Reliability Standard and Settings Review 2022 – Modelling Report

Final Report

31 August 2022

Intelligent Energy Systems

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Version History

Version	Date	Change(s)
V01	24 August 2022	Initial draft. Includes additional analysis section and various updates.
V02	25 August 2022	Updates to APC section
V03	31 August 2022	Minor edits. Final version

Contents

1 Executive Summary

1.1 Background and scope

Intelligent Energy Systems (IES) was engaged by the Reliability Panel (Panel) to undertake modelling with respect to the 2022 Reliability Standards and Settings Review (RSSR) covering the period from July 2025 to June 2028 (Review Period). The scope of work carried out is significantly expanded from previous reviews and is summarised in Table 1 below. The objective of this project was to carry out modelling and analysis to inform the Panel whether the reliability standard and settings are appropriate over the Review Period. The assessment of the Market Floor Price (MFP) was removed from the modelling scope in favour of focusing on the Market Price Cap (MPC), the Cumulative Price Threshold (CPT) and the Administered Price Cap (APC).

Table 1 Scope of work summary

Task	Description
1. Efficient level of the reliability standard	Determine whether the level of the reliability standard (currently set at 0.002% expected USE) remains appropriate or whether the level of the reliability standard should change. The modelling and advice under this part is to assume the reliability standard will remain expressed in terms of expected USE.
2. Optimal level of the reliability settings based on the current form of the standard	Modelling and analysis to support the Panel's consideration and determination of the level of the reliability settings to maintain the reliability standard over the review period, covering the: (1) MPC, (2) CPT, (3) MFP, and (4) APC.
3. Appropriateness of the form of the current reliability standard	Determine whether the reliability standard remains appropriate or should be expressed in alternative forms. For example, the existing reliability standard is defined in 3.9.3C(a) of the NER as the maximum expected USE in a region of 0.002% of the total energy demanded in that region for a given financial year. However, there may be alternative measures, such as Loss of Load Probability and Loss of Load Expectation, that are used internationally and could provide an alternative standard.

The reliability framework underpins one of the key pillars of the National Electricity Objectives and relates to promoting efficient investment in, and efficient operation of the electricity system in achieving reliable power supply. Reliability under the reliability framework is measured by the expected amount of unserved energy (USE) in a region over a financial year. USE is the amount of customer demand that cannot be supplied within a region due to a shortage of generation, demand-side participation, and/or interconnector capacity.

USE results presented in this report may differ from actual outcomes because (1) some events which lead to unmet demand is not regarded as USE under the reliability framework, (2) the modelling assumes no pain sharing[1] of USE in accordance with the Australian Energy Market Operator's (AEMO) 2021 Electricity Statement of Opportunities (ESOO) methodology, (3) AEMO utilises other non-market mechanisms such as directions and the Reliability and Emergency Reserve Trader (RERT) to limit load shedding, and (4) many of the results presented here are based on the distribution of USE events before the reliability gap is addressed by the marginal new entrant. The reliability gap refers to the volume of USE over and above the reliability standard.

The two key changes from the modelling supporting the 2018 Reliability Standard and Settings Review (2018 Review) relate to additional inputs from AEMO's improved ESOO modelling methodology and a fundamentally different modelling approach adopted in this work. The current modelling explicitly considers the interaction between the MPC and CPT in determining the optimal combination and standardises the USE volume, under the reliability gap, addressed by the marginal new entrant.

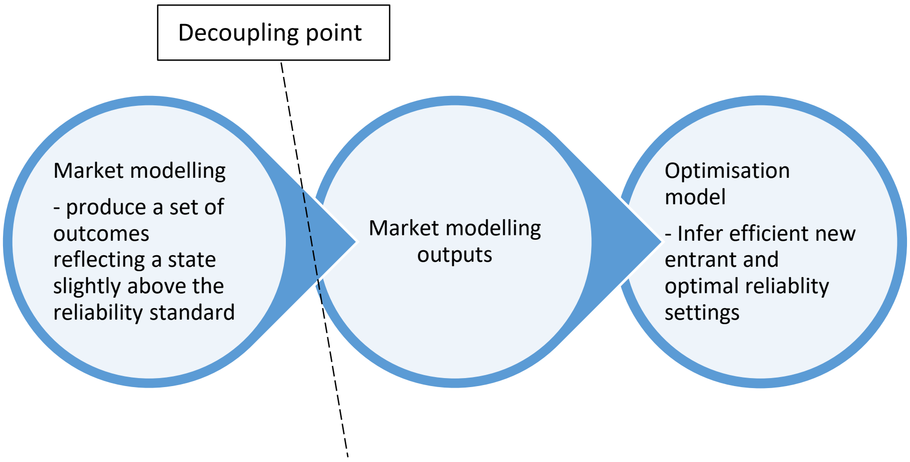
1.2 Modelling framework

The core modelling approach remains the same and is based on statistical simulations of detailed time-sequential modelling of the supply and demand dynamics in the National Electricity Market (NEM). To address the expansion in scope, particularly the interaction between the reliability settings, a bespoke optimisation model was developed to provide insights into new entrant options and related sensitivities without having to revisit the time-intensive market modelling.

The modelling framework, illustrated in Figure 1, is based on undertaking most of the supply and demand modelling, in a market simulation model, targeting a level of USE slightly above the reliability standard before decoupling. The optimisation model solves for the marginal new entrant to address the remaining USE and the corresponding optimal reliability settings separate to the market model.

[1] Pain sharing, or equitable load shedding, in the NEM is based on spreading USE across interconnected regions and is pro-rated by demand.

Figure 1 High-level overview of the modelling framework



In general, the modelling accounts for the following key issues highlighted in the Panel's 2022 Reliability Standard and Settings Review Issues Paper (Issues Paper) below.[2] Key features of the modelling steps are summarised in Table 2.

- Continued penetration of large and small-scale renewable energy (RE) generation,
- Changing operating regime and exit of traditional thermal generation,
- Increasing storage investment,
- Jurisdictional government policies incentivising new investment, and
- Extreme weather events and weather dependency.

The market modelling leverages AEMO's public 2021 ESOO PLEXOS database and was adjusted for the scope requirements of this project.

Table 2 Key features of the modelling stages

Modelling stage	Key features
Market model	1100 Monte Carlo samples per year under the Base case, and 500 samples per year for scenarios
	Includes eleven (11) reference years from 2011 to 2021, P10 and P50 demand shapes, forced outages across plants, de-ratings of interconnectors, and plant maintenance
	Accounts for latest plant closure announcements (Eraring in Aug 2025), and committed RE policies and RE policy new entrants
Optimisation model	Minimisation of total region costs (wholesale energy and USE costs) subject to revenue adequacy constraints for the marginal new entrant
	Minimisation of total region cost with respect to the reliability settings (MPC and CPT)

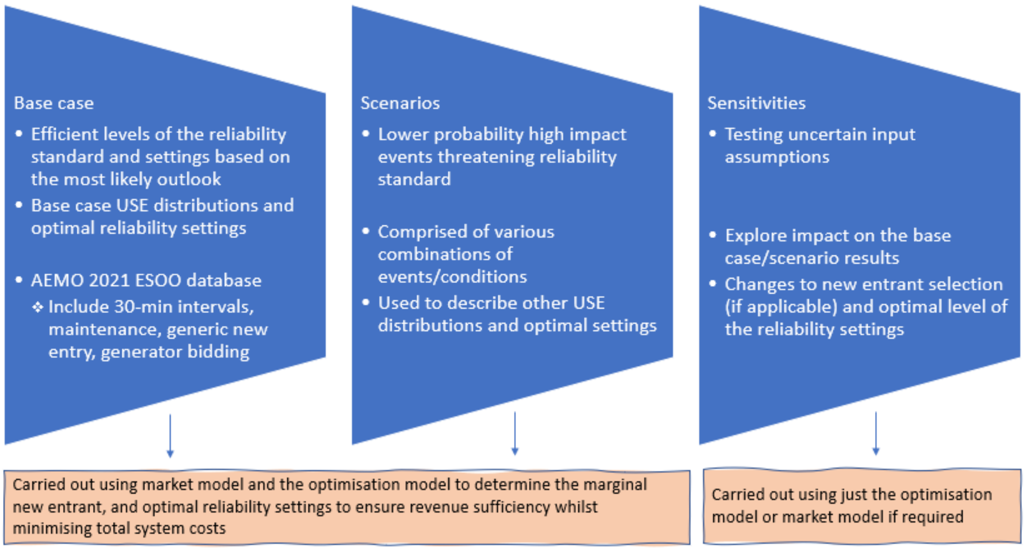
[2] Reliability Panel, 2022 Reliability Standard and Settings Review, Issues Paper, 27 January 2022.

Modelling stage	Key features
	Technology agnostic. Includes open-cycle and closed cycle gas turbines, wind and solar, battery energy storage systems and demand response
	Specific constraints or operational risks reflected for each of the different new entrant options
	Optimisation across all reliability events over Review Period, maintaining chronology for battery dispatch

The optimisation model only accounts for the optimal reliability settings from a pure cost perspective. The assessment principles set out in the Panel's Review of the Reliability Standard and Settings Guidelines (Review Guidelines) covers various other relevant aspects which talk to broader out-of-model considerations such as regulatory stability, market integrity and financial risks, contract market implications, new entrant revenue predictability, and investment price signals.[3] These issues are outside the scope of what the optimisation model can address, i.e., the results from the optimisation model can only partly inform the Panel of all the relevant considerations and in no way should be interpreted on a standalone basis.

The assessment principles and scope of work require that the modelling be based on a base case which comprises a set of assumptions, including committed policies, that are most likely to represent the state of the NEM over the Review Period. The additional scenarios to be modelled reflect alternative outlooks that would still be plausible, threaten the reliability standard, and show different USE distributions and possibly a different marginal new entrant and corresponding optimal level of the reliability settings. The approach into addressing the scope of work relies on modelling a base case, a low RE generation scenario and a mix of sensitivities to test uncertain input assumptions. This is illustrated in Figure 2.

Figure 2 Role of the Base case, scenarios, and sensitivities

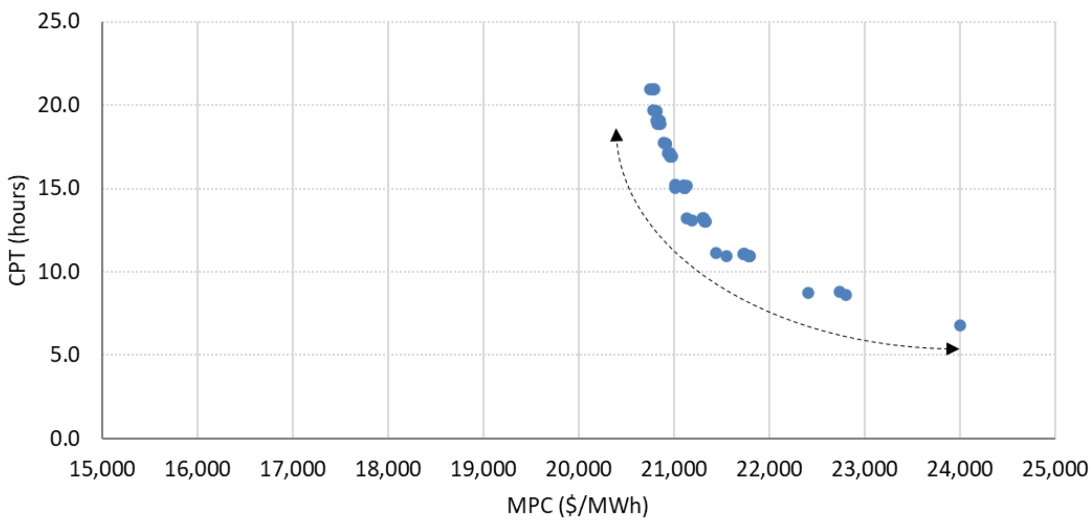


[3] Reliability Panel, Review of the reliability standard and settings guidelines, Final Guidelines, 1 July 2021.

1.3 MPC and CPT interaction

A key interaction from the optimisation model that underpins the optimal level of the MPC and CPT for a given generation technology is presented in Figure 3. The modelling found a series of MPC and CPT combinations (dots) which lie on an implicit frontier (dotted line) where the OCGT is revenue sufficient and total region costs are minimised within a small margin of error. The findings confirm a reduction in the CPT can be offset by an increase in the MPC and conversely, the reverse holds true and rules out the notion there is a single optimal MPC and CPT combination, if considering total region costs only.

Figure 3 **Plausible MPC and CPT combinations for NSW OCGT**



1.4 Key findings

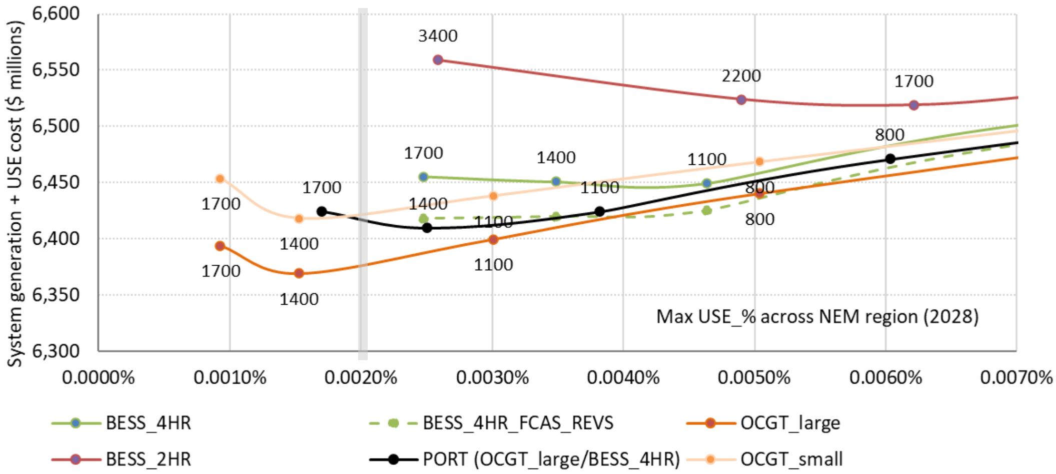
Table 3 summarises the key findings across each of the tasks outlined in Table 1. Key charts across the scope items are also provided in Figure 4 to Figure 9.

Table 3 **Summary of key findings**

Scope	Findings
Task 1 Efficient level of the reliability standard	The OCGT (large) is the most efficient from a generation cost perspective, across all relevant reliability points due to its ability to address short and long duration events. See Figure 4.
	The efficient level of the current form of the standard is around 0.0015%, however, the system cost benefit over the current 0.002% level is less than 0.2% ($10 million).
	The efficient level for the high value of customer reliability sensitivity is 0.0012% corresponding to a cost benefit of 0.5% (or $35 million) over the current 0.002% level.
Task 2 Demand and supply outlook	A reliability gap is not expected in any regions over the Review Period, consistent with updated ESOO 2021. NSW and VIC are the regions closest to threatening the reliability standard.

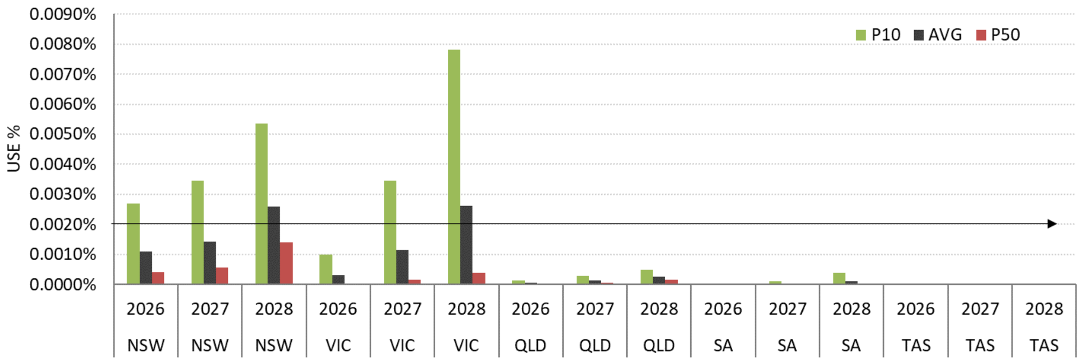
Scope	Findings
	A Base case sensitivity was run and required the removal of 1.3 GW and 1.0 GW of coal capacity in NSW and VIC, respectively, to generate a reliability gap around 0.0025% in FY2028. See Figure 5.
	Analysis of the USE outcomes in FY2028 from the Base case sensitivity show USE is expected to be driven by high demand and forced outages. Low RE contribution and reduced import limits had a secondary importance across all modelled cases.
Task 2 USE distributions before introduction of the new entrant	Short duration events, events of less than 5 hours, comprised 80% of all events simulated. See Figure 6.
	Long duration events (10+ hours) are expected to be infrequent but comprises a material share of the expected USE volumes (up to 25% in NSW, and 11% in VIC under the Base case sensitivity). See Figure 7.
	Event shapes by duration are likely to remain similar and are expected to be centred around peak demands. It is the distribution of the events that differs across the cases and shifts towards longer duration events in the case of VIC under the Low RE scenario.
	On a per sample basis, there is more than a 40% chance that there will be no USE in FY2028 across both regions.
Task 2 Optimal reliability settings	The current level of the MPC ($15,100/MWh) is likely too low over the Review Period to adequately address the reliability standard in its current form.
	There exists a range of MPC and CPT outcomes that describe the optimal set of reliability settings that produces total region costs close to the absolute minimum and allows sufficient revenue recovery for the new entrant. Broader implications should be considered to determine what would be the most appropriate. See Figure 8.
	The combination of MPC and CPT corresponding to lowest region cost favours 2-hour batteries and will not incentivise other new entrants, i.e., the combination would result in short duration new entrant capability only. However, the selection of other MPC and CPT combinations to promote a range of technologies will lead to revenue over-recovery for some new entrants, i.e., result in a higher total system cost. This would need to be balanced against the out-of-model considerations.
	The corresponding MPC and CPT combinations in VIC are significantly higher than that in NSW owing to the different underlying base USE volume corresponding to 0.002% of its demand, and the associated USE distribution.
	Sensitivities based on increasing costs or applying operational constraints, further shift the MPC and CPT combinations to the right, i.e., revenue requirements of the new entrants would be higher. The increased frequency of longer duration events and higher number of zero USE samples in the VIC Low RE case also translate to higher MPC and CPT combinations for all relevant new entrant options.
Task 3 Form of the standard	USE expressed as a percentage of demand translates to a higher cost of addressing the reliability standard in smaller regions. See Figure 9.
	Differing reliability in different regions is effectively a feature of having common price settings across all NEM regions. Selecting the optimal MPC and CPT combination that is appropriate for all regions is challenging under the current framework.
	The risk neutral approach to USE volume means it is most efficient to address short duration events to meet reliability gap but doesn't materially address long-tail events.

Figure 4 Task 1 - Efficiency functions (base value of customer reliability)



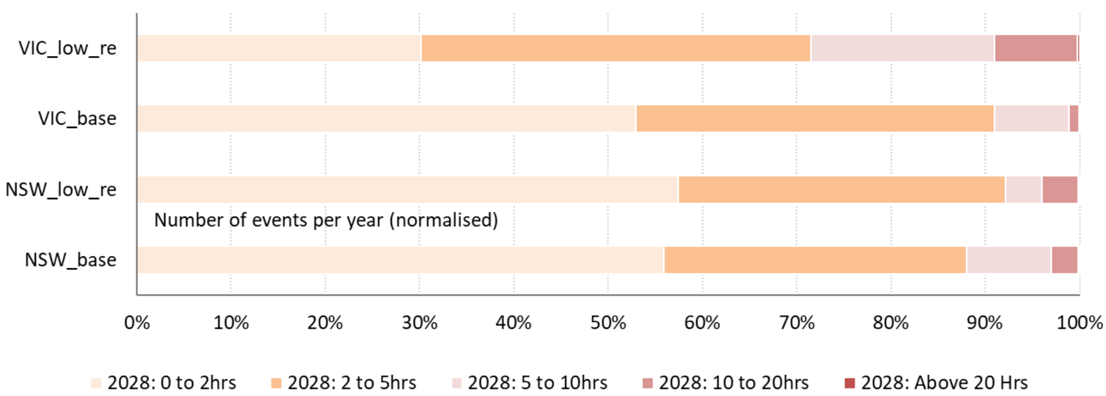
Notes: the annotations correspond to the incremental capacity added to the baseline (off chart to the right). Chart is truncated along the vertical and horizontal axis.

Figure 5 Task 2 - Base case sensitivity USE outlook



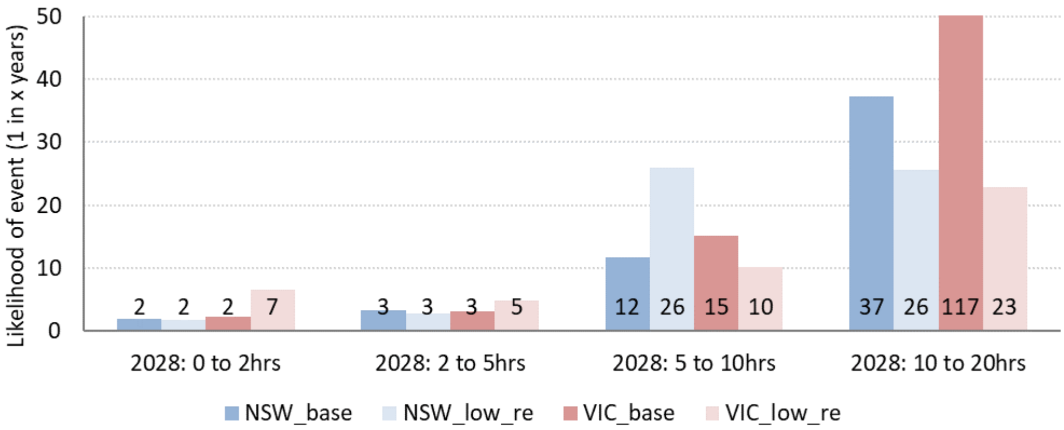
Note: Average is based on weighting the P10 and P50 outcomes 30% and 70%, respectively.

Figure 6 Task 2 - Expected events by duration (with reliability gap, normalised)



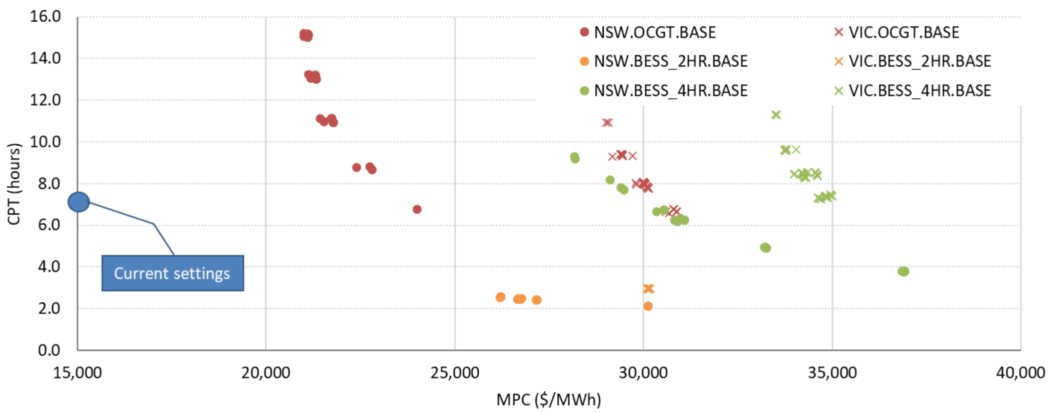
Note: Corresponds to 0.0025% in NSW and 0.003% in VIC, i.e., before the introduction of the marginal new entrant.

Figure 7 Task 2 - Likelihood of events by event duration (with reliability gap)



Note: Base refers to the Base case sensitivity and Low_RE refers to the Low RE scenario. Event distribution corresponds to 0.0025% in NSW and 0.003% in VIC, i.e., before the introduction of the marginal new entrant.

Figure 8 Task 2 – VIC and NSW baselines (Base case sensitivity)



Note: The vertical and horizontal axis has been truncated at 16 hours, and $40,000/MWh, respectively.

Figure 9 Task 3 - USE volume differences

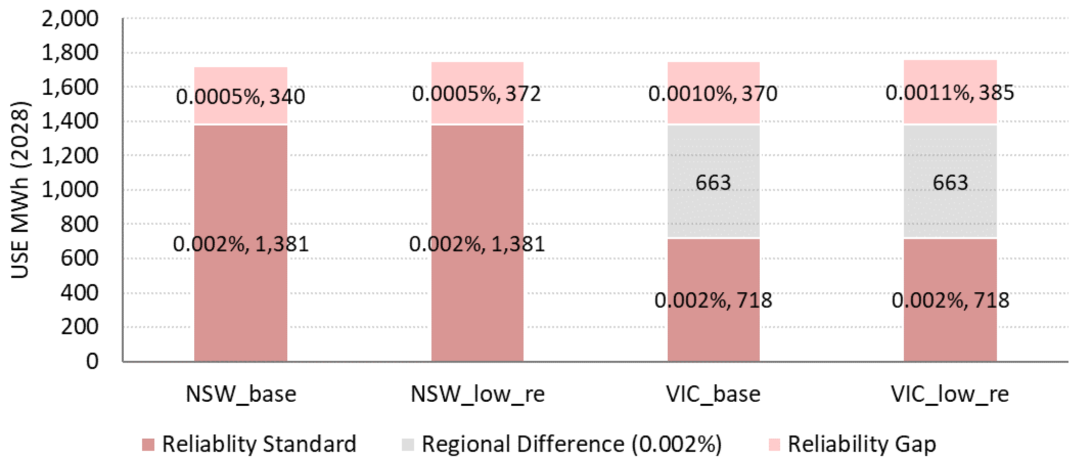


Table 4 summarises findings relating to additional analysis carried out subsequent to the draft modelling report, mainly focused on assessing the impact of higher MPC and CPT outcomes and the appropriate level for the APC. The MPC and CPT combinations considered were based on Base case sensitivity and the NSW OCGT frontier under the Base case sensitivity with MPC and CPT ranging from $21,000/MWh and 18 hours to $24,000/MWh and 7.5 hours.

Table 4 Key model findings – additional analysis

Impact	Finding
Frequency of exceeding the CPT	The average spot price allowed before triggering APP will increase from $674/MWh to more than $1,000/MWh under the combinations of MPC and CPT considered. At a minimum this corresponds to an increase of more than 55%. However, the actual likelihood of experiencing conditions triggering APP for the $21,500/MWh MPC and 8.5 hour CPT would be once every six (6) years assuming the region is at 0.002% reliability. This compares with an expected frequency of once every four (4) years based on the current MPC and CPT.
Contract settlement prices	The increase to MPC and CPT is expected to increase spot volatility and lift swap and cap settlement prices from $75.8/MWh and $8.4/MWh, respectively, by up to $7/MWh or $4/MWh in the case of a $21,500/MWh MPC and 8.5 hour CPT. The increase to swap and cap settlement prices correspond to an increase of 5% and 47%, respectively.
Average retailer costs (wholesale energy)	Average retailer costs, based on optimal hedging arrangements to minimise risk, would be expected to increase by $7/MWh to $13/MWh under the MPC and CPT combinations considered by the Panel and mainly relate to the increase in spot energy costs. See Figure 10.

Impact	Finding
	The $21,500/MWh MPC and 8.5 hour CPT combination corresponds to the low end of this range ($7/MWh) and an increase of 8% based on the same hedging arrangements for the risk averse retailer under the current MPC and CPT levels. The wholesale cost increase of 8% translates to a 3% increase to a retail consumer's bill assuming component costs remain the same.
Financial risk and prudential requirements	The added spot volatility with increasing the MPC and CPT would increase credit requirements from $60,000/MW to $95,000/MW based on a demand shape consistent with the region profile. The corresponding increase in cost was computed to be up to $0.55/MWh. The actual cost impact is likely to be significantly lower than this given the range of offsets used in the NEM, including generation credits and reallocations.
Demand response sensitivities	Allowing for zero fixed cost demand response options (up to 30 MW in the Step Change scenario) reduces the required OCGT capacity and the MPC requirements by $1,000/MWh compared to the OCGT-only portfolio. Doubling this amount of DR would further shift the frontier by $2,000/MWh to the left. At a CPT of 8.5 hours, this would correspond to an MPC of $21,500/MWh and $20,500/MWh, respectively. See Figure 11.
Appropriate level for the APC	APC and MPC/CPT: the impact of the OCGT new entrant earning revenues during APP for an increased APC up to $1000/MWh is not significant, i.e., the frontier describing viable MPC and CPT combinations for revenue adequacy does not shift and the APC can be set independent of this. APC and thermal generation costs: based on high fuel prices, an APC set to $500/MWh would cover 80% of all de-rated thermal generation capacity compared to 70% under the existing $300/MWh. Higher diesel prices only impact the level of capacity coverage above 90%. See Figure 12. APC and retailer costs: preliminary analysis indicates a lower APC favours an unhedged retailer whereas a high APC favours a prudently hedged retailer. An APC that is significantly lower than a lot of generating units' SRMCs can lead to the perverse outcome of penalising the prudent retailer.

Figure 10 Summary of average retailer cost impact

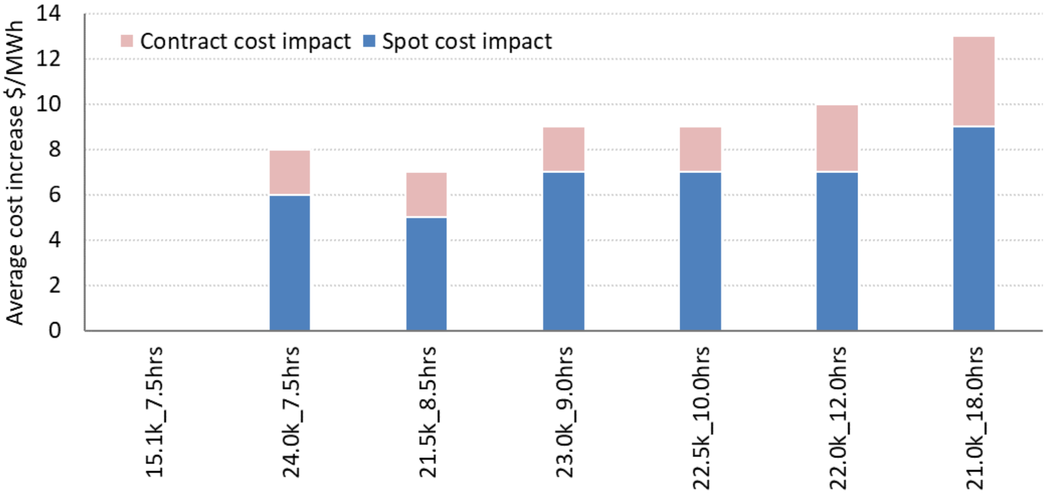


Figure 11 MPC and CPT combinations for demand response sensitivities

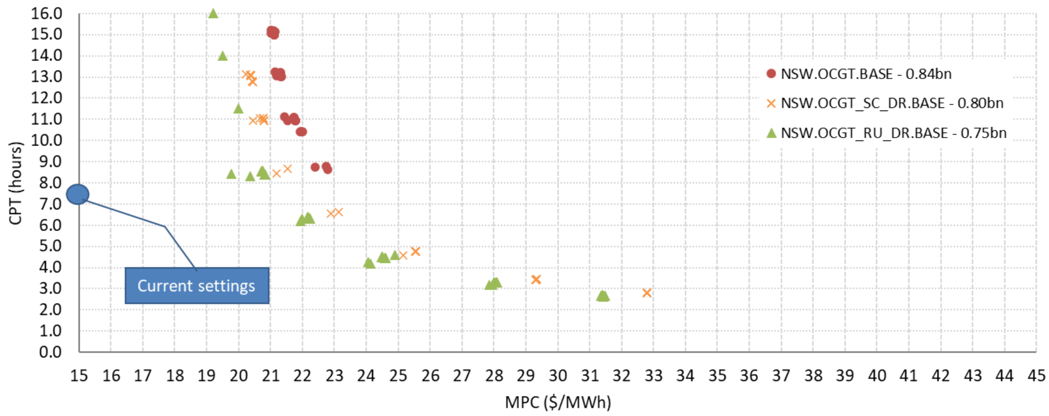
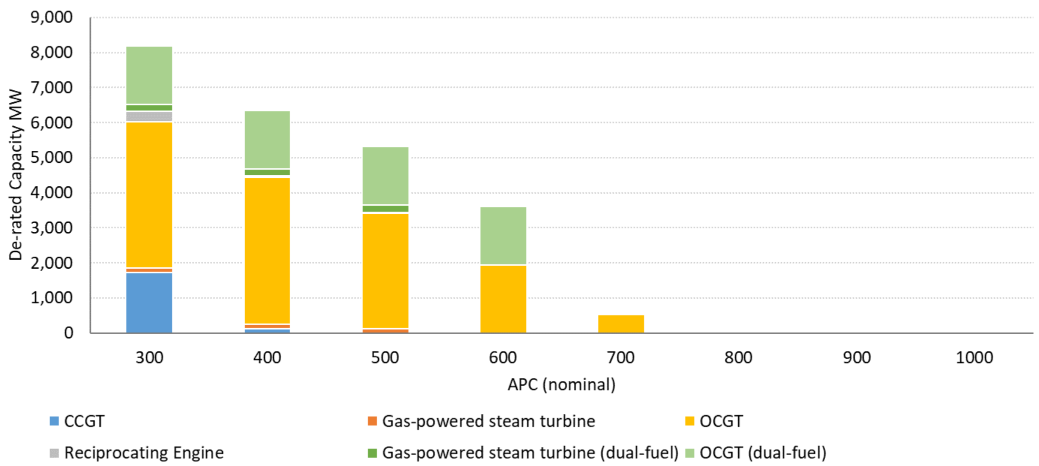


Figure 12 Supply stack above $300/MWh (de-rated capacity, FY2028)



1.5 Recommendations

Although reliability gaps are not expected under Base case modelling, it is still important the reliability settings are updated in accordance with supply and demand changes to the NEM expected over the Review Period. Based on the modelling carried out, IES recommend the following:

- Carry out further review of the form of the reliability standard to address whether the current form still meets the expectations and preferences of all stakeholders. The implications of differences in USE volumes associated with the percentage-based reliability standard and risk neutral approach of the framework may support changes to the existing form.
- The identified efficient level of USE based on the current form of the reliability standard corresponds to 0.0015% based on a large OCGT. This is lower than the current level of 0.002%, however, the relative cost difference in changing from the current level of the reliability standard to the identified efficient level (0.0015%) corresponds to a cost saving of 0.2% or $10 million. Under the high VCR sensitivity, the cost difference in shifting from 0.002% to the identified efficient level of 0.0012% is approximately 0.5% or $35 million. The cost savings in both cases are likely to be immaterial relative to other model and input uncertainties.
- Notwithstanding potential concerns around the current form of the standard, the current MPC level of $15,100/MWh is significantly lower than what is required for new entrants to deliver the current reliability standard. The modelling shows a minimum MPC of $21,000/MWh, corresponding to a CPT level of 15 hours, is required for OCGTs in NSW, or $23,500/MWh if the current CPT of 7.5 hours is maintained.[4] VIC OCGTs require significantly higher MPCs than that in NSW, of approximately $30,000/MWh. The MPC and CPT combinations for short duration battery new entrants have significantly higher MPC and lower CPT than the current levels and would not incentivise a range of technologies.
- The recommendation of increasing the MPC and CPT is supported by additional cost modelling which indicates an increase to a $21,500/MWh MPC and 8.5 hour CPT would increase a risk averse retailer's average cost of load by $7/MWh. This corresponds to an 8% increase in wholesale energy costs, or 3% of a retail consumer's total bill. The cost of the increased prudential requirements is expected to be lower than $0.30/MWh.
- The appropriate level of the APC can be set independent of the MPC and CPT. Market suspension, experienced in June 2022, is an extremely undesirable outcome and the APC should be increased to cover a higher percentage of generation costs based on high fuel prices to reduce the likelihood of experiencing similar circumstances.

[4] CPT in this report is expressed in hours of MPC for simplicity. The actual CPT is expressed in $/MWh terms.

2 Introduction

2.1 Background

The National Electricity Objective is “to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to: (a) price, quality, safety and reliability and security of supply of electricity, and (b) the reliability, safety and security of the national electricity system." As such, the reliability standard is a key feature of the NEM and the NEM’s reliability framework. This framework effectively guides the trade-off between cost of supply and reliability of the system.

The RSSR focusses on the level and form of the NEM’s reliability standard and the level of the reliability settings. The reliability standard is expressed as the maximum expected USE in a region for a given financial year.[5] It is a measure of the extent to which the electricity generation and transmission system can meet consumer demand. The reliability standard is currently set at 0.002% of regional demand. Determination of the reliability standard involves balancing the value that consumers place on the supply of electricity with the investment costs required to deliver this level of reliability.

The reliability settings are ex-ante price mechanisms that are designed to incentivise investment in sufficient generation capacity and demand-side response to deliver the reliability standard, while providing limits that protect market participants from periods of very high or very low prices, both temporary and on a sustained basis. The reliability settings consist of the:

- Market Price Cap, which places an upper limit on high dispatch prices in the wholesale market.[6]
- Market Floor Price, which places a lower limit on low dispatch prices in the wholesale market.[7]
- Cumulative Price Threshold, the limit of aggregate dispatch prices over the previous seven days that, when surpassed, triggers an Administered Price Period (APP).[8]
- Administered Price Cap, the prevailing dispatch price that applies during an APP after a set of sustained high dispatch prices exceed the CPT.[9]

The objective of the project was to carry out modelling and analysis to inform the Panel of whether the reliability standard and settings are appropriate over the Review Period. The modelling and analysis have been carried out in accordance with the National Electricity Rules (clause 3.9.3A) and the Review Guidelines.

[5] Clause 3.9.3C of the National Electricity Rules.
[6] Clause 3.9.4 of the National Electricity Rules.
[7] Clause 3.14.1 of the National Electricity Rules.
[8] Clause 3.9.6 of the National Electricity Rules.
[9] Clause 3.14.1 of the National Electricity Rules.

2.2 Report notes

The basis of figures quoted in this report, unless otherwise stated, is listed in Table 5. References to the AEMO's Electricity Statement of Opportunities refers to the August 2021 release.

Table 5 Reporting basis

Reference	Basis
Years	Financial year basis starting 1 July to 30 June
Capacity and generation	As generated
Demand	Operational sent out basis
Dollars	Real, June 2021 Australian dollars
Average prices	Time-weighted
Cumulative Price Threshold	Expressed in hours of MPC for interpretability[10]
Short-run marginal cost	Sent-out
Fuel prices	Delivered

[10] The actual CPT is expressed in $/MWh terms.

3 Scope of work

3.1 Scope of work

The scope of this review is to carry out the assessment of the reliability standard and settings in accordance with the requirements set out in the NER (Chapter 3) and adhere to the guiding principles and assumptions set out in the Review Guidelines. The assessment must also cover the impact on spot prices, investment in the NEM, market participants and reliability of the power system. The RSSR covers the three-year period from 1 July 2025 to 30 Jun 2028.[11]

The NEM is rapidly evolving with significant supply and demand uncertainties persisting over the Review Period which will require additional modelling inclusions relative to the modelling carried out as part of the 2018 Review. Furthermore, new market reforms and state-based policies, and changing market conditions need to be accounted for in this work.

The modelling scope initially included all four reliability settings, but the MFP was subsequently removed from the overall scope to focus on the MPC, CPT and APC.[12] The revised scope of work is summarised in Table 6.[13] See Appendix B for definitions of the reliability settings.

Table 6 Scope of work summary

Task	Description
1. Efficient level of the reliability standard	Determine whether the level of the reliability standard (currently set at 0.002% expected USE) remains appropriate or whether the level of the reliability standard should change. The modelling and advice under this task assume the reliability standard will remain expressed in terms of expected USE.
2. Optimal level of the reliability settings based on the current form of the standard	Modelling and analysis to support the Panel's consideration and determination of the level of the reliability settings to maintain the reliability standard over the review period, covering: (1) the MPC, (2) the CPT, and (3) the APC.
3. Appropriateness of the form of the current reliability standard	Determine whether the reliability standard remains appropriate or should be expressed in alternative forms. For example, the existing reliability standard is defined in 3.9.3C(a) of the NER as the maximum expected USE (USE) in a region of 0.002% of the total energy demanded in that region for a given financial year. However, there may be alternative measures, such as Loss of Load Probability and Loss of Load Expectation, that are used internationally and could provide an alternative standard.

Note: Task 4 (Appropriateness of the form of the reliability settings) was removed from the modelling scope to focus on Tasks 1 to 3. Task 5 relates to additional modelling requirements covered in Section 11.

The work covers a base case reflecting the most likely outlook, a low renewable generation scenario and various sensitivities. The scenarios and sensitivities are intended to explore other

[11] AEMC, Extension of time and reduction in scope of the 2022 reliability standard and settings review, Rule determination, 03 March 2022.

[12] High-level analysis for the APC was included after the draft modelling report.

[13] Reliability Panel, Reliability Panel 2022 Review of the reliability standard and settings, Draft report, June 2022.

plausible circumstances likely to result in a breach of the reliability standard with the intention of exploring the distribution of USE outcomes (shape, depth, frequency, duration, location) and the efficient set of new entrants and corresponding reliability settings to bring the system back in line with the reliability standard.

3.2 Review guidelines

The Review Guidelines set out the criteria and processes for undertaking this assessment which may be used to inform the Panel's decision to recommend potential changes to the reliability standard and settings. These are summarised below:

- The assessment framework needs to consider the National Electricity Objectives, including (a) efficient market price signals for investment, whilst limiting extreme risks and risks to market integrity, (b) delivering a level of reliability consistent with the value placed on reliability by end-users, and (c) delivering reliability outcomes that balances stability of investment but is also capable of adjusting to a changing market environment.
- The assessment approach needs to consider the form and level of the reliability standard and the related reliability settings: MPC, CPT, MFP and APC.[14]
- The work needs to consider and provide insight into the impact of any changes to the reliability settings on spot prices, investment in the NEM, reliability of the system and market participants.
- The modelling must account for the value of customer reliability (VCR) determined by the Australian Energy Regulator (AER).
- The modelling approach needs to consider the long-term equilibrium between reliability and price (or revenues) and consider technology-neutral capacity investment and retirement over the Review Period. The assumptions underpinning the modelling work needs to be transparent and consulted on and sensitivity analysis applied for uncertain inputs that may have a material bearing on reliability outcomes.

The approach underpinning the modelling described in the report follows the assessment principles of the Review Guidelines and addresses the scope of work as set out by the Panel.

3.3 Key assessment principles

The assessment principles and approach for each of the reliability settings are summarised in Table 7. The determination of the optimal level of the reliability settings is covered in the main modelling framework, however, additional analysis will also be carried out to address broader scope questions that do not specifically relate to costs.[15]

[14] Refer to Appendix B for definitions. Assessment of the MFP is not in scope.
[15] The modelling framework only considers costs, i.e., the results should not be interpreted on a standalone basis.

Table 7 Assessment principles of the reliability settings

Setting	Assessment principles
Market Price Cap	(a) The MPC should not be used to actively steer the market into a short-run equilibrium position, or to actively drive disinvestment decisions, (b) While the MPC may move either up or down over time, these movements should be gradual. These movements should occur over a period of several review periods, and (c) When setting the MPC, the Panel should give consideration to the MPC's effect on the financial burden faced by participants from high market prices, including price volatility and impacts on retailers.
Cumulative Price Threshold	(a) The CPT should protect all market participants from prolonged periods of high market prices, with consideration to impacts on investment costs and the promotion of market stability, (b) The CPT should not impede the ability of the market to determine price signals for efficient operation and investment in energy services, and (c) The CPT should be determined giving consideration to the level of the MPC.
Market Floor Price (not in scope)	(a) The number and frequency of trading intervals where the market price has been, or has approached, the level of the MFP, and (b) Whether there have been significant changes in the generation fleet, such that average generator cycling costs have changed significantly.
Administered Price Cap	(a) Significant changes in the typical short-run marginal costs of generators in the NEM, and (b) Any compensation claims since the last review.

Source: Review Guidelines.

3.4 Scope changes from the previous review

The key differences between the scope of work underpinning the current RSSR and the 2018 Review is summarised below. The scope for the current review is significantly expanded to address a wider spectrum of questions and changes expected over the Review Period. Other key differences expected with the current review relate to the changing energy landscape and appropriately capturing these new dynamics (refer to Section 4.1).

Table 8 Comparison to 2018 Review scope

Scope item	Previous review	Current review
Determine whether the level of the current reliability standard remains appropriate or is efficient	Not included	Included (Task 1)
Modelling and analysis to determine the optimal level of the reliability settings	Included, except the MFP	Included but MFP removed from scope (Task 2)

Scope item	Previous review	Current review
Determine whether the form of the reliability standard is appropriate	Not included	Included (Task 3)
Determine whether the reliability settings in its current form is appropriate	Not included	Removed from scope.[16]

The approach adopted for the modelling work is fundamentally different to that used in the previous review. This is discussed in more detail in Section 5.6.4. The current approach also includes the following considerations not present or were not relevant or available in the previous review:

- Extended reference year data (11 years) combined with corresponding renewable generation traces. The previous review was based on 6 reference years.
- Outages and partial de-ratings of inter-regional interconnectors, and the inclusion of plant maintenance.
- Consideration of frequency control ancillary services (FCAS) revenue streams for various new entrant options, and the impact on the optimal level of the reliability settings.
- Scenarios to investigate a broader range of drivers of USE focused on low solar and wind yields.
- Consideration for the interaction between the MPC, CPT and APC.

[16] Reliability Panel, Reliability Panel 2022 Review of the reliability standard and settings, Draft Report, June 2022.

4 Appreciation of the issues and challenges

4.1 Rapid power system changes

The Issues Paper highlights the rapid changes occurring across the power system. These changes have increased at a rapid pace which introduces significant uncertainties from an operational, commercial and/or regulatory perspective and is likely to continue well beyond the Review Period. The drivers of change are summarised in the table below with high-level implications for system reliability and the modelling work.

