ANALYSIS SUPPORTING THE AMENDMENT OF THE MPC, CPT AND APC RULE CHANGE (ERC353)

Final Report

6 December 2023

Intelligent Energy Systems

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Version History

Version	Date	Change
V01e	4 August 2023	Initial draft
V02b	17 August 2023	Reordered tasks, inclusion of Task C efficacy work, minor edits
V03c	11 September 2023	Task C efficacy update, counterfactual update, formatting
V04a	6 December 2023	Final report, minor edits, fixed error references

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1 Executive summary

1.1 Background and scope

The Reliability Panel (Panel) has submitted a rule change request to amend the level of the Market Price Cap (MPC), Cumulative Price Threshold (CPT), and Administered Price Cap (APC) in the National electricity Market (NEM) applying to the period 1 July 2025 to 30 June 2028 (Review Period).[1] The Panel has submitted this rule change request following the completion of its 2022 Reliability Standards and Settings review (2022 RSSR).

The AEMC is required to determine whether the rule change request submitted by the Panel promotes the National Electricity Objective (NEO). In particular, whether it promotes efficient operational and investment decision-making in the long-term interests of consumers.

The objective of this work was to (1) update the previous modelling with new market developments and assumptions, (2) provide a range of MPC/CPT combinations and the consumer cost impact to inform the Commission, and (3) provide additional analysis and modelling, including a counterfactual case, to provide further context to the potential impacts of changes to the MPC/CPT.

1.2 Modelling approach and updates

The approach leverages all the existing models and model outputs derived from the 2022 RSSR to carry out the additional scenario modelling and sensitivity analyses. The main modelling elements and updates are summarised in Table 1.

Table 1 Modelling components and assumption updates

Component	Description	Main assumption updates
Re-profiled price distributions	The underlying levels and price distributions from the 2022 RSSR was updated to reflect representative levels of prices.	Prices updated to levels consistent with the last 5 years and the median 5 of the last 7 years based on MPCs of \$22,000/MWh and \$25,000/MWh and CPT of 8.5 hours.
Optimisation model	The MPC and CPT frontiers were derived using a bespoke optimisation model that minimised the total system cost by varying the MPC and CPT while ensuring revenue adequacy for the new entrant generator.	Base weighted average cost of capital increased from 5.5% to 7.0%. Battery energy storage system (BESS) capital costs increased by approximately 30%. Inclusion of the small OCGT new entrant. Updated non-reliability revenues based on historical percentiles.

[1] https://www.aemc.gov.au/rule-changes/amendment market-price-cap-cumulative-price-threshold-and-administered-price-cap

Component	Description	Main assumption updates
Wholesale cost model	The modelling of the wholesale component of consumer cost was based on half-hourly prices and the combination of swap and cap contracts that minimised the standard deviation of load cost outcomes. The consumer cost impact is solely focused on the wholesale component of the residential retail tariff.	Adjustment to the region load shape to represent retail load shapes more accurately. Updates to the underlying price traces use to calculate the wholesale cost component.
Counterfactual assessment	The counterfactual case expands on the wholesale cost modelling to explore cost outcomes based on retaining the existing reliability setting levels.	Accounts for the relative cost of unserved energy volumes when considering consumer cost, and accounts for price impacts from a supply-side response to a change in the MPC/CPT.
Efficacy of higher price settings	Reviewing the impact of higher price settings on volatility, and spot and contract prices in the context of incentivising capacity investment in the NEM.	Analysis based on historical cap settlement values against the equivalent cap settlement values based on higher price settings.

1.3 Key findings

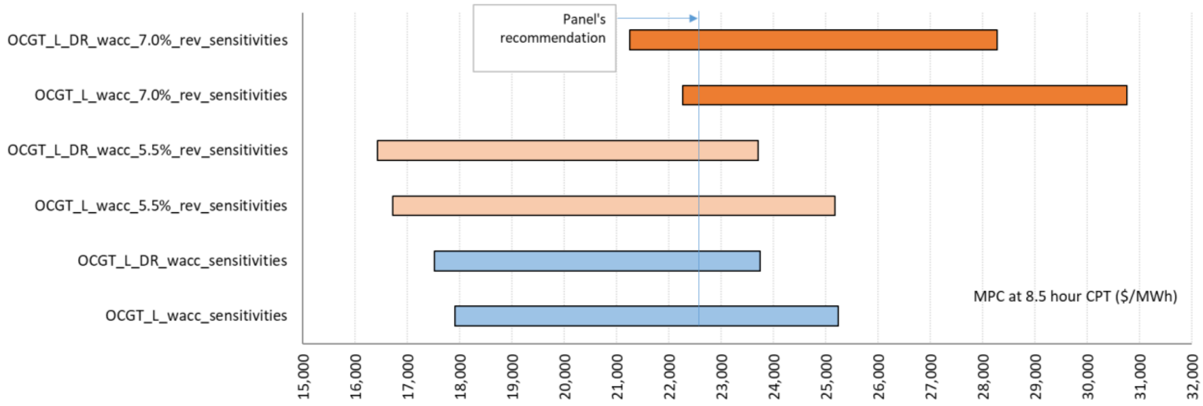
The key findings are summarised in Table 2.

Table 2 Key findings

Category	Key findings
MPC/CPT combinations	- The required MPC levels for small OCGT and BESS (2 and 4-hour), and its related sensitivities, continues to be significantly higher than that of a large OCGT due to the difference in underlying capital costs and energy constraints associated with BESS. - The WACC and the assumption of non-reliability revenues play a significant role in determining the required MPC for large OCGTs. The outcomes show a wide range of MPC values at a CPT of 8.5 hours, ranging from \$16,500/MWh to \$31,000/MWh, depending on the WACC and revenue sensitivities considered (Figure 1). - The level of the APC is not material in determining the MPC/CPT combination as the revenues derived from Administered Pricing Periods comprise a negligible share of the OCGT's revenue. - The Panel's recommendation of \$22,800/MWh sits firmly in the middle of the MPC sensitivity ranges explored.
Carbon cost impact on the MPC/CPT	- The net revenues for a large OCGT plant under the two carbon scenarios are influenced by its carbon intensity relative to other plants and the total capacity of higher SRMC plants setting the spot price.

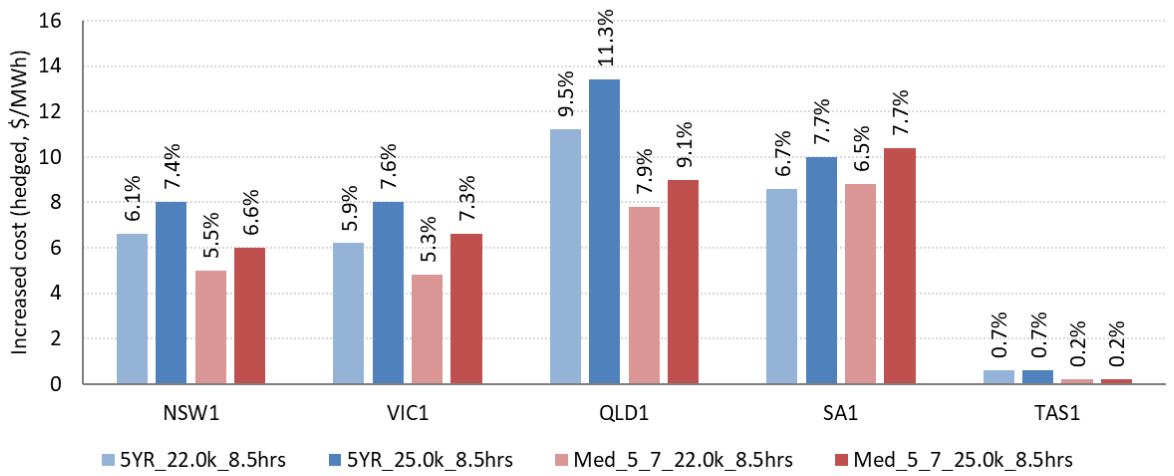
Category	Key findings
	- The impact of a $20/t carbon cost was found to be negligible, indicating that it has minimal influence on the required MPC/CPT for a large OCGT. However, the sensitivity analysis with a $50/t carbon cost shows a material impact. The additional revenues associated with a $50/t carbon cost corresponds to $6,380/MW/year, which reduces the required MPC by approximately $3,500/MWh at the 8.5-hour CPT level. - The additional net revenues potentially accruing to a large OCGT located in NSW are limited compared to VIC. This is because VIC has a higher number of generators that are positioned above the new entrant OCGT SRMC and have significantly higher carbon emissions intensity.
Consumer cost assessment	- In QLD, the impact of higher price settings would be the most significant, with wholesale cost increases ranging from $7.8/MWh to $13.4/MWh (8-11%) under both median 5 of last 7-year and 5-year average pool conditions. NSW and VIC would experience cost increases of between $4.8/MWh and $8.0/MWh (5-8%). SA would see increases ranging from $8.6/MWh to $10.4/MWh (7-8%). TAS would be relatively unaffected, with a minimal increase of less than 1%. See Figure 2. - The average increase across all regions, except TAS, is $9.9/MWh under a $25,000/MWh MPC and 8.5-hour CPT. This is comprised of $7.3/MWh in energy costs and an additional $2.6/MWh related to contract premiums for the higher MPC and CPT settings. Risk-averse retailers would face increased, but manageable, risks. - The doubling of the assumed risk premium assumption would lead to an average cost increase of $2.4/MWh or 1.6% across NSW/QLD/VIC/SA.
Counterfactual assessment	- For an unreliable state, the current price settings (counterfactual) would lead to a structurally higher equilibrium level of reliability at 0.004%, which is double the current reliability standard of 0.002%. The counterfactual case would also result in higher pool prices and wholesale costs compared to the sufficient settings case. The overall cost increase is $9/MWh, including $4.5/MWh in additional USE costs, or 7.5% higher than the sufficient settings case. See Table 3.
Efficacy of higher price settings	- The historical trend of low cap values aligns with the lack of peaking capacity investment. If the objective were to facilitate more capacity investment, it becomes evident that the historical and current levels of MPC/CPT would have fallen short of meeting this objective. - The present MPC/CPT levels do not adequately incentivise prospective investment in peaking capacity, with OCGT representing the most economically viable option at present. See Figure 3. - Raising the MPC to $22,000/MWh will raise spot volatility, cap values and contract prices to levels commensurate with the cost of building OCGT capacity when supply is needed to meet potential reliability gaps.

