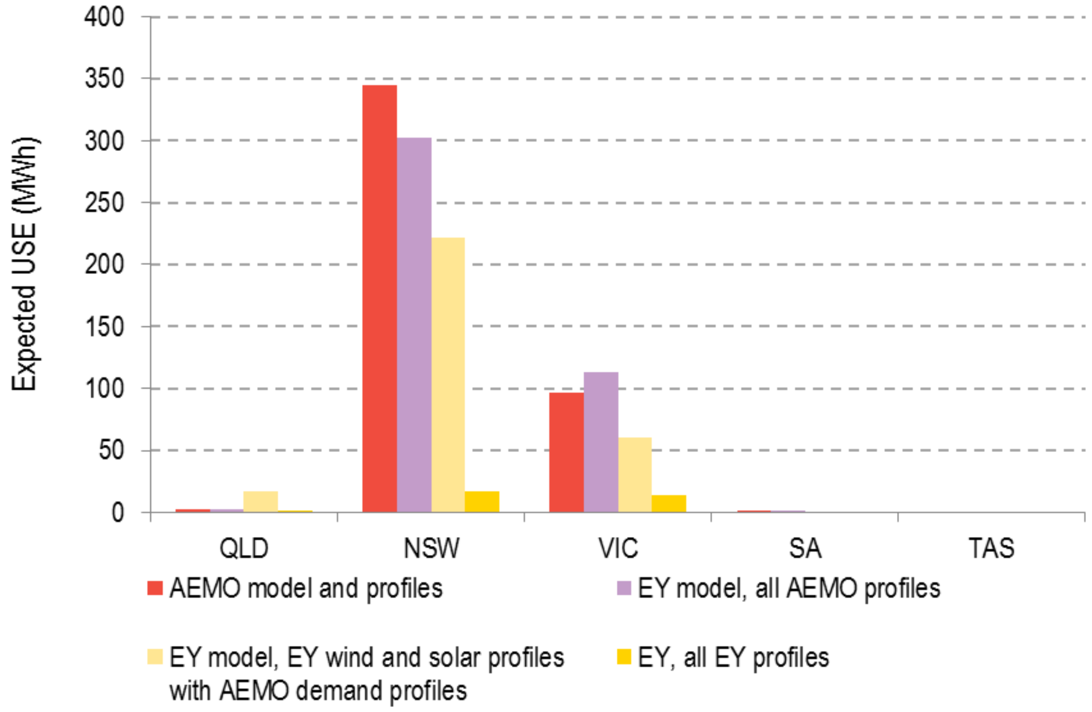
Comparison scenario	AEMO	EY - AEMO profiles	EY - EY wind and solar profiles	EY – all EY profiles
Modelling conducted by	AEMO	EY	EY	EY
Common assumptions	► ESOO Strong economic growth scenario ► ESOO Dispersed Renewables capacity mix ► ESOO thermal generator capacity mix ► ESOO 2017 constraint equations ► 100 Monte Carlo iterations ► Five reference years			
Half-hourly demand* profiles	AEMO	AEMO	AEMO	EY
Half-hourly wind and solar profiles	AEMO	AEMO	EY	EY
Modelling time-step	Hourly[85]	Half-hourly	Half-hourly	Half-hourly