Table 9 Current drivers of change in the NEM and RSSR implications

Driver	Implication
Continued penetration of large and small-scale renewable energy generation	Variable renewable energy (VRE) has materially changed the supply and demand mix, and pricing dynamics in the NEM. The increasing share of renewable generation has displaced significant amounts of thermal generation resulting in retirement implications.
Changing operating regime and exit of traditional thermal generation	Coal power stations provide baseload energy and other system services contributing to system security and reliability. The retirement of coal plant without appropriate new entrant replacements can reduce system reliability.
Increasing storage investment	Its capability in providing multiple services (energy, FCAS, network, etc.), and therefore multiple revenue streams should be considered when determining the optimal level of the reliability settings.
Increasing demand-side participation and introduction of Wholesale Demand Response (WDR) market reforms	The reliability standards and settings reviews have traditionally focused on supply-side options to deliver reliability outcomes. The introduction of WDR can impact the marginal new entrant option and corresponding reliability settings.
Increasing spot and frequency control and ancillary services price volatility	Price signals reflect underlying supply and demand dynamics directly impacting the marginal new entrant generator. The reliability framework needs to account for the balance of generation costs recovered through the reliability settings.
Increased network congestion and important of increasing interconnectivity	Network congestion across the system limits generation output to meet demand, directly impacting reliability but also revenue outcomes of new entrant plants.
Jurisdictional government policies incentivising new investment	Impacts market price signals that drive commercial new entrant investment and addresses system reliability through added supply. The review needs to account for these supply impacts.
Increasing use of reliability directions by AEMO, and the Interim Reliability Measure	The Interim Reliability Measure, use of RERT and reliability directions is an out-of-market process which falls outside the reliability framework and is therefore out of scope.
Extreme weather events and weather dependency	The increasing renewable energy generation mix translates to a power system that is more reliant on weather outcomes. The corresponding distribution of USE may exhibit longer tails which will have implications for how this risk is captured in the reliability framework.

4.2 Interactions between the reliability standard and reliability settings

It is important to recognise the interdependencies and interactions of the reliability standard and settings that underpin the reliability modelling. The reliability settings are determined to encourage suitable investment to meet the reliability standard, and conversely, changes to the reliability settings will impact the level of new entrant investment and the generation mix, and in turn the level of system reliability. Investment in the new entrant is only feasible if the new entrant can recover its costs. The following underpins the modelling approach:

- There is an efficient new entrant portfolio that adequately addresses supply shortfalls up to the reliability standard. Out of this portfolio, there is a marginal new entrant that addresses the last MWh of USE in reaching the reliability standard.
- The reliability settings are set so that the marginal new entrant earns just enough revenue to recover its costs, consistent with the long-term equilibrium requirement in the guidelines.[17]
- The marginal new entrant is a function of the reliability standard and settings, supply and demand factors driving the distribution of USE, and the associated new entrant capital and operational costs.
- The level of the reliability settings can also impact or incentivise various new entrant types.

In theory there could be many combinations of the reliability settings which would address the marginal new entrant revenue recovery requirement and deliver the same reliability; however, various combinations of the reliability settings would have different total system costs. From a modelling perspective, the optimal level of the reliability settings is the set corresponding to the lowest system cost.[18]

4.3 Modelling challenges

The general modelling approach, consistent with previous reviews, is to iteratively run many statistical simulations across variations in forced outage profiles, weather sensitive peak demands, and demand shapes, across a base case and a number of relevant scenarios and sensitivities. The expanded scope of work combined with limits on computing resources and project timeframes, constrains the level of detail or number of samples that can be simulated. Simplifying assumptions have been made to ensure the approach can adequately capture the interactions between the marginal new entrant and the reliability settings. These trade-offs are discussed in the approach and modelling methodology sections that follow.

[17] Capacity investment decisions are made over horizons corresponding to the economic life of the project which can exceed 20 years. The scope focuses on the Review Period as a simplification.
[18] Refer to Section 5.6.5 for out-of-model considerations and limitations.

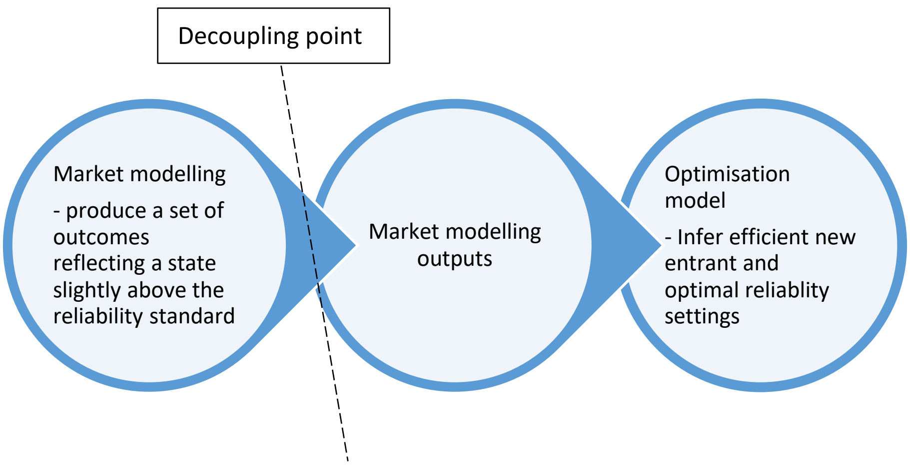
5 Modelling Framework

5.1 Overview

The core modelling and analysis is based on statistical simulations of detailed time-sequential modelling of the supply and demand dynamics in the NEM. However, the expanded scope of work including the scenarios and sensitivities to be carried out, and a clear scope requirement to deliver insights, has necessitated changes from the traditional approach solely based on market modelling for assessing various components of the scope of work. Carrying out this work solely through traditional market modelling tools was not feasible given project timeframes and cost constraints.

The approach was to undertake most of the supply and demand modelling in PLEXOS, a market simulation tool, targeting a level of USE slightly above the reliability standard before decoupling and addressing the marginal new entrant and the optimal reliability settings in a separate optimisation model. The optimisation model is a bespoke model developed by IES to address the interaction between the MPC and CPT. Figure 13 provides a high-level overview of this and Table 10 summarises the key features of each modelling step.

Figure 13 High-level approach



The decoupling is key a feature of the approach but requires that the market modelling deliver a system state and set of outcomes that is close to the reliability standard so that the marginal new entrant can be inferred without impacting generator dispatch and pricing outcomes. This allows for the simplifying assumption that for small additions of capacity, the marginal new entrant has no impact on prices and dispatch. This allows for separate modelling of various new entrant options and sensitivities to explore the impact on the optimal level of the reliability standard without having to revisit the time- and compute-intensive market modelling step. This approach allows for flexibility in exploring the various dynamics, but only within a certain level of change.

Table 10 **Key features of the modelling stages**

Modelling stage	Key features
Market model	1100 Monte Carlo samples per year under the Base case, and 500 samples per year for scenarios
	Includes eleven (11) reference years from 2011 to 2021, P10 and P50 demand shapes, forced outages across plants and de-ratings of interconnectors, plant maintenance
	Accounts for latest plant closure announcements (Eraring in Aug 2025), and committed RE policies and RE policy new entrants
Optimisation model	Minimisation of total costs (wholesale energy and USE costs) subject to revenue sufficiency for the marginal new entrant, i.e., the CPT and MPC are optimised to minimise cost but still allow for revenue sufficiency
	Technology agnostic. Includes open-cycle and closed cycle gas turbines, wind and solar, battery energy storage systems and demand response as viable options
	Specific constraints and operational risks reflected for each of the different new entrant options
	Optimisation across all reliability periods, maintaining chronology for battery dispatch

Figure 14 illustrates how, for a given form and level of the reliability standard, the marginal new entrant is determined to meet the reliability standard and how the optimal reliability settings are determined to ensure revenue sufficiency.

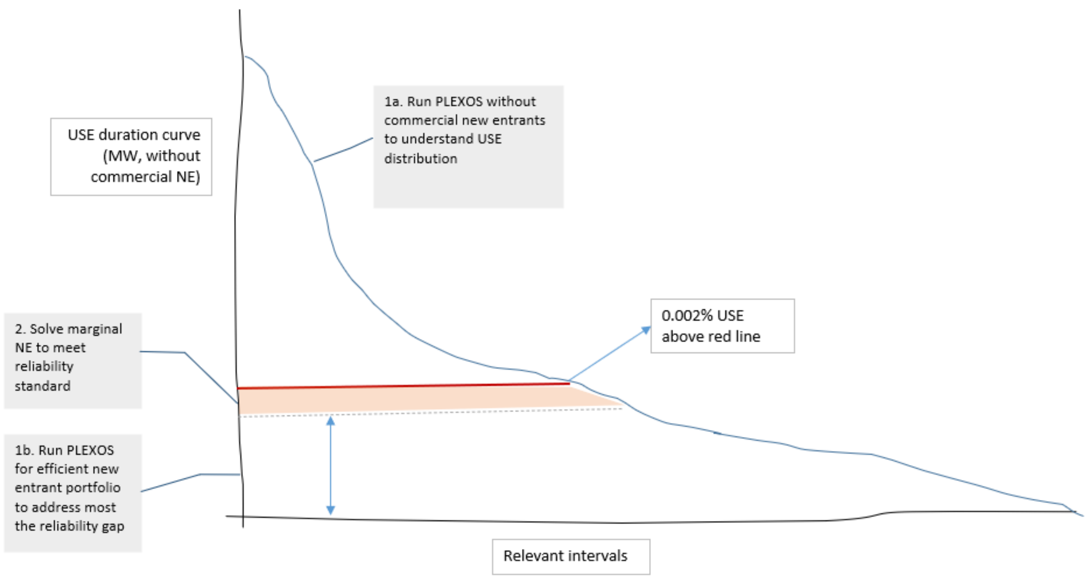
- The Review Period will be run without any commercial new entrants but will include RE policy new entrants to determine the level of the reliability gap.[19] An RE policy new entrant is defined as one that is supported by or derive a portion of its revenues from government RE policy schemes. The resultant USE is represented as a duration curve.[20] The area under the chart corresponds to the total USE volume, and the area above the red line corresponds to 0.002% of USE, i.e., the current level of the reliability standard.
- The market modelling step involves introducing an efficient portfolio of commercial new entrants to create a solution with USE (dotted line in the figure) that is very close to the 0.002% reliability standard (red line in the figure). Commercial new entrants are new entrants that rely purely on market revenues without assistance from subsidies or revenues from RE policy schemes. It is at this point the decoupling from the market model occurs.
  - If the outlook does not have a reliability gap, then remove coal units in the regions that are closest to the 0.002% reliability standard until a reliability gap is generated.

[19] The reliability gap refers to the volume of USE over and above the reliability standard.
[20] A duration curve is a method to describe the distribution and is based on ranking the values from highest to lowest.

- The market modelling outputs are fed into the optimisation model to solve for the efficient new entrant which addresses the remaining reliability gap (represented by the orange area between the dotted line and red line).
- The dotted line is set at 0.0025% of regional demand. This implies the reliability gap, or the volume that needs to be addressed by the marginal new entrant is 0.0005%. The reliability gap needs to be standardised to ensure outcomes are comparable across regions and scenarios.[21]

Table 11 summarises the steps but is covered in more detail in further sub-sections.

Figure 14 USE and modelling components



Note: Representation is based on modelling outcomes resulting in a reliability gap in step 1a.

Table 11 Modelling framework steps

Step	Objective	Description	Main outputs
1a	Determine if there is a reliability gap and the corresponding USE distribution	Run PLEXOS LT to determine the required policy-based new entrants, then the ST to verify whether there is a reliability gap. No commercial new entrants are allowed.[22]	USE distribution after the inclusion of RE policy-based new entry to determine whether a reliability gap exists.

[21] Iterations are carried out until the expected USE outcome is approximately within 5% of the desired level. The exact USE target is reached by scaling the USE outcomes. See Section 9.1 for more information.
[22] Refer to Appendix C.1 for details on the PLEXOS solve phases.

Step	Objective	Description	Main outputs
1b (if there is a reliability gap)	Address most of the reliability gap to obtain modelling outputs corresponding to 0.0025% of USE	Iteratively run PLEXOS LT and ST with commercial new entrants allowed to address most of the reliability gap. The idea of almost addressing the reliability standard from this step is so we can then decouple from the market modelling for step 2.	Obtain USE, dispatch, and pricing/revenue outcomes
1c (if there is no reliability gap)	Remove capacity to generate a reliability gap	Run PLEXOS ST, incrementally removing coal units from the regions that are closest to the 0.002% reliability standard. Target a reliability gap corresponding to 0.0025% USE.	
2	Determine the marginal new entrant and optimal reliability settings	Run the optimisation model to solve for the efficient new entrant and corresponding optimal reliability settings.	Efficient new entrant and its revenue profile, corresponding optimal reliability settings and total region costs.

Note: Refer to Appendix C.1 for more information on the PLEXOS market modelling tool.

5.2 Market modelling

The core modelling and analysis is based on statistical simulations of detailed time-sequential modelling of the supply and demand dynamics in the NEM incorporating:

- 30-minute resolution interval modelling,
- regional demand and transmission with intra-regional network constraints,
- seasonal generator ratings,
- generator bidding response,
- variable generation from solar and wind plants,
- jurisdictional RE policies,
- pricing and revenue outcomes, and
- USE outcomes.

The market modelling has been based on AEMO's 2021 ESOO public PLEXOS database adjusted for the scope requirements of this project.[23] The statistical simulations are based on running a suitable number of samples per year in the Review Period to account for variations of the following:

- Reference weather years from 2011 to 2021.

[23] Please refer to AEMO's 2021 Electricity Statement of Opportunities report for further details.

- Weather sensitivities in the form of 50 and 10 POE demand traces.
- Forced outage simulations at the plant level, and de-rating of interconnectors.

The reliability standard is expressed as an expectation (or mean) and carrying out many statistical simulations allows us to attempt to capture unlikely USE events to verify system reliability over a wide range of possible outcomes against the reliability standard. This modelling step for assessing reliability remains unchanged from the previous review and AEMO's ESOO work and underpins much of the project modelling.

The remainder of the section discusses the optimisation model, the approach to key issues and the tasks, information regarding the ESOO 2021 database, differences in modelling methodology to the previous review and other modelling considerations including the modelling limitations.

5.3 Optimisation model

The market modelling step provides inputs for the optimisation model to determine the marginal new entrant and the optimal level of the settings. The optimisation model covers all relevant periods of USE and periods relevant to calculation of the CPT, i.e., the periods after significant USE events which may trigger CPT.

The optimisation model only accounts for the optimal reliability settings from a pure cost perspective. The assessment principles for the reliability settings, refer to Table 7, cover various other relevant aspects which the reliability settings impacts, some of which extend beyond the reliability framework; such as regulatory stability, market risk and investment price signals. These issues are outside the scope of what the optimisation model can address. Hence, the results of the optimisation model should not be interpreted on a standalone basis. Where possible, these issues are raised and commented on qualitatively in the report.

Key features of this model are summarised in Table 12 below.

Table 12 Overview of optimisation model

Feature	Description	Comment
Objective function	Minimising total region cost defined as spot price * served demand + VCR * USE. Costs are weighted in accordance with P10 and P50 samples.	The system cost definition is different to the one used for addressing the task 1 efficiency question which is based on productive efficiency
Main variables	- MPC, CPT, APC, MFP - New entrant dispatch and capacity build - Prices as a function of the settings for the periods assessed	APC and MFP are fixed in the modelling. New entrant capacity modelled as continuous.
Constraints	- Revenue sufficiency of the marginal new entrant generator - Generator specific constraints such as battery minimum state of charge - Capacity factor constraints, as required - MPC bounded by region VCR	Revenue condition defined as:

Feature	Description	Comment
		Pool revenues (energy and FCAS[24]) – O&M costs – annualised capital cost repayments – fuel costs – charging costs.
Basis	Solved for each region with a reliability gap on a standalone basis, in line with the definition of USE	See Section 8.4.2 for more information
Periods assessed	Intervals across all samples of the market modelling with the following conditions: - USE intervals - Intervals leading up to the USE and after the event	Chronology in the solve is maintained.
Assumptions	- Marginal new plant does not impact existing generator dispatch and pricing outcomes - The marginal plant also earns revenues in line with average revenues for the same generation type in the same region outside of the periods assessed in the optimisation - Cost assumptions based on the same set used in the market modelling	
Inputs from the market modelling outputs	For each period that is assessed: - USE, capacity factors for each generation type for each period assessed, prices, surplus capacity For periods outside of the assessment: - revenues by region and generator type - assumed FCAS revenues (from external analysis)	See Appendix C.4 and 0 for information on the external revenue assumptions covering energy and FCAS.
Outputs	Optimal level of the reliability settings, marginal new entrant type and capacity required, total system cost, revenue breakdown of marginal new entrant	

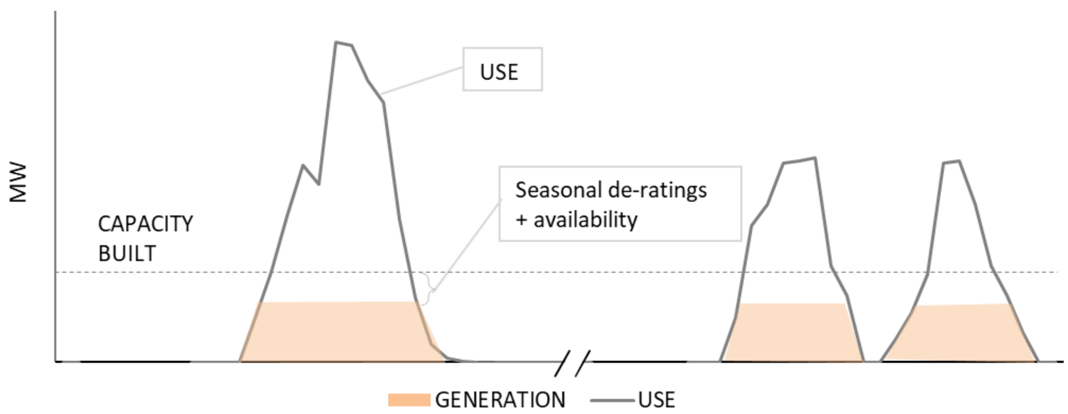
The optimisation model considers the dynamics associated with each of the new entrant generation types – these are summarised in Figure 15 to Figure 18.[25] The charts show USE (grey line) and the corresponding generation or demand response (orange area). If all USE events were plotted, the area under the grey line would correspond to the total expected USE, the total generation would correspond to the reliability gap, and the difference corresponding to the 0.002% reliability standard.

[24] FCAS revenues to be based on separate analysis as it is not accounted for in the PLEXOS energy-only modelling (see Appendix C.5).

[25] Coal and pump hydro was not considered due to its long lead times of 6 and 7 years, respectively.

- OCGT and CCGT (Figure 15): The actual availability will be de-rated for forced and planned outage assumptions, and seasonal de-ratings. The baseline modelling assumes 100% fuel availability but considers fuel supply limits and delayed responses to USE through sensitivities.
- Battery energy storage systems (Figure 16): The chronology of the USE events and periods leading up to it will be maintained so that the sizing of the battery energy storage system (BESS) is a function of available surplus energy prior to the event and the reliability gap that needs to be addressed.[26] FCAS revenues are also considered in the revenue condition.
- Onshore wind and large-scale solar (Figure 17): The actual input traces and curtailment levels from the market modelling will be used to account for new entrant solar and wind contribution towards USE periods in the solve.
- Demand response (Figure 17): is based on a fixed block of load across a maximum assumed number of hours per day relating to the response capability.

Figure 15 New entrant type considerations – OCGT and CCGT



[26] Surplus energy is based on curtailed energy from solar and wind plants, and surplus capacity at non-energy limited plants.

Figure 16 New entrant type considerations – BESS

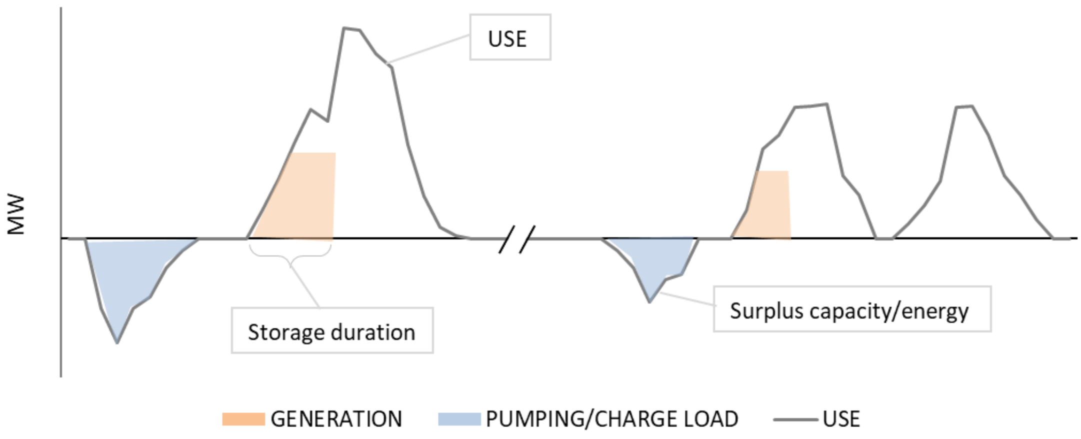
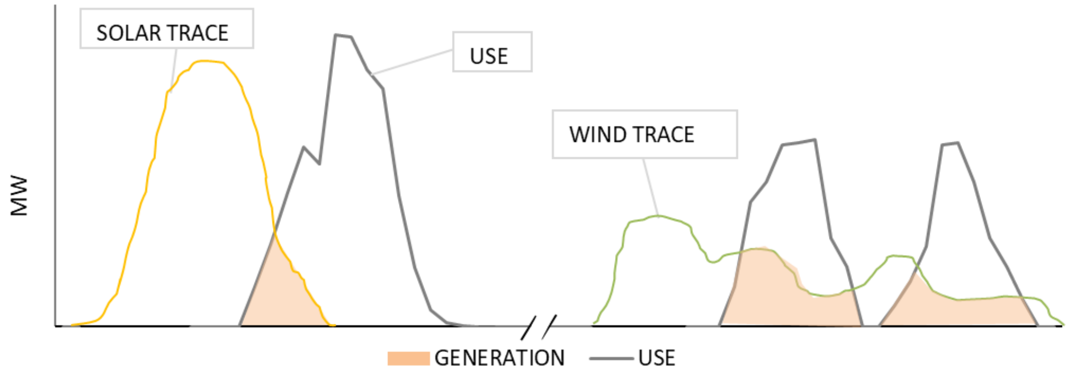
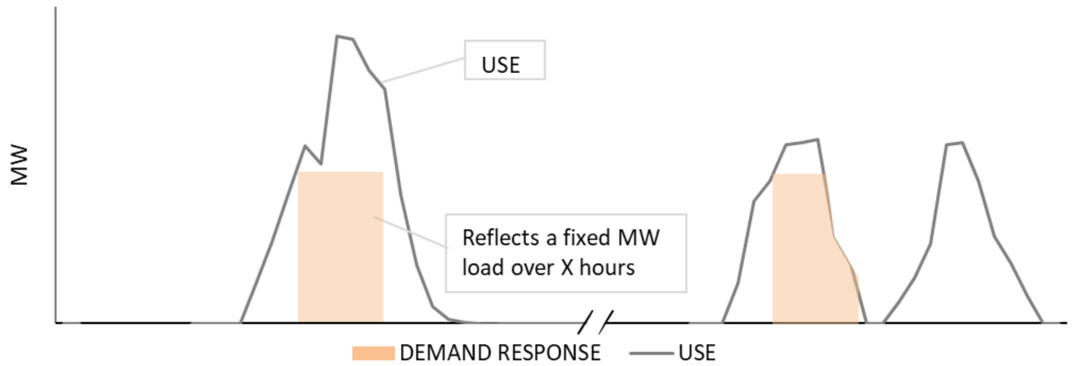


Figure 17 New entrant type considerations – Solar and Wind



Note: Solar and wind examples are plotted on the same chart here but is considered separately.

Figure 18 New entrant type considerations – Demand Response



5.4 Approach to key issues

Table 13 augments the key review issues presented previously in Section 4.1 by summarising how each of the individual issues are addressed. The main issues relating to the changing demand and supply mix over the Review Period are accounted for in the assumption inputs into the main market model, however, some aspects were assessed through scenarios or sensitivities.

Table 13 Key issues and approach

Driver	Implication	How the approach addresses this
Continued penetration of large and small-scale renewable energy generation	VRE has materially changed the supply and demand mix, and pricing dynamics in the NEM. The increasing share of renewable generation has displaced significant amounts of thermal generation resulting in retirement implications.	Covered through the main modelling framework which includes running eleven (11) reference year traces, increasing RE penetration through state-based RE policies, and assessing the impact on revenue outcomes of the marginal new entrant.
Changing operating regime and exit of traditional thermal generation	Coal power stations provide baseload energy and other system services contributing to system security and reliability. The retirement of coal plant without appropriate new entrant replacements can reduce system reliability.	Explore the potential of earlier retirements in the Base case and assessing the impact of higher retirements on reliability through scenario/sensitivity modelling.
Increasing storage investment	Its capability in providing multiple services (energy, FCAS, network, etc.), and therefore multiple revenue streams should be considered when determining the optimal level of the reliability settings.	FCAS revenue streams were accounted for in separate modelling work to complement the main market modelling approach adopted. All revenues outside of energy and FCAS, such as network revenues, were not considered.
Increasing demand-side participation and introduction of Wholesale Demand Response (WDR) market reforms	The reliability standards and settings reviews have traditionally focused on supply-side options to deliver reliability outcomes. The introduction of WDR can impact the marginal new entrant option and corresponding reliability settings.	Explored through the optimisation model step.
Increasing spot and frequency control and ancillary services price volatility	Price signals reflect underlying supply and demand dynamics directly impacting the marginal new entrant generator. The reliability framework needs to account for the balance of generation costs recovered through the reliability settings.	Spot energy prices are covered through the main modelling framework. FCAS revenues, not specifically volatility, is assessed separately.

Driver	Implication	How the approach addresses this
Increased network congestion and important of increasing interconnectivity	Network congestion across the system limits generation output to meet demand, directly impacting reliability but also revenue outcomes of new entrant plants.	Covered through market modelling based on the AEMO 2021 ESOO model which includes network constraints and committed and anticipated augmentations over the Review Period.
Jurisdictional government policies incentivising new investment	Impacts market price signals that drive commercial new entrant investment and addresses system reliability through added supply. The review needs to account for these supply impacts.	Included in the main market modelling, covering the NSW Electricity Infrastructure Roadmap, Victorian RET, Tasmanian RET, and Queensland RET.
Increasing use of reliability directions by AEMO	The Interim Reliability Measure, use of RERT and reliability directions is an out-of-market process which falls outside the reliability framework and is therefore out of scope.	Not applicable.
Extreme weather events and weather dependency	The increasing renewable energy generation mix translates to a power system that is more reliant on weather outcomes. The corresponding distribution of USE may exhibit longer tails which will have implications for how this risk is captured in the reliability framework.	Covered through scenario modelling.

5.5 Outputs and relevance

Although the objective is to determine the optimal level of the reliability settings, being able to understand how they are impacted by the underlying supply and demand conditions is key for stakeholder interpretability. To meet this objective the report presents a wide spectrum of outputs derived from various stages of the modelling process. The various interim outputs and relevance is summarised in Table 14 and is discussed in further detail in the results sections throughout the report.

Table 14 Relevance of modelling outputs

Modelling stage	Key outputs/analysis	Relevance
Market model	Expected volume of USE in MWh and in percentage terms	Determines whether there is a reliability gap.
	Drivers of USE	Understand what is driving USE across the regions and scenarios.
	Distribution of USE outcomes	Describes USE in terms of frequency, duration, likelihood per year. These dimensions impact revenue recovery and the reliability settings.
	Total system cost	Used to establish whether the current level of the reliability standard is efficient (Task 1)

Modelling stage	Key outputs/analysis	Relevance
	Level of spot prices and volatility (energy)	Impacts the balance of costs that needs to be recovered from reliability events, i.e., reliability settings, in the optimisation model step
Optimisation model	New entrant dispatch profiles and capacity built to address reliability gap	Impacts the optimal MPC and CPT levels
	Distribution of remaining USE	Provides insight into how the reliability gap is addressed in meeting the 0.002% reliability standard.
	Net settlement outcomes	Describes the impact of the MPC and CPT on the variability of settlement outcomes and broader contract market implications.
	Revenue composition and variability	Describes the impact of the MPC and CPT on revenue variability and bankability of the new entrant.
	Total region cost	Describes the impact on wholesale energy costs due to change in the optimal MPC and CPT outcomes

5.6 Other

5.6.1 Electricity Statement of Opportunities database

AEMO has publicly made available its PLEXOS database underpinning the 2021 ESOO reliability work. The 2021 ESOO is based on the Central outlook, or expected set of underlying assumptions over the 2021-2031 horizon, consisting of (1) an operational consumption and peak demand outlook comprising of residential PV uptake and other various technology outlooks, (2) the existing and committed generator entry, retirement timing and seasonal ratings, (3) network constraints, interconnector outages, and transmission developments over the horizon, and (4) eleven reference years for demand and wind and solar traces. The database provides an excellent base to build upon to address the RSSR scope. It does not include ramp rates, unit commitment parameters, and the frequency control ancillary services markets.[27] Please refer to AEMO's 2021 ESOO report for further details.

Adjustments applied to the model include the following:

- Updates to the existing and committed generator list to the latest update in November 2021, and the inclusion of the newly announced Eraring power station closure in Aug 2025.
- Changing generator bids from short-run marginal cost (SRMC) to LRMC recovery to reflect dynamic generator behaviour. All large generators were allocated to regional portfolios and bidding was calibrated to reflect a historical period of generator bidding.
- Inclusion of RE new entrant trajectories relating to legislated, or sufficiently committed, state based RE policies. The model includes policies included in AEMO's Integrated System

[27] The reliability results from the ESOO are conditional on the system being in a secure state.

Plan work, i.e., includes generic new entrants to meet the Victorian RET, Queensland RET, Tasmanian RET, and NSW Electricity Infrastructure Roadmap targets (see Section 6.1).[28]

5.6.2 USE definition

USE as defined by AEMO is *"the amount of energy demanded, but not supplied, due to reliability incidents. This may be caused by factors such as insufficient levels of generation capacity, demand response, or inter-regional network capability to meet demand"*. However, some events which lead to unmet customer demand is not regarded as USE under the reliability framework. How AEMO's ESOO and our modelling work maps to the definition of USE under the reliability framework is summarised in Table 15 below.

Table 15 NER reliability framework and ESOO model

NER reliability framework	ESOO model
USE outcomes based on intra-regional transmission events are not included under the reliability standard – NER 3.9.3(c)	Only outages on inter-regional interconnectors are modelled. Intra-regional transmission investment needs are addressed via the economic frameworks for network regulation.
Inclusion of USE caused by an event or events that include a single credible contingency event are included – NER 3.9.3C(b)	All outages in the ESOO model are simulated independent of each other. Therefore, USE arising from outage events in the model should be included.[29]
Inclusion of USE caused by delays to the commissioning of generating or inter-regional transmission elements – NER 3.9.3C(b)	Commissioning dates are included as fixed dates in the modelling. Delays can be explored in scenario modelling if required.
Exclude USE from system security incidents caused by an event or events that include a multiple credible contingency events or non-credible contingency events – NER 3.9.3C(b)	All outages in the ESOO model are independently simulated, i.e., outages are not modelled as dependent events. The implication of this is that the model is not able to produce multiple credible contingency events or non-credible contingency events.

The modelling assumes no pain sharing of USE across the regions in accordance with the ESOO methodology. Although AEMO have procedures relating to pain sharing, the process is related to operations rather than the reliability framework itself. Assuming no pain sharing also allows for more efficient locational signals for new entrant capacity.

In addition to the above, USE events presented in this report are expected to be different to the historical experience in the NEM. This is due to (1) the simulation and classification of USE under the reliability framework is a subset of that experienced in the actual market, (2) AEMO utilises other non-market mechanisms, such as directions and the RERT, to limit load shedding, and (3) many of the results presented in the report are based on the distribution of USE events before the reliability gap is addressed by the marginal new entrant.

[28] AEMO has based this on the 'public policy clause' from NER 5.22.3(b). See 2021 Inputs, Assumptions and Scenarios Report, AEMO (Dec 2021).
[29] See Section 8.4 for modelling analysis of coincident forced outages and its contribution towards total USE.

5.6.3 Number of samples and weighting

A sample is defined as a single iteration of the model and comprises variations in demand shapes, peak demands, outage profiles and renewable energy generation traces. The ideal number of samples to be run directly relates to the number required for convergence.[30] AEMO's 2021 ESOO work is based on 2,200 samples, and the modelling supporting the 2018 Review ran between 300 and 2,400 samples per year.

Given the expanded scope of this review and limited project timeframes, we have had to limit the number of samples. The number of samples simulated across the Review Period is summarised in Table 16.

Table 16 Number of samples

Run	Base case	Weather scenarios
Basis	Energy only, 30-min	Energy only, 30-min
Outage variations	50	125
Peak demand levels (POE)	2	2
Weather reference years	11	2
Forced outage assumption sets	1	1
Years in Review Period	3	3
Total simulations per case	3,300	1,500

Note: The total simulations per case is the product of each of the individual runs. For example, for the Base case 3,300 simulations is based on 50 x 2 x 11 x 1 x 3.

All samples are then re-weighted according to the P10 or P50 demand trace used. The weights used in this modelling compared to that used by AEMO and the 2018 Review are summarised in Table 17. AEMO assumes a weighting for P90, whereas the weight for P90 is implicitly incorporated into the P50 runs under the current and 2018 Review. Weights cannot be applied to a P90 in the context of this review because of the requirement of the modelling to also consider energy revenues.[31]

Table 17 Sample weights

Reference demand	AEMO	2018 Review	Current review
P10	30.4%	30%	30%
P50	39.2%	70%	70%
P90	30.4%	Not applicable	

5.6.4 Differences to the 2018 review

There are three key differences between the modelling approach adopted in this review and that in the 2018 review. These relate to the underlying new entrant cost assumptions, the volume of USE to be addressed by the new entrant and the level of spot prices which drive the

30 EY's MTPASA Review (2016) for AEMO suggested diminishing returns after 200 iterations/samples.
31 P90 demand traces are not available.

balance of generation costs recovered through the reliability settings. Refer to Appendix C.4 for more details.

5.6.5 Modelling limitations

The Panel should be aware of the following limitations of our modelling in addressing the scope of work and broader objectives of the RSSR. These are summarised in Table 18.

Table 18 Modelling limitations

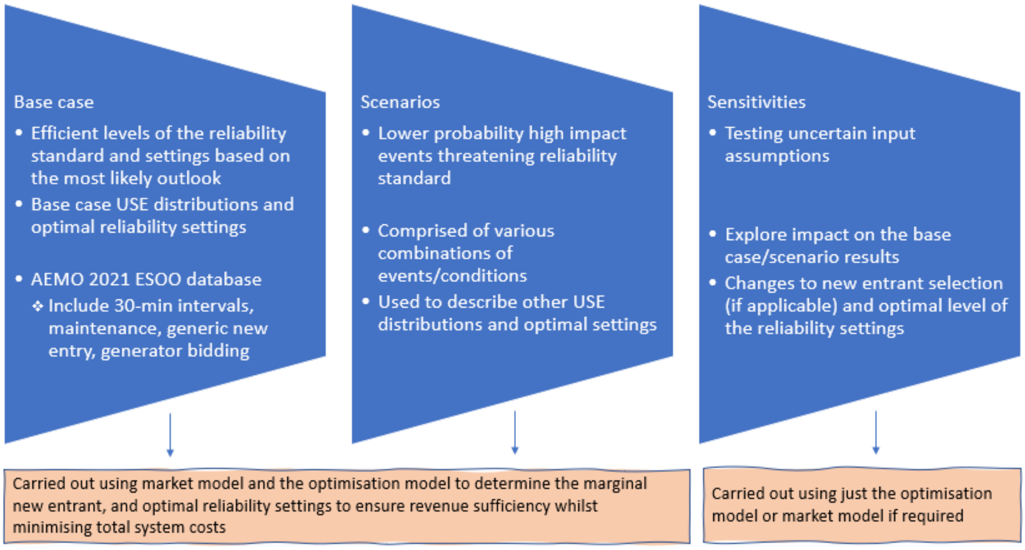
Category	Description
Modelling inputs	The conditions and the associated input assumptions that have been modelled are based on the Central scenario underpinning AEMO's 2021 ESOO, and a low RE generation scenario. The Base case assumptions set used represents the most likely outcome over the Review Period, however, there are many other possible combinations that have not been considered.
	Weather variations is based on 11 reference years. There is the risk the 11 reference years may not represent a longer or full weather cycle.
	The weather scenarios ideally require composite input data (demand, inflows, VRE traces, etc.,) to be statistically valid. As this was not available, the weather traces generated for the weather scenarios are more extreme and less probable than those of a properly constructed data set.
Approach	The modelling framework only considers total system costs and revenues for the marginal new entrant. There are broader issues outside the modelling scope that needs consideration such as regulatory stability, market integrity and financial risks, contract market implications, new entrant revenue predictability, and investment price signals, i.e., the results from the modelling can only partly inform the Panel and in no way should be interpreted on a standalone basis.
	The decoupling feature of the modelling framework assumes no change in spot prices and dispatch with the introduction of new entrant capacity to bring the system in line with the reliability standard. If the modelling was solely carried out through market modelling simulations, spot prices would likely be lower leading to a higher combination of the MPC and/or CPT. The constant price and dispatch assumption is required to allow for modelling flexibility given project constraints.
	Significant changes to the reliability settings are likely to shift revenue outcomes and supply and demand dynamics modelled in the market modelling step. The impacts of this on existing and committed generators are out of scope.
	The revenue condition considered in both the market and optimisation model steps do not account for underlying contracts and other portfolio dynamics which can be significant in the context of generator bidding and new entrant investment. Similarly, early retirement decisions are likely to be driven by more than net pool revenues. The revenues are also only assessed over the Review Period only which is significantly shorter than the investment decision horizons of new entrant plants.
Market modelling	The optimal reliability settings are highly dependent on the USE distributions. There is a risk the outcomes based on the number of samples run may not have reached convergence. Runtime was a significantly limiting factor in the expanded scope of work.
	The interdependent dynamics between the reliability standard, efficient new entrant portfolio and revenue sufficiency is highly contingent on generator bidding dynamics. The reference year the model is calibrated to may not capture actual competition dynamics during the Review Period.

Category	Description
	The market modelling is carried out at 30-minute resolution whereas there may be ramp rate implications for a system that is increasingly supplied from variable renewable energy sources. The initial work explored carrying out analysis into its impact but was subsequently ruled out due to indications of low materiality and the large impact on model run time.
Optimisation model	The optimisation model does not account for inter-regional and pain sharing impacts. Analysis of the modelled USE outcomes found less than 0.2% of all USE intervals where the interconnections into the region experiencing USE was not at the import limit. This is consistent with the definition of USE as defined in AEMO's ESOO modelling methodology and implies each region must build its own new entrant capacity to address its own reliability gap. Pain sharing can potentially impact the USE distribution but would also be limited by network constraints across two neighbouring regions.
	Generators can also earn significant non-market revenues impacting investment decisions. For example, batteries providing network services whilst still being able to participate in energy and FCAS markets. These revenue streams are out of scope.

6 Base case, scenarios and sensitivities

The guiding principles of the RSSR and scope of work require that the modelling be based on a base case which comprises a set of assumptions, including committed policies, that are most likely to represent the state of the NEM over the Review Period. The additional scenarios modelled reflect alternative outlooks that threaten the reliability standard, show different USE distributions, and possibly a different marginal new entrant and corresponding optimal level of the reliability settings. Sensitivities are included to test uncertain input assumptions. Figure 19 summarises the differences between these runs and relevance in the context of the project scope.

Figure 19 Role of the Base case, scenarios and sensitivities



6.1 Base case assumptions

The Base case directly leverages AEMO's 2021 ESOO model and all its underlying assumptions. Table 19 provides an overview of the model assumptions used in the Base case.[32] Cells shaded in green are either updates or changes to AEMO's 2021 ESOO model that are required to meet the RSSR scope of work. The main assumptions are based on the 2021 ESOO central case outlook which differs from the draft ISP 2022 Step Change outlook. Modelling assumptions were finalised in early February 2022.

[32] Most of these assumptions apply under the Low RE scenario as well. Only generator specific assumptions apply to the optimisation model.

Table 19	Base scenario – key assumptions

Assumption	Description or source	Additional details
Energy and Peak Demand	Eleven (2011-2021) reference traces based on AEMO's Steady Progress (renamed to Net Zero) demand outlook. Models both 10% and 50% POE peak demand outlooks	
Renewable traces and hydro inflows	AEMO 2021 input and assumptions dataset	
Committed new entrants	ESOO model to be updated to existing and committed generators from AEMO generation information (Feb 2022)	
Policy-based generic new entrants	Based on policies that are legislated or sufficiently committed as treated by AEMO in the ISP, including AEMO's generation and/or capacity trajectories of the QRET, VRET, TRET and NSW Electricity Infrastructure Roadmap in the ISP	These are generic new entrants required to meet RE policy targets.[33] The reliability component of the NSW Electricity Infrastructure Roadmap is not explicitly modelled
Commercial generic new entrants	New entrant options and parameters based on the AEMO 2021 input and assumptions dataset	These are generic new entrants based on commercial revenues
Competition model	LRMC cost-recovery. Recovery parameters calibrated against CAL2021 spot prices and generation volumes by portfolio and region	
Generator operating parameters	AEMO 2021 input and assumptions dataset	Additional sensitivities based on operational constraints are applied in the optimisation model
Generator forced outages	The outage rate assumptions to be based on the AEMO 2021 input and assumptions dataset with an adjustment for retiring plant.[34] Different outage profiles are simulated across each iteration	The forced outage rates capture reduced reliability over time to FY 2028 (VIC 7%, NSW 6.1%, and QLD 4.6%), however, may not reflect more recent events.[35]
Generator planned maintenance	Included based on AEMO 2021 input and assumptions dataset	Although maintenance is scheduled to avoid tight supply periods, USE may still coincide with planned maintenance

[33] There are several transmission projects, such as the Central West Orana REZ Transmission Link, intended to unlock generation potential across the RE zones, however, were not included in the 2021 ESOO. IES modelled RE policy new entrants outside the 2021 ESOO network constraints and applied curtailment factors based on the draft ISP 2022 curtailment results and was profiled using calendar year 2020 data.
[34] Increase in forced outage rates in accordance with Assessment of Ageing Coal-Fired Generation Reliability report, AEP, June 2020.
[35] AEMO's review of forced outage assumptions was not available for this project due to timing.

Assumption	Description or source	Additional details
Generator fuel, operational and capex costs	Included based on the AEMO 2021 input and assumptions dataset	Higher gas prices and impact on OCGT outcomes are explored in a separate optimisation model sensitivity
Weighted average cost of capital	AEMO 2021 input and assumptions dataset (pre-tax, real WACC of 5.5%). This is applied uniformly across all generation types	A higher WACC assumption is explored in separate optimisation model sensitivities
Coal retirements	Coal retirements based on announced retirement dates from AEMO's closure data, newly announced retirements, and economic retirements from the modelling	Includes the Eraring retirement in August 2025
Transmission outages	AEMO 2021 input and assumptions dataset	Inter-regional outages/de-ratings only
Interconnector upgrades	AEMO 2021 input and assumptions dataset	Includes those in the 2021 ESOO only[36]
Demand side participation (and wholesale demand response)	AEMO 2021 input and assumptions dataset	This only includes demand reductions and not demands that are incentivised by low prices. Excludes reliability response volumes[37]
Virtual power plants	AEMO 2021 input and assumptions dataset	
AEMO RERT and Interim Reliability Measures	These are out-of-market processes and falls outside of the scope of work	
ESB reforms	Potential market design changes are out of scope	The review is based on current policies and market mechanisms as of today

Note: The AEMO 2021 input and assumptions dataset is used in both the 2021 ESOO and Integrated System Plan work. The AEMO 2021 input and assumptions dataset refers to the Dec 2021 release.

6.2 Scenario overview

The scenarios provide different market outlooks which although may be unlikely relative to the Base case, are still within reasonable expectation or of particular interest. One of the objectives of formulating these scenarios is to produce different USE distributions than the Base case, that may give rise to different marginal new entrants and different optimal reliability settings.

IES has modelled a single alternate scenario in the form of a low renewable energy generation scenario, focused on sustained and coincident low yields from solar and wind plants across the

[36] The 2021 ESOO includes committed and two anticipated projects (Western Victoria Transmission Network Project and Project EnergyConnect). The HumeLink project, which supports Snowy 2.0 and is classified as an actionable project, was not included in the modelling. See the 2021 ESOO report for more information.
[37] The RERT is a non-market process and is out of scope.

NEM.[38] The objective was to explore low energy availability spanning a full year over the Review Period when the system is likely to be highly dependent on VRE.

Scenarios consist of different combinations of possible market conditions impacting both demand and supply side assumptions. The market conditions in Table 20 relate to potential changes to the base case assumptions and the subset that was applied to the Low RE scenario.

AEMO's existing reference year traces already incorporate historical weather events but may not capture an extreme scenario of interest. AEMO is currently collaborating with the Bureau of Meteorology on producing input data for use in its reliability work, however, this was not ready for this review. Instead, IES synthetically generated traces consistent with low yield expectations (discussed further in Section 8.3.1).

Table 20 Potential change in market conditions

Market Condition	Description	Methodology	Included in Low RE
Heatwave/Extended High Demand	Extended periods of high demand for large parts of the NEM	Select demand trace/s with extended periods of coincident high demands across the relevant regions	Yes
Drought conditions	Extended periods of low rainfall	Reduce hydro water limits and constrain thermal unit energy production based on 2007/2008 drought period[39]	No
Low wind yield	Low wind output due to extreme weather conditions	Analysis of input wind and solar traces and apply lowest monthly yield periods.	Yes
Low solar yield	Low solar output due to extreme weather conditions		Yes
Major transmission line outage for service	Interconnector outage focusing on region expected to export power to other regions	Apply line outage or de-rating across 3-6 months in the modelling horizon	No
Early coal retirements	Some coal plants to retire early due to economic outcomes	Refer to ISP retirement outlooks (up to 8 GW in the Step Change case)	Yes, relative to Base case
Snowy 2.0 Delay	Delay of Snowy 2.0 by 18 months. Original start date of Dec 2026	Exclude Snowy 2.0 from model generators list	No

[38] IES originally proposed three (3) scenarios. Due to time constraints, the draft report focuses on the model findings from the Base case sensitivity, the Low RE scenario and corresponding sensitivities.

[39] The coal plants may already have lower capacity factors because of RE penetration relative to capacity factors during the 2007/2008 drought.

6.3 Sensitivities

The following sensitivities were carried out in the optimisation model stage with the main purpose of exploring impacts of various uncertain data assumptions used in the main base case and scenario modelling. These are summarised in Table 21 below. The purpose of the sensitivities is to understand how the optimal reliability settings and type of the marginal new entrant may shift, and to understand the materiality of uncertain input assumptions.