Figure 1 MPC/CPT range summary



Note: The revenue sensitivities cover the 20th to 80th percentiles. The WACC sensitivities cover 5.5% to 7.0%. The Panel's recommendation has been converted to 2022 dollars.

Figure 2 Increased consumer costs relative to current settings

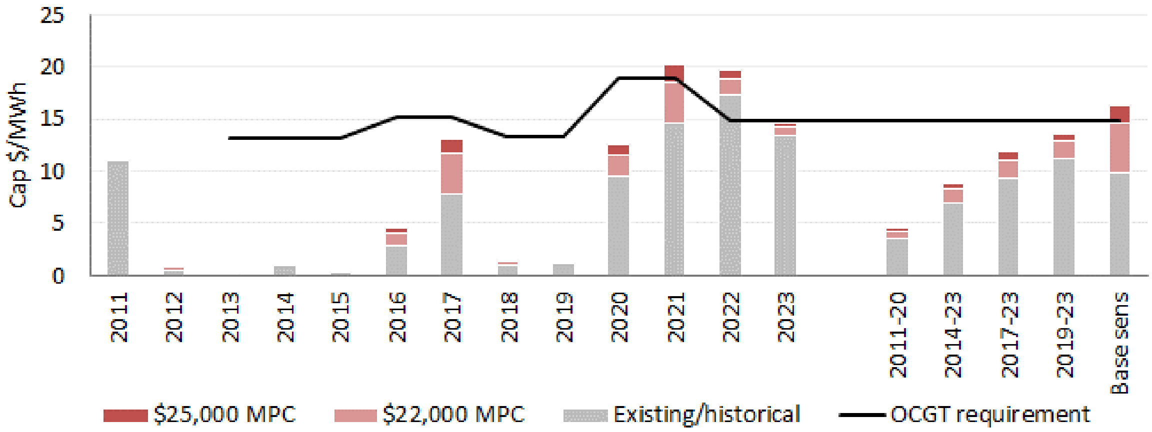


Note: These are compared to the current $15,500/MWh MPC and 7.5-hour CPT settings.

Table 3 Counterfactual assessment comparison ($/MWh)

Reliability state	Current settings	Sufficient settings	Difference (Current – sufficient settings)
Unreliable state before capacity investment (above 0.005%)	Wholesale: 119.6 USE: 8.9 Total: 128.5 Equilibrium USE: 0.004%	Wholesale: 115.1 USE: 4.4 Total: 119.5 Equilibrium USE: 0.002%	+$9.0/MWh (+7.5%)

Figure 3 Cap settlement values (NSW)



Note: The Base case sensitivity has a reliability gap, and therefore needs further new entrant investment to maintain the reliability standard.

2 Introduction

2.1 Background

The Panel has submitted a rule change request to amend the level of the Market Price Cap, Cumulative Price Threshold, and Administered Price Cap in the NEM applying to the period 1 July 2025 to 30 June 2028. The Panel has submitted this rule change request following the completion of its 2022 RSSR.

The Panel's rule change request is to amend the MPC, CPT, and APC set out in the NER to reflect the levels recommended in its final review report being:

- Progressively increasing the MPC to $21,500/MWh (in 2021 dollars) by 2028.
- Progressively increasing the CPT to $2,193,000 (in 2021 dollars), corresponding to 8.5 hours of market prices at the recommended MPC.
- The APC is to increase from its current level of $300/MWh to $500/MWh (nominal).

The AEMC is required to determine whether the rule change request submitted by the Panel promotes the NEO. In particular, whether it promotes efficient operational and investment decision-making in the long-term interests of consumers.

The rule change will also be progressed in the context of significant stakeholder interest given cost of living and inflationary pressures. Stakeholder engagement will be a key focus for the Commission as it progresses the rule change.

2.2 Scope of work

The AEMC seeks advice across three areas relating to potential changes to the MPC, CPT and APC. These areas are summarised in Table 4. The scope of the project expands on the modelling and analysis conducted by IES during the 2022 RSSR and was conducted in accordance with the requirements set out in the National Electricity Rules (Chapter 3).

The objective of the work was to (1) update the previous modelling with new market developments and assumptions, (2) provide a range of MPC/CPT combinations and the consumer cost impacts to inform the Commission, and (3) provide additional analysis and modelling, including a counterfactual case, to provide further context to the potential impacts of changes to the MPC/CPT.[2]

Table 4 Scope of work summary

Task	Sub-task	Description
A (MPC/CPT key parameter sensitivities)	A1	Assess how the MPC/CPT frontiers shift given a higher cost of capital consistent with forward-looking generation financing costs. The work will explore AEMO's latest WACC assumptions ranging from 5.5% (low), to 7% (central estimate).[3]

[2] The counterfactual case explores outcomes based on retaining the existing reliability setting levels.
[3] On a pre-tax and real basis.

Task	Sub-task	Description
	A2	Identify the impact of a reasonable range of OCGT CAPEX costs on the MPC/CPT frontiers, particularly small OCGT CAPEX costs relative to large OCGT CAPEX costs, and updated battery energy storage costs and demand response levels.
	A3	Identify the impact on the MPC/CPT frontiers from different levels of non-reliability period revenues.
	A4	Identify whether the level of the APC materially impacts the MPC/CPT outcomes.
B (Consumer cost impact assessment)	B1	Re-profile price samples from the 2022 RSSR to ensure consistency of outcomes with forward pricing expectations.
	B2	Robustly assess electricity wholesale and hedging cost increases arising from the proposed MPC/CPT and other MPC/CPT combinations.
	B3	Include sensitivities to capture key parameter uncertainty such as pool volatility, and risk premiums.
C (Additional modelling)	C1	Assessment of the materiality of carbon costs on the MPC and CPT.
	C2	Assessment of consumer costs based on a counterfactual, whereby the current level of the market settings is retained.
	C3	Assess the efficacy of higher price settings in incentivising capacity investment.

2.3 Report notes

The basis of figures quoted in this report, unless otherwise stated, is listed in Table 5. AEMO's Inputs, Assumptions and Scenarios Report 2023 (IASR) refers to the draft December 2022 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 2022 Australian dollars[4]
Average prices	Time-weighted
Cumulative Price Threshold	Expressed in hours of MPC for interpretability[5]
Short-run marginal cost	Sent-out
Fuel prices	Delivered
Cap settlement values and cap prices	Based on a $300/MWh strike

[4] The Administered Price Cap is expressed in nominal terms. The CPI adjustment from 2021 to 2022 is 6.1%.
[5] The actual CPT is expressed in $/MWh terms.

3 Approach and considerations

The approach was to leverage all the existing models and model outputs derived from the 2022 RSSR to carry out the additional scenario modelling and sensitivity analyses. No additional PLEXOS modelling was required. Additional key points include:

- The work has been based solely on the FY2028 period. Expanding the work to cover prior years was not warranted given the RSSR base case modelling showed those years did not have sufficient USE at or above the reliability standard. FY2028 is expected to cover the range of outcomes encompassing the FY2026 and FY2027 years.
  - The modelling methodology applied within the reliability framework differs from that used in the ESOO, primarily due to the inclusion of non-committed new entrants. This means that the 2022 RSSR modelling includes additional capacity beyond what was considered in the corresponding ESOO at the time of modelling. Additionally, the most recent ESOO release (August 2023) is based on an updated set of assumptions, which encompasses the list of committed generation and transmission projects.
- Leveraging the Base case sensitivity results which were used to calculate the MPC and CPT frontiers for NSW and VIC.[6] The consumer cost impacts, however, were based on re-profiled Base case results corresponding to a lower and upper bound of expected pricing outcomes over the Review Period.
- Expanding the consumer cost impact assessment to include all other NEM regions.
- Updating the price traces from the 2022 RSSR to reflect more recent, or more representative, levels of volatility and swap and cap prices.

Any references to the combination of MPC and CPT also encompass potential changes to the APC level.[7]

3.1 Modelling components

The key elements from the 2022 RSSR that were leveraged in this update is described in Table 6. Additional modelling tasks as part of Part C are discussed in Section 4.3.

Table 6 Relevant 2022 Reliability Standards and Settings Review components

Component	Description
Base case and Base case sensitivity (PLEXOS) outputs	The 2022 Reliability Standards and Settings Review considered three (3) scenarios, the Base case, Base case sensitivity and Low RE generation scenario.[8] Only the results from the Base case and Base case sensitivity were used in this work.