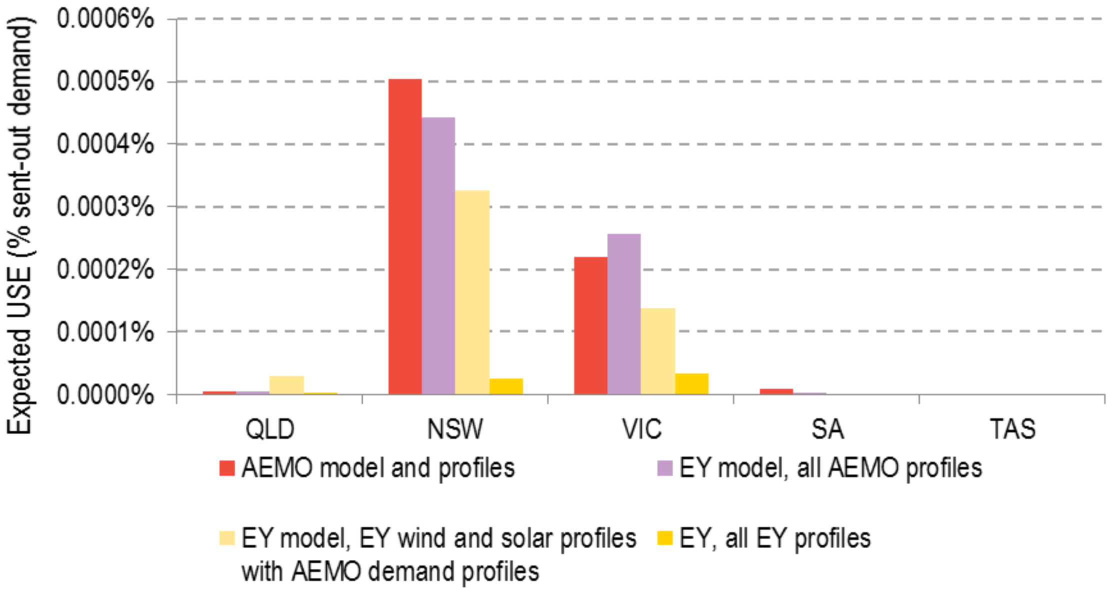
* Includes behind-the-meter battery storage and EVs

Figure 64 below shows the USE outcomes for the each of the comparison scenarios in both percentage of regional energy and absolute MWh terms.

[85] AEMO converts the half-hourly profiles for demand, wind and solar to hourly for their modelling by averaging consecutive pairs of data points to represent each hour modelled.

Figure 64: USE outcomes for the comparison scenarios*





*** Note that the y-axis extends to less than one third of the reliability standard.**

In the EY - AEMO profiles scenario, EY's modelling resulted in similar USE outcomes to AEMO's new scenario across all regions. The USE outcomes in AEMO's comparison scenario are also similar to the outcomes published for the same scenario in the ESOO. The reasons that may be contributing to the small remaining differences between AEMO's and EY's USE outcomes include:

- EY models on a half-hourly basis while AEMO models on an hourly basis
- Whilst EY and AEMO have used the same generator forced outage rates, EY's forced outages are likely to be assigned to different periods than AEMO's across the 100 iterations modelled
- Bidding profiles for generators have not been shared between EY and AEMO. Differences in bidding profiles can lead to different least-cost decisions on dispatch when constraint equations bind, which in turn can lead to different USE outcomes.

On using the EY prepared wind and solar generation profiles for each individual wind and large-scale solar farm, as well as rooftop PV generation, EY forecasts a lower USE forecast than AEMO in all regions, except QLD. Notwithstanding the reduction, the level of USE remains at comparable levels in both NSW and VIC to AEMO's outcomes. However, the USE forecast is very low in the scenario using all of EY's half-hourly profiles, at levels more comparable to the Base Scenario for this Review. This is explored further below by comparing the two sets of half-hourly profiles.

Comparing EY's and AEMO's half-hourly profiles

To compare the impact of EY's and AEMO's half-hourly profiles on USE, EY compiled the residual demand modelled in each region. As described earlier, residual demand is equal to electricity consumption minus rooftop PV, large-scale solar and wind generation and any impact of behind-the-meter battery storage[86]. Residual demand needs to be met by scheduled dispatchable generators (coal, gas and hydro), taking into account transmission constraints including across interconnectors.

As described above, in the scenarios compared in this appendix, both AEMO and EY used the same individual generators to represent the capacity mix of the ESOO dispersed renewables scenario. While the underlying electricity consumption in terms of annual energy and seasonal peaks is modelled by AEMO and EY in a similar way, residual demand will differ due to the modelling methodologies and underlying data sets for renewable generation and emerging technologies. The methodology and datasets used by EY are described in Section 7.2. Through consultation with AEMO, EY understands that the primary differences in these methodologies and data sets are:

- AEMO's wind profiles are based on the available historical generation dispatch data for wind farms in each historical year. For each future wind farm to be modelled, AEMO uses the observed wind generation from the closest available generator that existed in the historical year as a reference profile. New generators may have a reference generator which is relatively nearby or some distance away. EY's wind profiles are based on hourly wind speed data on a 12 km grid, as described in Section 7.2.2 and this data is fully available for all the reference years modelled.
- AEMO explicitly models behind-the-meter battery storage in its demand forecasts, but considers its contribution to peak demand to be highly uncertain. Currently, incentives for charging and discharging are not directly linked to wholesale market peak demand, and so AEMO assumes that the batteries discharge over a four or five hour period to benefit the consumer rather than the power system. At times of peak system demand, the contribution from behind-the-meter battery storage in AEMO's profiles is therefore assumed to be negligible. As described in Section 7.2.4, EY's behind-the-meter storage profiles assume that 70% of the installed behind the meter storage capacity will be discharging around the time of day of the seasonal peak demand.
- AEMO's selection of representative sites and panel orientations for rooftop PV generation may be quite different to those assumed by EY, leading to a potentially large difference in the contributions from rooftop PV to reducing or shifting peak demand.

EY compiled the highest 100 half-hourly periods of residual demand, after bundling together the five reference years modelled. These are the periods where there is the highest risk of USE in the modelling. For simplicity, EY analysed the future year 2022-23 only.

Figure 65 compares the top 100 half-hourly residual demands in Victoria, NSW and QLD as modelled by EY and AEMO while Figure 66 shows the outcomes for SA. The two residual demand profiles compared are based on the same large-scale renewable energy project developments, including at the same locations. The differences in the residual demands presented are due to the methodologies and resource data used in constructing the profiles.

[86] With this definition, electric vehicles are considered part of electricity consumption. While EY models the impact of EVs on demand separately to other aspects of demand, the amount of EVs forecast in the years analysed has a negligible impact on demand compared to the other aspects analysed.

Figure 65: Top 100 residual demand values in VIC, NSW and QLD based on EY's and AEMO's half-hourly profiles in 2022-23 using the ESOO Strong economic growth scenario

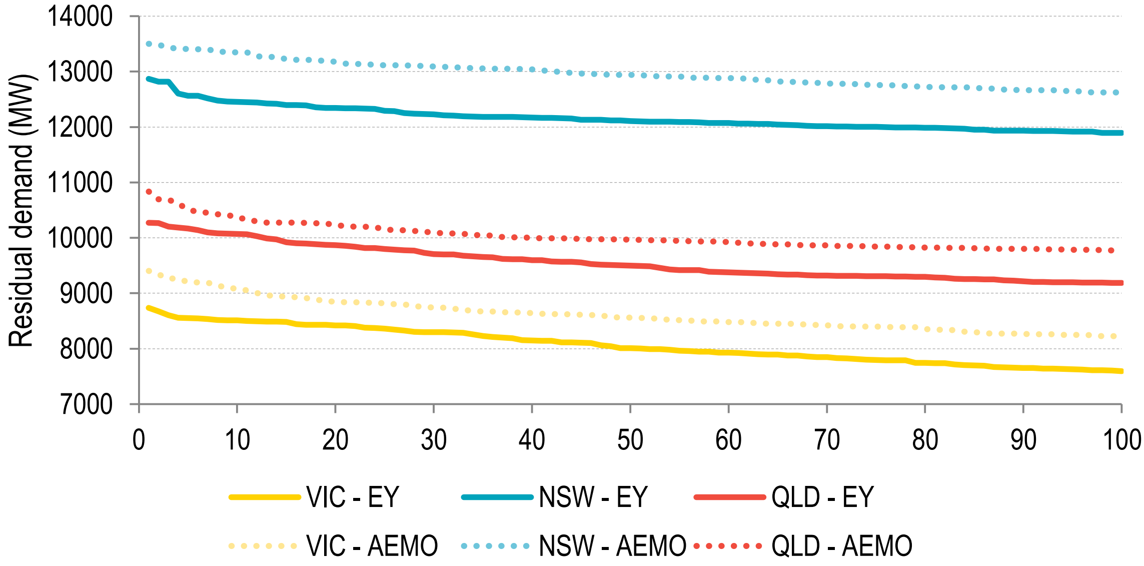


Figure 66: Top 100 residual demand values in SA based on EY's and AEMO's half-hourly profiles in 2022-23 using the ESOO Strong economic growth scenario