Table 21 Optimisation model sensitivities

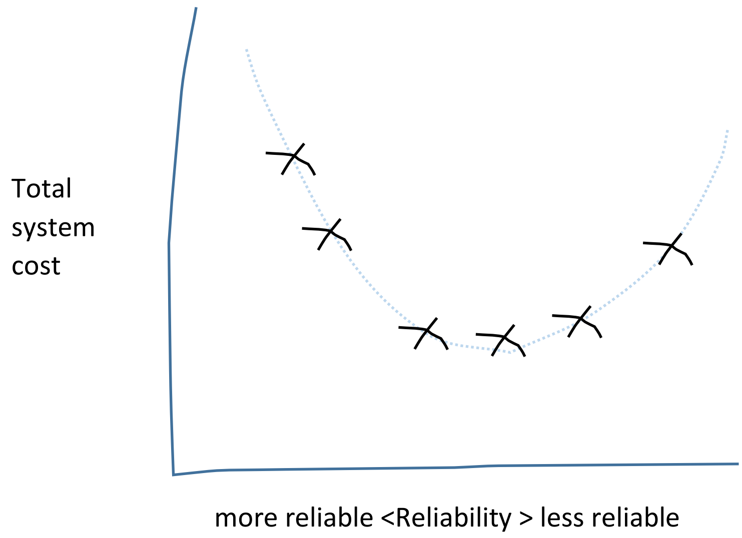
Sensitivity	Description
Imperfect foresight and operational constraints	The underlying modelling assumes perfect foresight which may understate actual risks across the marginal new entrants. Run sensitivities applying additional operational constraints.
FCAS revenue assumption	FCAS revenues used to reduce the capex cost base for the energy-only modelling is based on forward-looking estimates. Reduce this revenue stream to explore the impact on the settings.
Higher WACC	The WACC in the Base case may not adequately capture investment risks. Model increased risks through a higher WACC applied uniformly across all generators.
Higher gas prices	Gas prices are expected to drive the competitiveness of peaking gas plants relative to other new entrant options. Model the impact of significantly higher gas prices.

7 Task 1: Efficiency of the level of the reliability standard

7.1 Overview

The appropriateness of the current reliability standard is a question of efficiency or, stated differently, the trade-off between the total system cost and the acceptable level of the reliability standard.[40] The efficient level of the standard corresponds to the level of reliability consistent with the value placed on reliability by consumers. To address this question, the Base case has been run at different reliability levels by adjusting capacity levels in the system to determine the corresponding total system cost. This allows us to plot the cost and reliability trade-off as shown in Figure 20. We refer to this as the efficiency (or trade-off) function.

Figure 20 Cost and reliability trade-off function



The components of the total system cost and reliability level as defined on the vertical and horizontal axes, respectively, are:

- **Total system cost** is comprised of generation and USE costs.[41]
  - Generation cost: consists of fuel costs, fixed and variable operating and maintenance costs, and annualised capital costs. Cost assumptions are based on the same set used under the Base case. Annualised capital costs for existing and committed plants are excluded, however, this portion of generation costs would be fixed across all points produced on the function.[42]
  - USE cost: based on the VCR as determined by the AER is presented in Table 22 below. A high and low sensitivity is also included.

[40] The appropriateness of the form of the standard will be considered by the Panel separately.
[41] Transmission cost data is not available but should technically be included. The state of transmission has been kept constant therefore the associated costs can effectively be ignored in this comparison.
[42] Annualised capital costs for existing and committed plants are not available.

Table 22 VCR cases

VCR ($/MWh)	NSW & ACT	VIC	QLD	SA	TAS
Base case	43,526	42,586	41,366	44,673	33,234
Low case	34,202	30,581	32,617	38,338	26,685
High case	100,626	99,056	101,229	94,383	97,627

Source: AER VCR final report, re-weighted by Panel staff. Dec 2021 dollars.

- **Reliability** is based on the USE volume expressed as a percentage of demand across each region in a given financial year. As total system cost is NEM-wide, there needs to be consideration for how reliability across regions is treated in the analysis. The USE in the following analysis reflects the level of reliability in worst region which implies any changes to incremental capacity is applied to the region with the highest USE percentage.

7.2 Methodology

The Base case supply and demand outlook over the Review Period shows no reliability gap in any of the NEM regions (see Section 8.1). The current Base case reliability outcome is significantly skewed by RE policy new entrants, in particular the NSW Electricity Infrastructure Roadmap. To address this, all non-committed RE policy new entrants considered under the Base case were removed to produce a baseline system state with high USE.[43] From this baseline point, marginal new entrant capacity was then added progressively to establish the efficiency function. The baseline from which we carry out this modelling work is therefore a theoretical representation of the underlying system state.[44]

An example of this is plotted in Figure 21. Point B is the Base case which already has high reliability across all regions and is situated to the far left, and Point X is the baseline after removing all non-committed RE policy new entrants from the Base case. New entrant capacity is added from Point X and located in the worst reliability region. The marginal new entrant can potentially change as reliability increases. To avoid this issue, we chose to generate multiple efficiency functions by adding the same new entrant capacity across the reliability points. The most likely generation types identified to address reliability are (1) OCGT, (2) 2-hour batteries, and (3) 4-hour batteries.[45] This provides insights that the Panel can then consider in determining what is the most efficient level of the current reliability standard and materiality against the current 0.002% level.

The efficiency trade-off varies by technology because of different annualised capital costs and fixed costs. Fuel costs are immaterial given the incremental generation addressing USE is very small relative to the capital and fixed costs required. We used the following annualised and fixed operating costs and maintenance costs based on the Base case assumptions (refer to

[43] Although coal has the highest likelihood of capacity withdrawal, the removal of coal (going from high reliability to low reliability) would then be a comparison of the withdrawal of baseload capacity against the VCR, whereas the reliability framework is specifically targeting marginal new entry i.e., generation types at the top of the merit order stack.
[44] FY2028 was selected as the baseline year.
[45] See Section 10.1.

Table 23). Acknowledging that batteries also earn revenues outside of the energy market, the analysis includes a sensitivity allowing for a $22,000/MW/year FCAS revenue stream.[46]

Figure 21 Cost and reliability trade-off approach

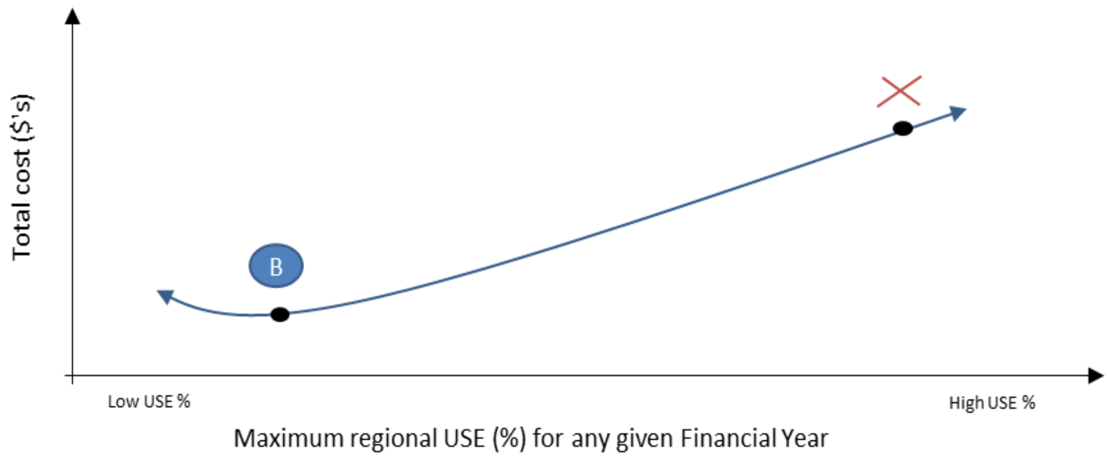


Table 23 Fixed cost assumptions

Generation type	Annualised capex and FOM ($/MW/year)
Open cycle gas turbine – large (OCGT_large)	76,000
Open cycle gas turbine – small (OCGT_small)	109,000
2-hour Battery (BESS_2HR)	85,000
4-hour Battery (BESS_4HR)	128,000

Source: Costs from the AEMO 2021 input and assumptions dataset, converted to annualised figures. Small and large OCGTs have a nominal unit capacity of 49 MW and 265 MW, respectively.

7.3 Results

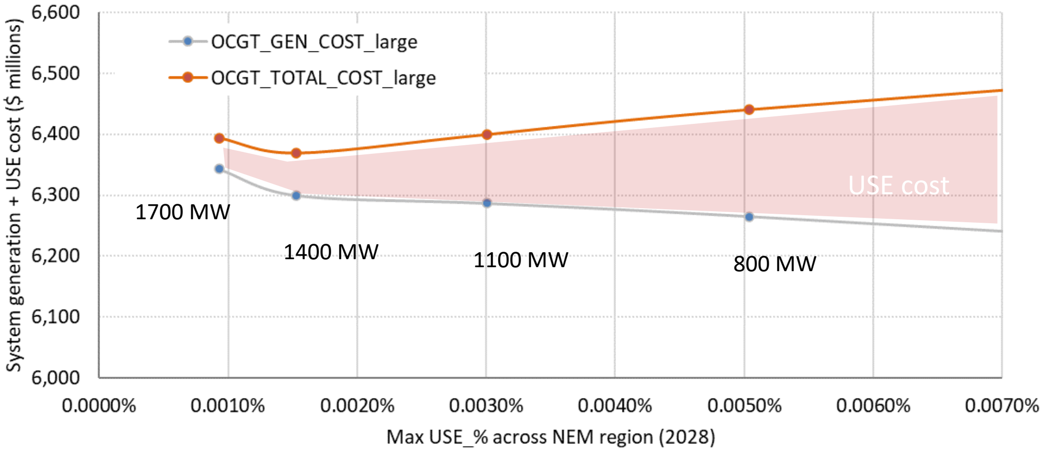
7.3.1 Overview

The baseline (after removing all non-committed RE policy new entrants) resulted in significant USE in NSW corresponding to 0.016%, or 8x the current level of the standard. The incremental capacity was added to NSW only as the other regions had low USE. To understand the cost drivers and trade-off with reliability, the results for large OCGT are presented in Figure 22. For visibility, the vertical axis on all charts has been truncated (floor of at least $6 billion) and the horizontal axis capped at 0.007%. The baseline (0.016%) sits to the right of the visible area of the charts. The first increment in capacity is 800 MW which improves reliability in NSW from 0.016% to roughly 0.005%. As additional capacity is added (as per the chart annotation) going from the right to left, the max USE percentage (NSW) reduces and results in an increase in generation costs (grey line). The increase in generation costs mainly reflects the increase in fixed costs due to the increase in OCGT capacity. The orange line (top line) is composed of generation costs and the cost of USE priced at the corresponding region's VCR (rose area). As the volume of USE reduces, the USE cost reduces. This reduction in USE cost against the

[46] See Appendix C.5.

increased generation cost is the trade-off that underpins the efficiency consideration. Based on Figure 22, the most efficient reliability point is approximately 0.0015% for the OCGT_large new entrant.

Figure 22 Total system cost components



Notes: the annotations correspond to the incremental capacity added to the baseline. Chart is truncated along the vertical and horizontal axis.

Figure 23 overlays all the various generation types and sensitivities carried out including 4-hour batteries with an assumed FCAS revenue stream (suffix FCAS_REVS), and a 50:50 portfolio comprised of large OCGT and 4-hour batteries with FCAS revenues (PORT).[47] We can make the following observations:

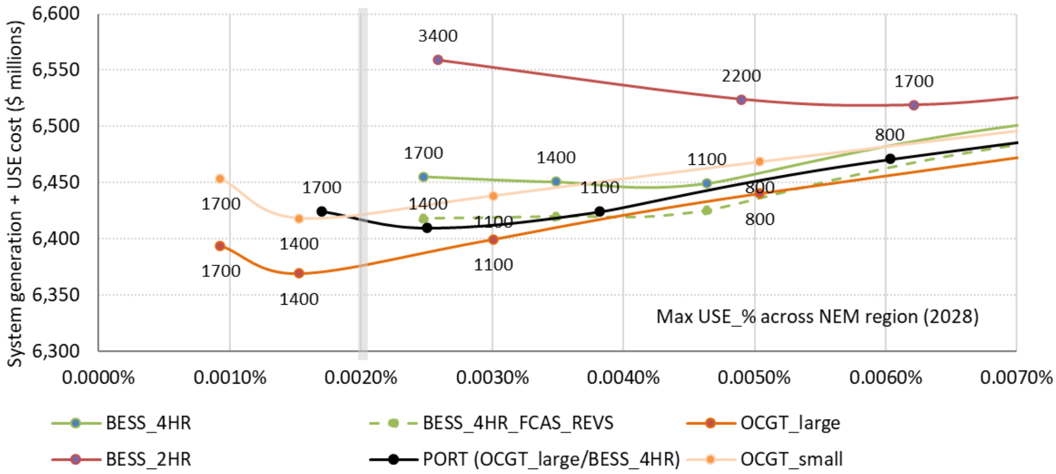
- Across all efficiency functions, adding capacity from the baseline (pictured off-chart to the right) results in an increase in reliability and reduction in system cost. At some point, the cost increases. The minimum cost point along each of the efficiency functions corresponds to the efficient level, subject to only building that generation type.
- The reduction in total cost is generally linear up until the minimum point corresponding to a point in which it is no longer efficient to keep building capacity. The implication is that it is more efficient to shed load and incur the cost of USE rather than continuing to build capacity to address incremental USE.
- The OCGT_large line generally corresponds to the lowest total system cost across all reliability points. The minimum total system cost is approximately at 0.0015% based on OCGT_large. The OCGT_small has the same shape as OCGT_large but is shifted up owing to the higher underlying capital cost assumption.
- The battery lines are situated above the OCGT_large, or that they are more costly to address USE. The 4-hour battery has a minimum around 0.004%, and the 2-hour battery

[47] The portfolio is based on taking the weighted average of the individual generation type efficiency functions.

around 0.006%. This is purely driven by a combination of capital cost and its storage limitations preventing batteries from addressing longer duration USE events.

- The portfolio consisting of 50% OCGT_large and 50% 4-hour batteries has a minimum around 0.0025%. The efficiency function for the portfolio is based on a linear combination of the underlying generation types.

Figure 23 Efficiency functions



Notes: the annotations correspond to the incremental capacity added to the baseline. Chart is truncated along the vertical and horizontal axis.

Figure 23 is truncated at $6.3 billion, and each grid corresponds to an increase of $50 million or 0.8% of $6.3 billion.[48] Although there are clear differences in the most efficient reliability level amongst the generation types, the relative change in cost shifting from the current 0.002% level represents a small difference (approximately 0.2% or $10 million). Other relevant points along the various efficiency functions compared to 0.002% on the OCGT_large line is summarised in Table 24.

Table 24 Reliability and total system cost

Point	USE (%)	Cost ($ billions)	Change [1]
OCGT_large (min)	0.0015%	6.36	-0.196%
OCGT_large (current std)	0.0020%	6.38	
OCGT_large (at 0.003%)	0.0030%	6.40	0.392%
OCGT_large (at 0.004%)	0.0040%	6.42	0.706%
OCGT_small (min)	0.0017%	6.43	0.863%
Portfolio (min)	0.0025%	6.41	0.471%
BESS_4HR (min)	0.0043%	6.45	1.098%
BESS_2HR (min)	0.0057%	6.52	2.275%

[48] If annualised capital costs of existing and committed plant, and transmission were to be included, this percentage would be even lower.

[1] *Change is relative to the 0.002% point along the OCGT_large function.*

7.3.2 Cost drivers

To understand the relative differences in total system cost, the amount of USE that is addressed by each generation type and the effective cost (expressed in $/MWh) are plotted in Figure 24 and Figure 25 respectively. The key points are:

- The first 800 MW of capacity addresses 8 GWh to 10 GWh of USE (BESS_4HR and OCGT, respectively) but the volume significantly reduces for each subsequent addition of 300 MW. BESS_4HR addresses less MWh relative to OCGT because it cannot address duration events that are longer than its storage limit (see Section 9.5). The difference is more evident with BESS_2HR.
- OCGT has lower overall generation cost than batteries (2 and 4 hour) because it has lower annualised fixed costs and addresses more USE than batteries. Thus, the OCGT_large has the lowest total system cost, expressed in $/MWh, at each reliability point.
- The incremental cost chart shows the increasing unit cost of addressing a smaller amount of USE as incremental capacity is added in NSW. When the incremental cost exceeds VCR, this leads to an increase in total system cost.
- The increase in incremental cost starts at a lower incremental capacity point for BESS_4HR (1100 to 1400 MW) relative to OCGT (1400 to 1700 MW). This is the reason why the minimum cost point occurs at a higher USE level for BESS_4HR and coincides with the point where the incremental cost exceeds VCR (see Figure 23).

Figure 24 Cumulative addressed USE

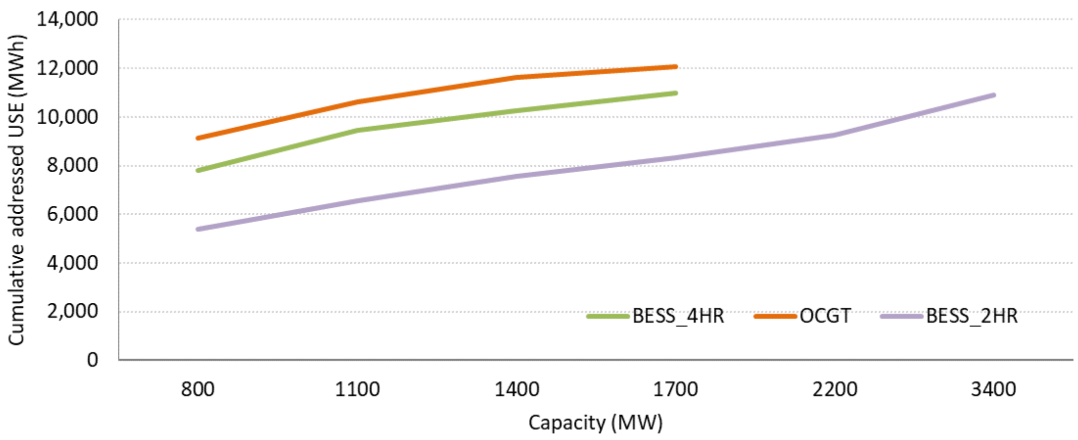
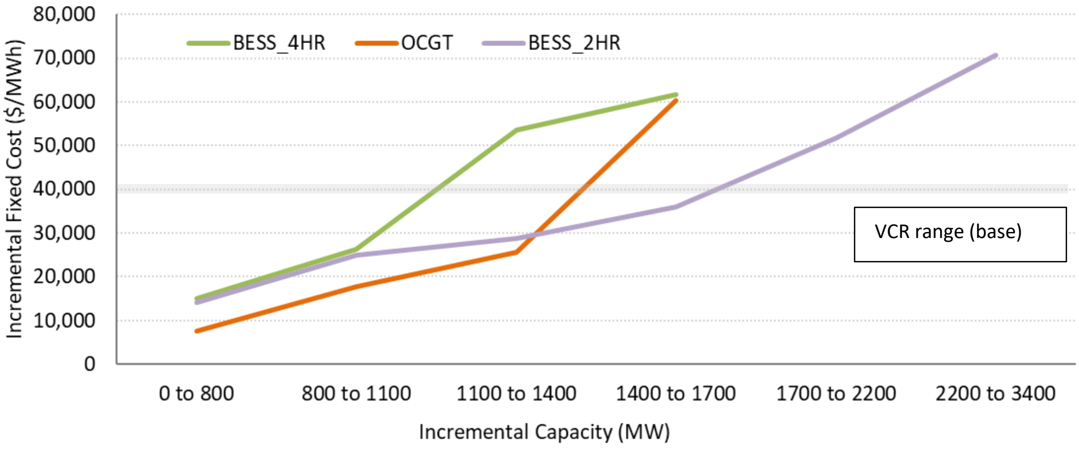


Figure 25 **Incremental costs and VCR range**



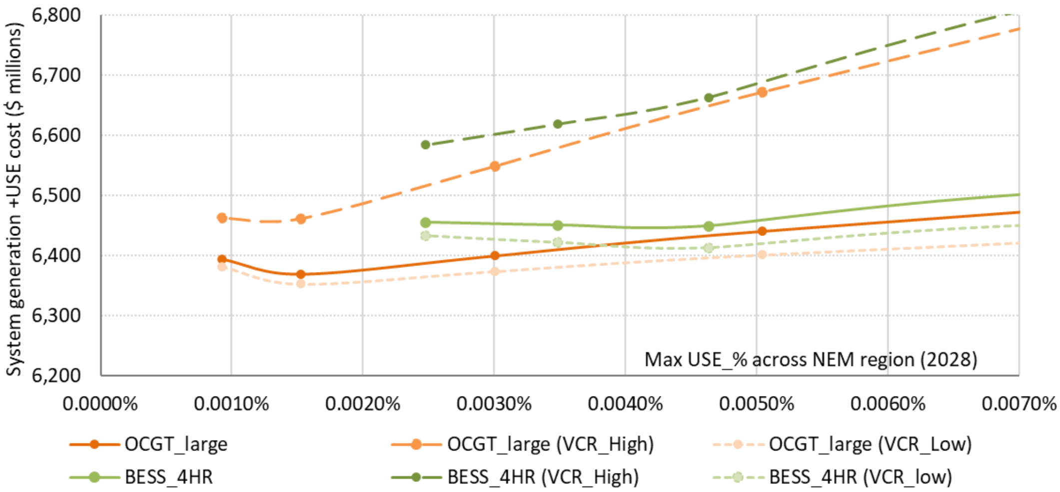
7.3.3 VCR sensitivities

The analysis carried out also includes a low and high VCR to understand if, and how, the efficiency functions and minimum cost points shift in response to different VCR levels. This is presented in Figure 26 and Figure 27. The low VCR values are roughly 25%-30% lower than the base VCR levels, whereas the high VCR values are more than double. Key results from this analysis show:

- The low VCR sensitivity slightly shifts the minimum points to the right (higher USE percentage), however, is not visually discernible i.e., does not materially shift the minimum points.
- The high VCR sensitivity significantly shifts the efficiency functions up and the minimum points to the left. The minimum for OCGT_large is greater than 0.0009% by very slight margin (estimated to be approximately 0.0012%).[49] For the BESS_4HR, the currently modelled results do not indicate the minimum point conclusively as the maximum additional capacity point (1700 MW) still shows a declining total system cost, however, the relative minimum point would still be greater than the corresponding OCGT_large minimum. The portfolio minimum is also likely to be below 0.002% but above the OCGT_large minimum of 0.0012%.
- Based on the high VCR, a shift from a reliability level of 0.002% to 0.0012% along the OCGT_large efficiency function corresponds to a cost saving of 0.5% or $35 million.

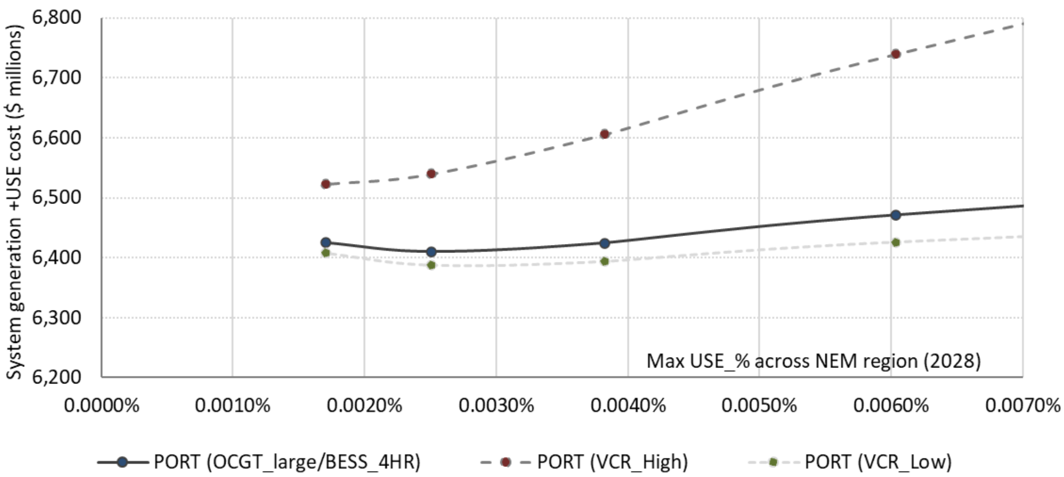
[49] The modelled capacity points do not provide the level of granularity to properly determine the minimum.

Figure 26 **VCR sensitivities – individual generation types**



Notes: Chart is truncated along the vertical and horizontal axis.

Figure 27 **VCR sensitivities – portfolio of OCGT and BESS_4HR**



Notes: Chart is truncated along the vertical and horizontal axis.

7.4 Key findings

The key findings for Task 1 relating to the efficient level of the current reliability standard is that an OCGT (large) remains to be the most efficient generation type to address USE volume across all reliability points due to its lower capital cost and ability to address larger volumes of USE relative to energy-constrained batteries. The most efficient reliability point is approximately 0.0015% based on the OCGT_large generation type and shifts to a lower 0.0012% based on the high VCR sensitivity. However, the relative difference in changing from the current level of the reliability standard at 0.002% to a more reliable and efficient level (0.0015%) corresponds to approximately 0.2%, or $10 million, difference in total system costs.

Under the high VCR sensitivity, the cost difference in shifting from the current 0.002% level to 0.0012% is approximately 0.5% or $35 million. The cost savings in both cases are likely to be immaterial relative to other modelling and input uncertainties.

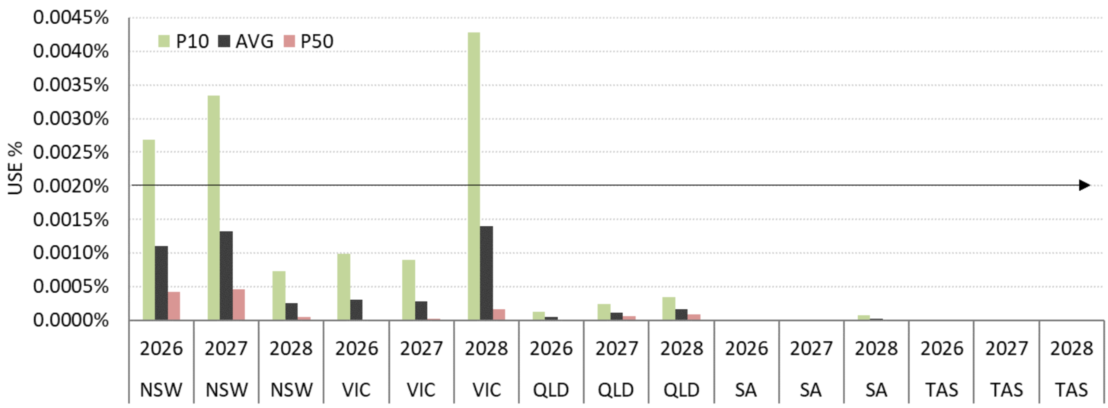
8 Task 2: Demand and supply outlook

This section covers the supply and demand outlook across NSW and VIC and the corresponding expected USE outcomes. The other NEM regions have sufficient capacity resulting in very low USE volumes across the Review Period and are therefore not covered here. In addition to the underlying supply and demand outlook, we analyse drivers of USE drivers across NSW and VIC. The supply and demand outlook and understanding the USE drivers is useful; however, we find that the USE distribution is ultimately the most important determinant of the optimal level of the reliability settings.

8.1 Base case

There is no reliability gap under the Base case, with NSW and VIC showing signs of potentially threatening the 0.002% reliability standard over the Review Period. QLD has the next highest USE percentage at 0.0002% (or one-tenth of the current standard) among the remaining regions. Figure 28 summarises the USE outlook and includes the P10, P50 and weighted average. Although the P10 outcomes exceed 0.002%, the relevant metric is the weighted average which shows NSW and VIC staying below the current standard over the Review Period. The significant differences between P10 and P50 results confirm peak demands are highly relevant in driving USE outcomes.

Figure 28 Base case USE outlook



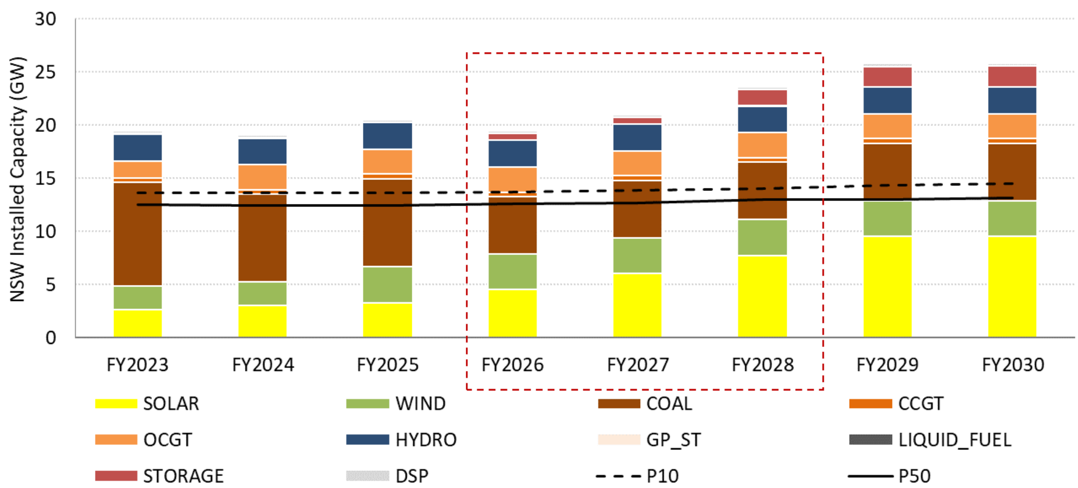
The supply outlook for NSW and VIC is presented in Figure 29 and Figure 30 respectively. The NSW USE outlook is explained by the closure of the Eraring plant in full in Aug 2025, or withdrawal of 2.9 GW; but is replaced with anticipated solar, wind and long duration storage capacity under the NSW Electricity Infrastructure Roadmap. The initial capacity under the NSW Electricity Infrastructure Roadmap (3 GW) in 2026 is not one-to-one replacement for Eraring power station resulting in an uplift in the expected USE, however, by 2028 is more than sufficient (7 GW) to replace Eraring power station resulting in a decrease in expected USE to 0.0003%.

The net profit outcomes from the market modelling over the Review Period show Eraring, Mount Piper and Vales Point power stations unable to fully recover its fixed operating and maintenance costs in 2026 due to ongoing investment in renewables in NSW and the broader NEM.[50] Net profit outcomes would have further deteriorated with the ramp up of renewables under the NSW Electricity Infrastructure Roadmap. The Eraring power station retirement essentially removes the need for any other further economic coal retirement in NSW.

The VIC outlook is relatively stable over the horizon and includes 750 MW of economic coal retirement in 2028, driven by increasing RE generation incentivised under the NSW Electricity Infrastructure Roadmap and the Tasmanian RET. Net profit outcomes for VIC coal units leading into FY2028 were borderline negative. The withdrawal of 750 MW of coal capacity lifts profitability across the rest of the VIC coal fleet and results in an increase in expected USE to 0.0014% in 2028, however, remains below the 0.002% reliability standard.

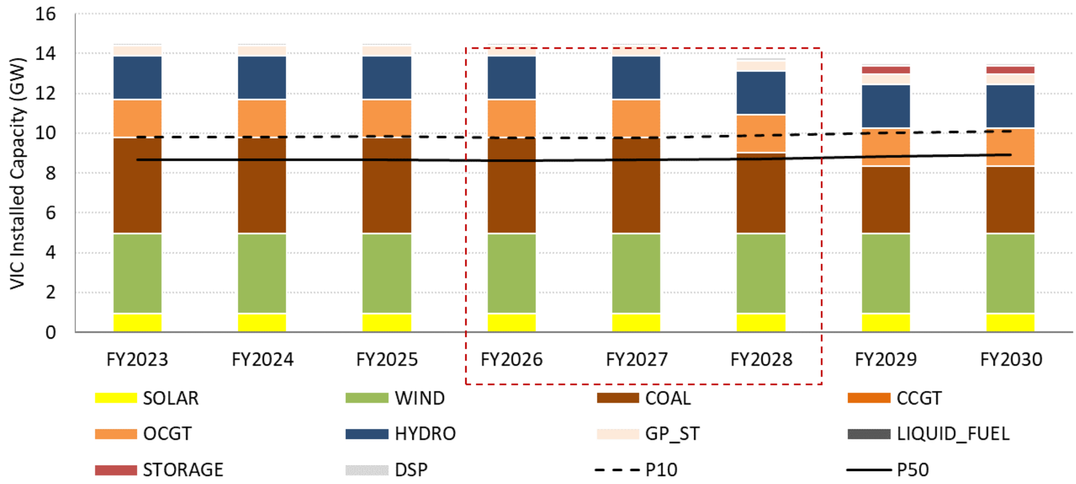
The USE results are broadly in line with AEMO's updated ESOO modelling, i.e., if anticipated developments including those under the NSW Roadmap proceed then NSW is expected to remain below 0.0006% and no reliability gap expected in VIC during the Review Period.[51]

Figure 29 Supply and demand outlook – NSW (Base case)



[50] Net profit defined as spot energy revenues – fuel costs – variable operating and maintenance costs – fixed operating and maintenance costs. Start-up and shutdown costs are not considered as modelling unit commitment is out of scope but would further reduce profitability had it been considered.
[51] AEMO, Update to 2021 Electricity Statement of Opportunities, April 2022.

Figure 30 Supply and demand outlook – VIC (Base case)



A Base case sensitivity was run to generate a reliability gap and is discussed in the next section.

8.2 Base case sensitivity

The Base case is not expected to have a reliability gap; however, a reliability gap is required to determine the optimal reliability settings. Given the high likelihood of additional coal retirements towards 2030 as suggested by AEMO's ISP 2022 work, additional coal units were removed from NSW and VIC to generate reliability gaps in 2028. An additional 1.3 GW and 350 MW of coal capacity was removed from the Base case in NSW and VIC respectively.[52] The timing of the additional coal retirements is assumed to occur in 2028, roughly one year earlier than the announced retirement dates. This results in an USE outlook as presented in Figure 31. All other years remain the same except for 2028 which sees NSW and VIC at approximately 0.0025%. The withdrawal of capacity results in USE slightly above the 0.002% and is close enough to solve for the marginal new entrant. No other commercial new entrants to address a larger reliability gap was needed. The demand and supply outlooks for NSW and VIC are provided in Figure 32 and Figure 33 which reflect the reduced coal capacity in each of these regions.

[52] This corresponds to a total of 1.1 GW of coal capacity in VIC as 750 MW was removed under the Base case.

Figure 31 Base case sensitivity USE outlook

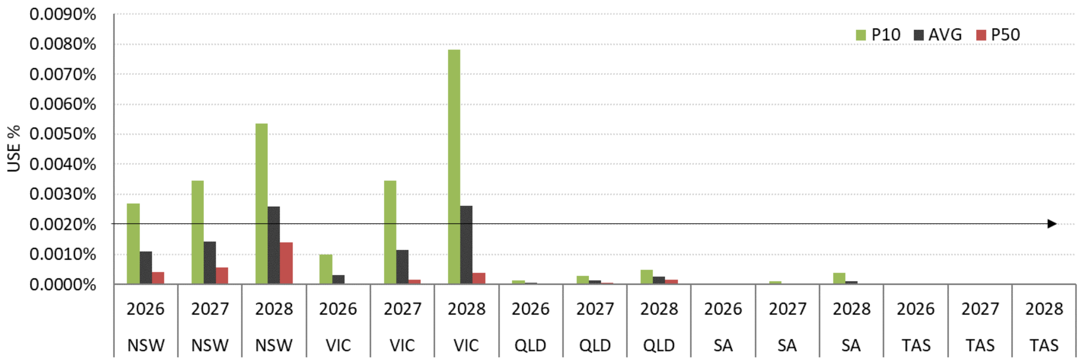


Figure 32 Supply and demand outlook – NSW

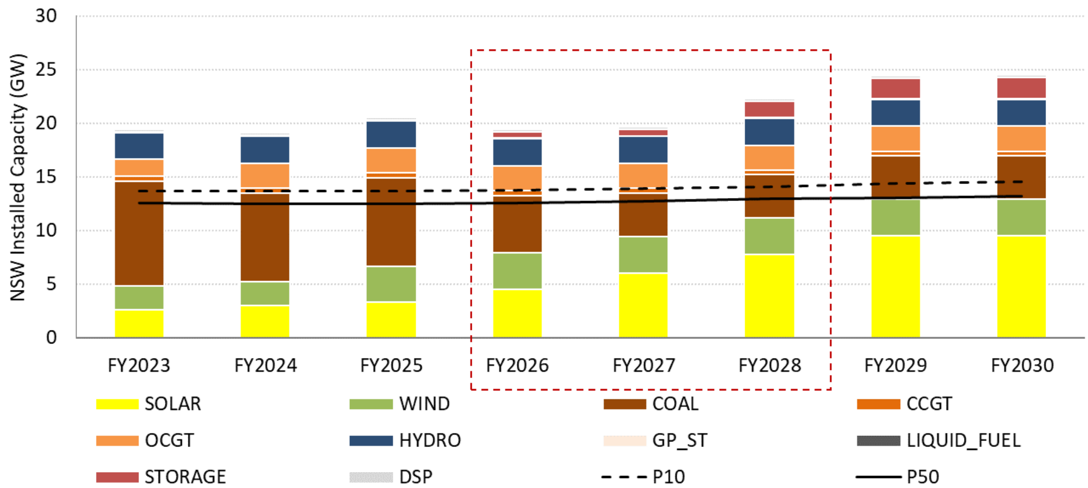
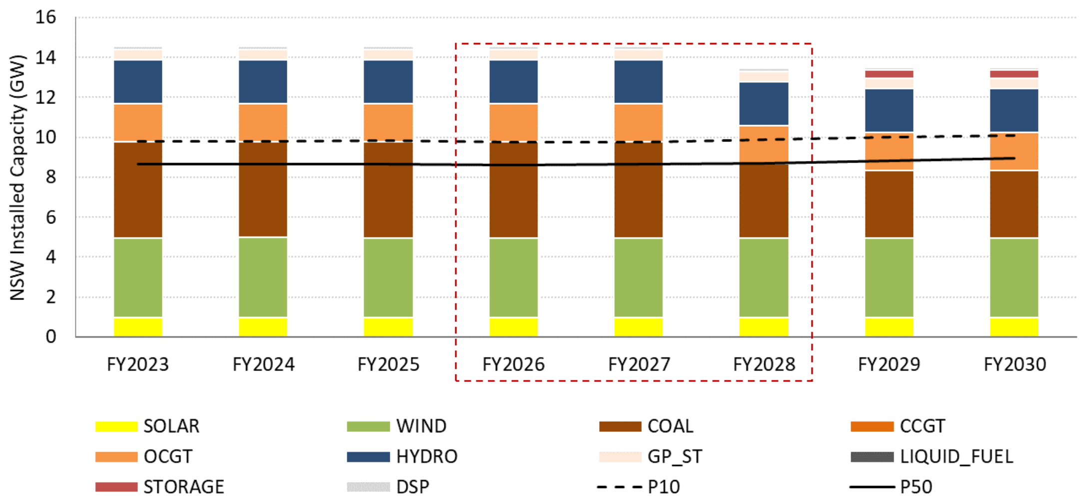


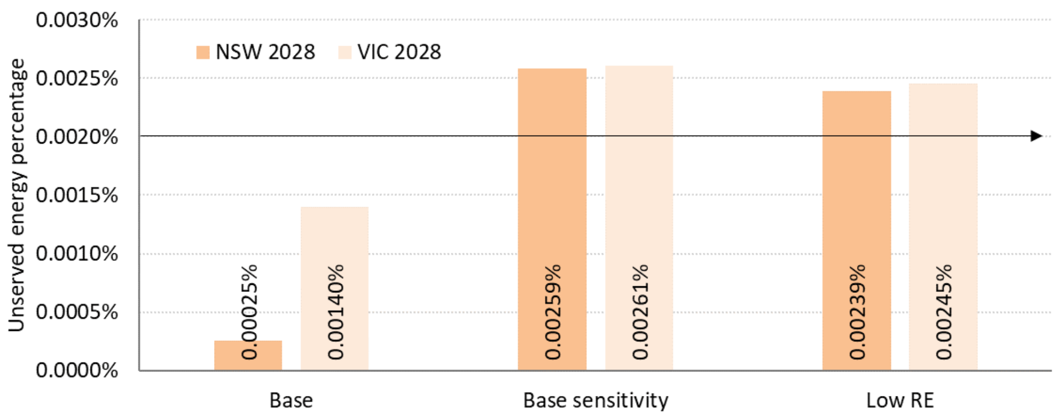
Figure 33 Supply and demand outlook – VIC



8.3 Low RE scenario

The Low RE scenario models USE using a modified set of assumptions from the Base case and Base case sensitivity. The Low RE scenario features 660 MW of early coal retirements in NSW and an additional 750 MW retirement of thermal capacity in Victoria relative to planned announcements. Total coal retirements in this scenario are lower than in the Base case sensitivity which had 1.3 GW MW and 1.1 GW of reduced thermal capacity in NSW and VIC, respectively. Instead, the Low RE scenario includes two weather traces containing lower monthly generation, and lower RE contribution to peak demand. This set of input assumptions results in a similar reliability gap of 0.0025% as pictured in Figure 34.

Figure 34 USE outlook (2028, all scenarios)



8.3.1 Approach

The weather traces provided by AEMO are based on composite data covering demand shapes, inflows, solar and wind traces, and line limits which reflect weather conditions. However, the 11 reference years are likely to not have covered worst case scenarios relating to sustained low RE yields. IES generated synthetic solar and wind traces to address this noting the likelihood of experiencing such weather conditions would be possible but statistically improbable. As the Base case and Base case sensitivity was already close to the 0.002% reliability standard, significant changes to the underlying capacity mix were not required. This also allowed IES to maintain some of the implicit correlation across generation types and regions in generating the low RE traces.

IES combined a single reference year (for demands, inflows, line limits) with two synthetically generated weather traces. The existing RE traces from the 11 reference years were blended to form a complete trace. The following describes the methodology used to create the required traces:

- **Low RE generation**: The total monthly generation for solar and wind combined was calculated for each region separately. The reference years which had the lowest monthly generation by region were combined to form a complete weather year for the corresponding region. This trace effectively allows us to explore the impact of low energy availability.

- **Low RE peak demand contribution**: The average solar and wind generation (combined) was calculated for the highest 10 demand intervals in each month for each reference year. The reference year which had the lowest RE peak contribution on average in each month was used to form a complete weather trace for that region. This trace effectively explores the impact of low peak demand contribution from RE.
- The traces generated maintains correlation between wind and solar generation within the region and month, however, other implicit correlations were effectively ignored.
- The 2011 reference year was selected for the demand trace. The 2011 demand year has the highest rolling peak demands over the summer period in both NSW and VIC on a standalone and combined basis.

Figure 35 and Figure 36 shows the monthly RE yield and the average generation during peak periods for solar and wind combined in NSW, respectively. The total monthly yield is 10% lower than the average of the 11 reference years, with up to a 25% difference in some months. The traces with minimum peak demand contribution are on average 32% lower with deviations of up to 70% against the average of the 11 reference years. Figure 37 and Figure 38 reports the monthly RE yield and average peak MW for VIC. The RE generation in VIC is much more variable such that the low yield traces are 22% lower than the average of the 11 reference years. Similarly, the low peak traces are 51% lower than the average. The P10 and P90 percentiles are also provided for context.