[6] Refer to Section 3.2.1 for details of the Base case and Base case sensitivity scenarios.
[7] The Market Floor Price is out of scope.
[8] Refer to Section 3.2.1 for details of the Base case and Base case sensitivity scenarios. The Low RE generation scenario was used to explore alternative USE distributions under sustained low-RE yield conditions.

Component	Description
Optimisation model	The MPC and CPT frontiers were derived using a custom-built optimisation model that minimised the total system cost by varying the MPC and CPT while ensuring cost recovery for the new entrant generator. [9] The same optimisation model was employed to generate alternative MPC and CPT combinations by considering different sensitivities of key parameters.
Wholesale cost model	The modelling of the wholesale component of consumer cost was based on half-hourly prices and the swap and cap combination that minimised the standard deviation of load cost outcomes. The consumer cost impact is solely focused on the wholesale component of the residential retail tariff.[10]

[9] Minor adjustments were made to explore the MPC/CPT frontier for discrete MPC levels.
[10] Any references to consumer cost impacts specifically relates to the impact on wholesale and unserved energy costs only.

3.2 Overview of modelling process

The modelling process involved two primary steps, as depicted in Figure 4 and summarised in Table 7. Refer to Section 3.4 for Task C requirements.

Table 7 Modelling process overview (Task A and B)

Modelling step	Overview
Task A: Solving the MPC/CPT for a given set of unserved energy distribution and cost assumptions	The objective was to update underlying assumptions likely to impact the MPC/CPT combinations and to determine a range of different MPC/CPT combinations based on various new entrant types, including small OCGT units for the NSW and VIC regions, and updates to other underlying assumptions such as cost of capital, demand response volumes and generator revenues.
Task B: Calculating the impact on consumer wholesale costs resulting from a change in MPC/CPT	The wholesale cost model evaluates the electricity wholesale and hedging cost increases that arise due to the proposed changes in MPC/CPT, considering a specific level of market risk. The key outputs of this step include contract settlement prices, underlying wholesale spot prices, and hedging costs associated with residential load shapes.

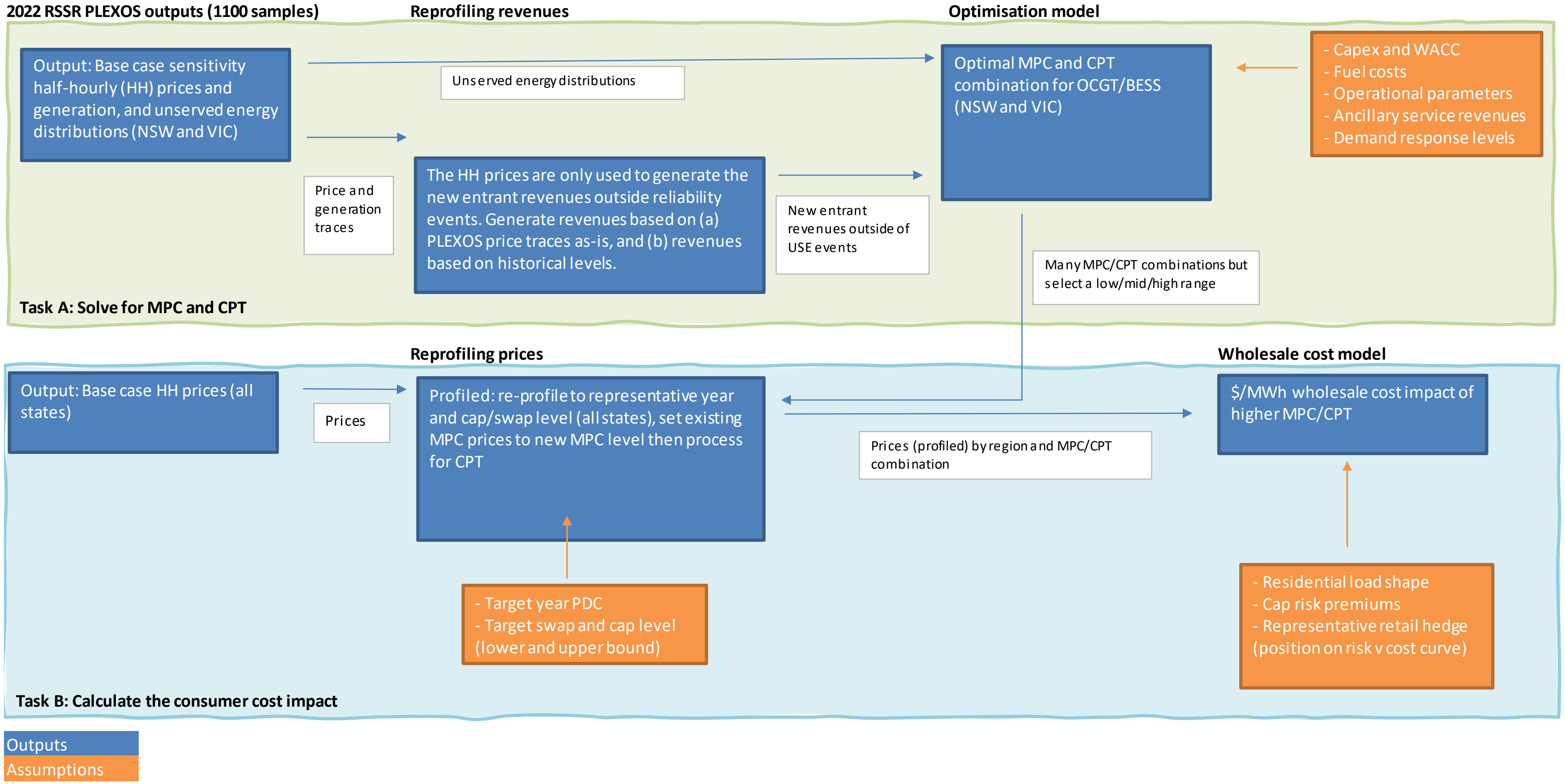
Table 8 Modelling elements, updates and outputs (Task A and B)

Step and objective	Description	Models/elements	Updates	Output
Task A: Solving the MPC/CPT for a given set of unserved energy distributions and cost assumptions.	The objective was to update underlying assumptions likely to impact the MPC/CPT combinations for each of the relevant new entrant plants.	- Base case sensitivity unserved energy outcomes - New entrant data: capex, WACC, non-reliability revenues, operational parameters, etc. - Optimisation model	Capital costs, weighted-average capital cost assumptions, also revenues outside reliability periods for the new entrant.[11]	Key outputs from this step are different sets of MPC/CPT combinations for the NSW and VIC regions.
Task B: Calculate the impact of changes to the MPC/CPT on consumer wholesale costs.	The assessment of consumer wholesale cost requires assumptions pertaining to the underlying prices which would be impacted by shifts in the MPC/CPT, consumer load shape and hedging arrangements. The price traces are fed into the wholesale cost model to determine, for a given level of retailer risk, the level and composition of hedges which in turn drives the overall	- Re-profiled Base case prices - Residential load shapes - Wholesale cost model	The Base case price traces from the previous 2022 RSSR modelling exhibit considerably lower levels of both energy prices and volatility compared to forward expectations. To address low volatility concerns, the prices are re-profiled to align with a representative PDC shape and market price level expectations.	Range of consumer cost increases/decreases based on a range of MPC/CPT combinations.

[11] Includes FCAS revenues for battery energy storage systems.

Step and objective	Description	Models/elements	Updates	Output
	wholesale cost component of residential tariffs.			

Figure 4 Modelling flows (Task A and B)



3.2.1 PLEXOS modelling dataset

The core market modelling conducted in the 2022 RSSR involved statistical simulations that incorporated detailed time-sequential modelling of the NEM's supply and demand dynamics. The 2022 RSSR modelling utilised the most up-to-date assumptions available as of March 2022.[12]

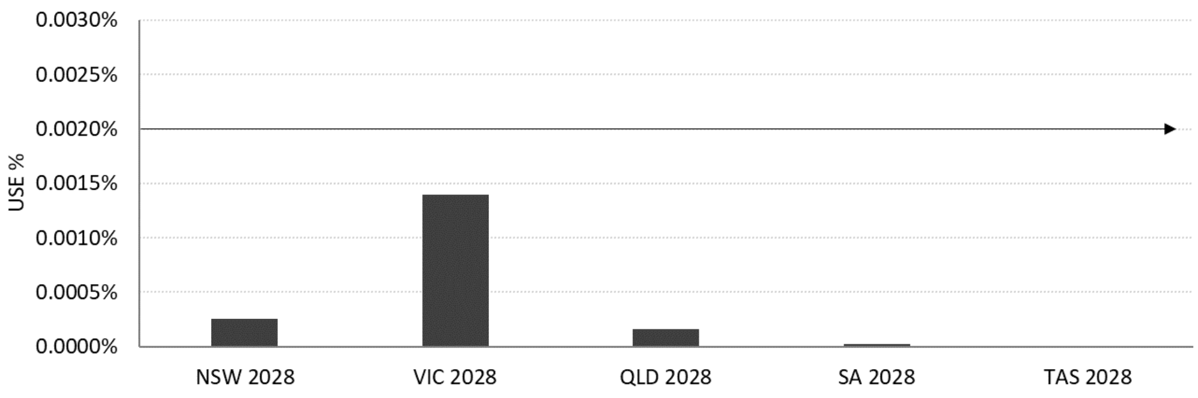
The underlying modelling encompassed various elements, including 30-minute interval modelling, regional demand, transmission considerations with intra-regional network constraints, seasonal generator ratings, the inclusion of variable generation from solar and wind power plants, jurisdictional policies related to RE, pricing and revenue outcomes, as well as the assessment of USE outcomes.