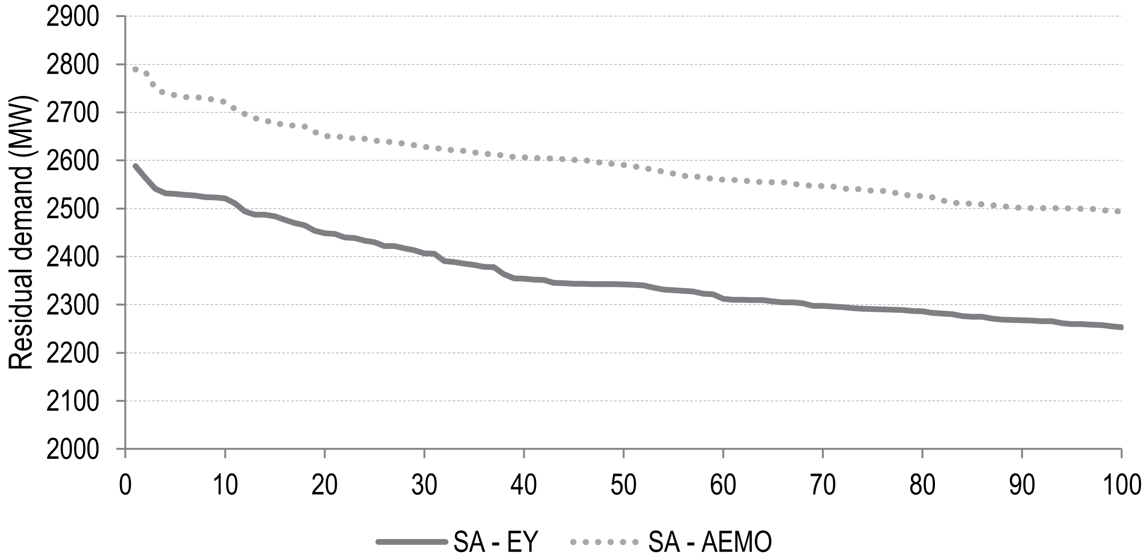


Table 28 compiles two key aspects to compare EY's and AEMO's profiles for each region: the difference in the maximum residual demand and the number of half-hourly periods in AEMO's profiles that are higher than any residual demand value in EY's profiles.

Table 28: Summary of some key aspects of difference between EY's and AEMO's residual demand profiles

Region	Difference in highest residual demand overall (AEMO minus EY) [MW]	Number of periods where AEMO's residual demand is higher than EY's highest overall value
QLD	564	16
NSW	633	62
VIC	663	30

Region	Difference in highest residual demand overall (AEMO minus EY) [MW]	Number of periods where AEMO's residual demand is higher than EY's highest overall value
SA	201	50

The above charts and the aspects in Table 28 help explain the extent to which AEMO's residual demand profiles would lead to higher USE outcomes. For example, the difference of 633 MW in the maximum residual demand in NSW means that, in that period, a simulation would need to have an additional 633 MW of generator capacity on a forced outage for the same risk of USE using EY's profiles rather than AEMO's (assuming all else equal). With AEMO's profiles having 62 half-hourly periods with a higher residual demand in NSW than any period using EY's profiles means that there are 62 periods where the risk of USE is higher with AEMO's profiles than in any period with EY's profiles.

EY analysed the residual demand in more detail (not shown) and concluded that AEMO's highest residual demands are higher than EY's due to the following combination of factors:

- **Methodology and data for modelling large-scale wind and solar generation**. This was found to have about a 50% contribution to the differences in the highest residual demands. This could be explained by EY's wind profiles having more diversity than AEMO's due to the more geographically diverse data set used by EY. Having more diversity in the profiles for individual wind farms is more likely to have milder extremes of very low (or very high) aggregate generation across a region leading to a bigger contribution to reducing the highest peaks in residual demand.
- **Modelling methodology and assumptions for behind-the-meter battery storage**. This was found to have a contribution of 25-40% to the differences, depending on the region. These differences come from AEMO assuming negligible contribution; and EY assuming 70% of capacity would contribute to peak demand. To give an example, with 786 MW of behind-the-meter battery storage assumed to be installed in NSW in 2022-23 in the ESOO Strong scenario, EY's behind-the-meter storage discharges 550 MW during peak demand periods.
- **Modelling methodology of rooftop PV**. This was found to contribute the majority of the remainder of the differences.