Figure 35 NSW solar and wind trace (low yield)

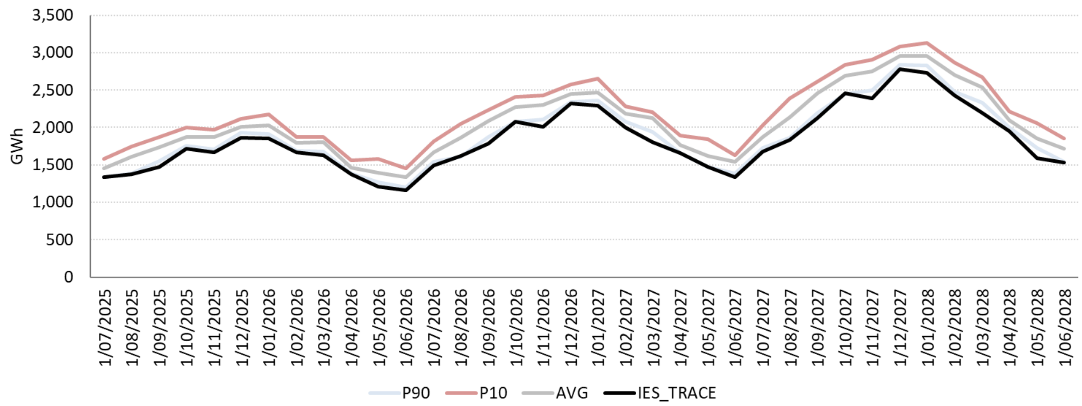


Figure 36 NSW solar and wind trace (low peak contribution)

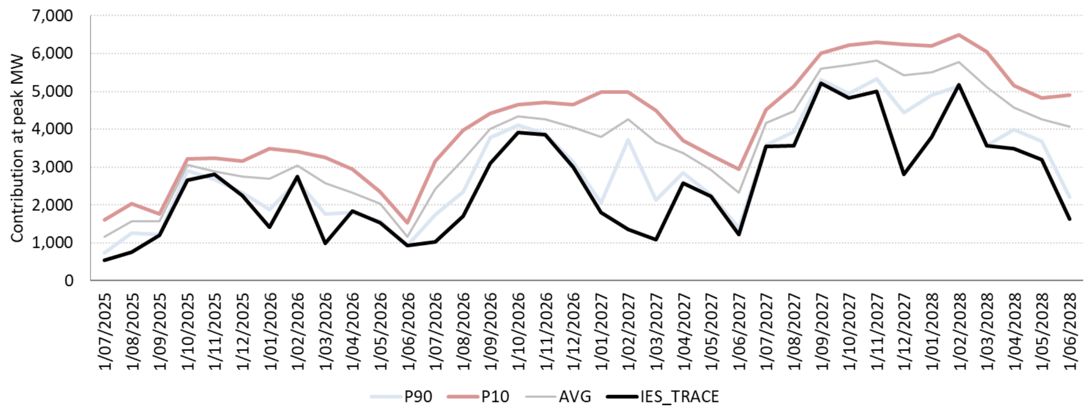


Figure 37 VIC solar and wind trace (low yield)

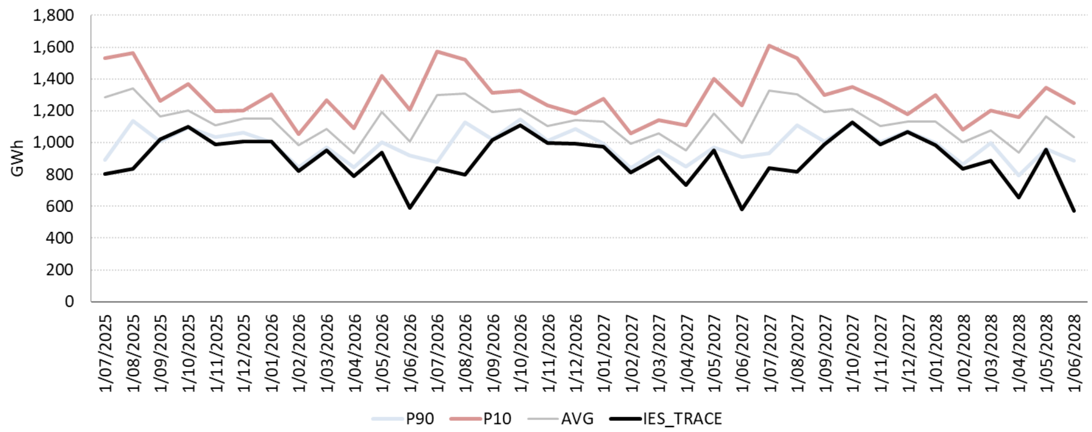
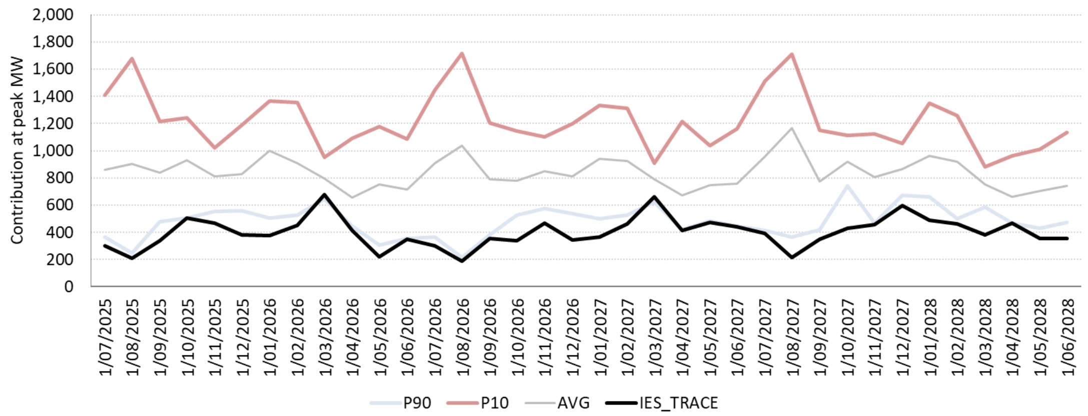


Figure 38 VIC solar and wind trace (low peak contribution)



8.4 USE drivers

USE occurs when there is insufficient supply to meet energy demand. It is unlikely that USE events are due to a single factor, rather they are likely due to a range of supply and demand factors incorporating high demand and reduced supply availability. The following tables (Table 25 to Table 28) present the drivers of USE categorised by depth in NSW and VIC for 2028 across the Base case sensitivity (suffix *base*) and low RE scenario (suffix *low_re*). The figures are based on USE outcomes corresponding to the system state with a reliability gap (approximately 0.0025%). The total column corresponds to the maximum capacity or demand and is provided for context. The general conditions associated with USE occurrence are as follows:

- Higher depths of USE correspond to higher demand and forced outages. Lower wind generation and import limits are secondary contributors to USE. This applies to all regions and cases.
- USE occurs mainly during the peak periods within 15% of the annual maximum demand in NSW and 10% in VIC. This is also coincident with higher forced outages of up to a third or more of coal capacity in NSW and VIC.
- Forced outages remain the most significant supply driver of USE in 2028. Figure 39 to Figure 42 plots USE against forced outages, averaged across the USE ranges, for the P10 and P50 outcomes and shows there is a clear (positive) relationship between the variables as indicated by the dotted line.[53]
- Solar contribution across the depths of USE is similar, i.e., solar is not significant, because USE occurs mostly in the evening peak. On the other hand, deeper levels of USE are associated with lower wind contribution, below 20% capacity factor.
- Under all regions and scenarios, the import limits are significantly reduced relative to the notional interconnector capacities.
- The USE drivers between the Base case sensitivity and the Low RE scenario are similar with high demand coincident with outages being the main driver, with low wind availability and import limits of secondary importance. The differences in outage values are driven by different assumed thermal capacities but are effectively similar when expressed as a percentage of the total coal capacity.
- The other difference in the Low RE scenario is the much lower RE generation during USE intervals with up to 40% decrease in wind contribution over the base case in NSW for intervals with above 1000 MW of USE.
- The distribution of USE outcomes under the Low RE scenario shift the most in VIC relative whereas the distribution in NSW remains relatively constant (discussed in Section 9). This is most likely due to the significantly higher storage capability available in NSW compared to VIC. NSW includes Snowy Hydro's significant storage capability and 1,500 MW of long

[53] Analysis into the forced outages show up to 700 and 1300 intervals (from a total of 56 million intervals) with coincident, but independent, forced outages within a 1-hour period in NSW and VIC, respectively. None of these instances resulted in additional USE within the same 1-hour period.

duration storage incentivised under the NSW electricity Infrastructure Roadmap, whereas VIC has less than 500 MW of storage capacity. The deep storage capability associated with the Snowy Hydro assets provides NSW the ability to smooth out demand and supply across a longer horizon effectively shifting surplus capacity from shoulder periods, despite the reduced solar and wind yields, to higher summer and winter energy requirements.

Table 25 USE drivers (Base case sensitivity, NSW)

Range (MW)	0 – 500	500 – 1000	Above 1000	Total
LOAD	12,865	13,007	13,214	14,067
FORCED OUTAGE	1,077	1,129	1,243	4,055
PLANNED OUTAGE	343	403	419	4,055
WIND	714	663	609	3,380
SOLAR	287	279	282	7,765
IMPORT_LIMIT	1,927	1,874	1,634	3755

Table 26 USE drivers (Low RE scenario, NSW)

Range (MW)	0 – 500	500 – 1000	Above 1000	Total
LOAD	13,026	13,089	13,098	14,067
FORCED OUTAGE	1,305	1,396	1,369	4,715
PLANNED OUTAGE	384	445	632	4,715
WIND	465	431	378	3,380
SOLAR	186	158	124	7,765
IMPORT_LIMIT	1,715	1,668	1,576	3755

Table 27 USE drivers (Base case sensitivity, VIC)

Range (MW)	0 – 500	500 – 1000	Above 1000	Total
LOAD	9,367	9,623	9,721	9,879
FORCED OUTAGE	693	789	986	3,720
PLANNED OUTAGE	336	391	484	3,720
WIND	913	758	678	4,013
SOLAR	204	132	101	955
IMPORT_LIMIT	367	452	577	4248

Table 28 USE drivers (Low RE scenario, VIC)

Range (MW)	0 – 500	500 – 1000	Above 1000	Total
LOAD	9,535	9,726	9,839	9,879
FORCED OUTAGE	809	878	1,074	4,070
PLANNED OUTAGE	350	480	571	4,070

Range (MW)	0 – 500	500 – 1000	Above 1000	Total
WIND	571	602	593	4,013
SOLAR	200	139	109	955
IMPORT_LIMIT	389	216	-7	4248

Figure 39 Average USE and forced outages (NSW, Base case sensitivity)

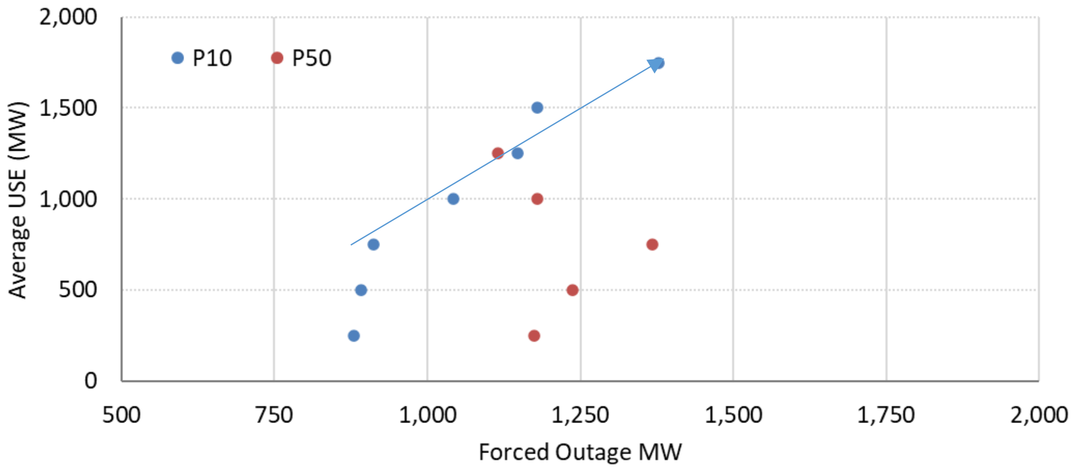


Figure 40 Average USE and forced outages (NSW, Low RE)

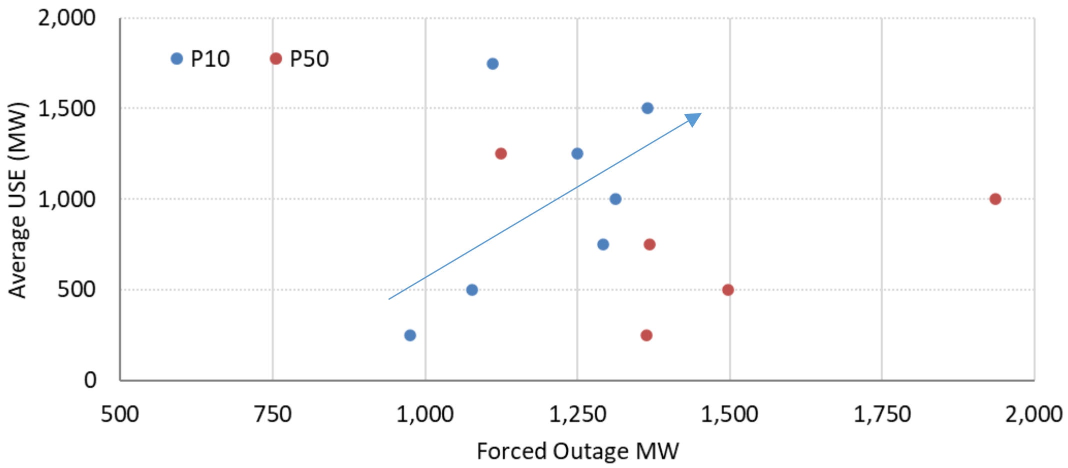


Figure 41 Average USE and forced outages (VIC, Base case sensitivity)

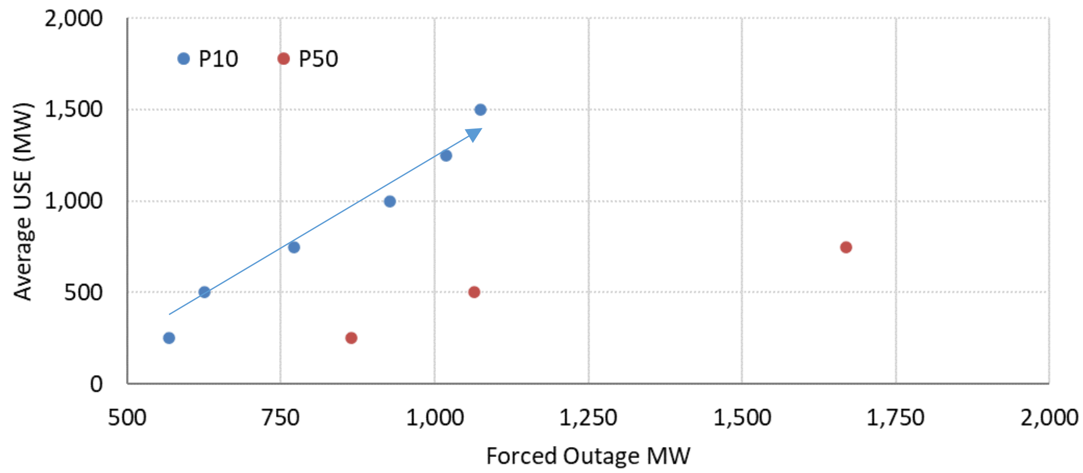
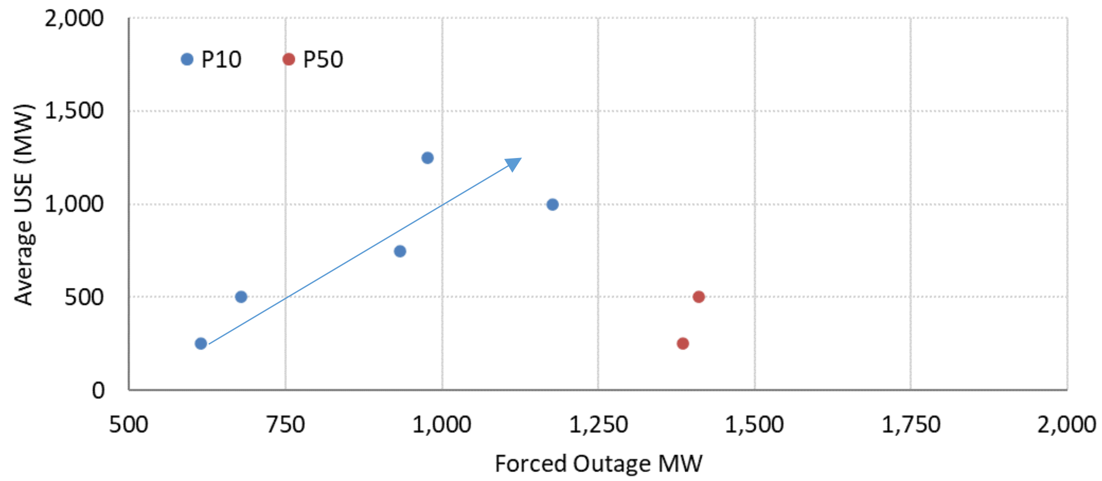


Figure 42 Average USE and forced outages (VIC, Low RE)



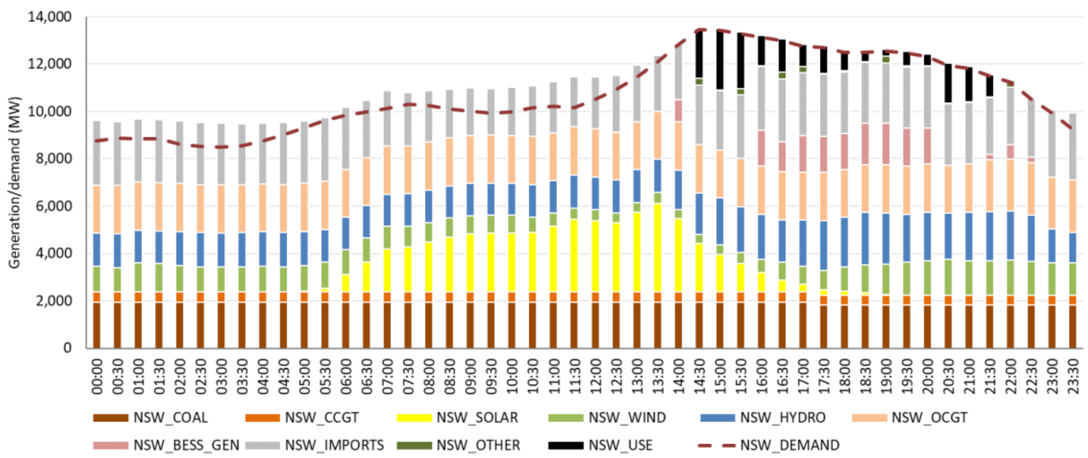
8.4.1 Dispatch charts

The following dispatch charts show sample days in 2028 with instances of USE including snapshot generation, interconnector flows and demand. In the periods where the total generation exceeds the demand line, the region is either exporting power and/or has generator pumping or battery charging loads. The samples selected generally show typical system conditions during longer duration events. The common themes are (1) USE occurring across the evening peak, (2) high forced outages at mainly coal plants, and (3) low wind contribution and constrained import limits.

8.4.1.1 NSW Base case sensitivity

Figure 43 shows the half hourly generation and dispatch for NSW in the base sensitivity scenario. The dispatch chart shows a 7.5-hour USE event between 14:30 and 22:00 covering the evening peak. There is 1.8 GW of coal available (out of 4 GW) due to outages which results in peaking gas plants and hydro running at max capacity throughout the day. Battery is being dispatched during the peak demands but is unable to completely meet demand which results in USE. There is available energy from VIC but the VIC1-NSW1 line is constrained at 1.3 GW against a notional capacity of 2.7 GW.[54] Increasing demands and continued low wind capacity factors of 13.5% (0.45 GW out of 3.3 GW) during the peak leads to increasing USE depth. After 19:00, wind generation picks up to 45% capacity factor, but battery energy storages remained depleted which results in an extended USE event.

Figure 43 Snapshot dispatch profile (NSW, Base case sensitivity)



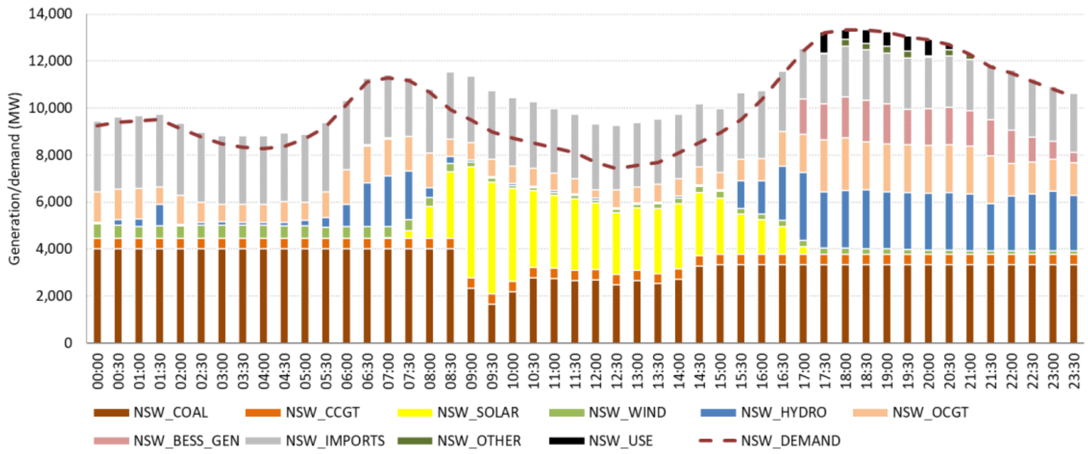
Notes: pumping and charging loads not included. CCGT = combined cycle gas turbine, OTHER = fuel oil and demand side participation

8.4.1.2 NSW Low RE scenario

The dispatch chart in Figure 44 shows a 4.5-hour duration event between 17:30 and 21:00 and coincides when demand starts to peak and solar output falling. During this period, wind capacity is at 0.22 GW (less than 6% capacity factor), there are 0.7 GW of coal related outages and the VIC1-NSW1 interconnector is constrained at 0.6 GW. Battery energy storage and DSP is fully utilised but is insufficient to meet the remaining demand. USE peaks at 0.9 GW and reduces only because of reducing evening peak demands.

[54] Flow figure includes contribution from EnergyConnect. The AEMO ESOO modelling of EnergyConnect is based on a boundary shift between SA, VIC and NSW.

Figure 44 Snapshot dispatch profile (NSW, Low RE)

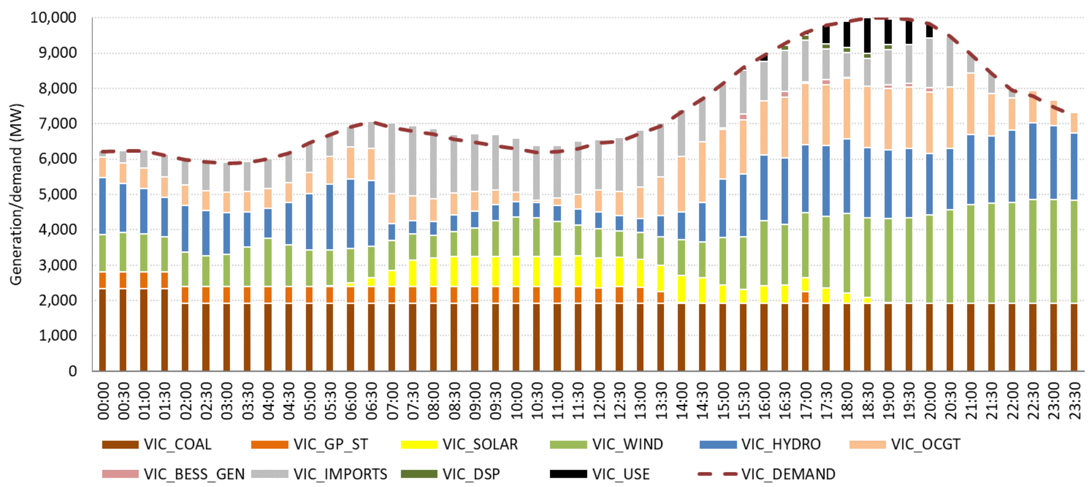


Notes: pumping and charging loads not included. CCGT = combined cycle gas turbine, OTHER = fuel oil and demand side participation

8.4.1.3 VIC Base case sensitivity

The dispatch chart in Figure 45 shows a 5.5-hour USE event between 15:00 and 20:30 which coincides with peak demand. Significant coal outage results in only 1.9 GW of 4.8 GW coal available and coincident outage at gas power stations results in largely decreased generation capacity. The interconnectors into VIC are notably constrained at 1 GW. Although wind generation is at a relatively high 2 GW (50% capacity factor), the significant outages and line constraints result in USE.

Figure 45 Snapshot dispatch profile (VIC, Base case sensitivity)

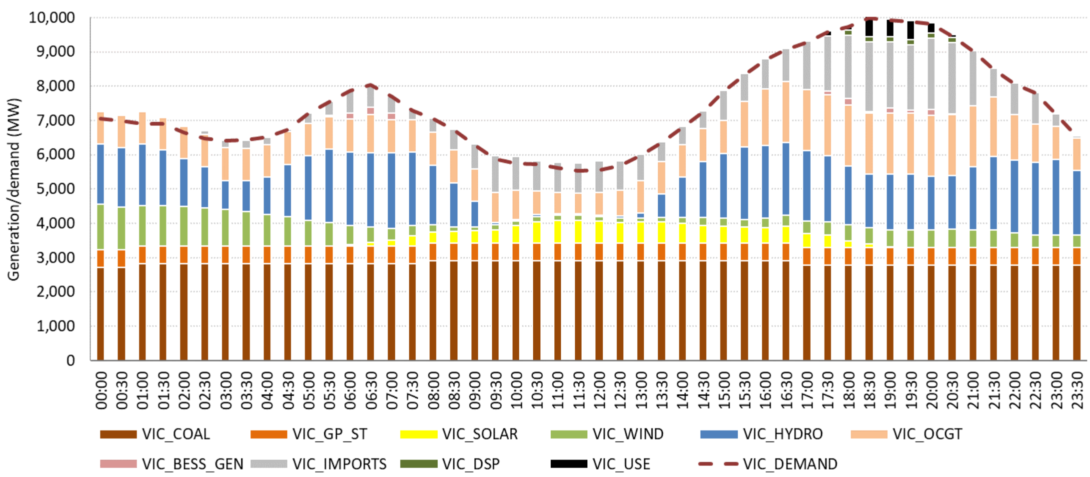


Notes: pumping and charging loads not included. GP_ST = gas powered steam turbines, DSP = demand side participation

8.4.1.4 VIC Low RE scenario

Figure 46 shows a 3.5-hour event between 17:30 and 21:00 across the evening peak. A combination of 1.3 GW of coal outages, wind generation at 12% capacity factor and constrained lines result in inadequate energy supply to meet peak demand. In comparison to the Base case sensitivity dispatch chart, there is much lower RE generation on this snapshot day.

Figure 46 Snapshot dispatch profile (VIC, Low RE)



Notes: pumping and charging loads not included. GP_ST = gas powered steam turbines, DSP = demand side participation

8.4.2 Coincident USE events and import limits

Based on the Base case sensitivity and Low RE scenario, there are only a handful of intervals with coincident USE between NSW and VIC out of a total sample size of more than 6,000 USE intervals across each of the regions. IES also analysed the interconnector import limits in each respective region during USE intervals and found less 0.2% of the intervals where interconnector flow was not at the limit.[55] This is consistent with the definition of USE as defined in AEMO's ESOO modelling methodology[56] and implies each region must build its own new entrant capacity to address its own reliability gap – this would also be irrespective of any USE pain sharing arrangements i.e., the region would still need to address the USE allocated to it on a standalone basis.

[55] There were only a limited number of intervals where this was not the case, including coincident USE periods, and periods where there were counter-price flows.

[56] Section 5.2, ESOO and Reliability Forecast Methodology Document, AEMO, August 2021.

9 Task 2: USE distributions

The following section summarises the USE distributions in 2028 for the Base case sensitivity and Low RE scenario. Both were designed to have USE volumes slightly above the 0.002% reliability standard, i.e., the USE outcomes presented in this section is before the introduction of the new entrant. The USE and other corresponding market modelling outcomes are input into the optimisation model which determines the efficient new entrant required to address the reliability gap and the requisite optimal reliability settings. The detail provided in this section highlights the key implications of the various dimensions of the USE outcomes and how they drive the optimal reliability settings determined in the optimisation model step.

9.1 Background

The USE outlook based on the market simulations presented in Sections 8.1 to 8.3 target a USE level of 0.0025%. The resultant reliability gap in NSW is approximately 350 MWh, compared to a smaller USE volume of 185 MWh in VIC.[57] Further analysis of the USE distributions and inputs into optimisation model to determine the optimal reliability settings highlighted significant discrepancies between NSW and VIC due to the difference in the underlying USE volume (reliability gap) addressed by the new entrant. This difference is discussed in this section and the impacts in Section 10. We note the following two key points regarding the difference:

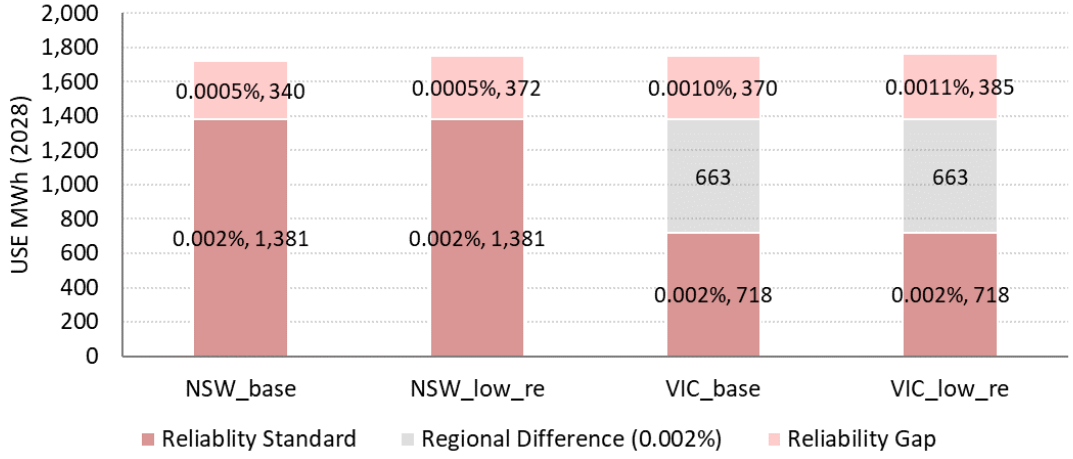
- A lower reliability gap in MWh terms equates to a lower capacity factor for the new entrant plant, and a higher generation cost per MWh, all else being equal; and
- A lower underlying volume from which the reliability gap is addressed, generally exhibits a peakier shape, i.e., it is inherently more costly to address the reliability gap.

Given the above points on the impact of USE MWh to be addressed by the new entrant plant, we resampled the VIC samples to start with equal reliability gaps in volume terms in both regions, thereby negating the impact of USE MWh differences on the reliability settings. The resampling was done by removing a portion of samples with no USE, which effectively increases the weighting of the remaining samples and leads to higher expected USE volumes. There are fundamental implications for the form of the standard which we reserve until Section ▯ of the report.

The impact of the adjustment and comparison of the USE volumes between NSW and VIC is shown in Figure 47. The underlying 0.002% reliability standard corresponds to 1,381 MWh in NSW but only 718 MWh in VIC (dark pink), almost 50% (or 663 MWh) lower than NSW. The reliability gap generated in this step of the modelling in NSW is roughly 350 MWh (being the 0.0005% gap between the targeted 0.0025% and the reliability standard of 0.002%). Standardising, as we have described, by increasing the reliability gap in VIC to 350 MWh corresponds to 0.001% of VIC demand. All the distributions presented in this section are based on this higher expected USE of 0.003% in VIC (being the 0.001% + 0.002% reliability standard).

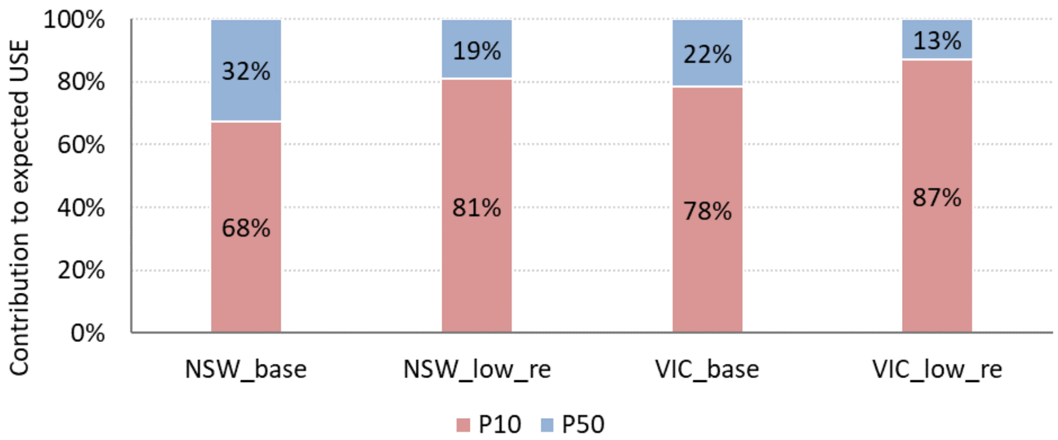
[57] VIC has lower energy demand than NSW which translates to lower USE MWh for a given percentage of demand.

Figure 47 **Expected USE (all scenarios, 2028)**



The figures and charts presented in this section have all been weighted in accordance with the expected weighting across the P10 and P50 samples. Although P10 has an assumed weighting of 30%, its contribution to the expected USE is higher than 65% as seen in Figure 48, i.e., peak demands are a significant driver of USE. Similarly, any charts that plot the number of samples or USE events, unless otherwise stated, have been scaled in accordance with these weightings so that P10 USE samples are not over-represented.[58]

Figure 48 **P10 and P50 contribution towards expected USE volume**



The following notes apply to the information presented in this section:

- All references to ‘Base’ refer to the Base case sensitivity.

[58] This is due to running an equal number of P10 and P50 samples.

- Unless otherwise noted, references to USE refer to the expected volume (in MWh) of USE. USE expressed in percentage terms is based on the region demand on an operational sent out basis.
- The expected number of events, or equivalent statistics, reflects a system state that is not within the reliability standard. The USE distributions presented here are *before* the introduction of the marginal new entrant.
- USE events presented here may also be different to the historical experience in the NEM. This relates to (1) the classification of USE under the reliability framework is a subset of that experienced in the actual market, (2) AEMO utilises other non-market mechanisms such as directions and the RERT to limit load shedding, and (3) the modelling does not include the potential for pain sharing across regions.
- A USE event is defined as any set of USE periods that are within 1 day of each other. This is different to the definition used in Section 10 in determining the optimal reliability settings.

9.2 Overview

The USE volumes when converted to the expected number of events per year and classified by average duration per year are different for each region and is presented in the following charts:

- Figure 49 plots the expected number of events per year against average duration from 2026 to 2028. The underlying USE outlook as seen in Figure 31, generally shows an increasing frequency and duration with an increasing expected volume of USE. By 2028, NSW is expected to experience a USE event almost once a year, and VIC slightly lower at 0.8 events per year. For further context, the equivalent number of events in VIC would have been closer to 0.65 if the volume associated with the reliability gap was not standardised to be the same as the NSW volume.
- The expected number of events per year in the Low RE scenario is similar in NSW (Figure 50), however, it shows higher duration but a lower number of events in VIC. A contributing factor to this was the selection of the 2011 demand reference year which has higher rolling peak demands combined with the low RE peak contribution traces. Although this is an output of the modelling, an increase in the duration dimension is balanced by a reduction in the number of events (to maintain the same USE volume in MWh).

Figure 49 Expected number of events per year (Base case sensitivity)

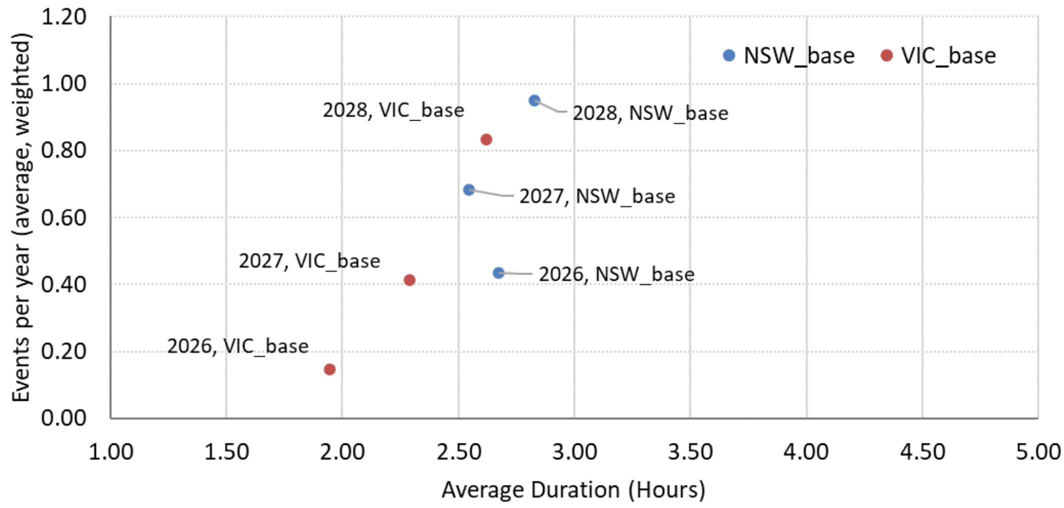
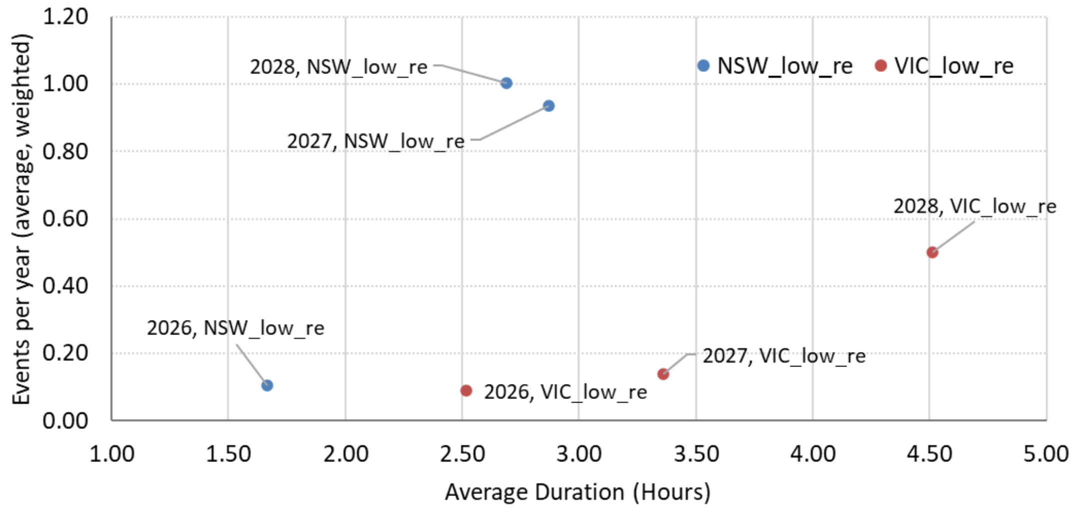


Figure 50 Expected number of events per year (Low RE)



- The expected number of events is further broken down by event duration in Figure 51 and normalised in Figure 52. Under all cases and regions, 0 to 2 hour and 2 to 5 hour events comprise most of the expected number of events, i.e., most events experienced in NSW and VIC are likely to be of short duration. The likelihood of experiencing each of the events, expressed as 1 event in X years, is presented in Figure 53, where the number of years is calculated by taking the inverse of the expected number of events. The likelihood of experiencing a 0 to 2 hour event is 1 in 2 years in the Base case sensitivity in both NSW and VIC, whereas long duration events (10-20 hours) have a likelihood of 1 in 37 years in NSW and 1 in 117 years in VIC. The selection of these ranges was chosen to reflect 1 or 2 intervals around the evening peak, a slightly longer duration centred around the evening peak (2 to

5 hours), one to two rolling days with USE (5 to 10 hours), and long duration events above 10 hours.

- The expected number of events is lower in VIC than in NSW due to the reduced base USE volume corresponding to 0.002%. Generally, lower USE volume is correlated with lower event frequency, and a lower chance of higher duration as seen with the much lower VIC likelihood of experiencing events of 10 hours or longer, all else being equal.

Figure 51 Expected events by event duration

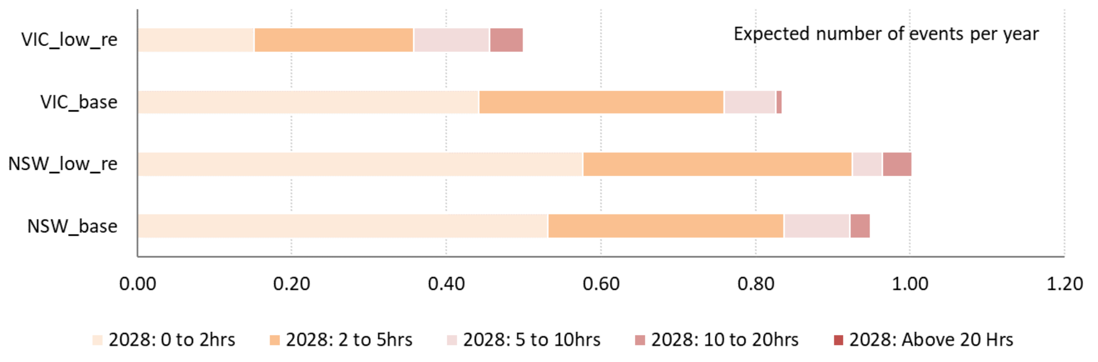


Figure 52 Expected events by event duration (normalised)

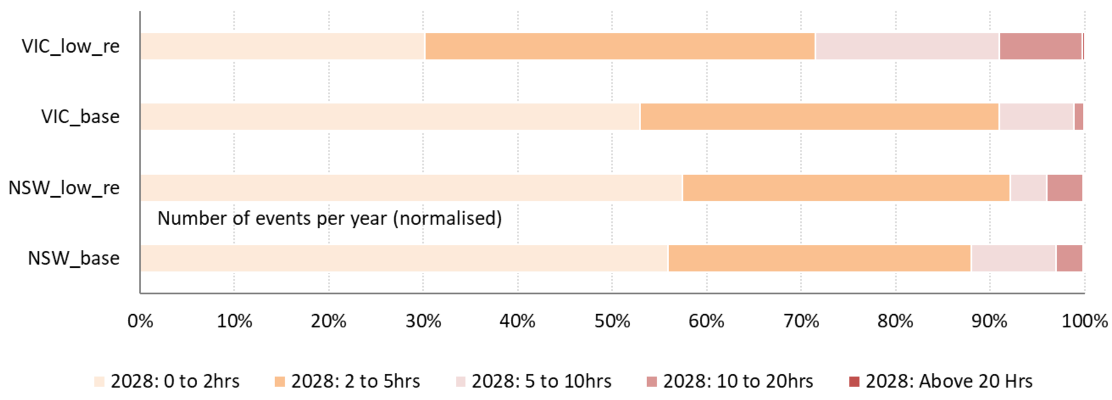
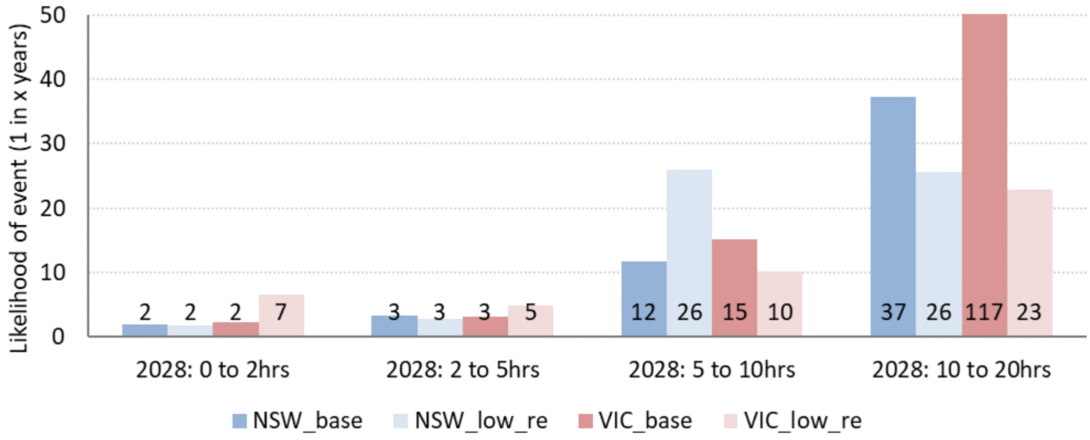


Figure 53 Likelihood of events by event duration



- The relative contribution of event duration towards the total expected USE volume, and volume expressed in percentage terms is plotted in Figure 54 and Figure 55, respectively. The 0-2 hour and 2-5 hour events comprise 50-60% of the total expected USE in NSW (both scenarios) and in VIC under the base case. Although long duration events (10+ hours) are relatively infrequent, these events comprise more than 20% of the total expected USE in NSW and approximately 10% in VIC under the Base case. The VIC Low RE case shows a shift from shorter duration to longer duration events with more than 40% of the USE volume relating to long duration events.

Figure 54 Expected events by event duration

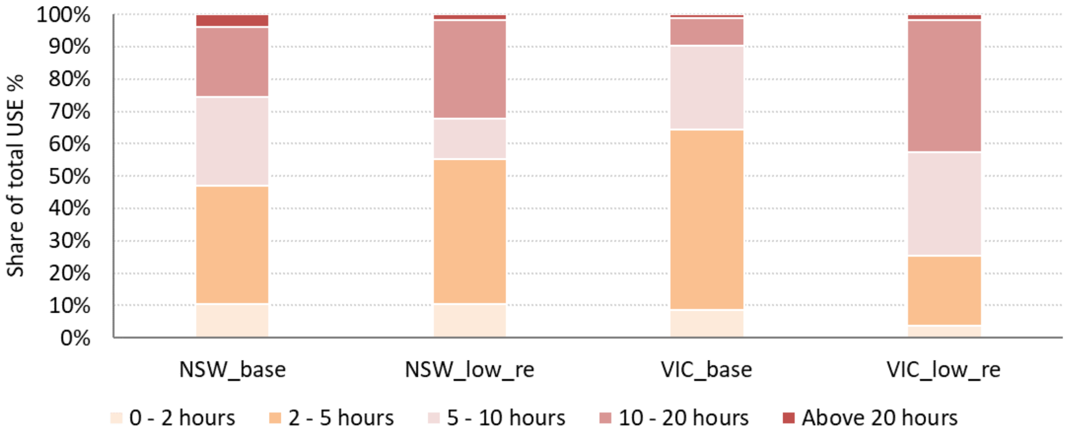
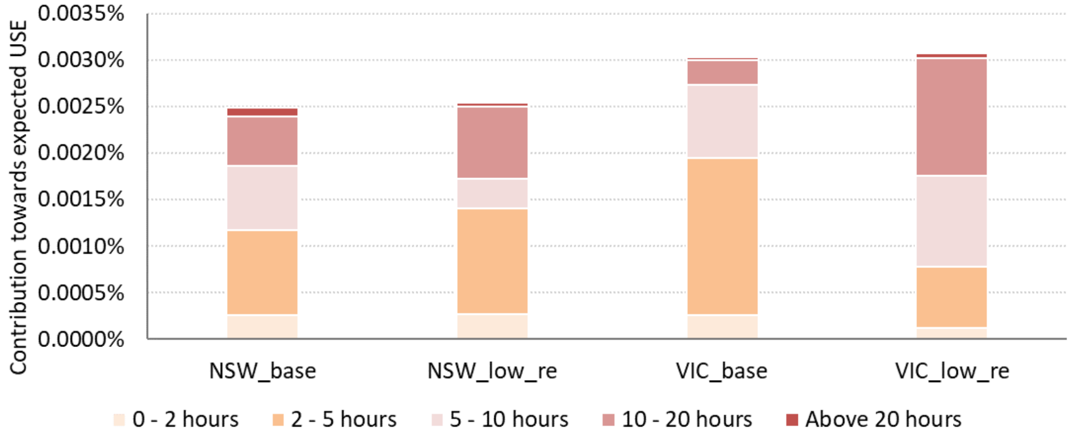


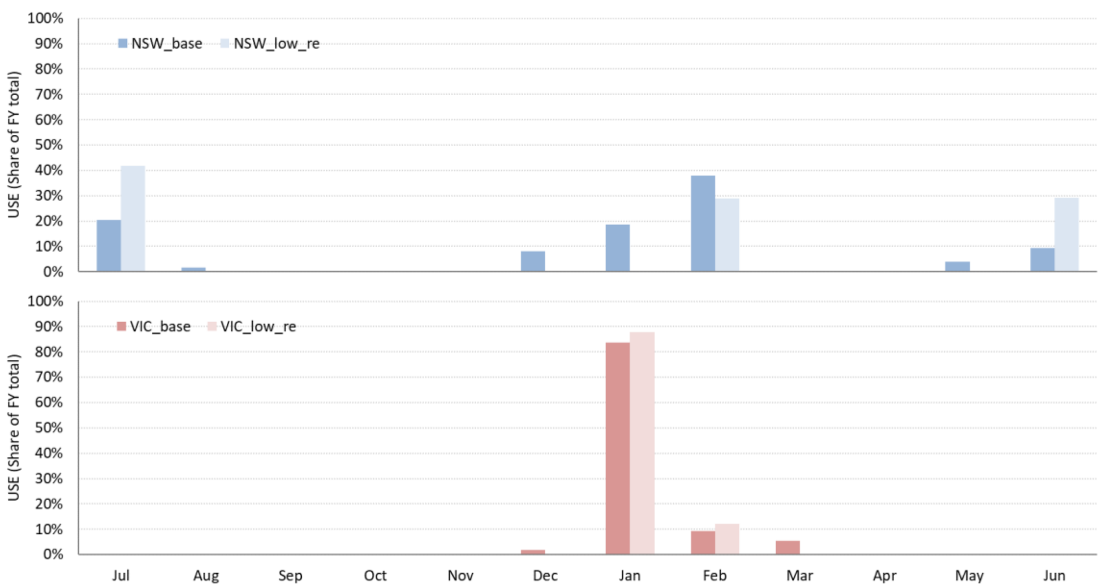
Figure 55 Expected events by event duration



9.3 Distribution by month

The USE by month expressed as a percentage of the annual volume in 2028 is presented in Figure 56 and shows NSW (upper panel) USE occurring in both summer and winter, whereas VIC (lower panel) is concentrated over the summer months only. The NSW Low RE case has a larger portion occurring in winter driven by the low RE yield traces relative to the NSW base case sensitivity.