No additional PLEXOS modelling was carried out in this update. Instead, the analysis leveraged the modelling results from two key scenarios, described below.

- **Base case**: corresponds to the most likely reliability outlook. The modelling of this scenario found no region exhibited a reliability gap. The price traces, covering 550 samples of P10 and 550 samples of P50, were re-profiled and used to estimate the wholesale cost impacts.
- **Base case sensitivity**: A reliability gap was required to determine the optimal reliability settings. AEMO's Integrated System Plan (ISP) 2022, indicated a high probability of further coal retirements by 2030, and additional coal units were removed from NSW and VIC to create reliability gaps in 2028. Specifically, an additional 1.3 GW of coal capacity was removed from the base case in NSW, while 350 MW of coal capacity was removed from the base case in VIC. The price, generation and unserved energy traces were used to determine a range of reliability settings.

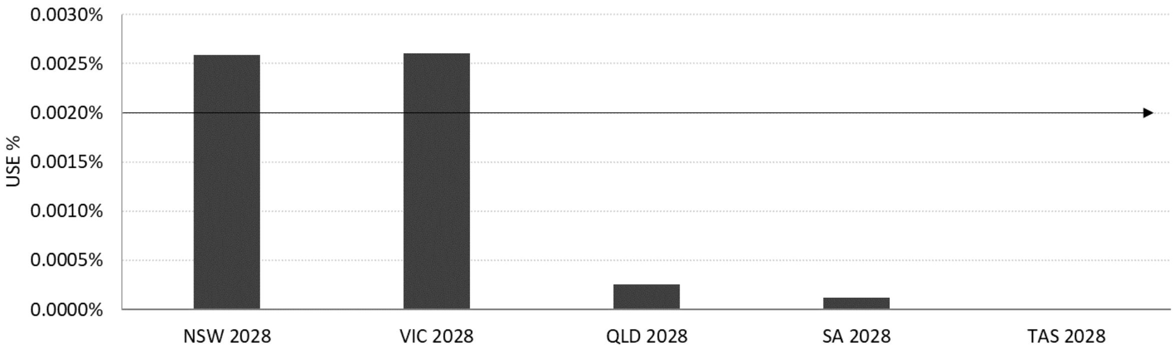
Details of how these results sets were used across the modelling components are discussed in Section 3.2.2 to 3.2.4. Figure 5 and Figure 6 plots the reliability outlook under the Base case and Base case sensitivity scenarios, respectively.

Figure 5 Base case USE outlook (weighted average)



[12] The updated analysis extends this work with further assumptions updates discussed in Section 3.3.

Figure 6 Base case sensitivity USE outlook (weighted average)



3.2.2 Optimisation model

The optimisation model processes unserved energy outcomes and solves for feasible combinations of the MPC and CPT for a particular new entrant type (or portfolio mix). Key features of the optimisation model are summarised in Table 9 below. The most important output from the optimisation model is the MPC/CPT frontier as shown in Figure 7.

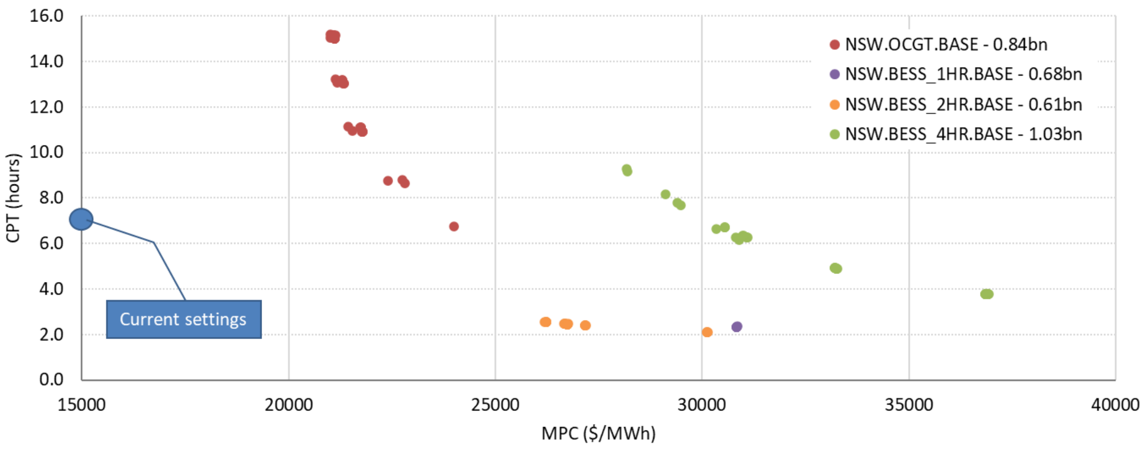
The optimisation model was updated to solve the minimum CPT for discrete MPC levels. This was to force the model to explicitly explore the MPC/CPT frontier rather than performing a grid search for the optimal combination of MPC/CPT based on the minimisation of the total region cost.

Table 9 Optimisation model features

Modelling stage	Key features
Optimisation model	Minimisation of the total region costs (wholesale energy and USE costs) subject to revenue adequacy constraints for the marginal new entrant.
	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, maintaining chronology for battery dispatch.
	Accounts for revenues outside of reliability events. The generation costs net of this revenue amount is the revenue level required from reliability events i.e., the MPC.

Relevant updates to the 2022 RSSR work include (1) MPC/CPT outcomes for different WACC levels because of a change in the risk profile of investment in the NEM, (2) updated capital costs as per the assumptions corresponding to the AEMO's draft 2023 IASR, (3) exploring the required MPC/CPT for a small OCGT plant[13], and (4) updates to forecast demand response volumes.

Figure 7 MPC and CPT combinations



** Example chart from the 2022 RSSR.*

3.2.3 Price re-profiling

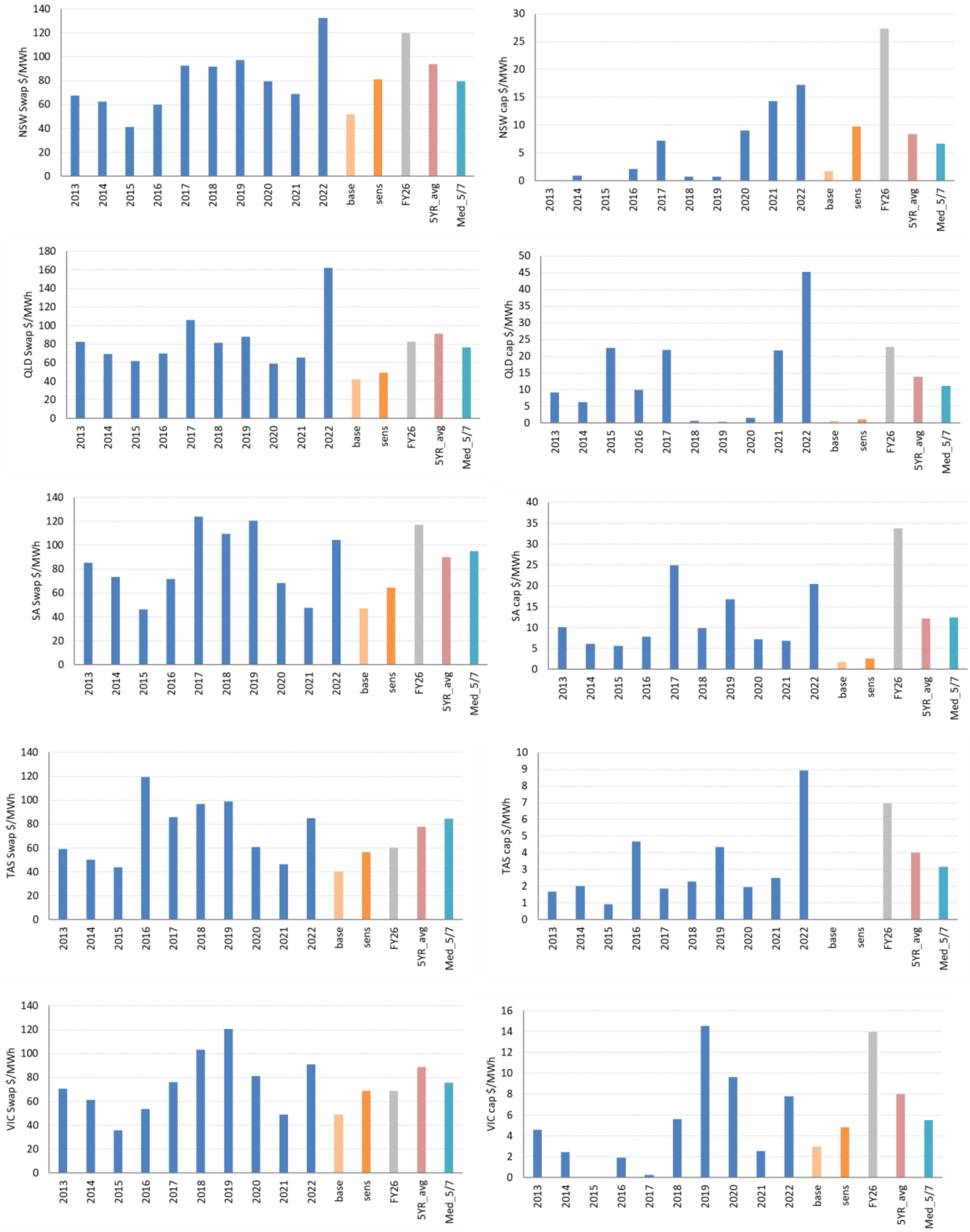
The previously modelled spot prices do not reflect price expectations associated with the latest developments in the NEM. Therefore, it was necessary to re-scale and calibrate the price traces before assessing the impact on consumer costs. To provide a comprehensive understanding of the price differences, historical prices including the 2018-2022 average, median 5 year from the last 7 (labelled 'med_5_7'), the FY2026 expectations as of May 2023, and the modelled PLEXOS prices from the 2022 RSSR for each of the regions are plotted in Figure 8. The re-profiling of prices reshapes the price duration curve (PDC) to ensure that both energy and cap settlement prices align with more representative levels.