The higher peak demands in AEMO's profiles give higher USE outcomes than from using EY's profiles.

Conclusion

EY conducted a USE forecast of 2022-23 using as many of the ESOO 2017 assumptions as possible and achieved a similar USE outcome to AEMO. Further scenarios conducted by EY have identified that the majority of the difference in EY's USE forecast of the ESOO assumptions is due to the following factors:

- EY's modelling assumes a much greater contribution to peak demand from behind-the-meter storage as descried above, which provides materially lower peaks in the demand to be met by scheduled generators in the NEM, compared to AEMO. This estimated impact of this assumption for NSW in 2022-23 is approximately 63% of the difference of forecast USE levels.
- EY's half-hourly modelling of wind, solar and rooftop PV uses some different assumptions to AEMO. In particular, AEMO and EY use different data sets that describe the characteristics of wind in different regions. This difference in wind resource data means AEMO and EY have different wind generation profiles. The contribution of this assumption to the differing USE levels was approximately 25%.
- EY's dispatch modelling software differs from AEMO's and as a result, some aspects of the modelling approach are not the same. The contribution of this assumption to the differing levels of forecast USE was approximately 12%.

The difference observed in the USE outcomes between the RSSR Base Scenario for this Review, and

AEMO's ESOO modelling, are not material to the modelling completed for the purpose of assessing changes to the MPC, APC and CPT. Further to the analysis presented in this appendix, the MPC scenarios are constructed from a different baseline of installed capacity that threatens the reliability standard.

Appendix E Definitions and acronyms

Defined terms

Capex	Capital expenditure
Iteration	Half-hourly modelling of a single possible outcome for a future set of years
Market modelling	The process of forecasting the expected generation mix and wholesale prices in the electricity market as an outcome of a set of input assumptions, including key drivers of the market. This involves iterating on several market Simulations to arrive at a final Simulation.
Region	There are five pricing regions in the NEM: Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia and Tasmania
Residual demand	The demand required to be met by large-scale scheduled generation. This is calculated by taking the total customer electricity demand and netting off rooftop PV and large-scale wind and solar PV generation, as well as the net effect of behind-the-meter battery storage
Sent-out	For *generation*, this is the electricity supplied to the electricity network (grid), as measured at the gate of a generator. This is equal to the total generation produced by a generator minus any auxiliary power they require for their operation. *Sent-out demand* is the total electricity demand required to be supplied by large-scale generators (i.e., excluding rooftop PV) in terms of their sent-out generation.
Simulation	Half-hourly modelling of a future set of years, including multiple iterations for each year
Expected unserved energy	*Unserved energy* means the amount of customer demand that cannot be supplied in a region of the national electricity market due to a shortage of generation or interconnector capacity. It is calculated in megawatt or gigawatt hours (MWh or GWh) and is typically expressed in terms of a percentage of customer demand. The term *expected unserved energy* means a statistical expectation of a future state; an average across a range of future outcomes, weighted for probability. This is described in more detail in Box 1 in Section 7.1.

Abbreviations

2-4-C®	EY's in-house wholesale electricity market dispatch modelling software suite
AEST	Australian eastern standard time
APC	Administered price cap, applied as an alternative market price cap when market exceeds the CPT
APP	Administered price period
BoM	Australian Bureau of Meteorology
CCGT	Closed-cycle gas turbine
CET	Clean energy target
CF	Capacity factor
CPI	Consumer price index
CPT	Cumulative price threshold
DSP	Demand-side participation
FOM	Fixed operation and maintenance
FOR	Forced outage rate
LCOE	Levelised cost of energy ($/MWh). Equivalent to the long-run marginal cost (LRMC).
LRET	Large-scale renewable energy target
MLF	Marginal loss factor
MPC	Market price cap
MWh	Megawatt-hour
NEM	National Electricity Market
NSW	New South Wales
OCGT	Open-cycle gas turbine
QLD	Queensland
SA	South Australia
SAT	Single-axis tracking
USE	Unserved energy, expressed as percentage of a region's energy demand (see also, *expected unserved energy* above for definition)
VIC	Victoria
VOM	Variable operation and maintenance

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