Figure 56 Share of expected annual USE by month (2028)

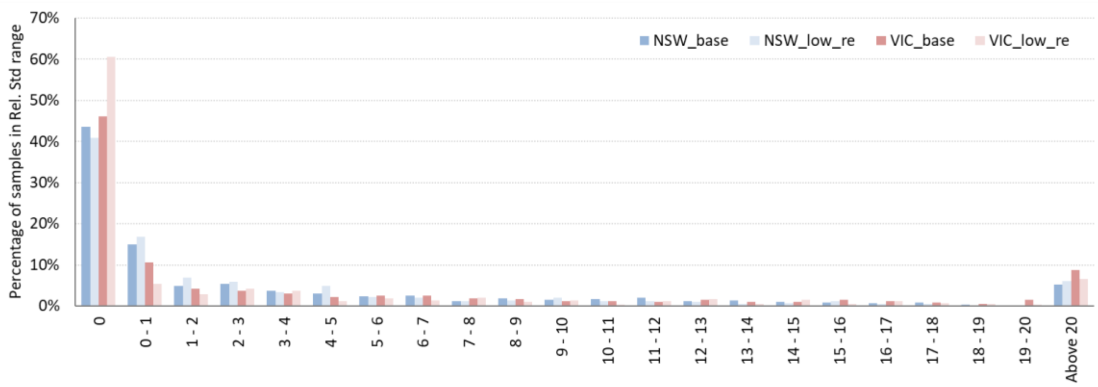


Note: both charts have a shared x-axis

9.4 Distribution by samples

The distribution of USE by samples in 2028 is plotted in Figure 57 and shows a large percentage of samples (40%) with no USE and a long tail with more than 10% of all samples experiencing more than 10 times the reliability standard. The high proportion of samples with no USE is expected to impact revenue recovery requirements as the new entrant would have an effective capacity factor of zero. The VIC Low RE case has an even higher number of zero USE samples, offset by higher proportion of longer duration events (not shown here).

Figure 57 USE by samples (2028)

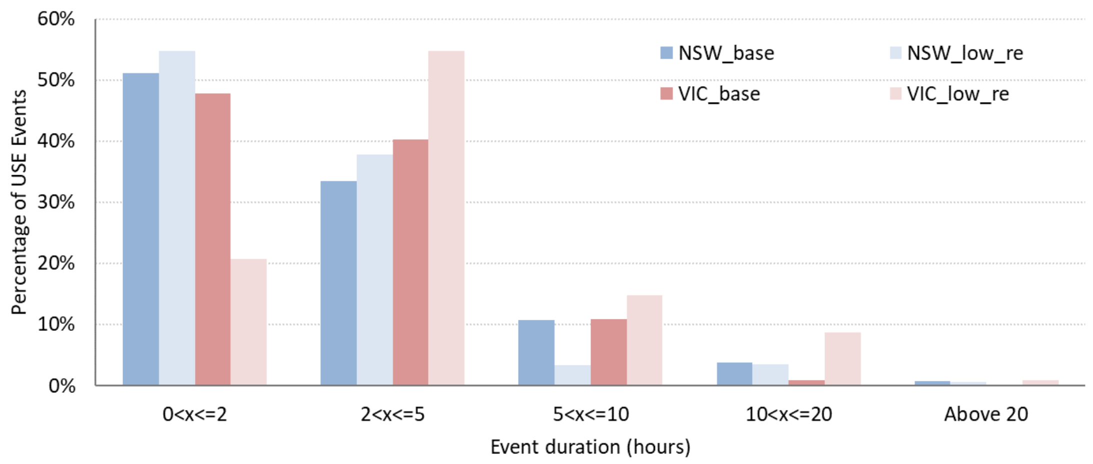


9.5 Duration and depth

Two key dimensions to the USE outcomes are duration and depth. Duration is defined as the total number of hours of USE during an event and depth relates to the MW of USE at the interval level. Maximum depth refers to the highest MW of USE within an event. Duration is relevant as stakeholders may have a different cost of inconvenience associated with different event durations, indicated by a growing concern for long-tailed events or tail risk. Distribution of depth is important as it indicates the capacity of new entrant build required to address event depth.

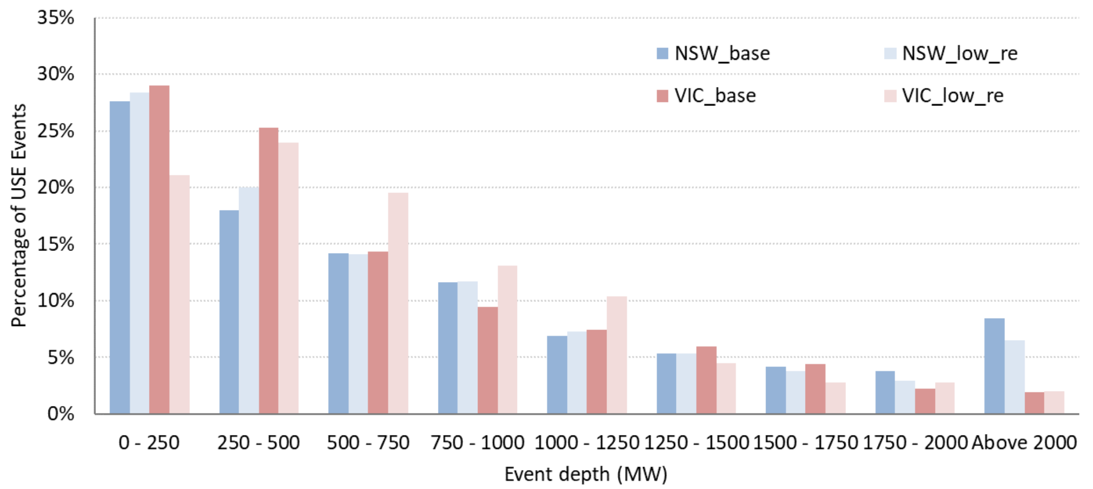
The distribution of event duration is plotted in Figure 58. The result, consistent with Section 9.2, shows a large percentage of events below 2 hours (approximately 50%) and between 2 – 5 hours (approximately 35%), while long duration events comprise a very small share of the total number of events. Under the Low RE scenario, VIC has a much larger share of USE events above 2 hours. This also implies that the reliability gap in both regions can be addressed by focusing on short duration events (see also Figure 64).

Figure 58 Distribution of event duration



The distribution of maximum event depth shows a large share of events with maximum depth less than 250 MW (30%) and 500 MW (roughly 50%) with more than half of the events higher than 500 MW. Event depth is also correlated with event duration (see time of day charts in Section 9.6). The charts suggest significant new entrant capacity would be required to address long-tail events which have both high depth and long duration.

Figure 59 Distribution of maximum event depth



9.6 Event shapes

Figure 60 to Figure 63 illustrate the general event shapes and timing of USE across each of the regions and scenarios. These are based on the average event shape, categorised by event duration, over a period of two consecutive days. The following observations can be made:

- The daily shapes are generally consistent across scenarios. The characteristics include (1) USE centred around the evening peak, also occurring during morning peaks to a lesser extent in NSW, (2) as duration increases, the window over which the events occur around the evening peak expands, (3) for longer duration, this normally occurs over more than 1 day but is also concentrated around the evening peak, and (4) longer duration events are associated with higher depth.

- Irrespective of the scenario, the event shape within the region remains similar but the frequency of these events differs across scenarios. Given this, we can infer USE will remain a capacity issue, rather than energy, under the supply conditions modelled to 2028 in the NEM, and that there is enough storage (includes large hydro) in the system to balance out supply and demand if conditions modelled under the Low RE scenario prevail.
- Comparisons of VIC and NSW clearly show VIC has more peaky events as USE occurs between 12pm to 10pm, whereas USE also occurs over the morning peak in NSW.

Figure 60 Daily shape by event duration (NSW, Base case sensitivity)

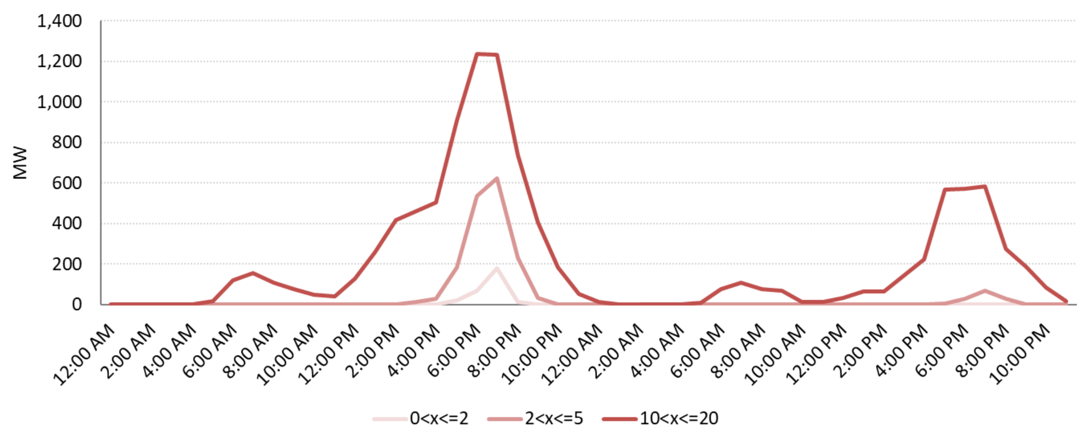


Figure 61 Daily shape by event duration (NSW, Low RE scenario)

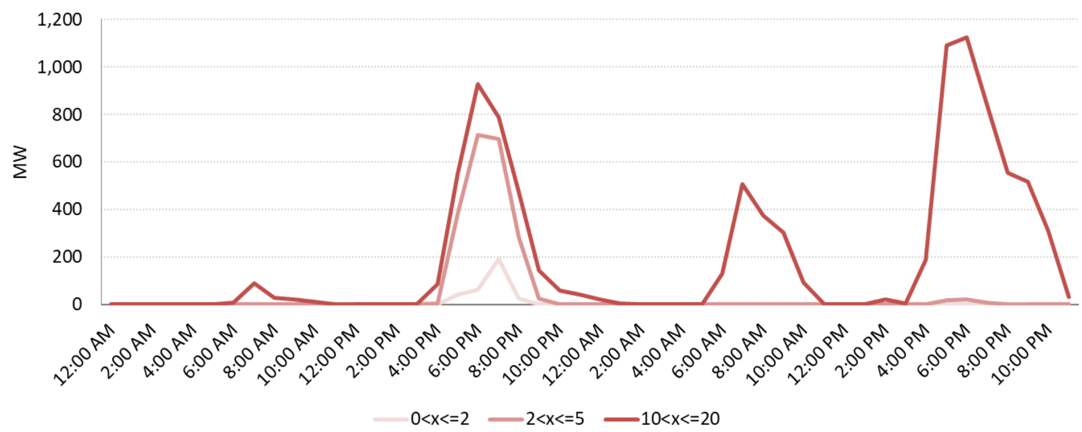


Figure 62 Daily shape by event duration (VIC, Base case sensitivity)

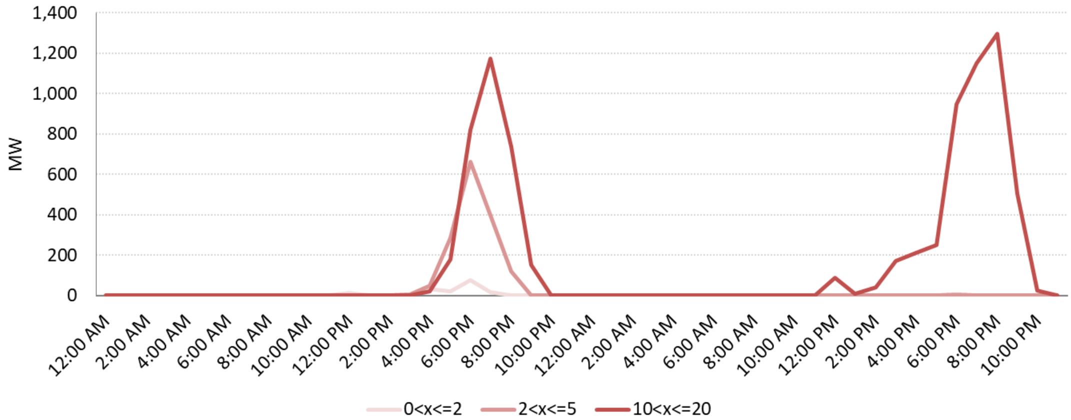
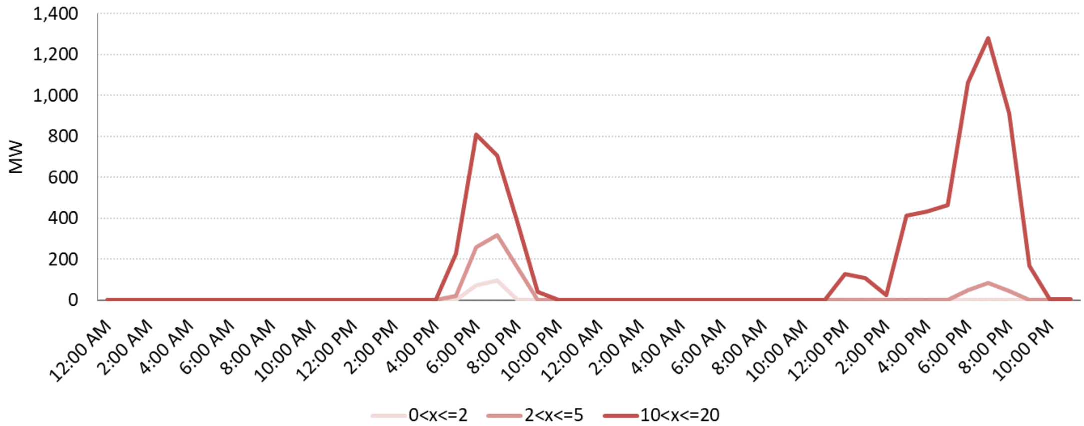
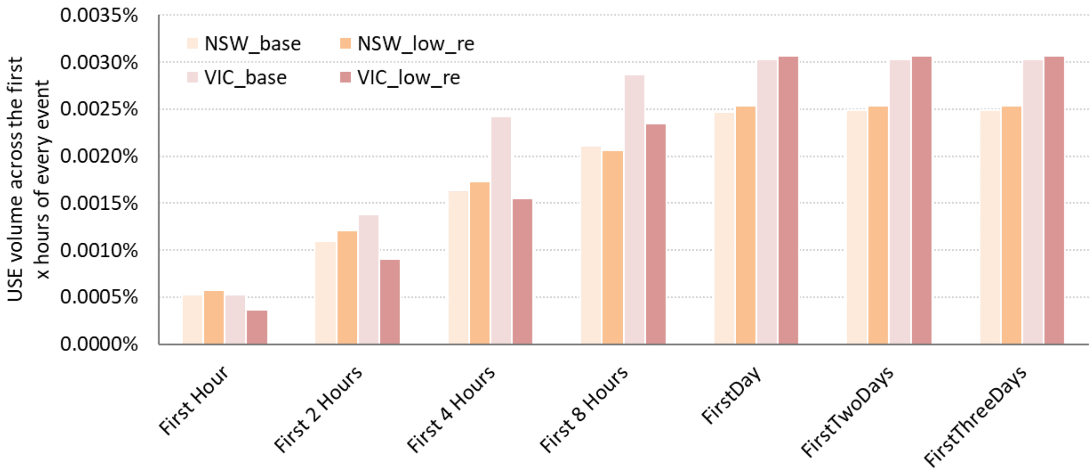


Figure 63 Daily shape by event duration (VIC, Low RE scenario)



We provide insights into the potential volume of USE that can be addressed through Figure 64 which plots the amount of USE in the first X hours of each USE event. This allows for a better comparison than simply looking at volume contribution by event duration (Figure 55) as energy-limited plants are still able to dispatch into the early hours of long duration events. There is roughly 0.005% of USE in the first hour of all events, and more than 0.001% of USE up to and including the second hour. The exception is VIC under the Low RE scenario due to the different underlying USE distribution. The key point is that the reliability gap (0.0005% in NSW and 0.001% in VIC) can be addressed by solely addressing the first two hours of every event, i.e., if enough capacity is installed, short duration batteries can deliver the 0.002% reliability standard.

Figure 64 USE volumes across the first x hours of every event



9.7 Key findings

Table 29 summarises the USE distribution results for NSW and VIC in 2028 along with their implications and relevance for determining the efficient new entrant and corresponding optimal reliability settings, to be discussed in Section 10.

Table 29 Key findings from USE distributions

Finding	NSW	VIC	Implication
Timing of reliability gap	2028	2028	Generated based on removing additional coal units, and simulating low RE yields in the Low RE scenario
Base USE volume	0.002%, 1,380 MWh	0.002%, 718 MWh	Lower base USE volume impacts underlying USE distribution
Reliability gap modelled	0.005%, 340 MWh	0.001%, 370 MWh	Approach was to standardise the USE volume that the new entrant addresses
Distribution of USE across samples	40% has 0 USE	45% has 0 USE (60% for the Low RE case)	Skewed USE across samples impacts revenue recovery
Distribution of event duration	Approximately 80% of events are less than 5 hours in duration, and 50% less than or equal to 2 hours. There is enough volume in the first and second hours of the events to address the reliability gap		Implications for storage duration requirements and CPT
Distribution of event depth	More than 50% of events have depth > 500 MW. VIC depth is generally lower because of lower base USE volume		Duration is unlikely to be addressed by new entrant capacity for events with high depth

Finding	NSW	VIC	Implication
USE event frequency	Approximately once per year. Long duration (10+ hrs) contributes 25% of the reliability gap	0.8 times per year. Long duration (10+ hrs) contributes 11% of the reliability gap	Long duration is rare but has a significant impact on the expected USE volumes

10 Task 2: Optimal reliability settings

The USE distributions and other modelling results from the market modelling step are used as inputs for the optimisation model (refer to Section 9). This section discusses the model interactions and dynamics, optimal reliability setting results, implications for the form of the standard and other key findings.

The specific focus of these results is to frame the thinking around the reliability framework and relevant components in determining the optimal reliability settings. Broader issues relating to regulatory stability, market integrity and risks and investment price signals are outside the scope of the optimisation model. The results presented here need to be considered within this broader context and not on a standalone basis. Where possible, additional analysis has been included to provide information relating to the broader assessment context.

The following notes apply to this section:

- The inputs and results for VIC are based on standardising the reliability gap volume to the same level as NSW, i.e., the total USE energy volume in VIC corresponds to 0.003%.
- The CPT is expressed in hours of the MPC for simplicity, however, the actual level is expressed in $/MWh terms.
- The APC and MFP was fixed in the modelling but was converted from nominal to real terms.[59] See Section 11.6 for a discussion of APC.
- An event includes all USE periods which are within 7 days of each other because of the 7-day lookback in assessing the CPT to identify APP and the application of APC. The definition of event in this section is different to that in used in Section 9.
- References to a sample refers to a full year simulation which can comprise zero, one or multiple USE events.
- Where appropriate, the magnitude of each component of the reliability settings has been rounded to the nearest $500/MWh. The rounding precision is intended to reflect the inherent uncertainties relating to the assumption inputs and modelling process.

10.1 Baselines and sensitivities

The market simulation results (Base case sensitivity and Low RE scenario) in conjunction with a number of new entrant baselines and sensitivities were modelled. A baseline generally represents a specific technology type with no additional operational constraints applied. The sensitivities are intended to reflect the impact of real world risks, operational limitations, and/or uncertainties in the underlying input assumptions.

The list of baselines and sensitivities provided in Table 30 represents a subset of what was run and has been filtered to report on the most relevant outcomes. The runs are structured to

[59] APC = $266/MWh, MFP = -$888/MWh based on 2% pa CPI adjustment.

demonstrate the various impacts on the various new entrant options. A summary of the modelled baselines and sensitivities is provided below.

- OCGT, based on the large configuration, in addition to 1/2/4 hour batteries have been presented as they are likely to be the most relevant in efficiently addressing the reliability gap.
- Demand response was included based on assumptions provided by a large demand response provider in the NEM. IES took a conservative view of the cost ranges that were provided. The modelled capacity is additional to demand side response volumes already captured in the market modelling. IES carried out additional demand response sensitivities after the draft modelling report and has been included in Section 11.6.
- The dispatch of the new entrant technologies assumes perfect foresight which can overstate revenue recovery. Additional sensitivities have been modelled to provide context around the associated costs of accounting for some of the operational risks associated with BESS and OCGT.
  - BESS are not guaranteed to enter USE events with a full state of charge, may discharge during an event earlier than what may be optimal, or may be subject to other contractual agreements such as network services. Given the broad range of possibilities, a minimum state of charge constraint (30%) was used to capture the range of concerns. The BESS revenue in these sensitivities does not include any non-market revenue streams which may be associated with maintaining a minimum state of charge.
  - OCGT runs infrequently, due to the nature of its cost structure and peaking generation role, and built on a standalone basis, is likely to depend on non-firm gas supply arrangements. A 4-hour energy limit was modelled to reflect this operating risk. The OCGT is also expected to miss USE intervals from time to time, especially if USE coincides with sudden changes to the power system. A sensitivity delaying the response of the OCGT, i.e., missing the first 10 minutes of every event, was included to reflect this risk.
- Higher gas prices were also modelled to understand the impact of variable costs on the optimal reliability settings.
- The weighted average cost of capital is assumed to be 5.5% (pre-tax, real basis) for all generation types. A high cost sensitivity applying a 7.5% WACC is included for the BESS and OCGT and would reflect a generic basket of risks covering policy, market, and operational risks.[60]

[60] The 7.5% WACC sensitivity is based on input provided by the Panel.

Table 30 Optimisation model scenarios

TYPE	LABEL	DESCRIPTION
Baseline	OCGT	Only allow OCGT. Cost is based on OCGT_large, no delayed response and no energy limits
Baseline	BESS_1HR	Only allow 1, 2, and 4-hour batteries. FCAS revenue ($22,000/MW/year) is assumed but no minimum state of charge constraint is applied
Baseline	BESS_2HR	
Baseline	BESS_4HR	
Baseline	DR	Demand response based on the following assumptions: $50,000/kW, $5,000/MWh and 2 hour daily energy limit[61]
Sensitivity	BESS_2H_30SOC	Only allow 2 or 4-hour batteries but apply a 30% minimum state of charge constraint
Sensitivity	BESS_4H_30SOC	
Sensitivity	OCGT_delay	Only allow OCGT. Cost is based on OCGT_large, apply a 10-min delayed response i.e., OCGT misses out the first 10-minutes of every event
Sensitivity	OCGT_4HR	Only allow OCGT. Cost is based on OCGT_large, apply 4-hour daily energy limit
Sensitivity	OCGT_75WACC	Only allow OCGT/BESS, and increase WACC to 7.5% (from 5.5%)
Sensitivity	BESS_75WACC	
Sensitivity	OCGT_GAS3x	Only allow OCGT, increase gas prices by factor of 3[62]

Note: The scenarios presented here has been filtered to capture the most relevant outcomes in addressing the reliability settings.

The modelling work also included large-scale solar, onshore wind and CCGT technology as a potential new entrant type but the results have been omitted as the corresponding costs (or corresponding MPC and CPT combinations) were not viable.[63] The solar and wind results were due to its low peak contribution, particularly at times of USE (see Section 8.4) and requires MPC levels in excess of the VCR.[64] CCGT was found to be inefficient relative to the OCGT and BESS options in addressing the reliability gap due to its higher capex and expected reduction in capacity factors over the Review Period leading to a higher balance of costs recovered from the reliability settings. Coal and pump hydro options were excluded due to long lead times.

10.2 Results overview

The following charts in Figure 65 and Figure 66 present the total region cost and capacity required under each of the baseline and sensitivity runs for the Base case sensitivity. These

[61] See Section 11.6 for additional demand response sensitivities.
[62] Higher gas prices would impact the underlying price and dispatch outcomes from the market modelling step. This sensitivity solely focuses on the OCGT and assumes the OCGT can maintain the same revenue margins outside of the USE events in assessing the gas price impact on the reliability settings without having to re-run the market modelling. All else being equal, higher gas prices are likely to increase the required MPC for OCGTs.
[63] MPC outcomes were higher than the assumed region VCR for the standalone solar and wind options.
[64] Solar and wind capacity was also not required for the BESS new entrant as there was spare surplus capacity in the system between contiguous USE periods.

results reflect the 2028 reliability gap. The subsequent sections explore the results in more detail. Results of the Low RE scenario is discussed in Section 10.8.

Table 31 Results overview (Base case sensitivity)

	NSW	VIC
Total region cost	Of the baseline runs, the BESS_2HR run has the lowest total region cost followed by BESS_1HR then OCGT. The demand response option has a cost that is more than double the BESS_2HR option. The total region costs are not comparable to VIC due to differences in region size.	The 2-hour battery has the lowest region cost, followed by the OCGT, 1-hour battery, then 4-hour battery. The demand response resulted in no MPC combinations below the VCR and was therefore considered invalid, i.e., not a viable new entrant option.
Capacity built	The OCGT requires the least capacity to address the reliability gap. Under the BESS baselines, a reduction in storage duration requires additional capacity to address the same volume of USE.	The capacity trends follow that of NSW, however, the capacity required in VIC is higher than that in NSW. This is a direct consequence of the USE distributions where VIC has (1) higher number of zero USE samples, and (2) more peakier USE shape owing to the lower USE base volume. The 1-hour battery capacity build is significantly higher than NSW as duration requirements in VIC are higher (see Section 9.5).
Sensitivities	All outcomes correspond to either a higher region cost than the corresponding baseline, and/or increased capacity to be developed. The impact of the gas price sensitivity results in a marginal increase in region cost.	Same as NSW. Some of the WACC sensitivities requires a higher MPC than that of the VCR, i.e., the model found no valid solution.

Figure 65 Results overview (NSW, Base case sensitivity)

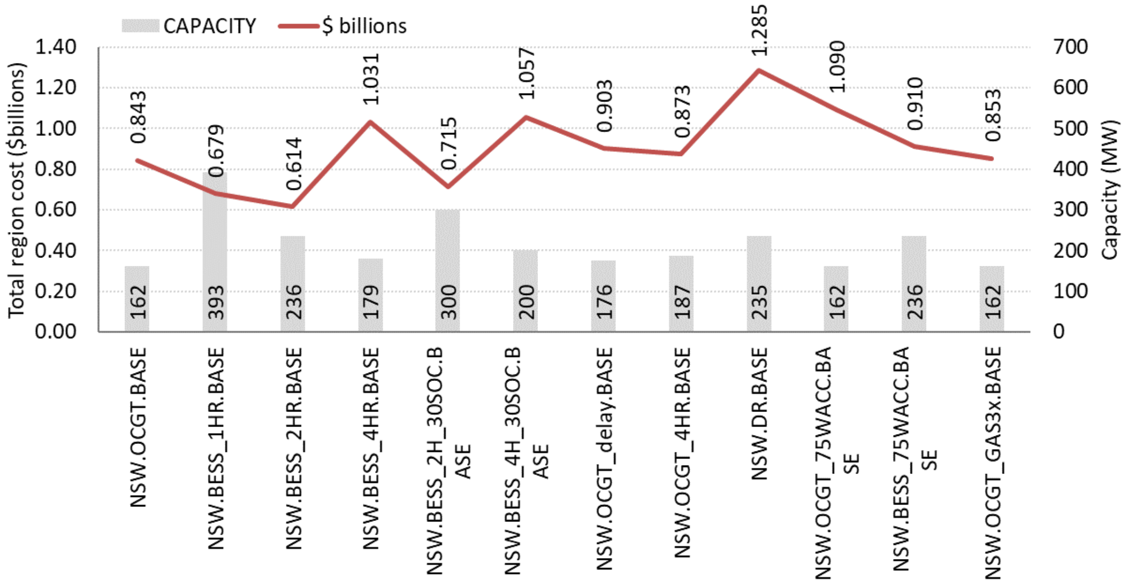
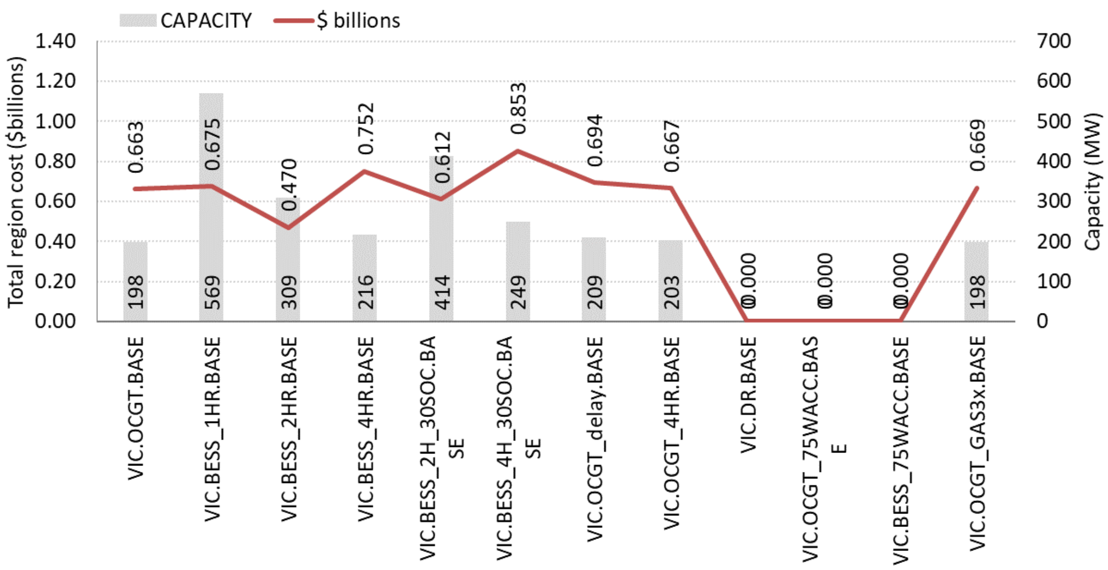
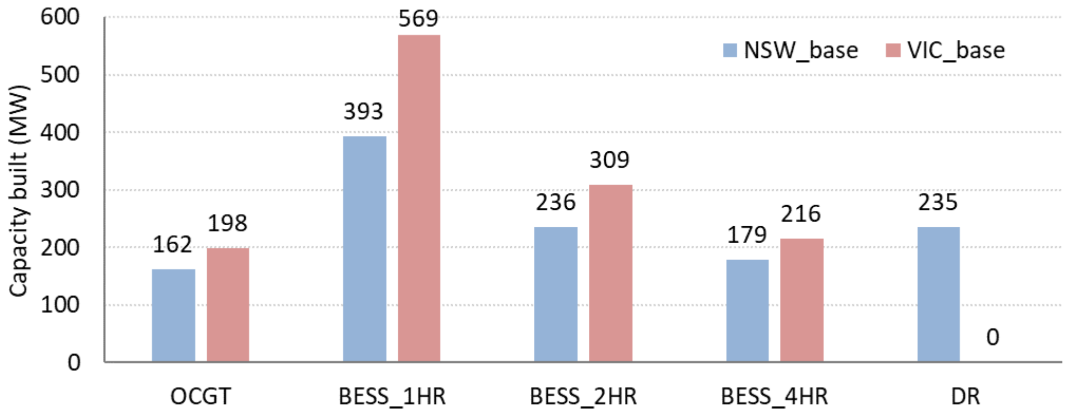


Figure 66 Results overview (VIC, Base case sensitivity)



Note: A zero capacity in the chart indicates no valid solution was found, i.e., the MPC required was greater than the VCR.

Figure 67 New entrant capacity requirements (Base case sensitivity)



Note: A zero capacity in the chart indicates no valid solution was found, i.e., the MPC required was greater than the VCR.

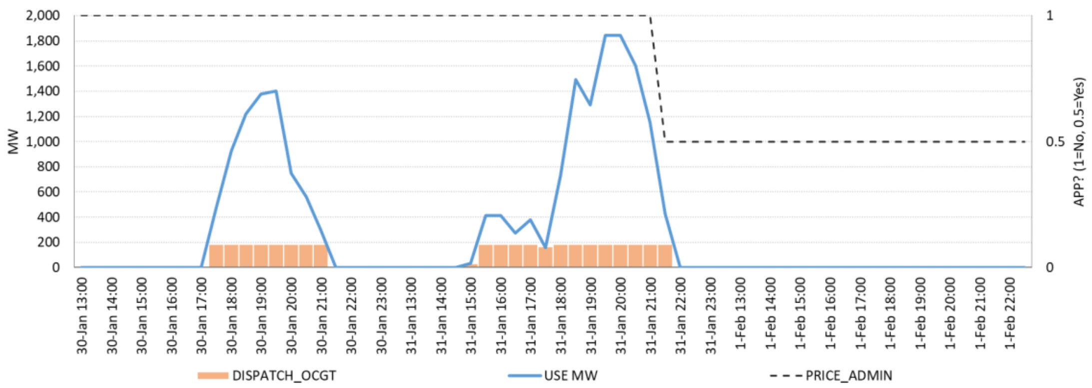
10.3 Dispatch profiles and CPT

The dispatch profiles from the optimisation model for the OCGT and BESS_2HR baselines and for the same sample event are presented in Figure 68 and Figure 69. The blue line corresponds to USE, the coloured bars are generation addressing USE, and the dotted line represents the MPC and APC when the CPT is reached. Each period represents a half-hour. If all events were included, the difference between the area under the line and generation would equate to the remaining USE volume corresponding to 0.002%. The sample event that is shown has a duration of more than 10 hours but has a low associated weighting in the set of USE events that is considered by the optimisation model.

The OCGT dispatch profile shows almost 200 MW of OCGT capacity which is dispatched during all USE periods over the event. The optimal CPT was determined to be 15 hours. The OCGT dispatch covers more periods than that of the BESS_2HR.

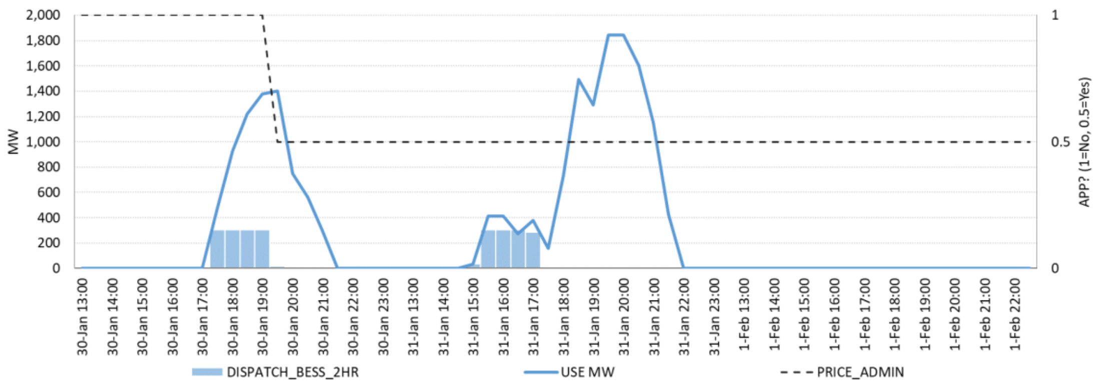
In contrast, the BESS_2HR profile shows 300 MW that is required but can only be dispatched for 4 periods (2 hours) across each contiguous set of USE periods. There is sufficient surplus capacity for the BESS_2HR to charge in response to the second contiguous set of USE periods. The formulation of the model, specifically the objective of minimising the total region cost, leads to reducing CPT to approximately 2 hours in line with the limited duration capability of the BESS_2HR option. Alternatively, allowing for CPT to extend past the generation capability of the BESS_2HR option increases the total region cost but doesn't contribute towards the revenue recovery as the battery storage is empty and is unable to generate past hour 2.

Figure 68 Dispatch chart example (OCGT)



Note: only 1pm-12am periods shown

Figure 69 Dispatch chart example (BESS_2HR)



Note: only 1pm-12am periods shown.

One of the key modelling outcomes is a clear incentive for the model to reduce the CPT to minimise the total region cost objective, however, this is generally offset by the shorter period in which the BESS_2HR option needs to recover revenues leading to a higher MPC. The lower CPT but higher MPC combination results in materially lower total region costs as shown in both NSW and VIC outcomes (Figure 65 and Figure 66). Example MPC and CPT solutions for the OCGT and BESS_2HR options are summarised in Table 32. The current MPC and CPT is $15,100/MWh and $1,359,100/MWh.

Table 32 Sample outcomes for OCGT and BESS_2HR

	OCGT	BESS_2HR
Total region cost ($ billions)	0.84	0.61
MPC ($/MWh)	$21,000	$30,000
CPT (hours) [1]	15	2.1
CPT ($/MWh) [2]	$3,780,000/MWh	$756,000/MWh

[1] The CPT is expressed in hours of MPC for simplicity. [2] This is based on 5-min trading intervals.

10.4 Interaction between CPT and MPC

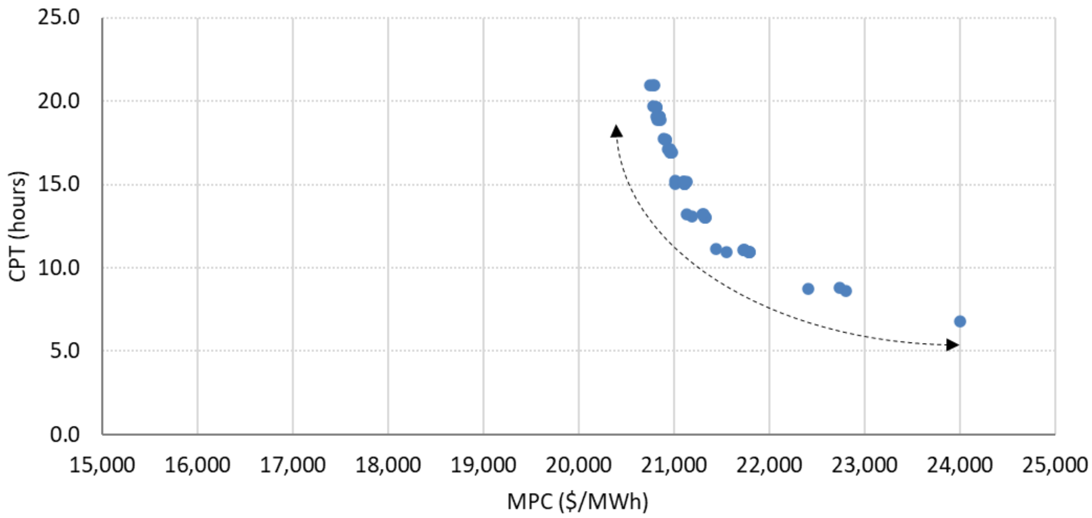
The optimisation problem is non-linear, and the model employs a grid search algorithm which searches for the lowest total region cost subject to various constraints including revenue recovery for the efficient new entrant.[65] Each iteration is solved and informs the reliability settings for the next iteration. The model generally locates the minimum point after 100 iterations and produces a single MPC and CPT combination that represents the lowest total region cost. Closer inspection of the results revealed the presence of clusters of iterations or solves where the total region costs are very close to the optimal solution and the new entrant is also revenue sufficient – the difference is generally within a 5% tolerance.[66] It is possible there are other combinations the model has not explored, however, what is presented here is expected to be representative.[67]

Extracting all these solutions produces the following MPC and CPT combinations for the OCGT and BESS_2HR options in the NSW Base case sensitivity (Figure 70 and Figure 71). Each one of these MPC and CPT combinations corresponds to a solution within a small tolerance of the optimal solution, or, each one of these MPC and CPT combinations results in similar region cost and meets the new entrant revenue adequacy constraint, subject to a small tolerance. The combinations trace an efficient frontier with many plausible solutions which negates the notion of a single optimal MPC and CPT combination, if considering total region costs only.[68]

This finding is consistent with the dispatch profiles presented in Figure 68 and Figure 69. For a given MPC and CPT combination where the OCGT is revenue sufficient, any reduction in the CPT can be offset by an increase in the MPC and conversely, the reverse holds true. The non-linear gradient is also a function of the underlying USE distribution, in that an increase in CPT from 15 to 20 hours only requires a small reduction in the MPC as the number of events where a CPT of 20 hours is relevant is infrequent. A reduction in CPT from 10 to 5 hours requires a much larger increase in MPC because of the impact it would have across many events (see Section 9.5 for discussion of the distribution of event durations), or that a shift in CPT at lower levels has a higher impact on the overall revenue recovery requirements.

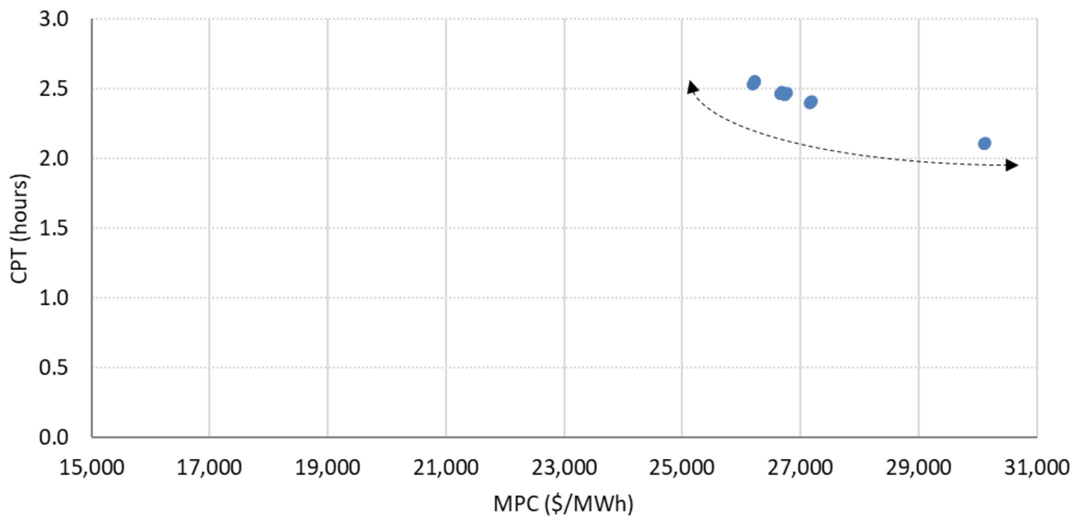
[65] See Appendix C.3.
[66] The tolerance of 5% is a reasonable threshold given the uncertainty in the underlying assumptions.
[67] Different initial solve values results in the same or similar total system cost.
[68] There are other out-of-model considerations when deciding the optimal combination.

Figure 70 MPC and CPT combinations for OCGT



The corresponding iterations for the BESS_2HR option also show a frontier, however, the number of points of MPC and CPT combinations and the range is much more limited. This is related to the energy-limited dispatch profile seen previously, where the battery's dispatch into much longer duration events is limited, and therefore limits the CPT range, i.e., increasing CPT to the current 7.5 hours has little to no impact on BESS_2HR revenue recovery and would just serve to inflate total region costs. The CPT range still extends to 2.5 hours above that of the BESS_2HR storage duration because an event which covers up to a 7-day period, can include rolling days of USE where the battery can recharge in between contiguous USE periods (as shown in Figure 69 above).

Figure 71 MPC and CPT combinations for BESS_2HR



The CPT and MPC combinations are clearly optimised for the underlying new entrant and result in significant discrepancies across the OCGT and BESS_2HR options shown above. The baselines and sensitivities limit the solve for a single generation type to understand the CPT and MPC dynamics for each generation option. Allowing the model to potentially select a portfolio mix results in the single most efficient option selected, i.e., the BESS_2HR option. This is driven by the USE energy distributions which are generally short duration in nature and addressing the first 2 hours of every event is all that is needed to address the reliability gap (see Figure 64).

10.5 Optimal reliability settings

The combinations of the optimal reliability settings for the baseline results for NSW and VIC under the Base case sensitivity are presented in Figure 72 and Figure 73, respectively; and are combined into a single chart in Figure 74. The vertical axis has been truncated at 16 hours, and the horizontal axis at $40,000/MWh. The current levels of the CPT and MPC are also indicated in the charts for reference. The following summarises the key results:

- Under all generation types in both NSW and VIC, the required MPC is well above the current $15,100/MWh level. One of the main reasons for this is the presence of samples that have no USE. In NSW and VIC under the Base case sensitivity, zero USE samples comprises 40% or more of the total samples and skews revenue recovery implications. Having 40% of samples with no unserved implies the new entrant, which relies on reliability events for revenue sufficiency, is not addressing USE 4 out of every 10 years and must recover a larger portion of revenues from the remaining samples, i.e., requires a higher MPC, compared to an outlook with USE more evenly distributed across the samples.[69]
  - The results are materially different to the 2018 Review. Thi is discussed in more detail in Appendix C.4.
- The CPT range for batteries starts at roughly its storage capability but also includes slightly higher CPT levels because events can span multiple days where the battery has opportunities to recharge after the evening peaks.
- Demand response in VIC was not feasible as the implied MPC was higher than the assumed VCR. Demand response in NSW requires and MPC of $41,000/MWh and has been omitted from the following charts. IES carried out additional demand response sensitivities after the draft modelling report and has been included in Section 11.6.
- The associated total region costs are significantly lower for the 1- and 2-hour battery configurations because of the significantly lower CPT ranges relative to the OCGT. However, the MPC that is required is significantly higher than the OCGT and the current $15,100/MWh level.
- There is a significant difference for the same new entrant option in NSW compared to VIC. At a CPT level of 7.5 hours, the NSW OCGT requires approximately $23,500/MWh compared to $30,000/MWh in VIC. The main driver of this difference is the underlying USE

[69] The new entrant can sell contracts to minimise variability, but the underlying spot revenue recovery dynamics would be fundamental in the pricing of risk, i.e., determining the contract price.

distribution that feeds into the optimisation model. Because VIC has a lower base USE volume, it is inherently more expensive to address the reliability gap, despite standardising the volume that the new entrant addresses (see Figure 47).