There are three segments of the PDC that are under consideration: (1) prices at or near the MPC, (2) prices below the MPC but above $300/MWh, and (3) energy prices below $300/MWh. These segments are plotted in Figure 9, where the blue line represents the weighted-average PDC derived from the underlying P10 and P50 price traces.

The steps for re-profiling the prices are summarised in Table 10, taking into account the necessary adjustments to align the modelled prices to a target PDC shape (grey line), scaling of the prices to target cap and swap price levels (black line), followed by setting all prices within 5% of the current MPC to the higher MPC level and capping prices to APC under Administered Pricing Periods (APP).

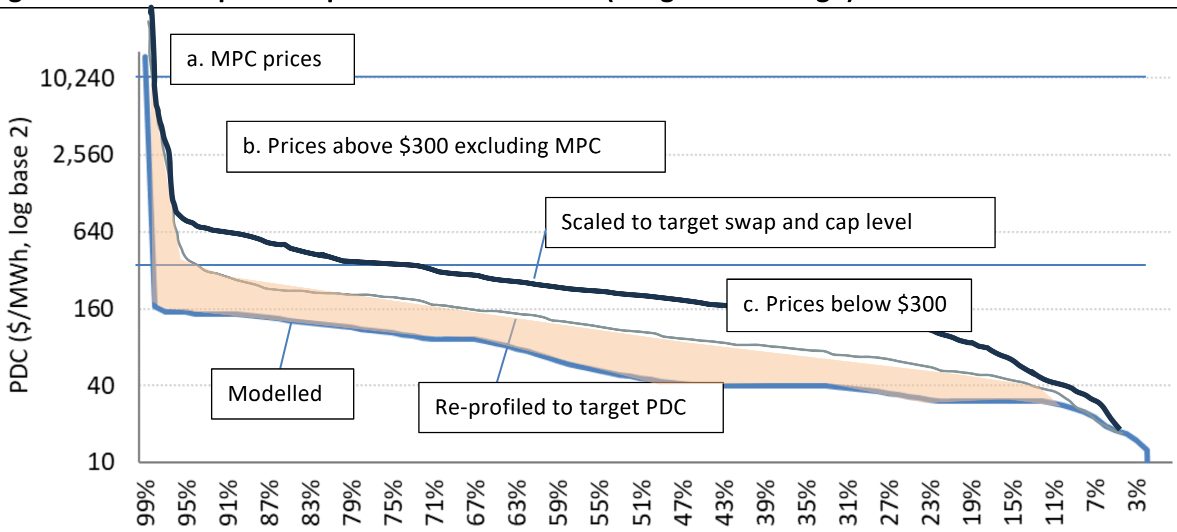
[13] Large OCGT was used previously.

Figure 8 Historical spot prices and PLEXOS price traces (June 2022 dollars)



Source: FY2026 baseload futures based on May 2023 settlement prices. TAS is based off historical 5-year TAS/VIC ratio. The 5-year average is based on FY2018-FY2022. Med_5/7 refers to the median 5 of the last 7 years (2016-2022).

Figure 9 Re-profiled price duration curves (weighted-average)



Note: the blue line represents the weighted-average PDC across all P50 and P10 price samples (1100 in total). The re-profiling process is applied to each of the underlying samples to achieve a desired PDC shape (grey line), then scaled to achieve the desired swap and cap price level (black line).

Table 10 Price re-profiling steps

Step	Description
1	Take the raw PLEXOS values (for each of the 1100 price samples) and convert each sample to a PDC and calculate the weighted-average PDC (average per ranked point). This corresponds to the blue line.
2	Select target PDC year and plot the PDC. This corresponds to the grey line.
3	For each point along the blue and grey PDCs, i.e., for the same ranked point in the weighted average PLEXOS PDC and the representative year PDC, calculate the $/MWh difference. This produces a 17,568 vector of differences (orange shaded area).
4	Take this vector and apply it to all underlying PLEXOS PDC samples except for prices already at or close to the existing MPC.[14] This effectively converts all the PLEXOS price samples to have a similar PDC shape as that of the target PDC. The same price rank within each sample is retained, for example, if the rank of the price at 23/01/2028 6pm was 11,523rd, this same interval would still be ranked 11,523rd after the adjustment.
6	On average the weighted-average PDC of the re-profiled PLEXOS PDCs will end up close to the shape of the grey line. However, the prices still need to be scaled to the desired swap and cap levels.[15]
7	To calibrate the prices to the desired energy and cap values: (a) energy prices (prices below $300/MWh) would be scaled linearly, and (b) iteratively add an exponential price function to the PDC until the cap value is achieved.[16] Prices are capped at the MPC and MFP.

[14] Values within 5% of the existing MPC are not adjusted.
[15] The target swap and cap levels are assumed to be based on the current MPC and CPT.
[16] Of the form: 150 * exp (-150 * x) * 10 * y, where x is the percentile of the PDC, and y is set to 1 for P50 samples but a higher multiple based on the raw PLEXOS P10/P50 cap settlement value ratio. The y variable attempts to retain the implied volatility from the raw modelled prices. Volatility in cap pricing outcomes is important when assessing consumer costs.

Step	Description
	Steps 1-6 targets the gradient of the target PDC, and step 7 to targets the overall energy and cap settlement levels.
8	Re-order the underlying PDC samples and convert all sample PDCs back to the original time-sequential order. The chronology mapping of prices is retained from an earlier step to be able to do this.
9	Set all prices close to or at the existing MPC to the new MPC then process the time-sequential prices for CPT and APC (not shown here). There will be a mismatch between the targeted energy and cap values and the final energy and cap values because of this but is required to assess the impact of changes to the MPC/CPT.
Output	Samples of half-hourly prices scaled to the desired MPC/CPT combination which feeds into the wholesale cost model. Swap and cap settlement values are calculated from these price traces (see Appendix C).

3.2.4 Wholesale cost model

The consumer cost impact was based on the same model developed as part of the 2022 RSSR to assess the overall wholesale cost increase relating to a change in the MPC and CPT.[17] The model simulates all combinations of annual swaps and caps and the corresponding overall load cost to produce the optimal hedging combination for a given level of risk.[18] The work has been expanded to cover VIC, SA, QLD and TAS.

There are several key assumptions to the modelling:

- In the 2022 RSSR, the region load was utilised as a representative shape of residential load, potentially resulting in understating the level of hedging and associated costs for higher MPC/CPT combinations. Residential load typically exhibits more pronounced load factors, and higher correlation to MPC events compared to the overall region load shape. An improvement to the approach was to convert the industrial energy component into a flat load and subtracted from the region load (see assumptions update in Section 3.3).[19]
- The wholesale costs are based on the hedging level corresponding to minimising the variance in cost outcomes for the standalone retailer.
- A high-level assumption was made regarding the risk premium associated with swap and cap contracts. The doubling of this assumption did not have a significant impact on the overall assessment of consumer costs during the 2022 RSSR. This assumption will be carried forward in the updated consumer cost assessment. [20]
- The 2022 RSSR modelling work was primarily based on the Base case sensitivity. The updated consumer cost assessment has been based on the re-profiled Base case prices. The re-profiling of prices implicitly assumes no demand or supply-side response.[21]

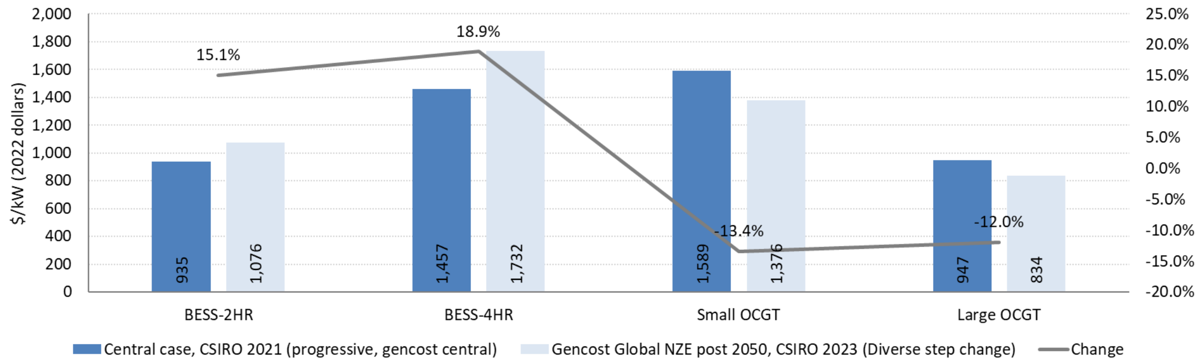
[17] Wholesale cost only includes the cost of energy and contract hedging costs.
[18] Refer to IES' modelling report for the 2022 RSSR for further details.
[19] Includes CSG load as defined by AEMO.
[20] Cap contracts and the cap component of the swap was assumed to have a 30% premium over the standard deviation of cap settlement value outcomes derived from the 1100 re-profiled pricing samples (weighted).
[21] This dynamic is covered in the counterfactual assessment, see Section 3.4.2.