The optimisation model is based on solving each region's reliability gap on a standalone basis, i.e., there is no reserve sharing amongst the new entrants in NSW and VIC. Further analysis into the market modelling found that out of the 6,000 to 7,000 intervals of USE simulated in each of VIC and NSW, there was no spare import capacity across any of the interconnectors into the region experiencing USE.[70] The implication is that the reliability gap must be addressed within the region itself and further supports why the reliability new entrant in VIC would have a higher $/MWh revenue recovery requirement.

Figure 72 NSW baselines (Base case sensitivity)

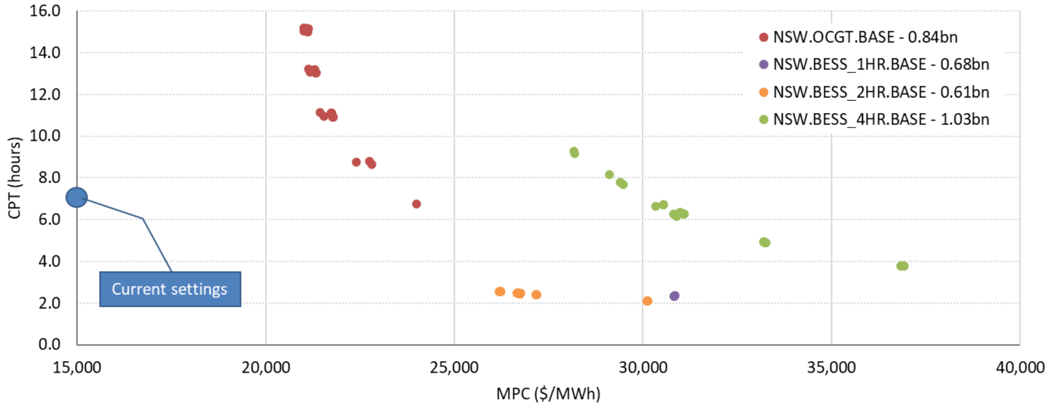
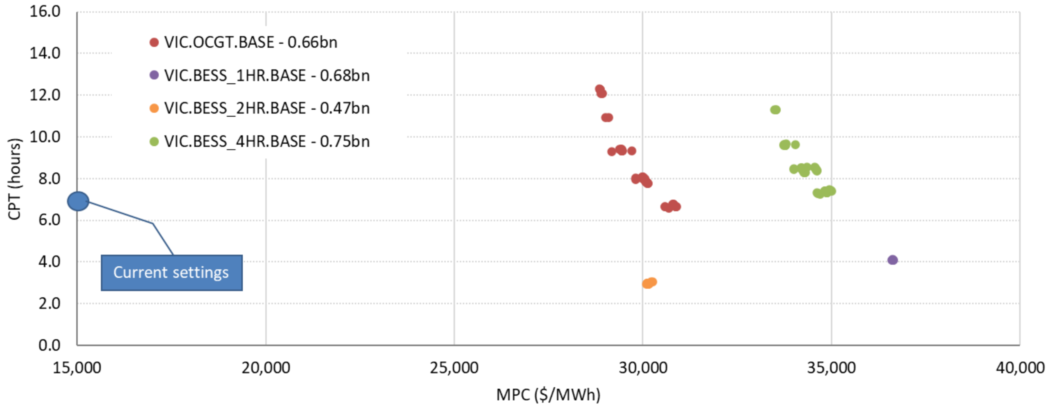
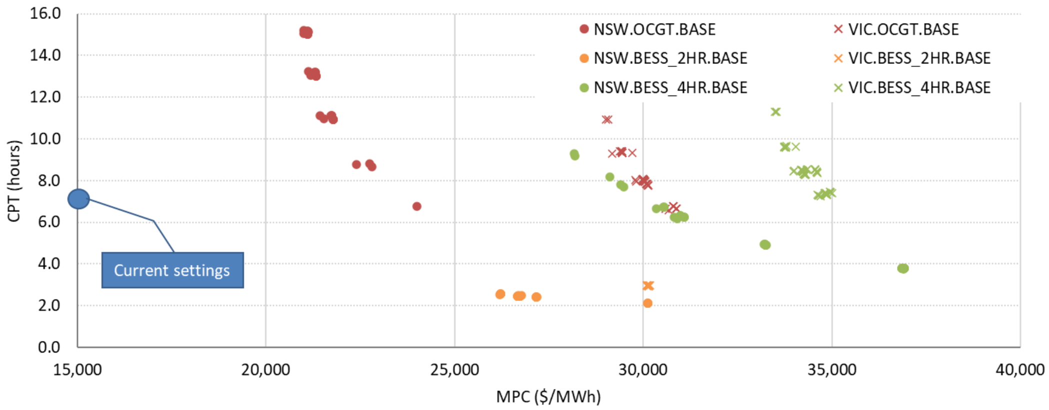


Figure 73 VIC baselines (Base case sensitivity)



[70] There were less than 0.2% of USE intervals where the interconnector remained open due to coincident demands, and/or had counter price flows.

Figure 74 VIC and NSW baselines (Base case sensitivity)



10.6 Revenues and hedging outcomes

The optimal level of the reliability settings needs to consider more than total region cost, which is all the optimisation model accounts for. Two important aspects relate to the revenue variability (which affects bankability) of the new entrant generator, and potential contract market implications. Detailed quantitative analysis into these areas is out of scope, however, high-level analysis has been provided for the Panel to qualitatively consider the impacts of shifting away from the current MPC and CPT levels.

10.6.1 Revenue outcomes

The revenue composition of the new entrants under the baseline cases for NSW and VIC are provided in Figure 75 and Figure 76. The revenues are broken down into (1) external revenues (EXT. REVS) which include assumed revenues from the energy-market outside USE events and FCAS revenues in the case of batteries, and (2) revenues recovered from USE events categorised by duration. The new entrant types have different revenue compositions due to its different dispatch profiles and the corresponding optimal MPC and CPT combinations.[71] OCGTs have a higher reliance on the reliability settings (approximately 50%) relative to the BESS options (up to 35%) to recover generation costs as the BESS options earn more regular energy revenues through energy arbitrage and the FCAS markets.

[71] The charts are based on the MPC and CPT combination corresponding to the minimum total region cost solve.

Figure 75 Revenue composition (Base case sensitivity)

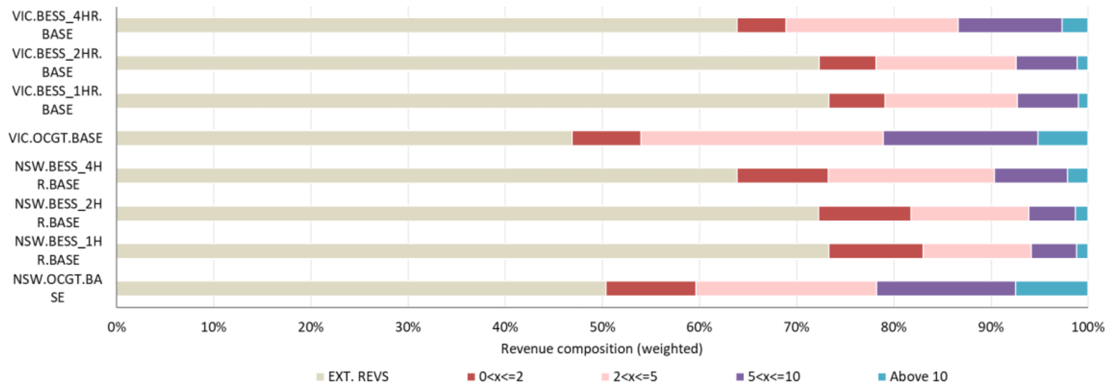
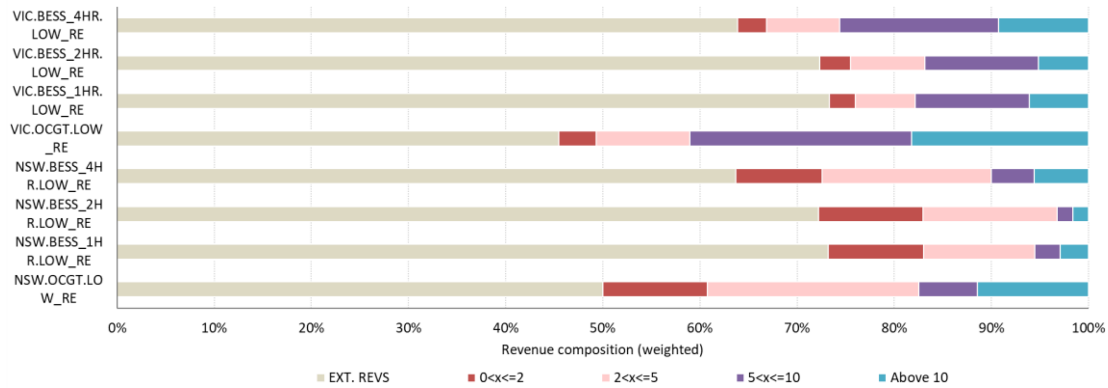


Figure 76 Revenue composition (Low RE)



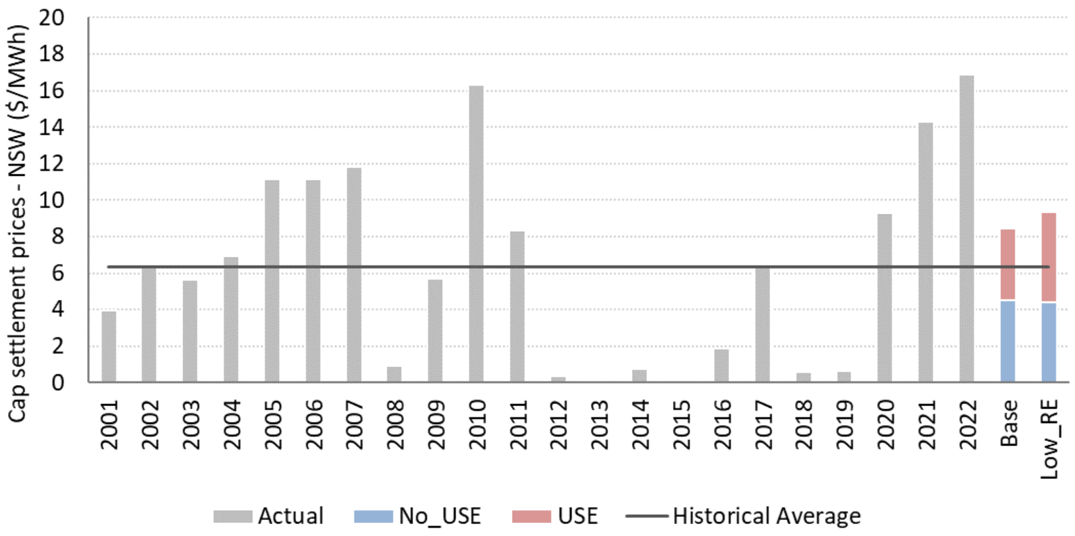
The breakdown of revenues assists in understanding how much revenue recovery depends on highly infrequent but high impact scenarios. Depending on location and scenario, the OCGT earns between 5% under the Base case sensitivity up to 17% in the VIC Low RE case from long duration events. This compares to a much smaller share derived from long duration events for BESS which generally sits around 5%. BESS still earns revenues during the long duration events as they are capable of discharging in the first few hours of the event. BESS_2HR earns proportionately more of its revenues from 0 to 5 hour events relative to the OCGT which would suggest a lower variance in annual revenues.

The revenue composition would also be impacted by the underlying level of volatility and therefore energy revenues achieved outside the USE events. Lower volatility translates to lower energy revenues and would require a higher balance of costs to be recovered from USE events. The underlying pricing outcomes expressed in terms of the annual cap price against historical settlement is shown in Figure 77 and Figure 78 below.[72] The cap value is split into periods outside of USE events (labelled NO_USE) and the portion that is driven by USE events. The USE component is not relevant to the current modelling as the optimisation model will

[72] Based on the current level of the reliability settings and a reliability gap of 0.0005%.

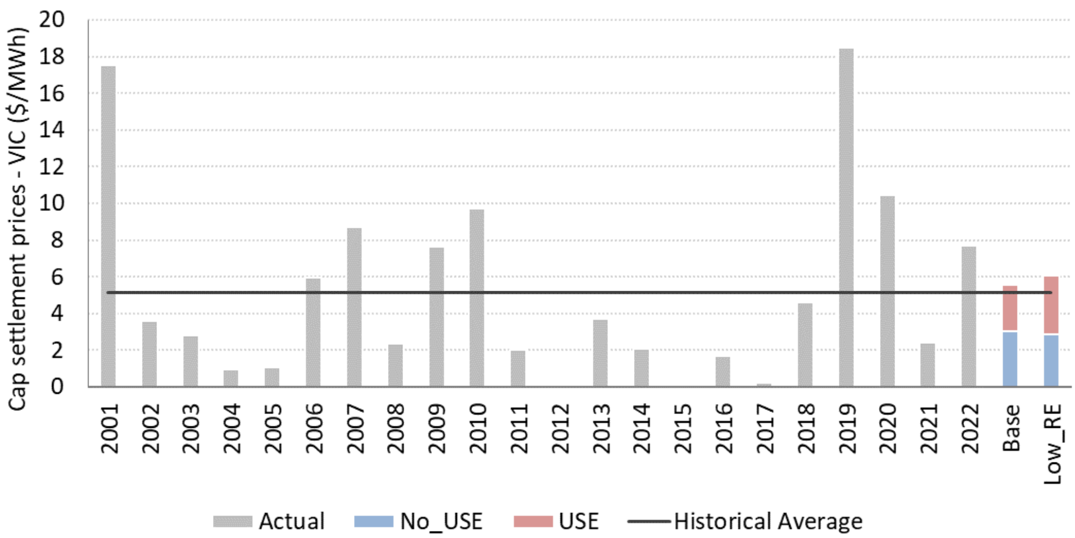
determine the required MPC and CPT for the new entrant but is provided to show the modelled cap value relative to history. The historical line represents the 20-year average, but also sits relatively close to the average over the last 7 years. Modelled cap values are generally higher in NSW relative to history. The difference in modelled VIC and NSW cap values (total) is a function of bidding dynamics and the underlying USE volumes associated with the reliability standard and the reliability gap. Marginal new entrants were assumed to earn external energy revenues based on the NSW and VIC average to minimise this impact.

Figure 77 Modelled cap values and historical settlement (NSW)



Note: Historical values are presented on a nominal basis.

Figure 78 Modelled cap values and historical settlement (VIC)



Note: Historical values are presented on a nominal basis.

Figure 75 and Figure 76 are based on the MPC and CPT combination corresponding to the minimum total region cost solution. However, given the range of plausible MPC and CPT combinations along the frontier, we can generalise that a higher MPC and lower CPT would shift these revenue buckets towards shorter duration events which provide more revenue certainty. However, this could potentially disincentivise new entrants that can address longer duration USE events. This aspect should be considered if the objective of the reliability framework is to incentivise a mix of technologies including both short and deep storage.

An example of the impact of high CPT/low MPC and low CPT/high MPC combinations on the revenue profile of the NSW OCGT is provided in Figure 79 and Figure 80.[73] Four combinations of MPC and CPT, each corresponding to various points along the NSW OCGT frontier are plotted. The peach line corresponds to a CPT of 7 hours, and the various blue lines for CPT levels at 13/17/20 hours. The horizontal axes correspond to the top 15 percent and 15-75th percentile, respectively, of all samples under the Base case sensitivity.

A high CPT of 20 hours and $21,000/MWh MPC results in revenues up to $80 million from the highest samples relative to $60 million based on a CPT of 7 hours and MPC of $24,000/MWh. The lower revenues (peach line) in the top 15% are driven by the long duration events within the samples, which reaches the lower CPT and triggers APP sooner. The lower revenues as a result of the lower CPT in the top 15 percent of samples trades off against higher revenues across the 15-75th percentiles as seen in the second figure. The high revenue samples (top 15 percent) are generally associated with P10 and long duration events which are infrequent, relative to the samples seen in the 15-75th percentile ranges. Although CPT combinations for 13 and 17 hours are also charted, the actual revenue differences are minimal mainly because the corresponding MPCs are close together and samples potentially comprise multiple events which are likely to include events which trigger CPT and some that don't, i.e., differences at the event level are likely to be averaged out at the sample level.

Revenue outcomes across plausible MPC and CPT combinations for batteries show limited variability due to the narrower range of CPT and are not shown here.

[73] Samples are not weighted here for chart visibility and include the same number of P10 and P50 samples.

Figure 79 Revenue profile (NSW OCGT, Base case sensitivity, top 15 percentile)

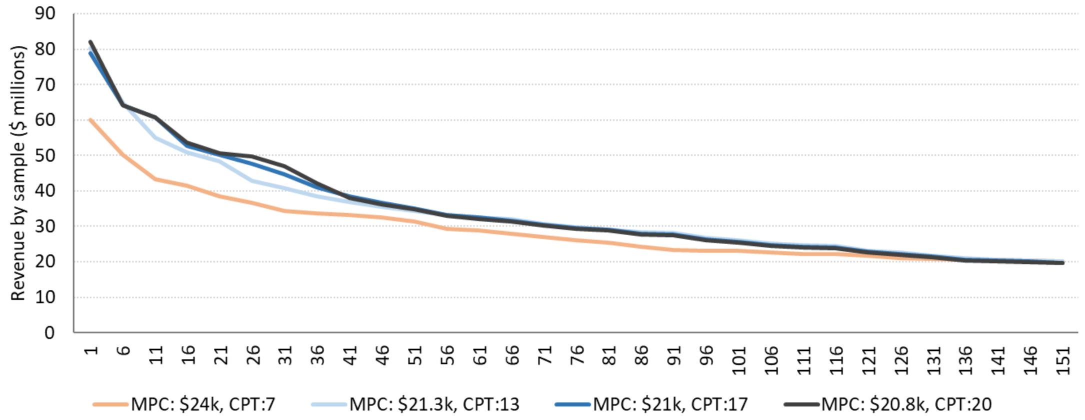
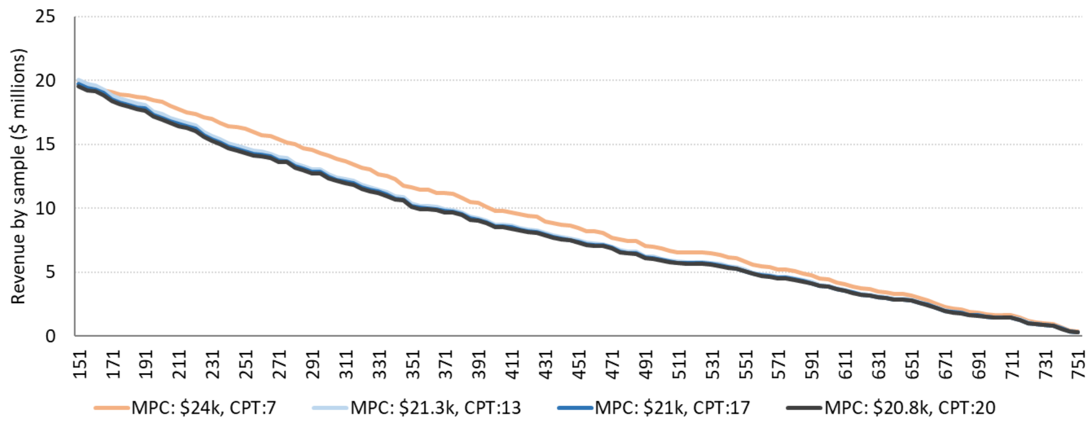


Figure 80 Revenue profile (NSW OCGT, Base case sensitivity, 15-75th percentile)



10.6.2 Hedging outcomes

IES formulated a more robust approach to assessing the cost and risk impacts of increasing the MPC and CPT after the release of the draft modelling report. The update is provided in Section 11.

10.7 Impact of sensitivities

The plausible MPC and CPT combinations previously discussed only included the baselines. The following figures (Figure 81 and Figure 82) include a comparison to the various sensitivities exploring imperfect foresight, operational risks and higher WACC. Across all sensitivities, the MPC and CPT combinations shift to the right, and upwards for some sensitivities. Movement to the right indicate higher MPCs (for the same CPT level) are required to compensate the new entrant generator. Other observations include:

- NSW OCGT: the delayed response sensitivity (red triangle) results in having to build slightly more capacity, however, the dispatch profile remains similar to the baseline. This translates into an increase in cost and shifts the frontier to the right by approximately $2,000/MWh. Restricting the OCGT to a maximum 4 hours of generation (red cross) significantly impacts the dispatch profile, similar to that of a 4-hour battery, and shifts the frontier down and to the right.

- NSW BESS_2HR: the minimum state of charge constraint (purple cross) requires additional battery capacity to be built to address the reliability gap but does not impact the overall shape of dispatch. The WACC sensitivity (purple square) only impacts cost and shifts the curve further to the right of the baseline point.
- Generally, a shift in costs moves the frontier to the left (lower cost) or right (higher cost) but limiting generation volume shifts the frontier down, in line with BESS dynamics, and to the right because the effective costs are higher. The corresponding region costs indicated in the labels correspond to an increase in the region cost associated with the sensitivities.

Figure 81 NSW baseline and sensitivities (Base case sensitivity)

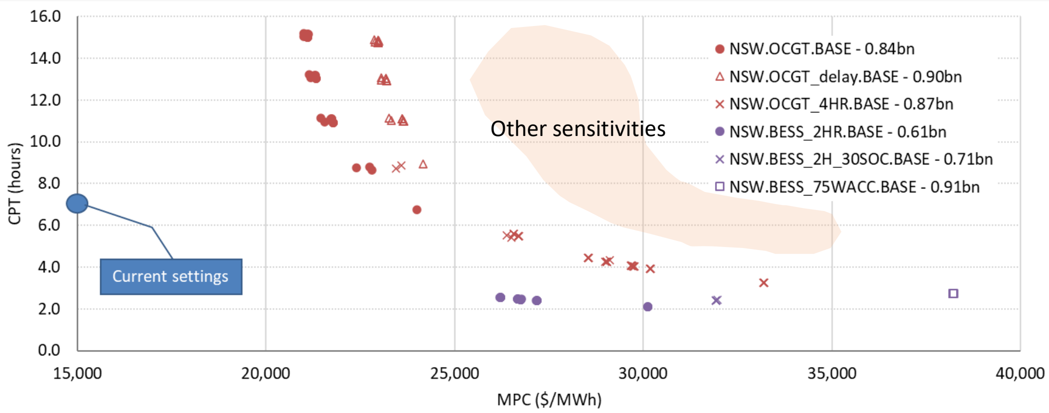
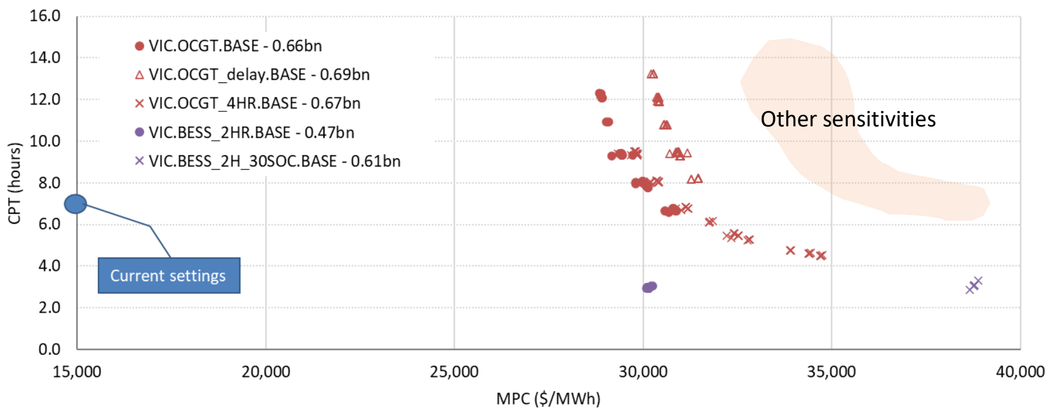


Figure 82 VIC baseline and sensitivities (Base case sensitivity)



Other sensitivities sit in the area shaded in orange and would follow the same dynamics.[75] The baseline MPC and CPT combinations are the closest to the current MPC and CPT levels. Additional demand response sensitivities carried out after the draft modelling report release are included in Section 11.5.

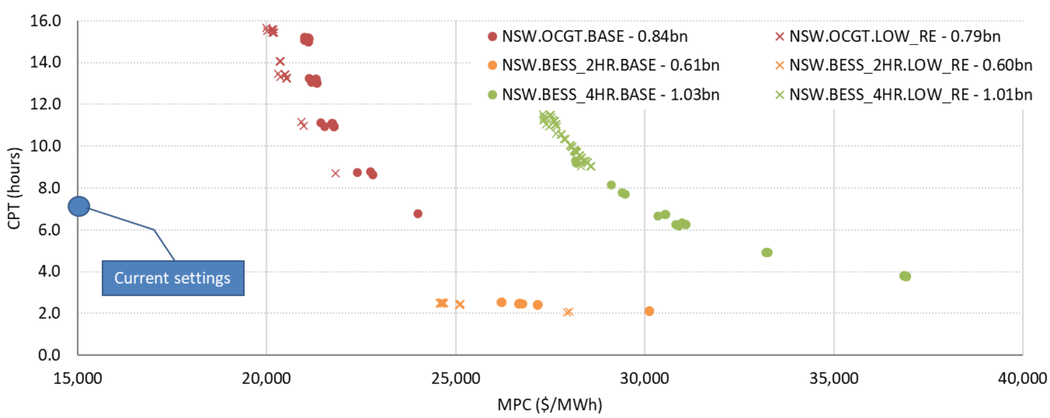
10.8 Low RE scenario

The Low RE scenario results are provided with the Base case sensitivities for NSW and VIC in Figure 83 and Figure 84, respectively. Due to very similar USE distributions across the NSW scenarios, the results from the optimisation model are also fairly similar. The main difference is a slight shift to the left for the OCGT which is likely due to the lower number of zero USE samples for the NSW Low RE scenario.

There are larger differences across the VIC scenarios. The underlying USE distributions had a higher proportion of events with longer duration and a higher number of zero USE samples. The latter increases cost and shifts the frontier to the right, however, the increase in duration significantly increases the cost of the BESS options due to storage limitations. The points for the BESS options shift further to the right than the OCGT.

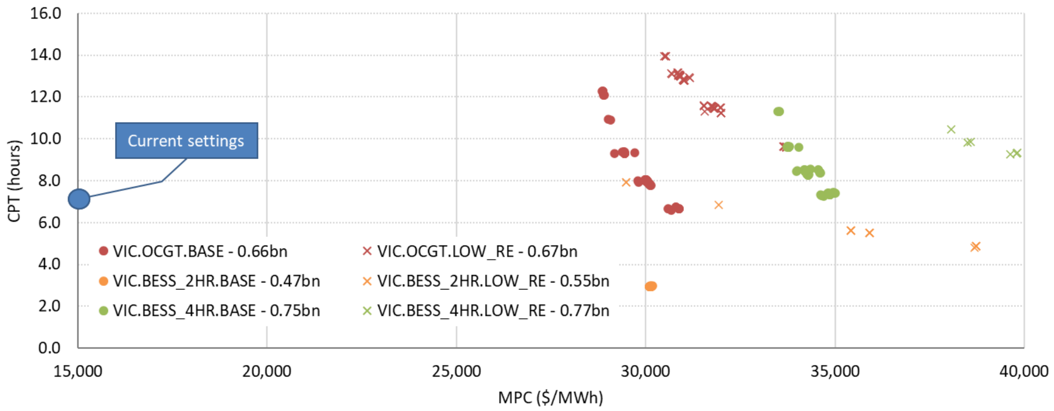
Sensitivities for the Low RE scenario are not shown as the corresponding points sit further to the right than those included in the figures.

Figure 83 NSW MPC and CPT combinations (Base and Low RE)



[75] A reduction in FCAS revenues for the batteries is captured under these dynamics, i.e., frontier shifts to the right, and was therefore not presented in the report.

Figure 84 VIC MPC and CPT combinations (Base and Low RE)



10.9 Remaining USE distribution

A key output of the modelling is to understand the distribution of the USE that remains when the 0.002% reliability standard is met or after the reliability gap has been addressed. The remaining USE has been plotted in the following duration and depth distribution charts for NSW and VIC across both scenarios (Figure 85 to Figure 92). The charts show the percentage of events categorised by duration and maximum event depth compared against the original distribution (WITH REL. GAP). The key observations for the Base case sensitivity outcomes are summarised below:

- The first category labelled ‘No USE’ indicates the total number of events that were completely addressed by the new entrant generator. This category increases from 0% to approximately 20% for the OCGT/BESS_2HR/BESS_4HR options in both VIC and NSW under the Base case sensitivity. The BESS_1HR bar increases to 29% for NSW and 42% in VIC.
- The increase in the number of events with no USE, corresponds to a reduction in events in the other categories. The change in distribution across the duration categories mainly occurs in the 0 to 2 hour events which sees the share of events declining from 48% in NSW to approximately 40% for OCGT/BESS_2HR/BESS_4HR options, and to 27% under the BESS_1HR case. A similar trend occurs in VIC.
  - The observation above is driven by the higher capacity requirement of BESS_1HR to address the reliability gap (393 MW in NSW) compared to the other options (160 MW to 240 MW in NSW). The higher capacity allows it to address more hours of short duration events.
- The reduction in events longer than 2 hours across the OCGT/BESS_2HR/BESS_4HR options is generally only marginally higher than the BESS_1HR option. This is due to the positive correlation of event depth with event duration, i.e., the capacity built under the OCGT/BESS_2HR/BESS_4HR options is small relative to the depth of the actual event. OCGT has the benefit of addressing all hours of USE but needs lower capacity to address the reliability gap, whereas BESS builds more capacity but can’t address all USE periods.

- There are slight differences in the trend of the longer duration category (above 10 hours) between NSW and VIC. The reduction in events in VIC is larger than that in NSW. For example, the percentage of events in NSW is 4% (WITH REL. GAP) but only reduces to 3% with the new entrant, whereas VIC also starts at 4% but reduces to 1.5%. This is due to the higher capacity built in VIC relative to NSW, which is also a function of having to address peakier USE intervals because of the smaller USE base volume corresponding to 0.002%.
- Similar trends apply to the distribution of maximum depth. The impact on the short duration events is evident whereas the longer duration events are only slightly reduced.

In general, the modelled outcomes show the impact on duration is concentrated in the shorter duration events and that the longer duration events, which are rare, are not significantly addressed by the new entrant options. The reductions in duration and depth are associated with short events which comprise a large share of the expected USE volumes.

We can conclude under the current reliability framework, the most efficient way of addressing the reliability gap is to address short duration events. This is driven by the risk-neutral form of the reliability standard which does not discriminate between USE volumes across event types (or any other dimension) and the constant VCR that is assumed in the modelling. Stated differently, the penalty for not addressing long duration events, which are infrequent, is the same as that for short duration events. The implications of this on the form of the standard is discussed in Section ⍰.

Figure 85 Distribution of event duration (NSW, Base case sensitivity)

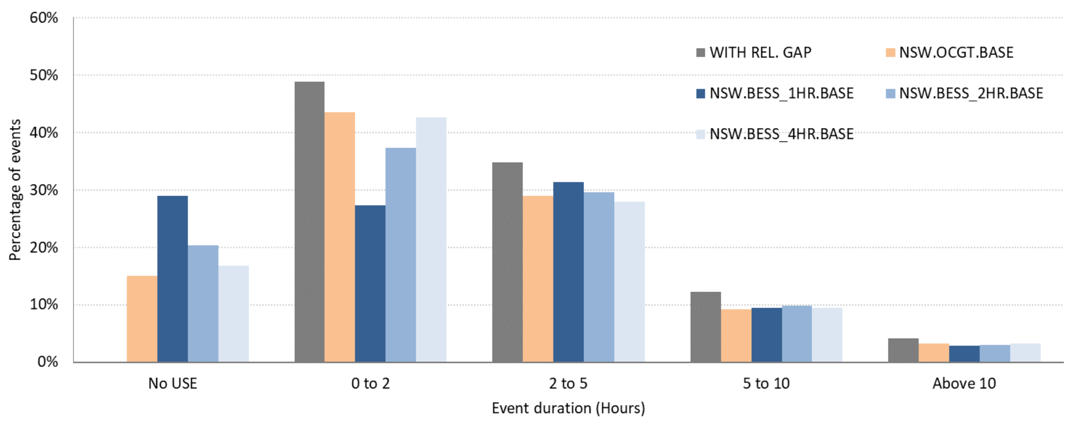


Figure 86 Distribution of event duration (NSW, Low RE)

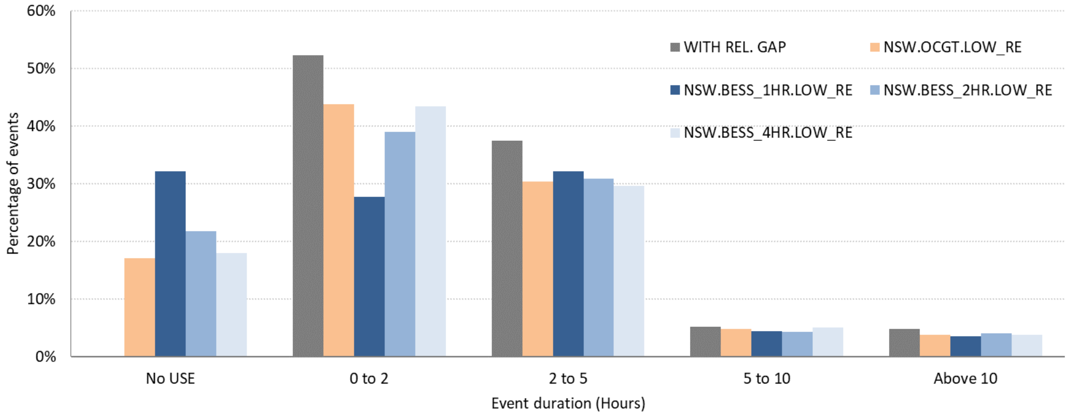


Figure 87 Distribution of event duration (VIC, Base case sensitivity)

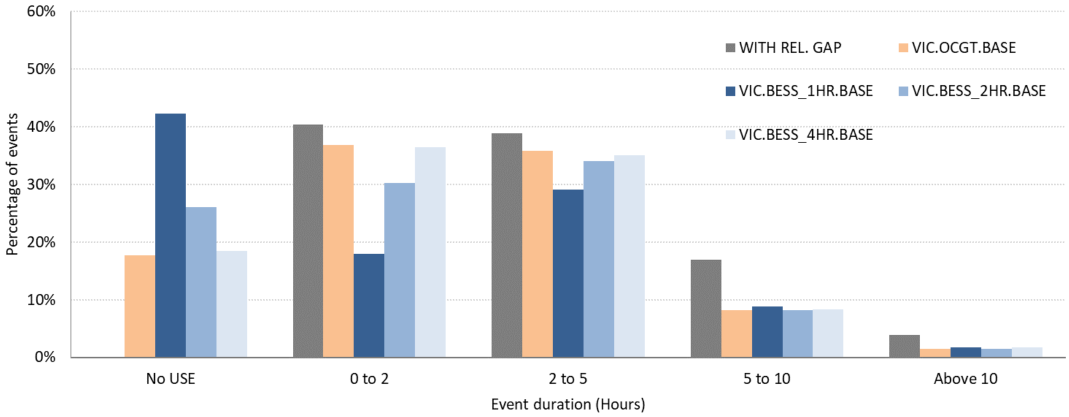


Figure 88 Distribution of event duration (VIC, Low RE)

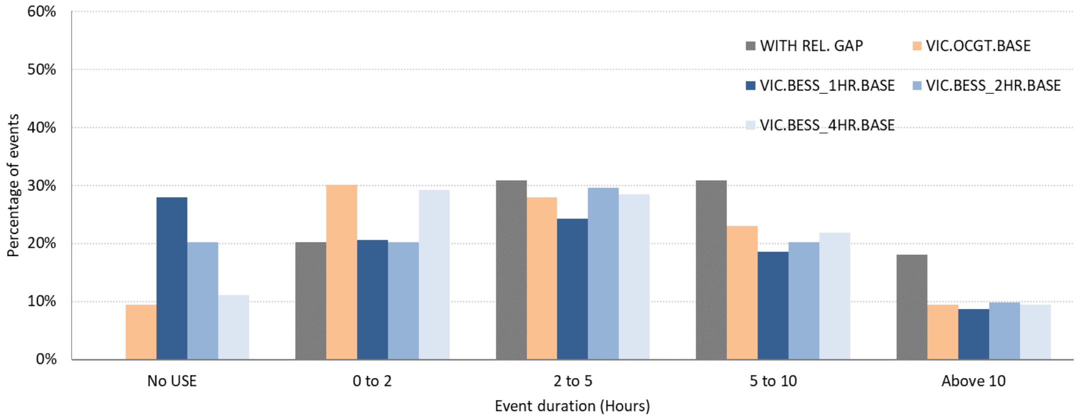


Figure 89 Distribution of event depth (NSW, Base case sensitivity)

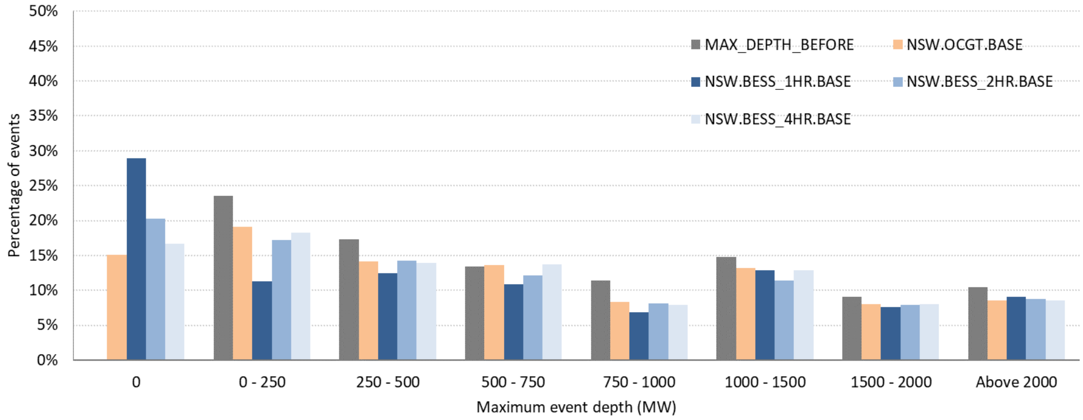


Figure 90 Distribution of event depth (NSW, Low RE)

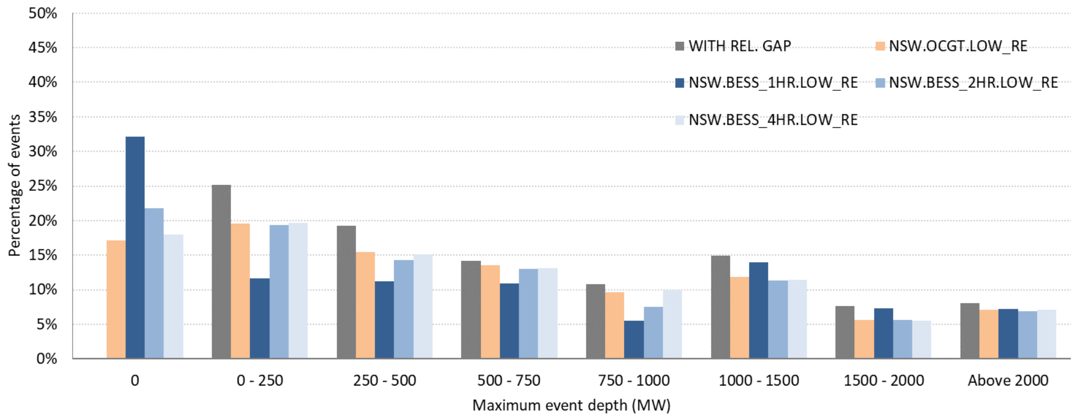


Figure 91 Distribution of event depth (VIC, Base case sensitivity)

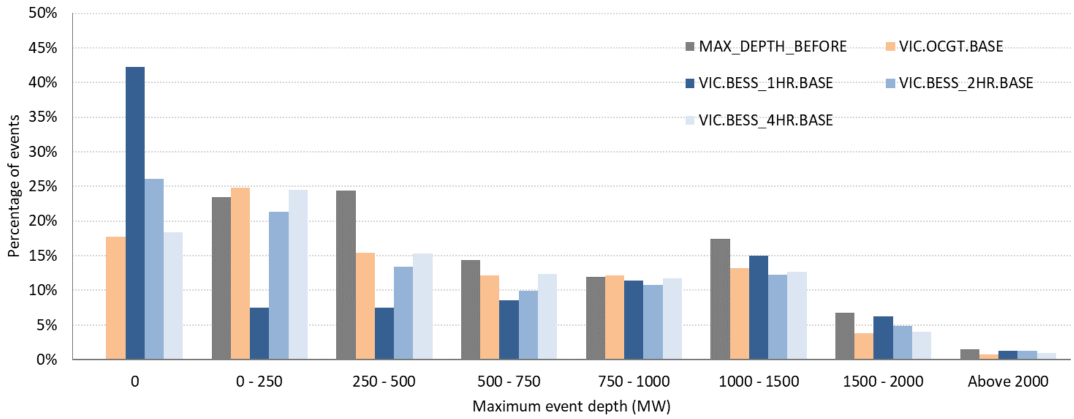
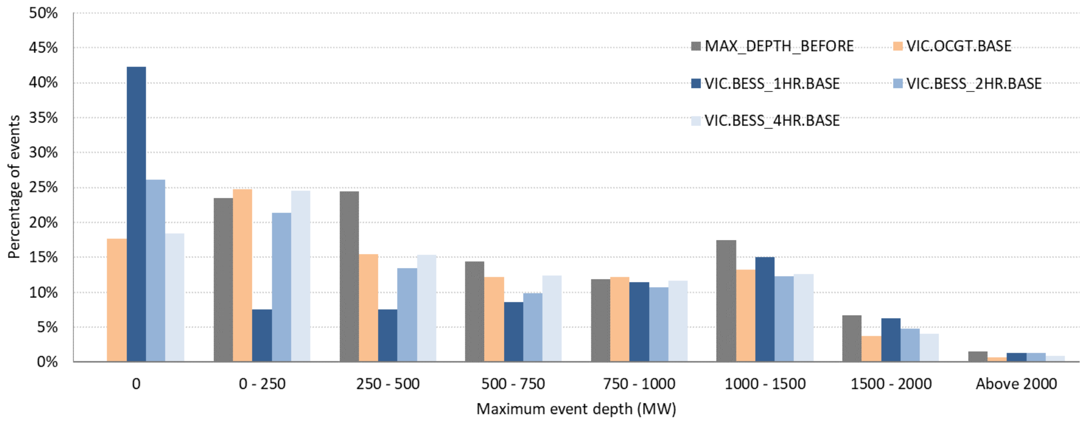


Figure 92 Distribution of event depth (VIC, Low RE)



Other forms of reliability standards are used in other power markets such as Loss of Load Expectation (expected hours of USE per year) and Loss of Load Probability (expected USE hours expressed as a percentage of time). The Loss of Load Expectation and Loss of Load Probability statistics were calculated from the USE distributions with a reliability gap (labelled BEFORE) and after addressing the reliability gap under the various new entrant options. These are presented in Figure 93 to Figure 96. These charts are provided for context but also supports the notion that a lower USE volume translates to a different reliability experience in VIC compared to NSW.

- The main observation is an expectation of experiencing on average 2-3 hours of supply interruptions each year. The 2-3 hours of USE is broken down into event duration to describe the impact of short and long duration events.
- The difference in NSW and VIC is also evident with a higher loss of load hours in NSW, approximately 0.5 hours or 15% to 20% higher than VIC, driven by the higher base USE volume implied by the 0.002% reliability standard.
- The magnitude of the total reduction in hours due to the new entrant is a function of the capacity required to address the volume-based reliability gap. There is a trade-off between lower capacity but higher duration capability, especially in the case of the OCGT, however, the longer duration capability is more than offset by increasing depth associated with longer duration events.

Figure 93 Loss of Load Expectation (Base case sensitivity)

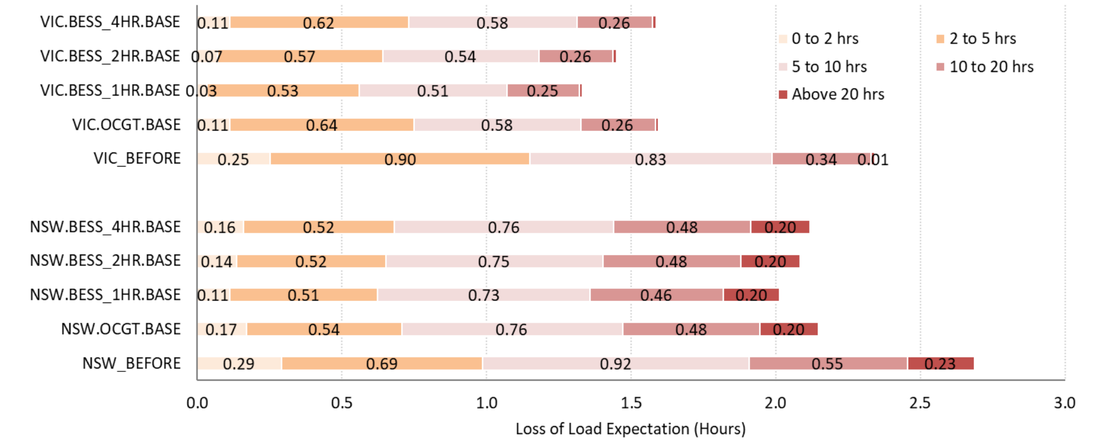


Figure 94 Loss of Load Probability (Base case sensitivity)

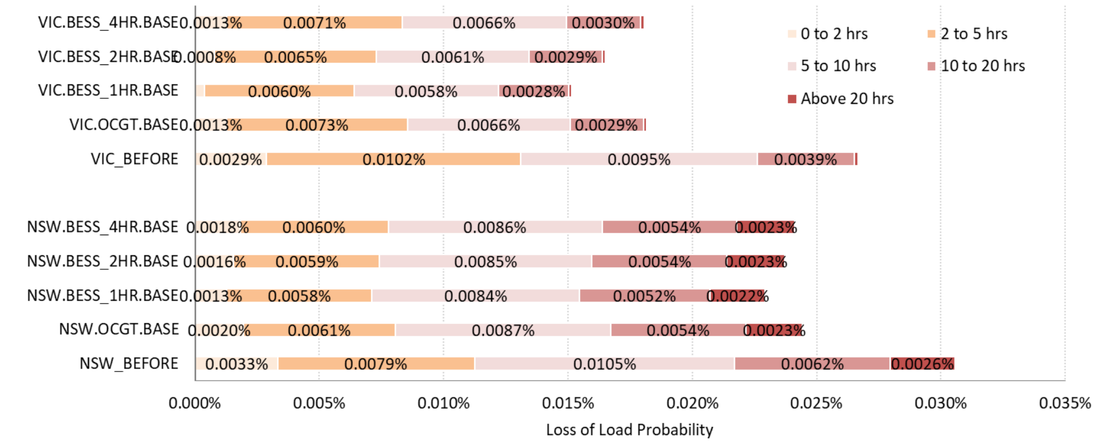


Figure 95 Loss of Load Expectation (Low RE)

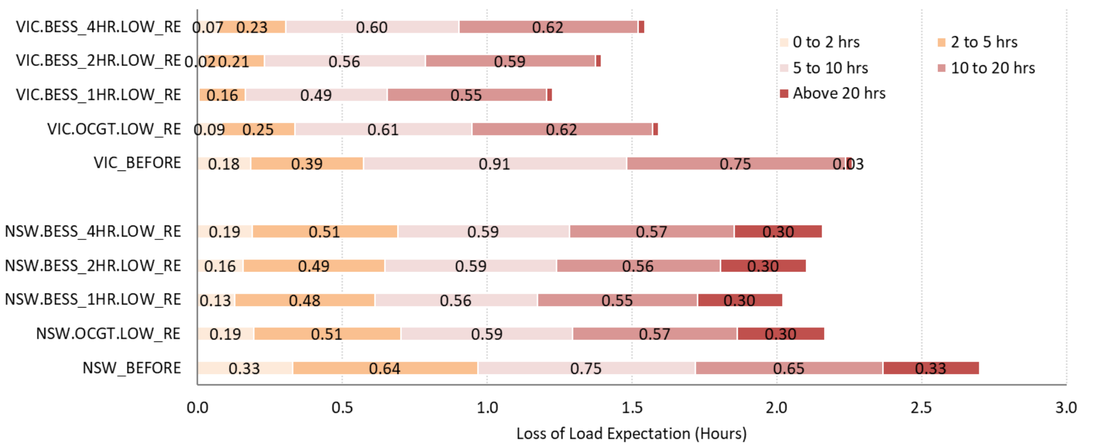
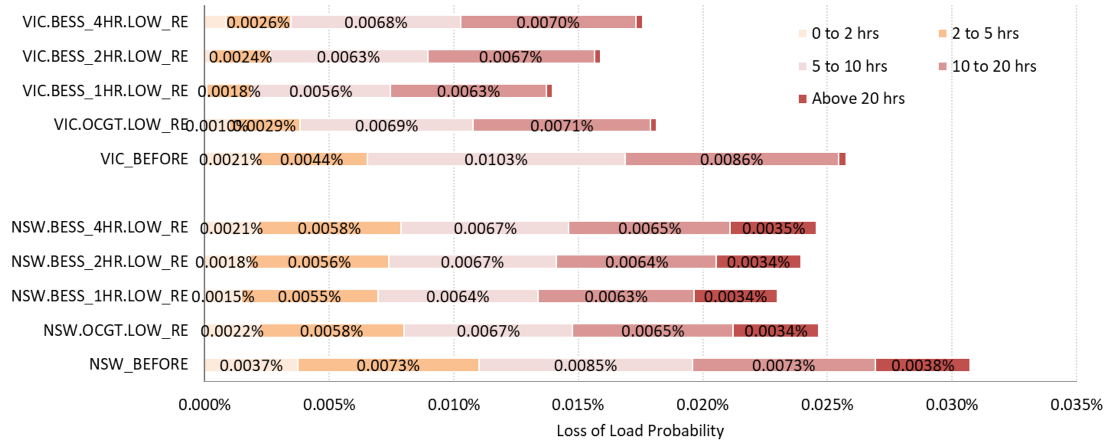


Figure 96 **Loss of Load Probability (Low RE)**



10.10 Considerations

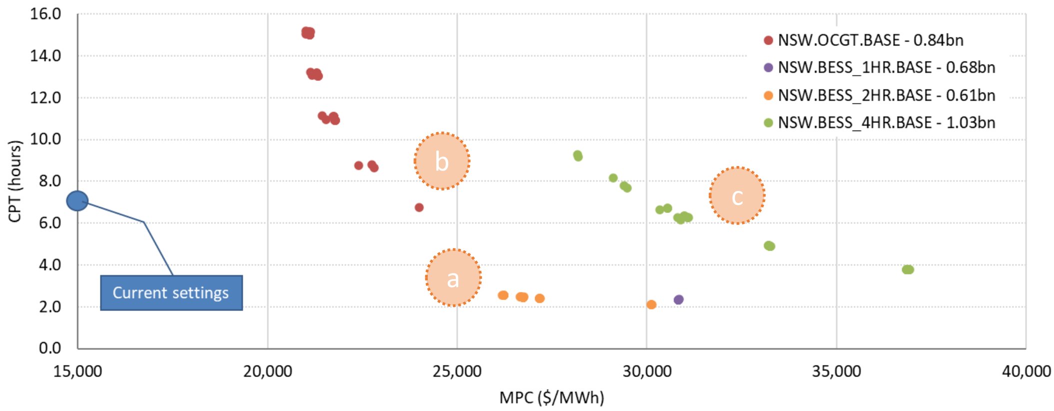
Although the Base case has no reliability gap, the reliability settings need to be updated in line with new entrant cost assumptions and expected USE distributions should conditions change. The modelling work carried out in this section points to many plausible MPC and CPT combinations depending on the new entrant option, but all represent a significant step-change from the current MPC and CPT levels. The NSW Base case sensitivity (Figure 97) is used as an example to describe some of the considerations in deciding what may be appropriate.

- Irrespective of the total region cost, a CPT level which sits above the frontier for a set MPC (or a higher MPC for a set CPT duration) will allow for that new entrant to be revenue sufficient, but results in increasing over-recovery of revenues the further away the point is from the frontier.
- Figure 97 has three example points marked A, B and C.
  - Point A: would incentivise BESS_2HR but the CPT level would be far too low for OCGT and longer storage duration options. A low CPT would signal to the market that long storage is not required and/or duration is not an important dimension to address.
  - Point B: would incentivise both OCGT and BESS_2HR, but BESS_2HR would be over-recovering revenues as its frontier sits below this point. This point also represents higher system cost relative to point A, although this may be warranted to promote both OCGT and BESS_2HR options. Point B still wouldn't sufficiently incentivise BESS_4HR.
  - Point C: is likely to promote a more diversified mix but the MPC is double that of the current level and corresponds to a significantly higher total region cost.
- If total region cost was the only relevant consideration, then setting a high MPC and low CPT combination would incentivise BESS_2HR and would correspond to the most efficient way of addressing the reliability gap. However, there are significant risks with choosing a

combination that only incentivises a single generation option, i.e., short duration storage, acknowledging significant uncertainty relating to the input assumptions and modelling. On the other hand, any other point would essentially trade-off higher costs to promote a mix of new entrant options.

- The MPC and CPT applies NEM-wide and VIC also needs consideration. VIC new entrants require settings that sit further to the right of the NSW points. Selecting the optimal CPT and MPC combination is challenging as the MPC and CPT needs to address the most costly region, i.e., the settings should incentivise new entrants to address reliability gaps in VIC as well. However, this would lead to NSW new entrants over-recovering revenues and/or building additional capacity leading to lower USE than the 0.002% standard. This is a broader issue relating to the form of the reliability standard expressed as a percentage of demand.

Figure 97 Considerations for MPC and CPT combination



The above considerations relate specifically to new entrant cost recovery and the cost to end-users in the form of the MPC and CPT. However, there are broader impacts from shifts in the reliability settings that the model does not account for. These include, but are not limited to, the following:

- The trade-off between higher total region cost and providing adequate investment price signals when setting the MPC and CPT to (1) address any potential reliability gaps, and (2) incentivise an appropriate mix of new entrant types.
- The increase or decrease in market risks will impact contract markets which could have wider and longer-term market impacts. The impacts can include an increased cost of contract premiums and prudential requirements if MPC is significantly increased.
- Revenue predictability is important and any significant revenue stream that is required for the new entrant to recover revenues but is contingent on very rare events should be discounted, or that the optimal combination of MPC and CPT should be adjusted to reduce the importance of these events in its revenue composition.

- Regulatory stability implies any significant shifts from the current levels should also account for the impact on existing generators, retailers, and commercial arrangements. This is out of scope and was not considered in our modelling.

10.11 Key model findings

The key findings from the optimisation model, from a pure cost perspective, are summarised in Table 33.

Table 33 Key model findings

Area	Finding
Marginal new entrant	OCGT, and short duration batteries are the most likely marginal new entrants over the Review Period.
MPC and CPT interaction	There is a range of plausible MPC and CPT combinations for each generation type as described by a frontier. Each one of these points on the frontier has the same region cost and the modelling firmly shows the MPC needs to be selected in conjunction with the CPT as the choice of one influences the level of the other.
CPT and duration	Minimisation of the region cost results in lowering CPT to levels consistent with generation capability in duration terms. This is most evident with BESS new entry. The MPC is then set to the level required to ensure revenue sufficiency.
Current MPC levels	The current level of the MPC is significantly lower than what would be required in 2028. The lowest MPC modelled is $21,000/MWh in NSW which incentivises OCGT, however, requires a CPT level approximately double that of the current CPT (expressed in hours of the current MPC). For the same corresponding CPT level of 7.5 hours, the NSW OCGT would require an MPC of $23,500/MWh. The VIC OCGT requires a minimum MPC of $29,000/MWh.
USE volumes and reliability settings	Differences in the underlying USE volume associated with the 0.002% reliability standard produces significantly different MPC and CPT combinations for the same new entrant type. VIC is expected to always have a higher cost to address its reliability gap because of this.
Depth and duration	Changes to depth and duration after the introduction of the new entrant mainly impacts short-duration events. This is due to the low capacity that is required to address the reliability gap relative to the higher event depth associated with longer duration events.
Price and revenue risks	Setting a low CPT is likely to reduce price and revenue risks associated with long duration but rare events. However, given that lowering CPT leads to higher MPC this should be balanced against the increased volatility across more frequent short duration events.
Addressing the reliability gap	The most efficient solution is achieved by addressing short duration events given (1) the reliability gap that needs to be addressed by the marginal new entrant corresponds to a small volume, and (2) the current reliability framework is risk neutral and does not place a greater value on long duration events, i.e., there is nothing in the framework to incentivise new entrant investment capable of addressing longer duration events.

11 Task 2: Additional analysis

The Panel asked IES to carry out additional analysis to further expand on the work undertaken in the draft modelling report in Section 10 to address stakeholder submission concerns and primarily focuses on the impact of increasing MPC and CPT, and an appropriate level for the APC. The relevant MPC and CPT combinations covered in this section are based on the NSW prices and OCGT frontier under the Base case sensitivity with MPC and CPT ranging from $21,000/MWh and 18 hours to $24,000/MWh and 7.5 hours.[76] The combinations, including the current settings, that have been assessed are listed in Table 34.

Table 34 MPC and CPT combinations under consideration

Label	MPC ($/MWh)	CPT (hours)	CPT ($/MWh)
15.1k_7.5hrs	15,100	7.5	1,359,000
24.0k_7.5hrs	24,000	7.5	2,160,000
21.5k_8.5hrs	21,500	8.5	2,193,000
23.0k_9.0hrs	23,000	9	2,484,000
22.5k_10.0hrs	22,500	10	2,700,000
22.0k_12.0hrs	22,000	12	3,168,000
21.0k_18.0hrs	21,000	18	4,536,000

The analysis covers (1) the likelihood of exceeding CPT under various MPC/CPT combinations, (2) the impact on contract settlement prices and retailer costs (wholesale energy), (3) the potential for increased financial risk and prudential requirements, (4) additional sensitivities on the role of demand response, and (5) analysis to support potential changes to the APC.

Pricing outcomes from the PLEXOS modelling were based on an MPC of $15,100/MWh and 7.5 hour CPT. To assess the impact of different combinations of MPC and CPT, the underlying prices were linearly scaled to the new MPC and capped to APC upon triggering APP. The approach taken was to only scale prices at or close to the existing MPC.[77] Dispatch outcomes were assumed to remain constant.

[76] For CPT above 7 hours. See Figure 72.

[77] Only prices within 5% of $15,100/MWh or from $14,345/MWh were scaled. Scaling prices from lower levels would impact the outcomes presented in this section but would also impact the assumption relating to revenues earned by the new entrant outside of reliability periods.

11.1 Frequency of exceeding CPT

The level of the CPT in $/MWh terms provide an indication of the level of financial risk (or volatility) that is permitted before application of the APC and is currently set to $1,359,000/MWh with potential combinations considered by the Panel reaching $4,536,000/MWh. An alternative way to frame this level of risk is simply the average spot price required over the preceding 7-days to trigger APP (see Figure 98). This shows an average spot price of $674/MWh based on the current MPC and CPT, compared to $1071/MWh under the lowest combination in $/MWh terms. The $21,000/MWh MPC and 18 hour CPT combination corresponds to an increase of 55% and up to 235% across the other combinations.

The likelihood of experiencing extreme conditions associated with exceeding CPT is unlikely. Figure 99 plots the likelihood of exceeding CPT under the various combinations of MPC and CPT. The frequency of exceeding CPT is based on the 1100 samples in FY2028 for the NSW region that sits at the reliability standard, i.e., the likelihood is expected to be more likely than the actual NEM experience due to reliability differences. Under the current settings, the CPT is expected to be triggered once every 4 years and would reduce in likelihood with the combinations considered by the Panel.

Figure 98 Average spot price to trigger APP

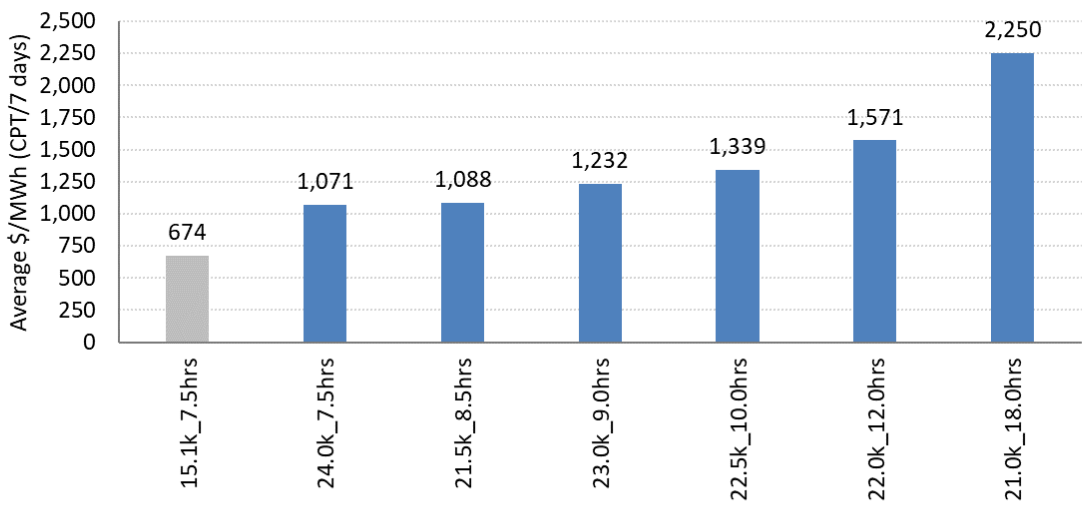
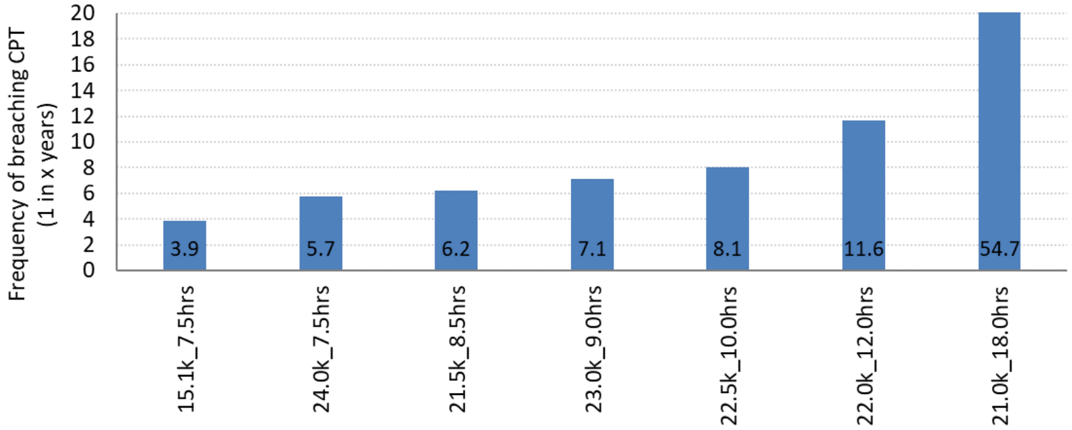


Figure 99 Expected frequency of exceeding CPT



11.2 Impact on contract settlement prices

An increase in the MPC and CPT would translate to increased volatility and spot prices on average. The settlement impact on annual swap and $300/MWh cap contracts is presented in Figure 100 and Figure 101. The uplift in settlement values range from $4/MWh up to $7/MWh. The uplift across the cap and swap settlement levels are the same, in $/MWh terms, as prices were scaled from prices close to the existing MPC. The increase to swap and cap settlement prices for the $21,500/MWh MPC and 8.5 hour CPT combination corresponds to an increase of 5% and 48%, respectively.

The distribution of cap settlement outcomes is presented in Figure 102 and shows a significant portion of the distribution, under current MPC and CPT (black dotted line), shifting from $10/MWh to $15/MWh to much higher levels around $30/MWh. The overall distribution under the increased MPC and CPT combinations are relatively more uniform and exhibits longer tails. The actual cost of bearing the increased price risk relating to longer tails and its effect on risk premiums would impact retailer cost outcomes and is discussed in Section 11.3.

Figure 100 Impact on annual swap settlement values

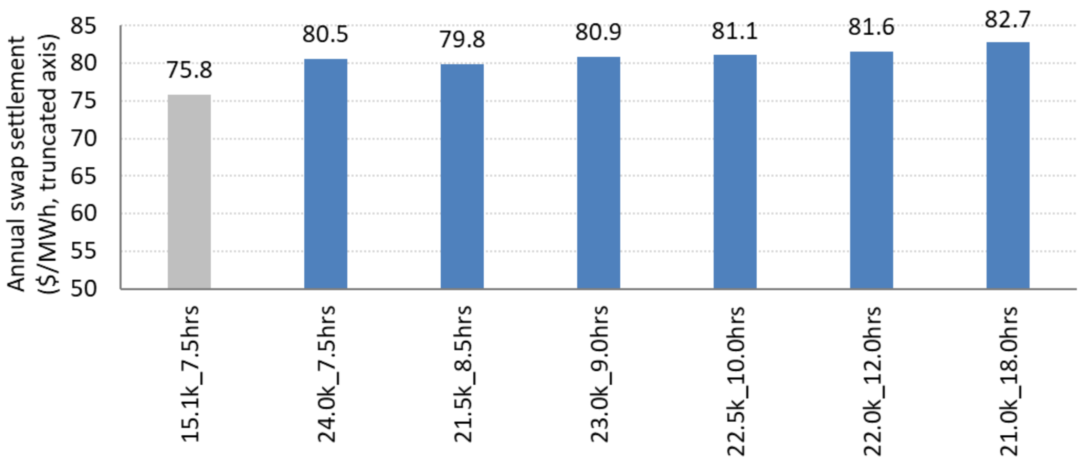


Figure 101 Impact on $300/MWh strike annual cap settlement values

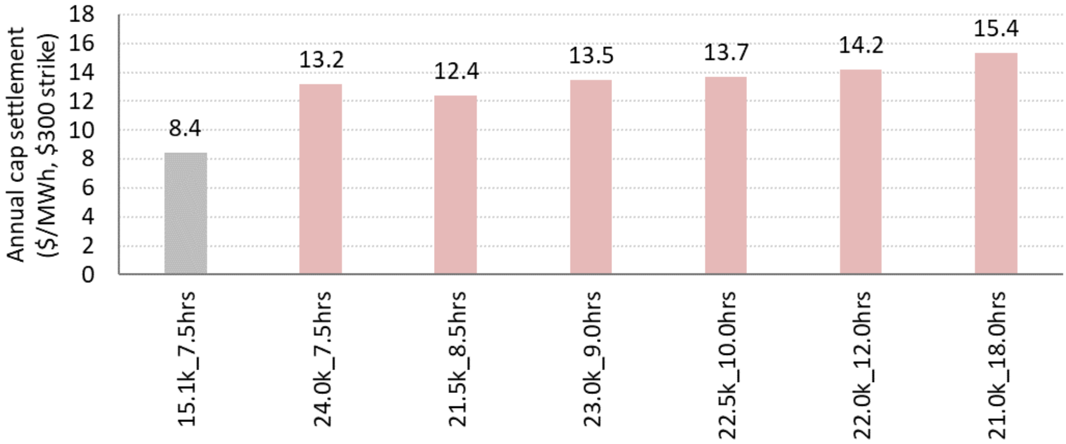
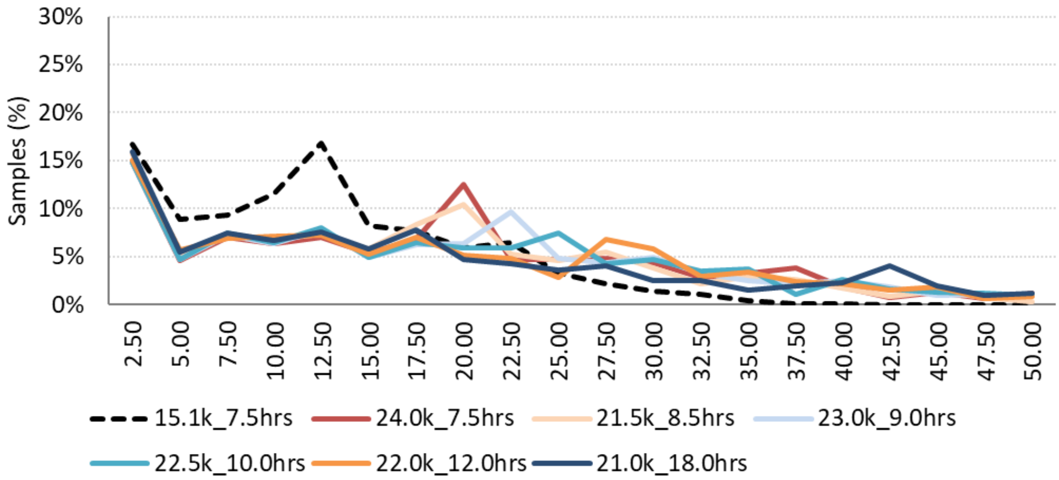


Figure 102 Distribution of annual $300/MWh cap settlement values



11.3 Impact on retailer costs

The difficulty with assessing retailer costs relates to how the representative retailer should be presented. The main issues cover the selection of demand shape/s, and the lack of representative price traces to robustly optimise outcomes and assess risk, however, it is just as important to acknowledge different retailers have different risk appetites which in turn drives the optimal hedging mix, i.e., how spot volatility impacts one retailer is different to another. The issue of ensuring the comparison is standardised across this risk dimension is particularly important as a change in MPC and CPT is expected to drive underlying spot volatility, i.e., taking a static approach to hedging across different pool volatilities is likely to result in incorrect comparisons.

IES' approach to assessing retailer costs is to formulate the optimal hedging mix with respect to various levels of risk. Risk is simply defined as the standard deviation of outcomes around the expected cost of load.[78] We assume for two portfolios of contracts that results in the same expected cost, retailers will prefer the less risky option or for the same level of risk the retailer would opt for the hedging mix that results in the lowest average cost. A frontier also exists that corresponds to the most efficient level of hedging at each level of risk.

The steps in carrying this out is summarised below:

- Assume the representative retailer has a load shape consistent with the region demand profile (NSW). For simplicity, the demand profile is standardised to 1 MW on average across the entire year. The demand profile peaks close to 2 MW.
- For a MPC and CPT combination, simulate all settlement combinations of spot exposure, annual swaps and caps up to the peak load in increments of 0.1 MW. Each combination of the hedging mix is run through 1100 pricing samples from the Base case sensitivity, scaled to the MPC and CPT, to generate 1100 cost of load outcomes. We can simply summarise the effectiveness of this hedging mix across two dimensions, (1) the average cost of load, and (2) the standard deviation of these outcomes.
- The analysis requires an assumption around the risk premium of swap and cap contracts. We have assumed the risk premium of cap contracts is a function of the standard deviation of cap settlement outcomes, i.e., there is a cost to taking out insurance to mitigate against long-tail risks. This is approximately 30% or $2.4/MWh for current MPC and CPT levels and increases up to 37% or $5.7/MWh for the $21,000/MWh MPC and 18 hour CPT combination.[79]

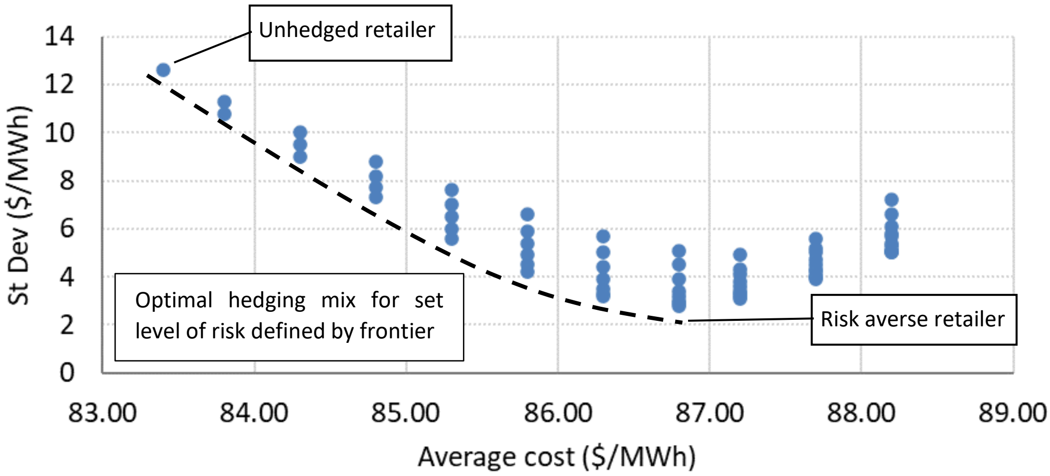
Figure 103 plots the results for all hedging combinations under the current MPC and CPT. Each point corresponds to a mix of annual swaps and caps and the dotted line corresponds to the hedging combination that are the most optimal for a set level of risk, i.e., for a targeted average cost of load, there is a single hedging mix that would have the lowest associated risk. Key points in this chart include:

- [Unhedged retailer]: corresponds to the left-most point and has the lowest average cost of $83.40/MWh but has the highest risk (standard deviation) because of its unhedged position. The unhedged retailer has the lowest average cost because swaps and caps are assumed to be out-of-the-money at settlement on average because of the risk premium assumption.
- [Risk averse retailer]: which optimises its position to minimise risk sits at the end of the dotted line and has an average load cost of $86.8/MWh. The hedging mix corresponding to this point is 1 MW in swaps and 0.4 MW in caps, or hedged to approximately 75% of its peak load.
- The cost difference between the unhedged retailer and the risk averse retailer ($3.4/MWh) would correspond to the cost of hedging.

[78] Other metrics such as the 95th percentile outcome can also been used.
[79] For additional context, a risk premium of 33% results in profitable outcomes across 65% of the pricing samples.

- Points along the frontier corresponds to the optimal hedging mix for risk profiles that sit between the unhedged retailer and the risk averse retailer. Points to the right of the risk averse retailer aren't relevant as these combinations of hedges corresponds to higher cost and higher risk than the hedging mix along the frontier.[80]

Figure 103 Hedging and cost outcomes under current MPC and CPT



Note: average outcomes are rounded to nearest $0.10/MWh.

The frontier presented in Figure 103 corresponds to the optimal hedging arrangements under the current MPC and CPT. Extending this analysis to cover all the other MPC and CPT combinations yields the chart in Figure 104 to enable comparisons standardising for risk. The key findings from this analysis are:

- The spot exposed retailer under each MPC and CPT combination (circled in red) show an increase in risk and cost, as expected, from increasing MPC and CPT. Compared to the current MPC and CPT levels, an MPC of $21,500/MWh and 8.5-hour CPT corresponds to an increase in average cost of $5.6/MWh and approximately $7/MWh in additional risk.

- The increased risk to the risk averse retailer is much lower (circled in black), and only increases $1/MWh going to an MPC of $21,500/MWh and 8.5-hour CPT. However, the average cost increase of $7/MWh is higher than the spot exposed retailer for the same MPC and CPT combination.

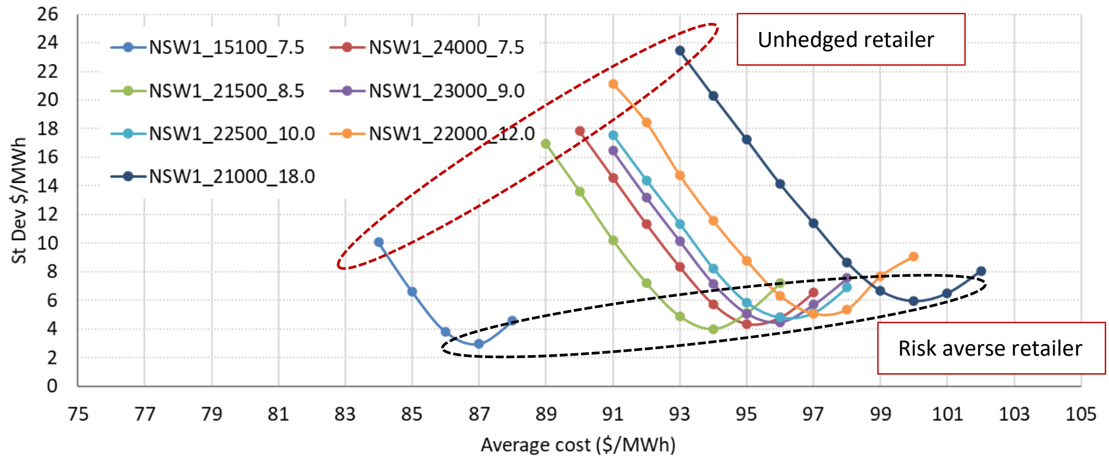
- We can generalise these findings. An increase in MPC and CPT will result in increased pool volatility and higher costs which all retailers regardless of hedging will incur, however, there will also be additional contract risk premiums applicable to a hedged retailer. The more risk averse the retailer the higher this cost. In the case of moving from the current settings to a $21,500/MWh MPC and 8.5-hour CPT, this corresponds to a total increase of $7/MWh mainly comprised of $5.6/MWh in energy costs and $1.4/MWh relating to additional contract premiums. There is also an increased risk to the risk averse retailer.

[80] These points would correspond to over hedging and unnecessary exposure to pool prices.

The average cost increase for the risk averse retailer across each of the MPC and CPT combinations are plotted in Figure 105. The total cost impact is mainly driven by the increase in spot costs incurred by all retailers directly or indirectly through the uplift in contract settlement prices. The risk averse retailer also incurs an increase in costs relating to the increase in contract risk premiums. Retailers with differing risk profiles, that is also optimally hedged, would incur a cost between these two bounds.

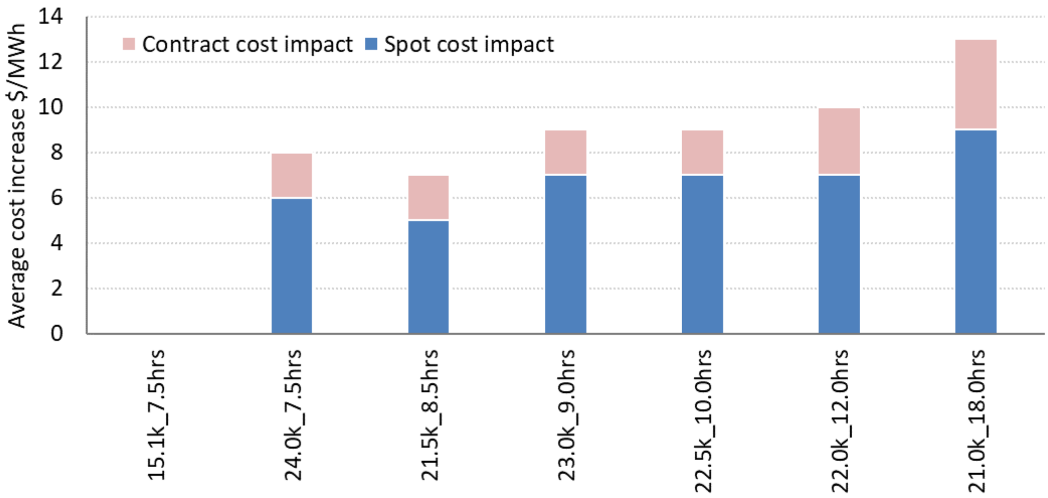
In the case of the \$21,500/MWh MPC and 8.5-hour CPT, the \$7/MWh increase (to \$94/MWh) corresponds to an 8% increase over current settings (\$87/MWh). Wholesale energy costs currently comprise approximately 33% of a retail consumer's electricity bill in NSW and across the NEM.[81] This translates to a 3% cost increase, all else being equal. As a sensitivity, the doubling of the assumed risk premium assumption does not materially change this finding.

Figure 104 Efficient frontiers under MPC and CPT combinations



[81] State of the Energy Markets 2021, Australian Energy Regulator. The comparison here implicitly assumes the retailer customer's load shape follows the region profile.

Figure 105 Summary of average cost impact (risk averse retailer)



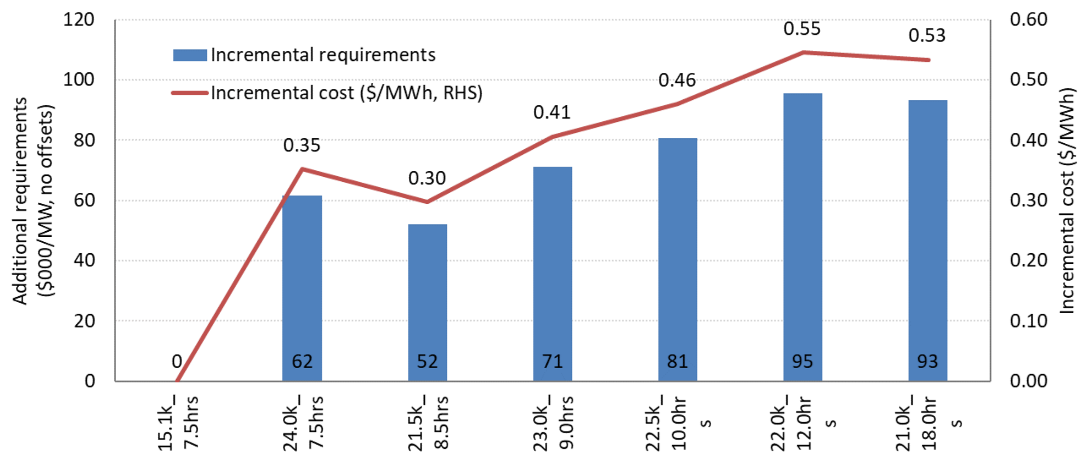
11.4 Financial risk and prudential requirements

Increased spot volatility is expected to increase credit support requirements of market participants which will have an associated cost. Current prudential requirements are intended to cover a 2% POE of outstandings with AEMO covering a 35-day period. The Maximum Credit Limit calculator provided by AEMO includes many parameters used to estimate potential pool volatility and correlation of load against prices for the participant. Our estimate of the increase in credit requirements is based on the 2nd percentile of the equivalent 35-day period using the modelled 1100 pricing samples and the NSW load shape which has been standardised to an average 1 MW of load.

The increase in credit is plotted in Figure 106 along with the associated cost in $/MWh terms assuming a 5% cost of credit assumption. The increase in credit requirement between $52,000/MW ($21,500/MWh MPC and 8.5 hour CPT) and $95,000/MW ($21,000/MWh MPC and 18 hour CPT) is indicative of the level of increased financial risk for an unhedged retailer and the cost expressed in $/MWh terms ranges from $0.30/MWh to $0.55/MWh.

The actual cost impact is likely to be overstated as we have effectively computed this based on opportunity costs whereas there are many factors which would significantly reduce the amount of credit required including (1) generation capacity which acts as an offset within a participant portfolio, and (2) reallocation of generation capacity across contract counterparties. AEMO have indicated actual settlement volumes is less than 20% of the total NEM turnover, or that the market is significantly hedged and mainly driven by the concentrated nature of retail and generation portfolios. Based on this analysis, the cost impact of higher prudential requirements is of a much lower order than the costs explored in Section 11.3.

Figure 106 Increased credit requirements and associated costs



11.5 Additional demand response sensitivity

The modelling work in Section 10 covering demand response was based on conservative assumptions, i.e., high fixed and variable costs, which resulted in MPC and CPT combinations significantly higher (further right) than the NSW OCGT frontier. IES was asked to carry out additional sensitivities of demand response, in conjunction with a portfolio of OCGT capacity, to explore the impact on the frontier assuming little to no fixed costs but higher variable costs based on various stakeholder feedback expressing the likelihood of future lower cost demand response options.

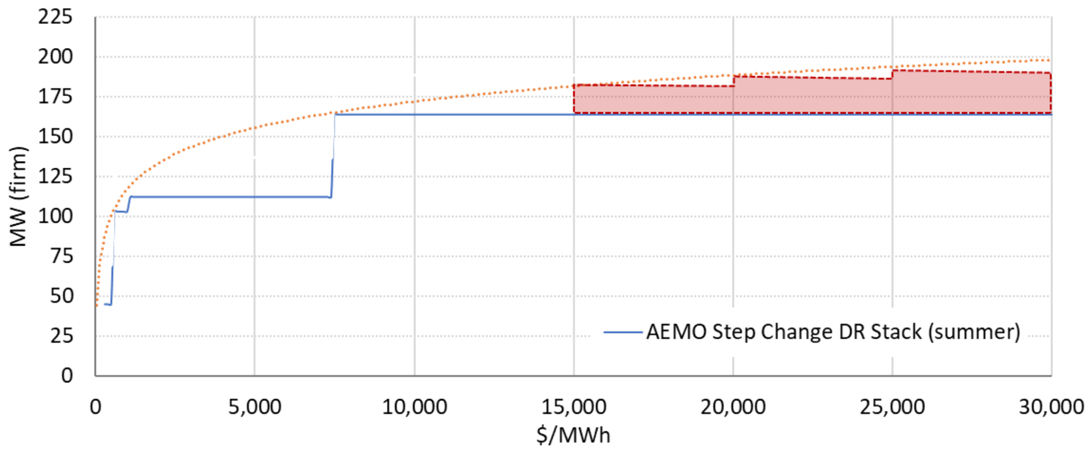
Forming assumptions relating to demand response is generally challenging, however, we have used AEMO's demand side participation assumptions (Step Change scenario) to further extend the supply stack based on fitting a logarithmic curve to derive additional demand response quantities at $15,000/MWh, $20,000/MWh and $25,000/MWh (see red shaded area in Figure 107). This is summarised in Table 35 and compares the total volumes in the Step Change scenario to assumptions used in the draft report modelling and an additional sensitivity where we have allowed for a doubling in quantity.

Table 35 Demand response sensitivity assumptions

Assumptions	MW limit	Fixed $/MW/yr	Variable $/MWh
Draft modelling	None	50,000	5,000
Step Change (SC)	NSW (30)	100	Tiered 15/20/25k
Ramp Up (RU)	NSW (60)	100	Tiered 15/20/25k

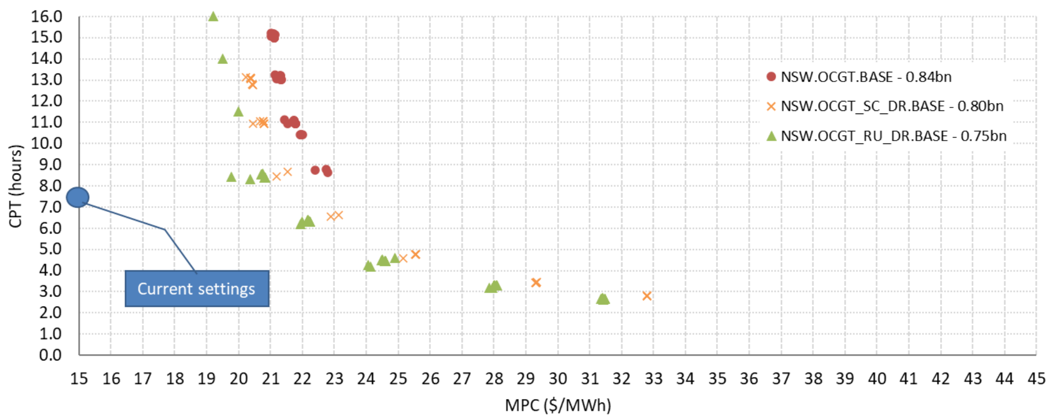
Note: The demand response capacities are in addition to that already modelled in Section 8, and are assumed to be firm.

Figure 107 Additional demand response quantities (Step Change)



The optimisation model was run and shows demand response under both scenarios dispatched sparingly into peakier sections of the unserved energy and reduces the amount of OCGT that is required to be developed to meet the reliability standard. Under the Step change scenario, the OCGT capacity requirement was reduced by 17 MW, with demand response addressing 9% of the reliability gap. The reduction in portfolio cost (OCGT and demand response) is driven by slightly higher OCGT utilisation and the lower average dispatch cost of demand response. This leads to a shift to the left of the frontier by approximately $1,000/MWh and $2,000/MWh when demand response quantities are doubled (Ramp Up case), see Figure 108.

Figure 108 MPC and CPT combinations for demand response sensitivities



11.6 Appropriate level of the APC

The APC was considered out of scope and modelling of the MPC and CPT in the draft modelling report was based on a fixed APC level of $300/MWh (nominal). After the events in Q2 2022, consideration for the APC was added back into the scope of work given its material impact on dispatch outcomes over the period. The following sub-section discusses the high-level analysis into what might be an appropriate level for the APC and covers (1) whether an increase to the

APC would impact MPC and CPT, (2) analysis into generator SRMC levels relative to the APC under extreme circumstances, and (3) the impact on retailers.[83]

11.6.1 Impact of APC on the MPC and CPT

IES assessed the impact of a higher APC on the MPC and CPT under the context of revenue adequacy for the new entrant, i.e., whether it shifts the frontier of the NSW OCGT plant. The objective of this analysis was to address whether a significant increase in the APC would reduce the MPC and CPT previously covered in Section 10. The optimisation model was re-run with higher levels of APC at $600/MWh and $1,000/MWh and then compared to the NSW OCGT frontier. The results are presented in Figure 109 and shows no shift, indicating the new entrant does not rely on revenues under the APC. [84]

To provide further context as to why the level of APC does not materially impact MPC and CPT required for the new entrant, Table 36 summarises the performance of the NSW OCGT during APP for two (2) combinations towards the boundaries of the frontier corresponding to low MPC and high CPT, and high MPC but low CPT.

- Low MPC and High CPT: leads to a reduction in the number of USE periods and generation during APP, and therefore the revenues derived under this setting comprises very little of the total revenue recovery requirements (0.1%).
- High MPC and Low CPT: corresponds to a higher likelihood of triggering APP and application of APC and results in a higher number of USE periods and generation under these periods (up to 20%). Even with a $1000/MWh APC, the revenues derived from APC comprise a relatively low share of total revenues (less than 2.5%).

The analysis suggests APC has no material impact on the MPC and CPT outcomes required for new entrant OCGT revenue adequacy and that APC should be set based on other considerations.

[83] The assessment principle of APC adopted here is based on the Q2 2022 experience and is slightly different to that listed in the Review Guidelines.

[84] The same conclusion can be made in the case of the VIC OCGT as well. New entrants under the optimisation model are only dispatched during periods of USE.

Figure 109 Impact of APC on MPC and CPT frontier

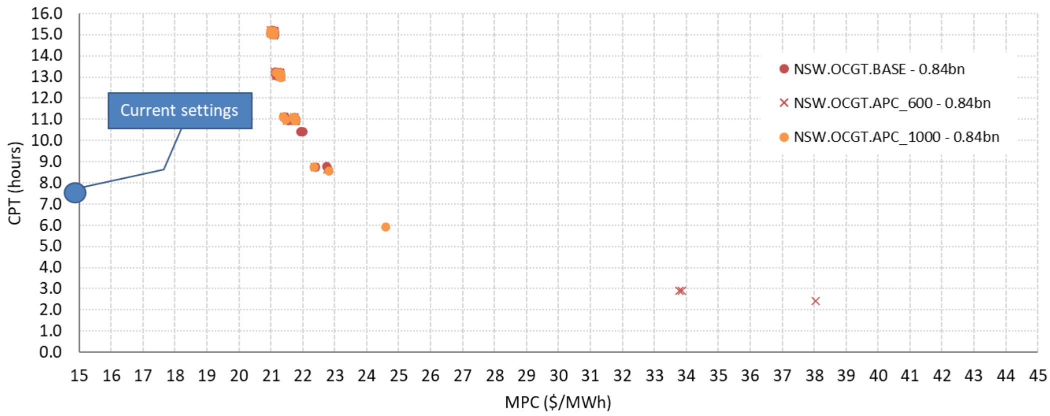


Table 36 NSW OCGT performance during APP ($1000/MWh APC)

Sensitivity	21k/21hrs (High CPT)	24.5k/6hrs (Low CPT)
MPC	21,000	24,500
CPT (hours of MPC)	20.9	5.9
USE during APP	0.5%	17.7%
Generation during APP	0.6%	20.1%
Revenues during APP	0.1%	2.4%

11.6.2 Other considerations for the APC – thermal generation

IES was separately commissioned by the AEMC to provide analysis to support the urgent rule change request to amend the APC.[85] The rule change request was initiated in response to the events of Q2 2022 and aims to amend the APC to (1) reduce the financial risk and operational risks during extreme market events, (2) minimise compensation to market participants, and (3) maintain appropriate market signals for dispatch and investment.