3.3 Assumptions updates

The key assumption updates anticipated to drive the assessment of MPC/CPT and consumer cost impact is summarised below:

- Updated capital cost and WACC assumptions: show an increase in underlying build costs across 2- and 4-hour batteries, and reductions across small and large OCGTs. However, the central WACC assumption has been updated from the previous 5.5% to 7.0% (real, pre-tax).[22] The change in build cost and annualised capital costs (accounting for WACC) is plotted in Figure 10 and Figure 11, respectively. The overall impact to new entrant costs, reflecting potential changes to MPC/CPT, is expected to increase significantly for batteries but remain relatively constant for small and large OCGT.[23]
- Re-profiling of prices and revenues: will drive (a) a wider range of non-reliability revenues for the reliability new entrant in determining the MPC/CPT combinations, and (b) changes to wholesale costs in the consumer cost impact assessment.
- The MPC/CPT combinations for BESS also considers the level of FCAS revenues. This was previously based on FY2021 levels. FY2022 saw a significant lift in spot prices which also impacted FCAS revenue levels. The corresponding FCAS revenues standardised per MW is plotted in Figure 12. The updated modelling incorporates both FY2021 and FY2022 levels in the calculation of revenue percentiles as sensitivities. The energy and FCAS revenue categories have also been de-rated by 50% to account for availability.
- AEMO released initial demand response volume assumptions for FY2023 suggesting no change to the overall volume in NSW.[24]
- Adjusting the region load shape to more accurately reflect residential load shapes. This results in peakier consumption profiles leading to higher hedging requirements and associated costs in the consumer cost impact assessment. See Figure 13 for the change in FY2028 load factors.

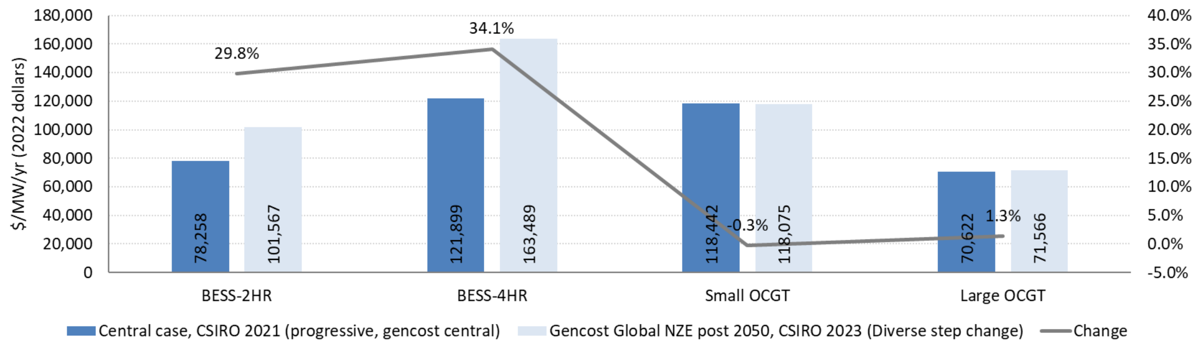
Figure 10 Build costs



[22] AEMO Draft 2023 IASR.
[23] The optimisation model needs to also account for changes to non-reliability revenues.
[24] Draft Demand Side Participation (DSP) forecasts, 31 May 2023, AEMO. IES took the FY2023 volumes and scaled this to FY2028 based on the implied growth rate in the 2022 RSSR work.

Note: location specific factors have not been included.

Figure 11 Annualised capital costs



Note: Based on a WACC of 7%. Location specific factors have not been included.

Figure 12 Historical FCAS revenues by year (BESS only)

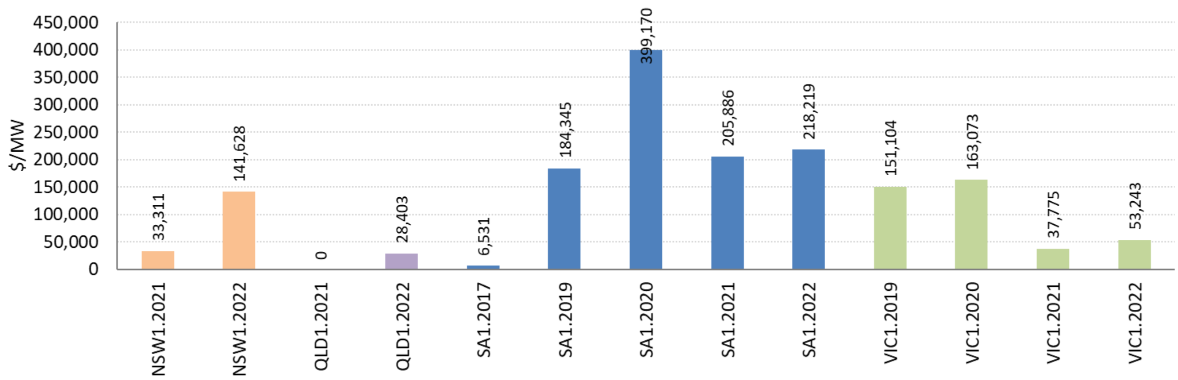
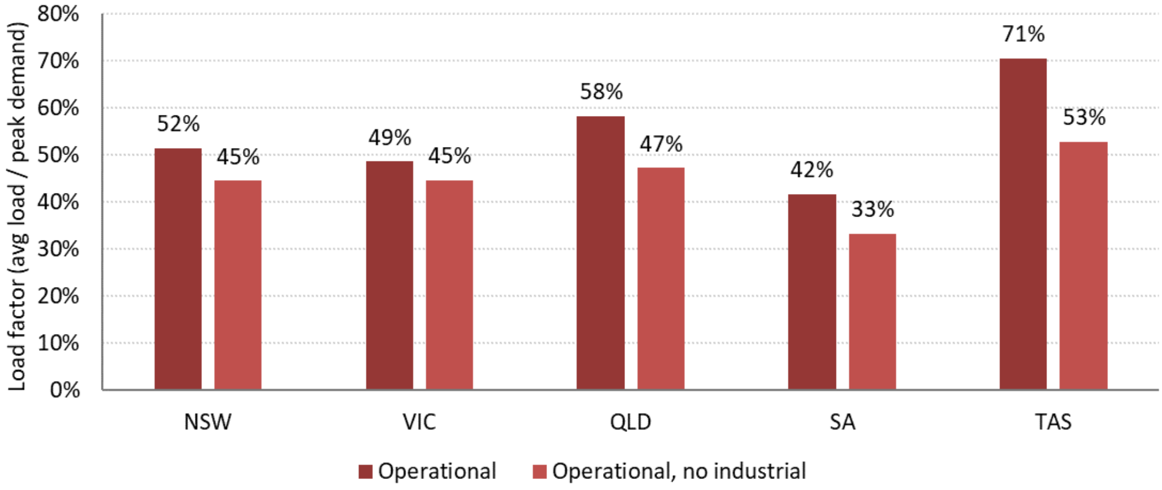


Figure 13 Regional load factors (industrial load removed)



3.4 Task C requirements

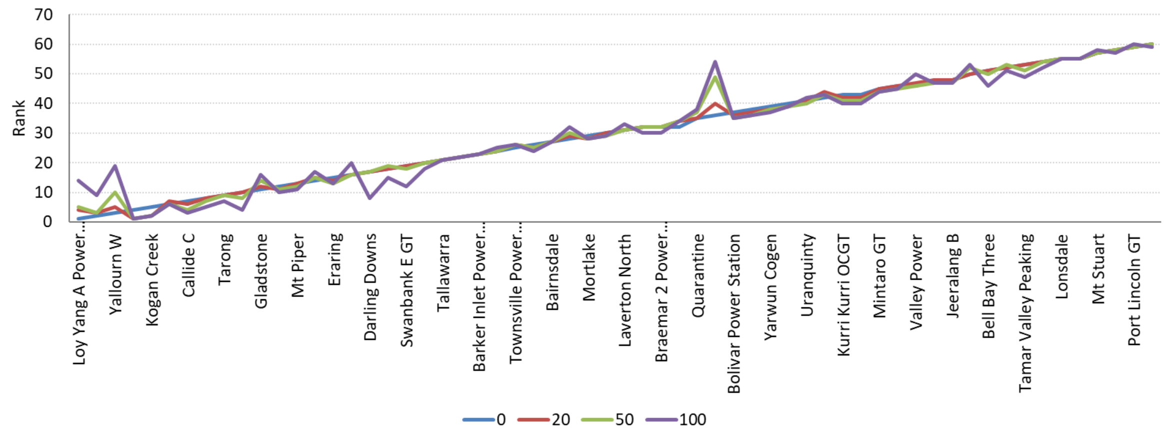
3.4.1 Carbon cost impact on the MPC/CPT

The NEM is anticipated to undergo a shift towards a low-carbon future which may feature the implementation of a carbon price during the Review Period. To assess the potential carbon cost impact on the MPC/CPT, two assumptions that contribute to the optimisation model were adjusted. These are discussed below:

- **[Costs]** Adding the carbon cost onto the SRMC of the reliability new entrant. However, it is expected to have a minimal impact on the overall assessment. Previous 2022 RSSR sensitivities conducted regarding higher fuel costs for OCGTs have shown negligible shifts to the MPC/CPT frontier.
- **[Revenues]** Inferring the uplift in the underlying energy prices which impacts the non-reliability revenues of the new entrant. To account for this change, a re-run of the PLEXOS modelling would technically be required. However, a simplified post-processing approach was adopted by embedding a carbon cost corresponding to the marginal generator in each region.
  - Under this approach, imports and exports would be ignored, and the highest cost generator running in each region would be identified. A carbon cost would be added to the region prices based on the carbon intensity of the highest cost generating unit and the assumed carbon price. The underlying merit order stack is assumed to remain unchanged for simplicity.
  - To validate the post-processing approach, or that the merit order remains unchanged, an analysis was conducted and is presented in Figure 14.[25] The analysis calculates the SRMC (including carbon cost levels) of various generating units and ranks them across the NEM. The results show minor shifts in the merit order stack up to $50/t, which support the feasibility of the approach.
- To determine the uplift in spot prices, generation outcomes are stacked based on ascending SRMC (without carbon) to identify the highest cost generation for every interval. A carbon uplift is applied based on the corresponding marginal generator's intensity multiplied by the carbon cost assumption. Figure 15, shows an example dispatch over a day by generation type. The marginal generator has been identified in the text box overlays. In hours 15-17 hydro is the marginal generator, however, the value of energy in resource constrained generators are assumed to reflect the marginal value of thermal generation and therefore the marginal generator is the next available thermal generator in the merit order (a gas unit in this case). The same applies in hours 18 and 19.

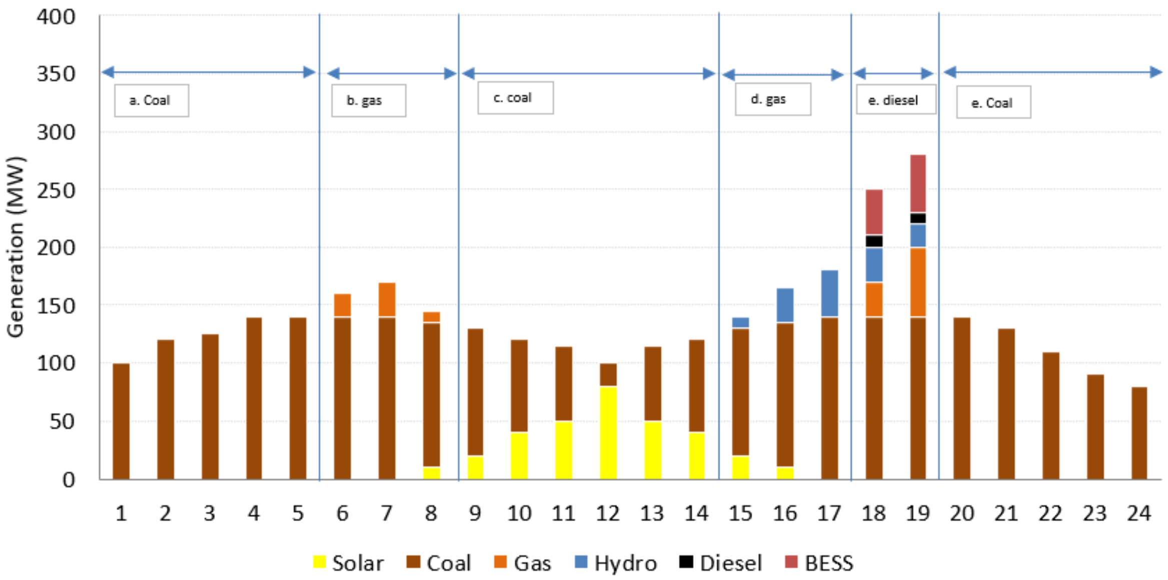
[25] Needs to also assume the capacity mix remains unchanged.

Figure 14 Relative SRMC ranking based on carbon cost sensitivity



Note: the main shifts in ranking relate to VIC brown coal, NSW/QLD black coal generators and peaking plants at $100/t.

Figure 15 Example dispatch profile and marginal thermal generator



Note: the boxes indicate what the marginal thermal generator is across an example day.

3.4.2 Counterfactual assessment

Increases to the MPC/CPT was previously shown in the 2022 RSSR to increase consumer costs. However, the analysis was implicitly conditional on the system/regional reliability already at 0.002% or that the reliability standard can be delivered under the current price settings. The counterfactual assessment updates the assessment to account for lower long-term reliability outcomes, i.e., USE levels remain above 0.002%, because of insufficient price settings and the associated cost of unserved energy for the consumer. Consumer costs based on the current level of the MPC/CPT (counterfactual case) is compared to equivalent outcomes based on higher MPC/CPT settings (sufficient settings case) when the underlying USE is above 0.002% and requires investment.

Several considerations were accounted for in the assessment:

- The comparison is based on a system with underlying USE above 0.002% before investment. The sufficient settings case will expectedly result in investment to bring the unserved energy back to the 0.002% level, whereas the counterfactual case may result in higher structural levels of unserved energy.
- The assessment of consumer costs includes direct costs expressed as changes to the wholesale component of the residential retail tariff. The counterfactual case where the MPC/CPT is retained at its current level would be expected to result in higher structural levels of unserved energy compared to the sufficient settings case where the MPC/CPT is sufficiently set to incentivise reliability new entrants. Therefore, a comprehensive assessment of consumer costs needs to expand its scope to include the cost of unserved energy, in addition to wholesale costs.
- The shape of the price duration curve is impacted by the overall levels of supply and the level of USE. However, the available modelling output from the 2022 RSSR is limited in the context of accurately projecting what energy prices may look like under varying levels of reliability. Given re-running PLEXOS is beyond the scope of this project, the approach needs to consider the relationship between new entrant capacity, levels of USE and spot prices.
- The reliability framework is focused on long-term outcomes and the MPC/CPT should be set to a level that incentivises investment over the long run. Annual reliability outcomes are, however, variable and the modelling uses a single year representative of the long-term USE level. Higher reliability states, where the expected long-term USE falls below 0.002%, has not been presented as that would require even higher price settings than what is currently being considered.

The approach leveraged the efficiency trade-off work from the 2022 RSSR (Table 11). The modelling outputs include price traces at various levels of NSW reliability and is restricted to the NSW region only. The findings, however, would be expected to apply to all other regions. The steps in carrying out the work involved the following:

1. Establish the equilibrium level of USE in the counterfactual case by assessing the new entrant revenues against costs. Then identify the corresponding amount of new entrant OCGT capacity required to reach this level.
2. Determine the amount of new entrant OCGT capacity required to meet the current reliability standard (0.002%).
3. Develop a price elasticity function to determine the set of price traces resulting from an increased level of new entrant OCGT capacity. The objective was to develop prices associated with the counterfactual equilibrium USE state, and the sufficient settings state corresponding to the 0.002% reliability level.

For each of the above points (summarised in Table 12), the consumer cost impact assessment also considered the level of USE in the system at each of these points to account for differing levels of USE and costs associated with the two cases. The results section (Section 4.3.2) provides additional details of this process.

Table 11 Efficiency of the reliability standard (2022 RSSR)

OCGT capacity (MW)	Reliability level (%, NSW)
800	0.0050
1100	0.0030
1400	0.0015
1700	0.0009

Table 12 Comparison of counterfactual and sufficient MPC cases

Reliability state before new entrant capacity investment	Counterfactual	Sufficient MPC
Above 0.002%	The equilibrium USE exceeds 0.002% because the MPC is too low to incentivise new entry. There is an equilibrium level of USE where underlying energy prices are high and the current MPC level does incentivise some level of new entry but would correspond to a structurally higher level of USE.	The equilibrium USE level is 0.002% because the MPC incentivises sufficient reliability new entrants.

3.4.3 Efficacy of higher price settings

The market design of the NEM relies on price signals to incentivise efficient investment in capacity to achieve the broader NEO. The MPC and CPT settings operate under the reliability framework with the objective of incentivising capacity investments to meet the reliability standard. This task involves addressing the broader question of the efficacy of higher MPC and CPT settings against the following factors in the context of historical and modelled outcomes, and current market arrangements.

- Importance of contracts in the context of capacity investment,
- Impact of higher spot prices on contract prices,
- Impact of increased volatility, and
- The implications for capacity investment.

Investment in this context refers to a pure commercial decision relying exclusively on market arrangements and without any external subsidy, or assistance from government policies. Other relevant factors such as policy uncertainty and concerns for government intervention are out of scope, and the assessment does not consider efficacy in the context of other market design arrangements or policy options.