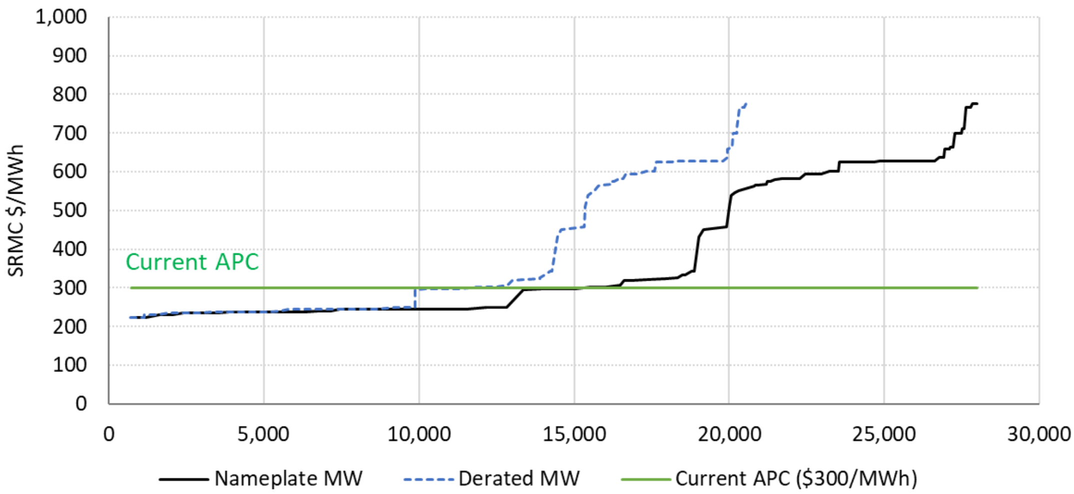
Although the process is still ongoing, high-level analysis into thermal generation costs under extreme conditions experienced in Q2 2022 was also provided to the Panel for consideration. The following summarises the analysis.[86]

- The assessment of an appropriate level of the APC needs to consider the underlying generation costs (including opportunity costs for batteries and pump hydro) and capacity that is likely to be available during APP. The following charts only cover thermal generation and excludes wind, solar, batteries, and pumped hydro.

[85] Rule Change Proposal: Amendment to the Administered Price Cap to mitigate the ongoing threat to the reliable operation of the market and system, Alinta Energy, 1 July 2022.
[86] The APC and SRMCs quoted in this section are in nominal terms consistent with the application of the APC in is current form.

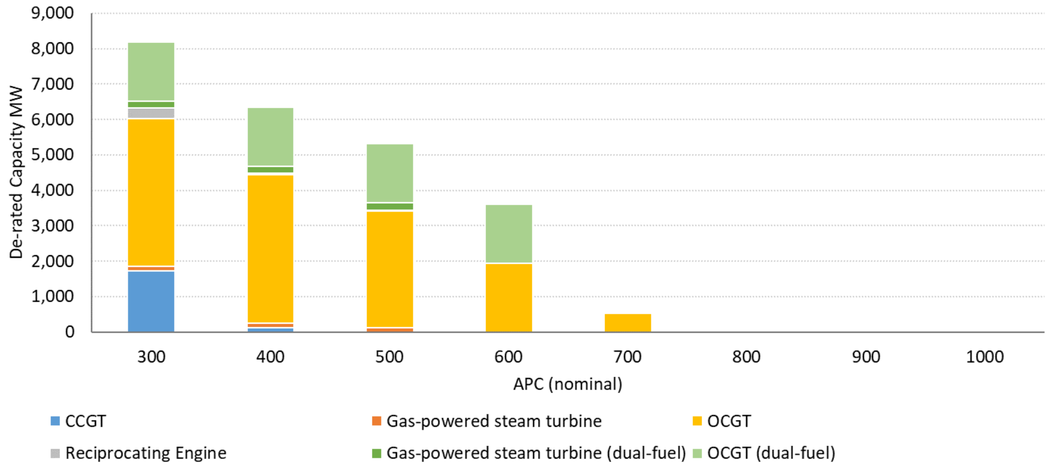
- We have assumed conditions, consistent with the events in Q2 2022, which trigger APP are also likely to be at the extremities, i.e., available capacity, fuel costs and gas supply availability are towards the tail ends of its respective distributions. The conditions, or assumptions used, are based on the notion that market suspension is an extremely undesirable outcome and therefore the setting of APC should be based on mitigating these circumstances.
- Figure 110 plots the supply stack across the entire NEM in FY2028 using nameplate and de-rated capacities based on the first week of June 2022 before the application of APC. The SRMCs are based on part-load heat rates and high underlying fuel prices, i.e., coal is based on $400/MT (USD), gas prices at $42/GJ and all dual-fuelled generators are unable to source gas and runs off diesel assuming a price of $39.4/GJ.[87] The supply stack shows (1) a significant de-rating of capacity mainly related to the high levels of forced outages experienced over the period, and (2) a significant portion of capacity with SRMC greater than the current APC.
- Figure 111 focuses on the generation capacity with SRMC above $300/MWh and plots the amount of de-rated capacity which sits above potential APC levels in increments of $100/MWh. If the APC is set higher, the amount of generation capacity with SRMC greater than the APC reduces leading to a lower number and dollar value of compensation claims. A higher APC would also allow for additional price variation to incentivise storage dispatch.[88] Higher diesel prices only impact the top 10% of de-rated capacity.

Figure 110 NEM supply stack in FY2028 (thermal capacity)



[87] Coal is based on the most recent high Newcastle coal spot prices and assumes port handling and transport. The gas price is based on the DWGM and STTM APC plus a $2/GJ transport charge. The diesel price is based on the 99th percentile of daily diesel prices. Dual-fuelled stations include Laverton North, Colongra, Mt Stuart, Hallet, and Valley Power. Heat rates are based on AEMO's IASR June 2022 heat rate data.
[88] Refer to APC rule change request.

Figure 111 Supply stack above $300/MWh (de-rated capacity, FY2028)



An APC of $800/MWh would cover all capacity under the modelled conditions, however, is likely to be too conservative as the entire supply stack may not be required to be dispatched.[89] The highest-SRMC generators, above $500/MWh and comprising approximately 5 GW, are older OCGT plants and/or those that are dual-fuelled. An APC of set to $500/MWh would cover approximately 80% of all thermal generation compared to 70% under the existing APC level, based on the high fuel prices assumed.

11.6.3 Other considerations for the APC – spot costs and retail hedging

Analysis into the impact of APC on spot and retail costs is still underway for the APC rule change request, however, the preliminary findings and trade-offs were presented by AEMC in the Amending the Administered Price Cap – Public Forum and is presented in Table 37.

The most recent set of events has shown that a significant increase in the number of generators with SRMCs above the APC also translates to a non-trivial amount of compensation that falls outside of the market framework and is therefore by definition unhedgeable, i.e., the true marginal cost of the directed generator/s is not reflected in the underlying price signal which all contracts settle against. The preliminary analysis indicates the following:

- An unhedged retailer prefers a lower APC to a higher APC because of lower spot prices and therefore settlement costs. This is consistent with the analysis carried out in the 2018 Reliability Standard and Settings Review which looked at the trade-off between lifting the cap to cover a small subset of generators compared to the increase in wholesale energy costs.
- A fully hedged retailer incurs additional costs over and above its contracted position due to the value of compensation claims associated with a low APC. A higher APC allows for the spot prices to reflect the true marginal cost which the retailer is hedged against and reduces compensation costs.

[89] The likelihood of dispatch of the supply stack at various depths is out of scope.

The findings suggest a lower APC favours a spot exposed retailer whereas a high APC favours a prudently hedged retailer. An APC that is significantly lower than a lot of generating units' SRMCs can lead to the perverse outcome of penalising the prudent retailer.

Table 37 Impact on consumer costs

During APP	Lower APC	Higher APC
Fully hedged retailer	+ Hedges cover APC - More compensation cost - Lag in cost recovery from consumers	+ Hedges cover APC + Less compensation cost
Unhedged retailer	+ Lower prices for electricity during APP - More compensation cost - Lag in the cost recovery from consumers	Higher prices for electricity during APP + Less compensation cost
Spot exposed customer	+ Lower prices for electricity during APP - Smaller signal signals to respond (provide demand response) - More compensation costs	- Higher prices for electricity during APP + Greater signal signals to respond (provide demand response) + Less compensation cost

Source: Amending the Administered Price Cap – Public Forum, AEMC, 16 August 2022.

11.7 Key findings

Table 38 summarises the key findings from the additional work undertaken for the Panel's final modelling report and is focused on the NSW Base case sensitivity and MPC and CPT combinations relating to the NSW OCGT new entrant in FY2028.

Table 38 Key model findings – additional analysis

Impact	Finding
Frequency of exceeding the CPT	The average spot price allowed before triggering APP will increase from \$674/MWh to more than \$1,000/MWh under the combinations of MPC and CPT considered. At a minimum this corresponds to an increase of more than 55%. However, the actual likelihood of experiencing conditions triggering APP for the \$21,500/MWh MPC and 8.5 hour CPT would be once every six (6) years assuming the region is at 0.002% reliability. This compares with an expected frequency of once every four (4) years based on the current MPC and CPT.
Contract settlement prices	The increase to MPC and CPT is expected to increase spot volatility and lift swap and cap settlement prices from \$75.8/MWh and \$8.4/MWh, respectively, by up to \$7/MWh or \$4/MWh in the case of a \$21,500/MWh MPC and 8.5 hour CPT. The increase to swap and cap settlement prices correspond to an increase of 5% and 47%, respectively.
Average retailer costs (wholesale energy)	Average retailer costs, based on optimal hedging arrangements to minimise risk, would be expected to increase by \$7/MWh to \$13/MWh under the MPC and CPT combinations considered and mainly relate to the increase in spot energy costs.

Impact	Finding
	The $21,500/MWh MPC and 8.5 hour CPT combination corresponds to the low end of this range ($7/MWh) and an increase of 8% based on the same hedging arrangements for the risk averse retailer under the current MPC and CPT levels. The wholesale cost increase of 8% translates to a 3% increase to a retail consumer's bill assuming component costs remain the same.
Financial risk and prudential requirements	The added spot volatility with increasing the MPC and CPT would increase credit requirements from $60,000/MW to $95,000/MW based on a demand shape consistent with the region profile. The corresponding increase in cost was computed to be up to $0.55/MWh. The actual cost impact is likely to be significantly lower than this given the range of offsets used in the NEM, including generation credits and reallocations.
Demand response sensitivities	Allowing for zero fixed cost demand response options (up to 30 MW in the Step Change scenario) reduces the required OCGT capacity and the MPC requirements by $1,000/MWh compared to the OCGT-only portfolio. Doubling this amount of DR would further shift the frontier by $2,000/MWh to the left. At a CPT of 8.5 hours, this would correspond to an MPC of $21,500/MWh and $20,500/MWh, respectively.
Appropriate level for the APC	APC and MPC/CPT: the impact of the OCGT new entrant earning revenues during APP for an increased APC up to $1000/MWh is not significant, i.e., the frontier describing viable MPC and CPT combinations for revenue adequacy does not shift and the APC can be set independent of this. APC and thermal generation costs: based on high fuel prices, an APC set to $500/MWh would cover 80% of all de-rated thermal generation capacity compared to 70% under the existing $300/MWh. Higher diesel prices only impact the level of capacity coverage above 90%. APC and retailer costs: preliminary analysis indicates a lower APC favours an unhedged retailer whereas a high APC favours a prudently hedged retailer. An APC that is significantly lower than a lot of generating units' SRMCs can lead to the perverse outcome of penalising the prudent retailer.

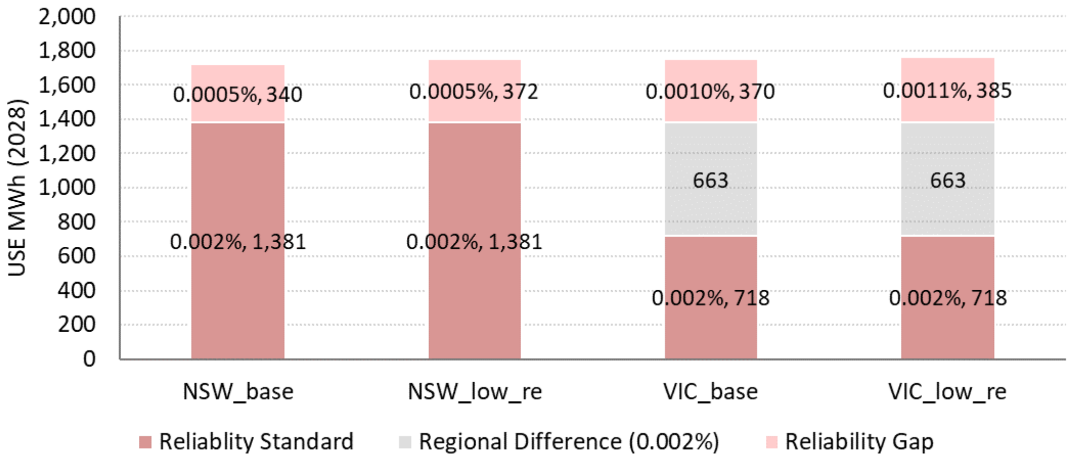
12 Task 3: Form of the reliability standard

The current form of the reliability standard is a volume of unserved expressed as a percentage of regional demand. The modelling work carried out in Task 2 highlights several aspects of the current form of the reliability standard which is discussed in more detail. The form of the standard is a key question to address as it guides the level and potentially the form of the reliability settings.

12.1 USE expressed as a percentage of demand

The reliability standard expressed as a percentage of regional demand is inherent more costly to address in smaller regions. Figure 112 is presented here again showing the significant discrepancy in the base volume of USE in NSW compared to VIC. The underlying distribution associated with the base volumes corresponding to 0.002% (1,381 MWh and 718 MWh) is materially different between NSW and VIC.

Figure 112 Base USE volume differences



The optimisation model results show a difference in the USE distribution translates into discrepancies in the form of higher MPC and CPT settings for the same generation type in VIC relative to NSW. However, the application of the MPC and CPT is NEM-wide. The MPC and CPT is intended to address reliability across all regions implying the higher MPC and CPT combinations relating to VIC should be applied. NSW reliability new entrants would be able to over-recover revenues and/or will lead to NSW experiencing a higher reliability than VIC.[90] This outcome of differing a reliability experience in different regions is possibly an unintended feature of having common price settings across all NEM regions. Based on the results presented here, it would be challenging to choose a combination of MPC and CPT appropriate for the NEM.

[90] Implicit with this is a higher associated reliability cost in NSW.

12.2 Risk-neutral standard

The current reliability standard is risk neutral in the sense that the objective of the reliability framework is to ensure the volume of USE is below the 0.002% threshold and the corresponding reliability settings are set to incentivise this outcome. There are no further dimensions to the standard to address what the reliability experience within the 0.002% volume should look like. The modelling in Task 2 shows USE outcomes under 0.002% can differ significantly under the current framework. If there are indeed stakeholder preferences for reliability outcomes, such as minimising long duration events, or reducing depth for operational considerations, these are certainly not embedded within the current framework and an alternative may need to be considered.

An important input into the current reliability framework is the VCR input. At present, this input assumption is a weighted average of the sector-level VCR estimates, however, the resulting input is still a constant value specified in $/MWh terms. This does not account for how stakeholders may value different types of supply interruptions. The single VCR input directly impacts the results presented in Task 2, which shows the most efficient outcome is to focus on short duration events which favours short duration storage.

From a pure cost-perspective, i.e., minimising total region cost as per the optimisation model:

- Although the corresponding MPC and CPT combinations for BESS is the most efficient outcome in accordance with the current reliability framework and formulation underpinning the optimisation model, the combination is unlikely to be feasible or palatable because of (1) the risks of a non-diversified supply mix to address reliability i.e., incentivising a narrow new entrant type that may jeopardise the capability to address long duration events, and (2) the current CPT of 7.5 hours implies cost may not be the only consideration at stake.[91]
- If a low CPT is not palatable for the market, then this suggests there are other considerations not specified in the reliability framework, such as addressing long duration events, that could be considered for incorporation into the standard. Among the possibilities are, a change to the form of the standard itself, augmenting the standard with additional dimensions, or including significantly higher VCRs associated with longer duration events. These inputs could then be fed into a model to quantitatively assess the optimum outcome. This would result in much higher total region costs for the battery baselines and sensitivities as the battery capacity required to address longer duration would increase, or that the optimal solution would pivot towards longer duration new entrant options.

[91] This conclusion may be driven by the commercial feasibility of battery energy system storages which has significantly improved over the past 5-years.

Appendix A Abbreviations

Abbreviation	Term
ACT	Australian Capital Territory
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APC	Administered Price Cap
APP	Administered Pricing Period
BESS	Battery energy storage system
CCGT	Combined cycle gas turbine
CPT	Cumulative Price Threshold
DSP	Demand-side participation
DWGM	Declared Wholesale Gas Market
ESB	Energy Security Board
ESOO	2021 Electricity Statement of Opportunities
FCAS	Frequency control ancillary services
FOM	Fixed operating and maintenance costs
GW	Gigawatt
GWh	Gigawatt hours
IES	Intelligent Energy Systems
ISP	Integrated System Plan
LOLE	Loss of load expectation
LOLP	Loss of load probability
LRMC	Long-run marginal cost
MFP	Market Floor Price
MPC	Market Price Cap
MW	Megawatt
MWh	Megawatt hours
NEM	National Electricity Market
NER	National Electricity Rules
NSW	New South Wales
OCGT	Open cycle gas turbine
POE	Probability of exceedance
QLD	Queensland
QRET	Queensland Renewable Energy Target
RERT	Reliability and Emergency Reserve Trader
RET	Renewable Energy Target
RSSR	2022 Reliability Standard and Settings Review
SRMC	Short-run marginal cost
STTM	Short Term Trading Market
TAS	Tasmania
TRET	Tasmania Renewable Energy Target
TSC	Total system cost
USE	Unserved energy
VCR	Value of customer reliability

Abbreviation	Term
VIC	Victoria
VRE	Variable renewable energy
VRET	Victorian Renewable Energy Target
WACC	Weighted average cost of capital
WDR	Wholesale Demand Response

Appendix B Reliability framework definitions

The definitions for the various components of the reliability framework are summarised in Table 39.

Table 39 Definitions of reliability framework components

Components	Definition/purpose
Reliability standard	The current reliability standard is expressed in terms of outputs. It expresses the maximum expected amount of energy demand that can be unmet in each NEM region in a year. It is expressed as a proportion — 0.002 percent of the total energy demanded in a region in a financial year. NER, Clause 3.9.3C(a)
Market Price Cap	The MPC sets the maximum price that can be reached in the wholesale market for energy and FCAS. The MPC is set, together with the CPT, at a level to provide financial incentives for investment and operational decision-making that are sufficient to achieve the reliability standard.
Cumulative Price Threshold	The CPT is the maximum cumulative energy and FCAS price that can be reached over a period of seven days, before an APP commences and the APC, is applied to market prices. The CPT acts to cap risk to market participants while maintaining the effectiveness of the MPC.
Market Floor Price	The MFP sets a lower limit on wholesale market prices that can be reached in any trading interval. The NER states that the Panel may only recommended an MFP it considers will allow the market to clear in most circumstances. The MFP should be set to reflect the amount that inflexible generators are willing to pay to remain dispatched.
Administered Price Cap	The APC is the maximum market price paid to participants that can be reached in any dispatch interval and any trading interval, during an APP. The APC, combined with the CPT, is a mechanism to minimise financial stability risks to the market arising from an extended period of supply scarcity and corresponding high prices. It is set at a level sufficiently high to incentivise generation to make itself available during an APP.
Administered Price Period	The APP applies to trading intervals where the sum of the spot prices in the previous 2,016 trading intervals, calculated as if this APP did not apply, exceeds the CPT. The APP also applies to all trading intervals within a trading day in which a prior trading interval is an APP.

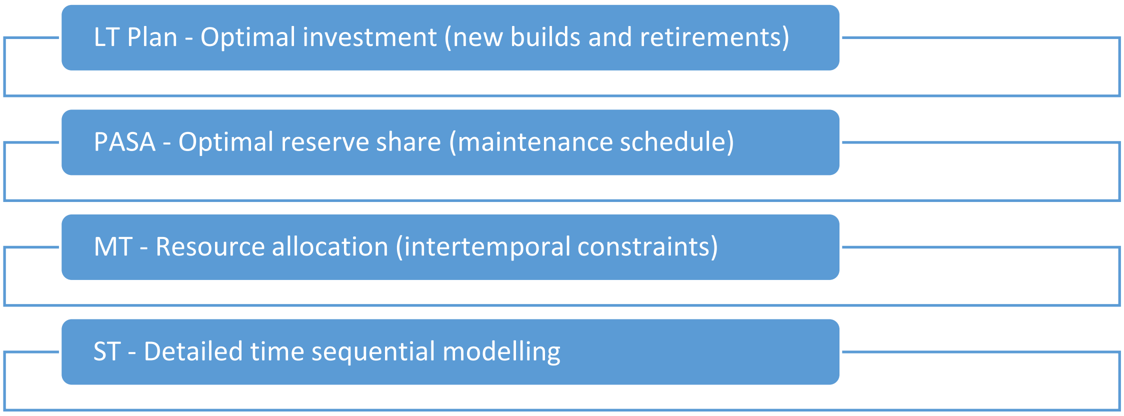
Source: Issues Paper.

Appendix C Detailed modelling approach

C.1 PLEXOS

PLEXOS is an integrated energy model that can be used to simulate the power market. It is the modelling tool used by AEMO to carry out its reliability work including the annual Electricity Statement of Opportunities. PLEXOS was used in this review to leverage the 2021 ESOO work and public ESOO model made available by AEMO. PLEXOS is comprised of various simulation phases which are run sequentially based on the end-user requirements and is shown in Figure 113.

Figure 113 PLEXOS simulation phases



- **LT Plan**: The LT Plan solves the capacity expansion problem over the planning horizon. This relates to finding the optimal combination of new entrant generators and transmission upgrades to meet system energy requirements whilst minimising total system costs. This module is used to determine the efficient new entrant portfolio in combination with the Expected Energy Not Served output parameter.[92]
- **PASA**: PASA determines the planned maintenance scheduling to optimise reserves over time by equalising capacity reserves accounting for peak load, available capacity, transmission capacity and constraints.
- **MT schedule**: The MT schedule optimises medium to long term decisions including intertemporal constraints such as hydro dispatch, storage optimisation, fuel offtake constraints or other user-defined constraints. This module decomposes intemporal limits for the ST schedule.
- **ST schedule**: The ST schedule emulates the dispatch and pricing outcomes of real market-clearing engines. This is used for time-sequential modelling of the supply and demand dynamics at the interval level to produce the USE outcomes and includes pricing after accounting for generator behaviour and network constraints. The ST schedule is used for

[92] Used as an indicator only. The verification of USE still requires Monte Carlo simulations.

the large number of statistical simulations to verify reliability across the NEM regions and generates the required interval level outputs such as USE for the optimisation model.

C.2 Market modelling steps

C.2.1 Step 1a: Determine if there is a reliability gap

The first step is to model the outlook without any commercial new entrants to determine whether there is a reliability gap.

- **[Policy-based new entrant determination]** Run PLEXOS LT plan to determine the policy-based new entrants that are required to meet the various state-based RE policies. Policy-based new entrants are defined as new entrant projects that have project economics underpinned by the various state schemes and derive a portion of its revenues from these schemes. These plants are not included in the efficient new entrant portfolio because they obtain non-market revenue streams. Commercial generic new entrants, i.e., plants that derive its revenues purely from the market, are not considered in this step.
- **[Detailed time-sequential modelling]** Run PASA, MT schedule and ST schedule across a limited number of samples to determine whether economic coal retirements are required. After coal retirements are determined, the ST schedule is re-run across the full number of samples.[93] If the USE results in a lower system reliability than the standard, i.e., USE higher than the 0.002% threshold, we proceed to Step 1b. If the system is reliable, coal units are incrementally removed - see Step 1c.

C.2.2 Step 1b: Address most of the reliability gap through PLEXOS

Given that the system has a reliability gap, the objective of this step is to run PLEXOS to determine the efficient new entrant portfolio that addresses most of the reliability gap (targeting 0.0025%) so the new entrant to address the remaining USE volume can be inferred. The decoupling requires sufficiently developed generator dispatch, pricing, and revenue outcomes so that we can make the simplifying assumption the marginal new entrant generator does not impact market outcomes.

- **[Commercial new entrant determination]** Incorporate policy new entrants from Step 1a and run LT plan allowing for commercial new entry and with a LOLP target corresponding to a slightly lower target system reliability. [94] PLEXOS will determine the efficient new entrant portfolio to meet this target. As the LT plan simplifies demand and supply assumptions to determine capacity expansion and only has the LOLP parameter to target USE, system reliability needs to be verified using time-sequential modelling (ST schedule) in a subsequent step.

[93] See Section 5.6.3 for the number of samples.

[94] To be run as a deterministic solve using the median of demand inputs. The LOLP target is used as a proxy for expected USE in the LT Plan.

- The LT Plan is run to the end of 2030. Supply and demand dynamics that may apply over the economic life of the new entrant is not captured.

- **[Detailed time-sequential modelling]** Run PASA, MT schedule and ST schedule with the commercial new entrants as determined in the previous step across the full set of samples to confirm whether system reliability is close to the targeted reliability standard (0.0025%). Depending on the outcome, the LT or ST will be re-run until we meet this condition.
  - Checks against coal revenues are also made to ensure the additional commercial new entrants do not materially impact coal revenues. For material impacts, coal retirement is reassessed, and this step is repeated as required.
  - There is a limit to the level of granularity that can be achieved with market modelling in the context of addressing the reliability standard. Iterations are carried out until the expected USE outcome is approximately within 5% of the desired level. The exact USE target (0.002%) is reached by scaling the USE outcomes.

C.2.3 Step 1c: Remove capacity to generate a reliability gap

A reliability gap needs to be generated to determine the optimal reliability settings that will encourage new entry to return the system back to the reliability standard.

- **[Capacity removal]** Coal units are removed from the system from the regions that are the closest to the reliability standard. Retirement is based on the order of the announced closure times and revenue outcomes.
- **[Detailed time-sequential modelling]** Run PASA, MT schedule and ST schedule until the reliability gap is close to the target of 0.0025%. Iterations are carried out until the expected USE outcome is approximately within 5% of the desired level. The exact USE target (0.002%) is reached by scaling the USE outcomes.

C.2.4 Outputs from the market modelling

The main outputs from the market modelling (USE outcomes, spot prices and revenues, and generator dispatch) are fed into the optimisation model in step 2.[95]

C.3 Optimisation model

One of the goals of the RSSR is to find the values of the reliability settings that incentivise new entrant construction and dispatch corresponding to the minimum total region cost, subject to delivering a specified reliability standard.[96] The optimisation model is formulated based on this objective and consists of an *inner problem* nested within an *outer problem*. The outer problem is the constrained selection of the reliability settings. The inner problem is set up as a linear problem (LP), where the reliability settings are fixed (taken from the outer problem), and

[95] The prices from PLEXOS correspond to prices before CPT is applied. Raw prices are required for the optimisation model.

[96] The model is set up to solve for all four reliability settings, however, the APC and MFP were constrained to current levels.

solved for the optimal selection of how much new capacity will be constructed and dispatched subject to technology-specific constraints and minimisation of total region cost. Total region cost is defined as spot price * served demand + VCR * unserved demand, weighted and summed across all USE events over the Review Period.

At market equilibrium, the net revenue constraint for the new entrant specifies it must be $0, i.e., neutral net revenues. Therefore, in the inner LP, the new entrants' net revenue (which can be positive or negative) is maximised while constraining the new entrants to produce enough energy to attain the reliability target. Thus, net revenue and total region cost are both outputs from the inner problem. The outer problem then minimises total region cost subject to a zero (or negligible) net revenue.

C.3.1 Outer problem

The outer problem is a constrained nonlinear problem that minimises total region cost subject to net revenue = 0. Note that the inner problem is a linear program, whose objective coefficients—*but not constraints*—depend on the reliability settings. Therefore, at a generic point in the four-dimensional reliability settings space, the optimal variable values of the LP (the new capacity amounts and the dispatch sequences) are constant. Conveniently, this makes it very efficient to compute the values and gradients of the outer problem's objective and constraint functions (total region cost and net revenue) for any given combination of reliability settings once the LP is solved.

Accordingly, we can perform an iterative constrained local search, based on local linear approximations for total region cost and net revenue, using an adaptive maximum step size. At each iteration, the revenue approximation determines a hyperplane; if we cannot reach that hyperplane using the maximum step size, then we step as close to it as possible, but if we can, then we minimise the approximated total region cost subject to the hyperplane, step size and box constraints, using a simple four-dimensional quadratic program. After stepping, we update the LP's objective coefficients and re-solve the inner problem. Thus, we can perform one iteration of the local search per LP iteration.

The problem does not suffer badly from multimodality and the initial settings are based on current level of the reliability settings to begin the local search. This was confirmed by trying various starting points —that is, independent local searches from randomly selected initial setting combinations—without discovering new, better optima.

C.4 Modelling differences to the 2018 Review

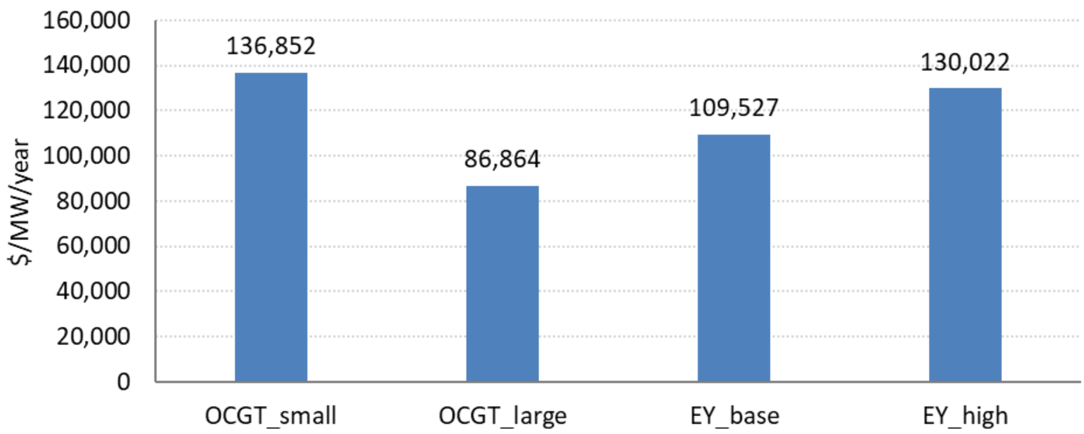
There are considerable differences between the results presented in this review and that from the 2018 Review. This section provides a high level assessment of the modelling differences and impacts on the determination of the optimal MPC. A comparison of CPT values is not provided as CPT in both methods are dependent on the level of the MPC.

The base case finding from the 2018 Review showed CCGTs could reduce USE below the reliability standard and were economically viable with an MPC as low as $300/MWh. The Panel decided CCGTs were not viable as the marginal new entrant due to its inflexibility and requirement for long-term high volume gas supply, and instead, based the theoretical optimal MPC on an OCGT with cost assumptions corresponding to the high cost sensitivity inputs. The modelling of the optimal MPC for the OCGT (based on VIC) was determined to be $12,500/MWh. Additional sensitivities were also carried out and resulted in considerably higher MPCs. Adjusting for indexation, this outcome would still be materially lower than the current Base case sensitivity results which show a minimum MPC required of $21,000/MWh in NSW.[97]

In addition to the differences covered in Section 3.4, there are several fundamental differences in the approach between the previous and this current review. Where appropriate, we have used our judgement to estimate the materiality based on the 2018 Review modelling report[98].

- **Fixed cost assumptions**: The previous work was based on a 10% WACC and capex of $1,188/kW, relative to a WACC of 5.5% pa and capex of $1,023/kW (large OCGT) in the current review.[99] The equivalent annual fixed cost is presented in Figure 114 and shows much higher fixed costs in the 2018 Review, however, the difference here only further adds to the discrepancy in MPC values.

Figure 114 Comparison of fixed costs



- **USE volumes**: Current modelling results show the MPC can be very sensitive to small shifts in the underlying USE volume corresponding to the 0.002% reliability standard, and the reliability gap that is being solved for. The previous review and this report highlight the difficulty in targeting an exact level of USE through probabilistic modelling due to computational limitations. However, we concluded an approach that does not standardise for the reliability gap would make comparisons difficult across scenarios and reviews.
  - Reliability gap: The previous review also found no reliability gap and had to withdraw capacity from the system to determine the optimal MPC. Although the review refers

[97] This is just used as a reference point and corresponds to the lowest viable MPC for an OCGT (large) in NSW under the Base case sensitivity.
[98] Ernst and Young, Reliability Standards and Settings Review 2018 – Modelling Report, April 2018.
[99] Previous review values have been indexed to June 2021 basis.

to the modelled outcome as being close to the reliability standard, the reliability level before the new entrant is added is significantly higher than the level we have adopted in this work. A summary of the USE levels is presented in Table 40. In the previous review, the reliability gap is generated across the entire review period, whereas the current modelling focuses on a single year. The USE associated with the reliability gap, for VIC, is also up to twice that of the current review. The volume of USE to be addressed by the marginal new entrant has implications for optimal level of the MPC. The scaling/resampling approach adopted in the current review allows for this volume to be standardised (see Section 9.1).

- Reliability target: The USE percentage that remains after the new entrant in the previous review is much lower than the actual reliability standard of 0.002%. In some of the years, the reliability almost reaches 0.001% in SA and 0.0015% in VIC. This is due to the previous review relying solely on market modelling which is computationally intensive and inexact by nature. The optimisation model used in the current review allows us to target an exact reliability level.

- The combination of a larger reliability gap and higher reliability standard reached has significant implications for the determination of the MPC because (1) a larger reliability gap allows for higher utilisation of the new entrant, (2) the higher corresponding base USE volume would generally be associated with a less peaky distribution, all else being equal, and (3) a higher reliability target than 0.002% also contributes to higher utilisation of the new entrant, however, addressing this additional USE volume may in fact be more costly.

Table 40 USE volume differences across 2018 and current review

2018 review	USE before new entrants	USE after new entrants
VIC (MPC scenario 2)	0.003% - 0.004%	0.0015% - 0.002%
SA (MPC scenario 1)	0.003% - 0.005%	0.0010% - 0.002%

Current review	USE before new entrants	USE after new entrants
VIC (all cases)	0.0030%	0.002%
NSW (all cases)	0.0025%	0.002%

Note: Figures for the 2018 review are based on reading off the report charts and are estimates only. The underlying VIC demands are not materially different.

- **Spot pricing outcomes**: A modelling limitation as noted in both the 2018 and current review is the dependency on spot pricing dynamics which drive the underlying energy revenues outside of the USE periods. The MPC and CPT is determined based on these external energy (and FCAS) revenues and the balance of generation costs. In both the previous and current review, generator bidding dynamics were calibrated to a historical period. Spot market conditions can vary significantly and there is no guarantee the calibration exercise would be representative of the period in which the review covers. Table 41 shows significantly higher annual spot prices in VIC relative to the current review which would result in a higher combination of MPC and CPT.

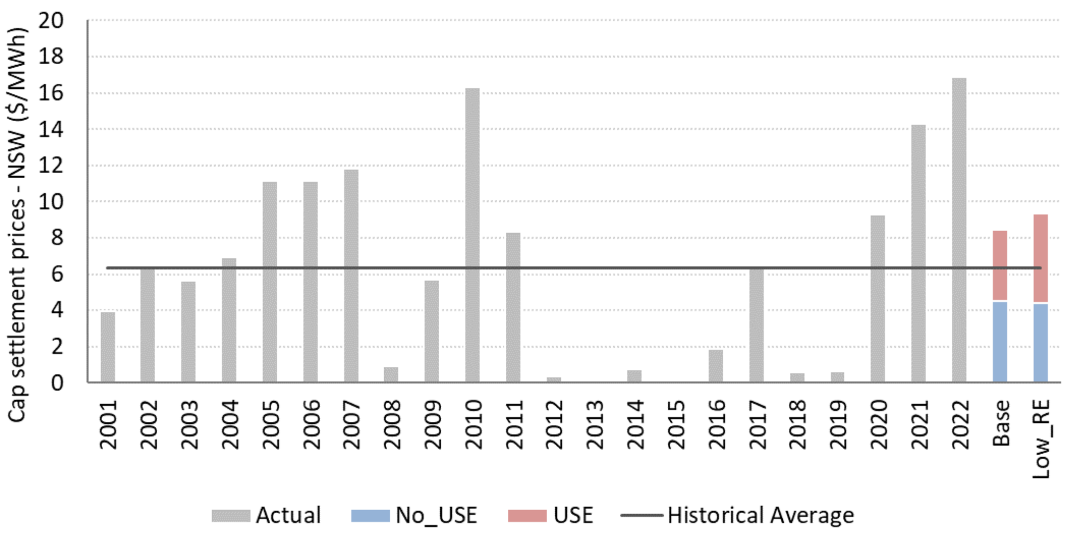
Table 41 Spot price differences across 2018 and current review ($/MWh)

Region	2018 review	Current review
VIC	84 – 100	65
SA	95 – 113	No reliability gap simulated
NSW	No reliability gap simulated	76

Note: The range of 2018 review prices are over a 4-year period, based on the MPC scenarios (1 and 2), and have been read off the report chart. Current review prices (2028) are based on the Base case sensitivity and current reliability settings. Prices have been indexed to June 2021 dollars.

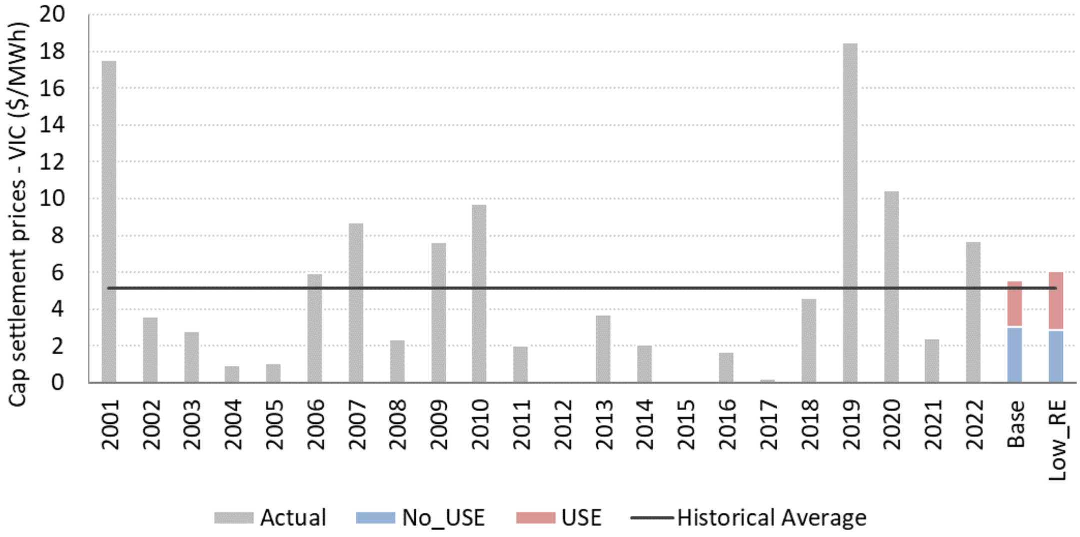
– Revenue composition of the new entrants are highly dependent on spot price volatility and $300/MWh cap settlement values would be indicative of the balance of costs recovered from the reliability settings. As an additional check, Figure 115 and Figure 116 compares modelled cap settlement values, based on the current level of the reliability settings and a reliability gap of 0.0005%, to historical levels. The cap value is split into periods outside of USE events (labelled NO_USE) and the portion that is driven by USE events. The USE component is not relevant to the current modelling as the optimisation model will determine the required MPC and CPT for the new entrant but is provided to show the modelled cap value relative to history. The historical line represents the 20-year average, but also sits relatively close to the average over the last 7 years. Modelled cap values are generally higher in NSW relative to history. The difference in modelled VIC and NSW cap values (total) is a function of bidding dynamics and the underlying USE volumes associated with the reliability standard and the reliability gap. Marginal new entrants were assumed to earn external energy revenues based on the NSW and VIC average to minimise this impact.

Figure 115 Modelled cap values and historical settlement (NSW)



Note: Historical values are presented on a nominal basis.

Figure 116 Modelled cap values and historical settlement (VIC)



Note: Historical values are presented on a nominal basis.

A summary of the MPC impact of the differences across the 2018 and current review is presented in Table 42. It is difficult to reconcile differences beyond a high-level summary, however, we can infer the reduction in USE volumes considered and lower spot prices has contributed to the material increase in MPC in the current modelling results.

Table 42 Summary of impacts from modelling differences

Impact	Difference relative to 2018 review	Implication for current review MPC
Fixed costs	Lower by approximately 30%	Leads to a reduction in MPC
USE volumes	Lower by up to 50%	Leads to an increase in MPC
Annual spot prices	Lower by up to 35%	Leads to an increase in MPC

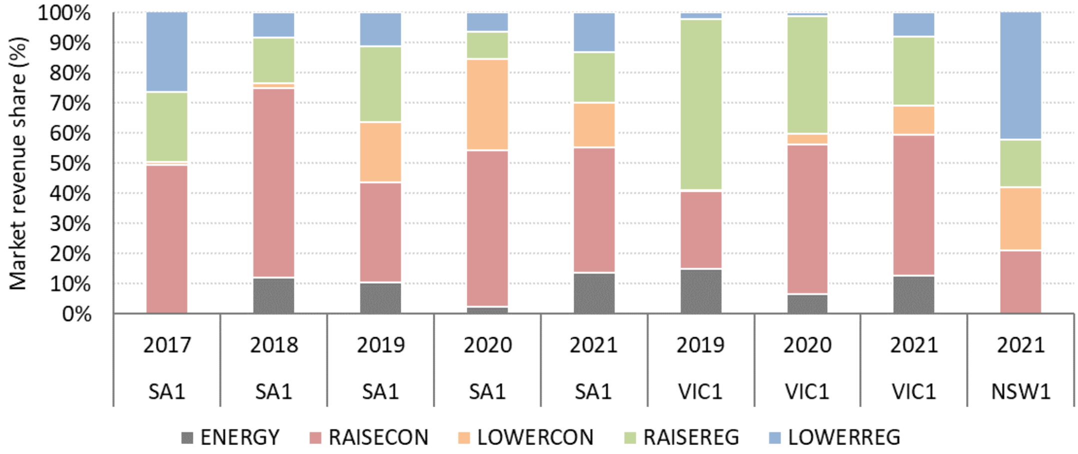
Note: Based on VIC outcomes.

C.5 FCAS revenues

The modelling framework adopted in the current review is based on energy-only revenues, however, many batteries commissioned over the past 5-years have earned a significant portion of its spot market revenues from providing FCAS. FCAS revenues for other new entrant options are generally less than 5% over the same period and have been omitted from the modelling.

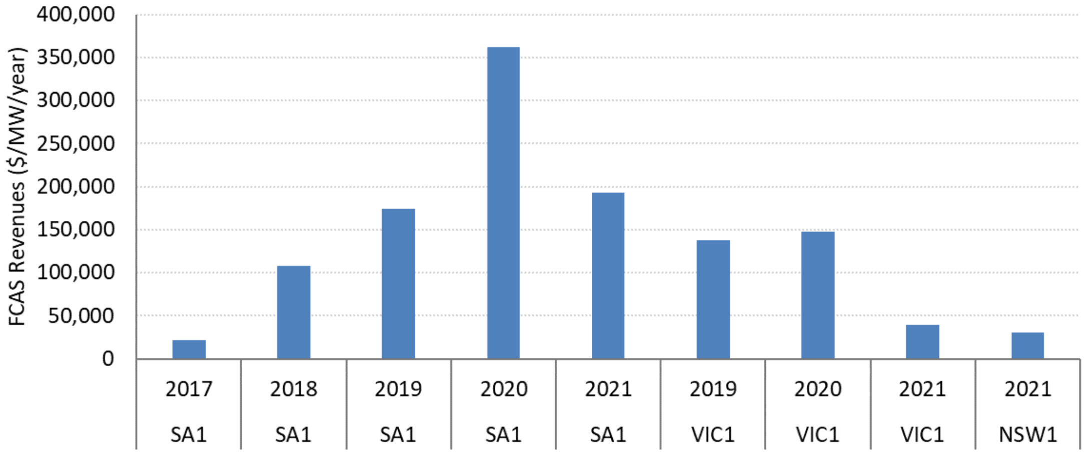
The market revenue share for batteries is presented in Figure 117 and show spot energy revenues (black wedge) comprise a very small percentage, of up to 15%, of total market revenues. Non-market revenues such as those derived from network agreements are not publicly available and therefore not considered in this analysis. The corresponding revenues expressed in dollars per MW terms is presented in Figure 118 and shows very high FCAS revenues earned by batteries in SA and VIC.

Figure 117 Historical market revenue share



Source: IES analysis. Services have been aggregated into contingency (CON), regulation (REG) and by raise and lower services.

Figure 118 Historical FCAS revenues per MW



Source: IES analysis

The amount of revenues earned from the energy and FCAS spot markets impacts the balance of generation costs that needs to be recovered from the reliability settings during the USE events. Historical FCAS revenues provides some context, however, it is generally agreed recent FCAS prices (and revenues) are unsustainable or have been subject to short-term supply and demand constraints. There are several conditions suggesting FCAS revenue streams will reduce and will pivot batteries towards higher energy revenues over the Review Period. These conditions are listed below:

- Increasing investment into battery energy storage systems across the NEM, adding to potential supply and participation across the FCAS markets. The increase in battery energy storage systems is also to support the reducing minimum demands across the day from further increases in small-scale rooftop PV systems, and investment in grid-scale solar PV.

- Increasing FCAS requirements due to increasing RE penetration. However, the requirements are expected to increase at a much slower rate than the supply-side increase.
- Introduction of Project EnergyConnect which will increase supply and diversity of supply conditions in SA. The expectation is that the FCAS prices in SA will converge towards price levels of the larger interconnected regions.

Based on the expected conditions discussed above, IES have taken the view that FCAS revenue streams are likely to decline from CAL2021 levels seen in VIC and NSW and have notionally applied a 5% pa reduction to arrive at a NEM-wide FCAS revenue stream of $22,000/MW/year for all batteries.[100] The FCAS revenue assumption is a fixed input and is assumed to be independent of the optimal reliability settings determined by the optimisation model. Sensitivities can be applied to assess the impact of the baseline FCAS revenue assumption.

[100] No distinction has been applied between shorter and longer storage durations.