4 Results overview

4.1 Task A: MPC/CPT frontier

This section presents the updated MPC/CPT frontiers for the OCGT (small and large) and BESS (2 and 4 hours) baseline scenarios, along with key sensitivities. These updates primarily reflect changes in build costs and the weighted average cost of capital, as outlined in Section 3.3. Important considerations for this section are as follows:

- MPC/CPT is based on the NSW new entrant, consistent with approach used in the 2022 RSSR modelling. However, the corresponding settings required for a VIC new entrant are notably higher and are not included in this report.[26]
- In the 2022 RSSR, the MPC/CPT that delivered the minimum region cost was determined to be based on a 2-hour battery with an MPC exceeding $25,000/MWh and CPT ranging between 2-3 hours. The region costs associated with the MPC/CPT combinations along the frontier are not provided in this report. This acknowledges the Panel's recommendation of setting the MPC corresponding to a CPT of 8.5 hours which considers other important out-of-model factors such as the duration of unserved energy events and incentivising a range new entrant types.
- For simplicity, the CPT is expressed in hours of the MPC, while the actual level is expressed in $/MWh terms.
- The assumptions of APC ($500/MWh) and MFP (-$1000/MWh) are fixed unless otherwise stated and are converted from nominal to real terms. The APC has no impact on MPC and CPT outcomes (see Section 0).
- The MPC/CPT frontier charts are truncated at $15,000/MWh and $45,000/MWh along the x-axis (MPC), and at 14 hours along the y-axis (CPT). For context, the NSW Value of Customer Reliability is $46,201/MWh in 2022 dollars.

4.1.1 Base scenarios

The base scenarios conducted encompass four different new entrant options, including small OCGT, with the weighted average cost of capital updated to 7.0% per annum (Table 13) and includes the previous MPC/CPT frontiers that underpinned the Panel's recommendation (in 2021 dollars). These scenarios also consider the inclusion of demand response (DR) where relevant. Table 13 also provides details on annual fixed costs, which include annualised capital costs and fixed operating and maintenance expenses (CAPEX), net revenues outside of reliability periods (REVS) and the net revenue amount to be recovered from the MPC (NET). The costs in the summarised scenario tables of Section 4 does not include variable costs or the cost of dispatching demand response.[27]

[26] This is consistent with the 2022 RSSR modelling work.
[27] Demand response is assumed to only be comprised of variable costs, dispatched at $15,000/MWh, $20,000/MWh and $25,000/MWh.

Figure 16 illustrates the MPC/CPT combinations for the base scenarios. However, it is observed that the required MPC levels for small OCGT and the updated BESS (2 and 4 hours) exceed $45,000/MWh due to high revenue recovery requirements.

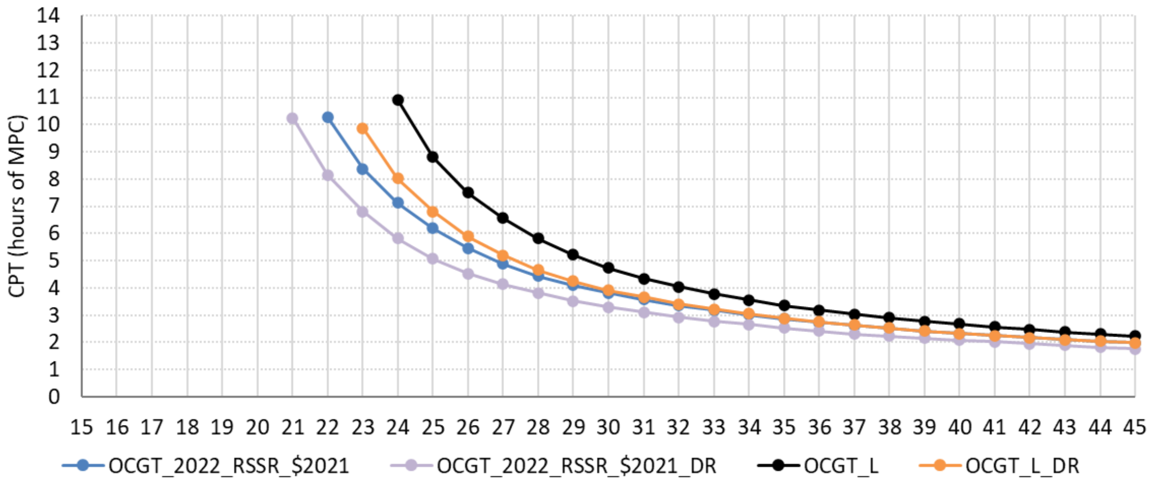
In determining the MPC/CPT combinations, the large OCGT remains the relevant new entrant type, and the Panel's previous recommendation of $21,500/MWh shifts to $23,500/MWh (roughly 10% higher) with the updated assumptions at the same CPT level of 8.5 hours.[28] The subsequent sub-sections in the report focus exclusively on the MPC/CPT combinations related to the large OCGT new entrant.

Table 13 MPC/CPT base scenario assumptions

CHART_LABEL	WACC	DR MW	CAPEX $/MW/YR	REVS $/MW/YR	NET $/MW/YR
OCGT_2022_RSSR_$2021	5.5%	0	86,733	43,573	43,161
OCGT_2022_RSSR_$2021_DR	5.5%	30.1	86,733	43,573	43,161
OCGT_L	7.0%	0	93,826	46,250	47,576
OCGT_L_DR	7.0%	30.1	93,826	46,250	47,576
OCGT_S	7.0%	0	145,724	46,250	99,474
BESS_2HR	7.0%	0	124,877	73,554	51,323
BESS_4HR	7.0%	0	196,911	98,620	98,291

** Non-reliability revenues (REV) are based on the 2022 RSSR assumptions. OCGT_2022_RSSR_$2021 refers to the scenarios which underpinned the Panel's recommendation (in 2021 dollars). The scenarios with DR results in less OCGT capacity to meet the reliability standard but would include additional dispatch/variable costs not shown in this table.*

Figure 16 MPC/CPT combinations - base scenarios (large OCGT)



Note: The chart is truncated across both axes. For comparison, the previous MPC/CPT frontiers that underpinned the Panel's recommendation (in 2021 dollars) are also presented.

[28] This includes an adjustment for CPI to 2022 dollars.

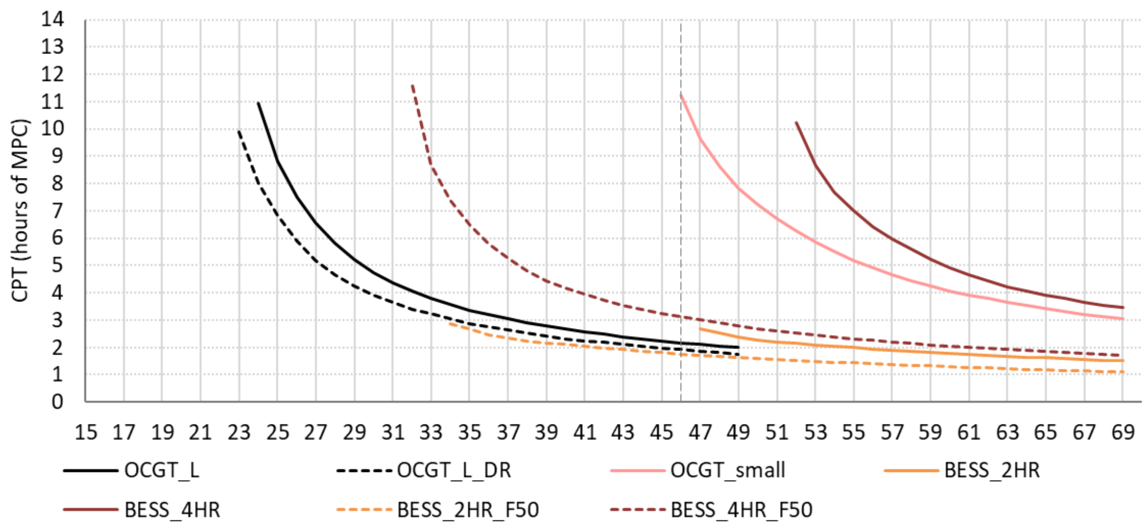
Table 14 Corresponding MPC at 8.5-hour CPT – base scenarios ($/MWh)

Revenue level	MPC ($/MWh)
OCGT_2022_RSSR_$2021	22,939
OCGT_2022_RSSR_$2021_DR	21,836
OCGT_L	25,239
OCGT_L_DR	23,747

Note: The Panel's recommendation for a $21,500/MWh MPC (2021 dollars) was based on the OCGT_2022_RSSR_$2021_DR case.

Figure 17 plots the frontiers for all the new entrant types covered and shows why large OCGT is the only relevant new entrant type to be considered. The BESS frontiers are positioned further to the right than in the 2022 RSSR modelling work and is primarily attributed to the significantly higher updated BESS capital expenditure assumptions. Additional sensitivities where FCAS revenues comprises 50% of capex (F50) has also been included.

Figure 17 MPC/CPT combinations (BESS and large OCGT)



Note: the vertical line represents the NSW VCR. Incurring the cost of USE would be a more efficient outcome than setting MPC/CPT to the right of this line but would not deliver the reliability standard.

4.1.2 New entrant revenues

The revenue earned by generators outside of reliability events plays a crucial role in determining the required MPC/CPT combinations to ensure revenue adequacy for reliability new entrants. Figure 18 presents the estimated OCGT net revenues based on historical cap settlement values.[29] It includes historical percentiles (indicated by the 'PC' label), the 2022 RSSR modelling revenue assumption, and the cost recovery line based on the base assumption of a 7% WACC. Figure 19 plots the revenue recovery requirement from the MPC during unserved energy periods.

[29] The cap component relating to unserved energy periods has been removed.

Figure 18 Estimated non-reliability revenues (large OCGT, NSW)

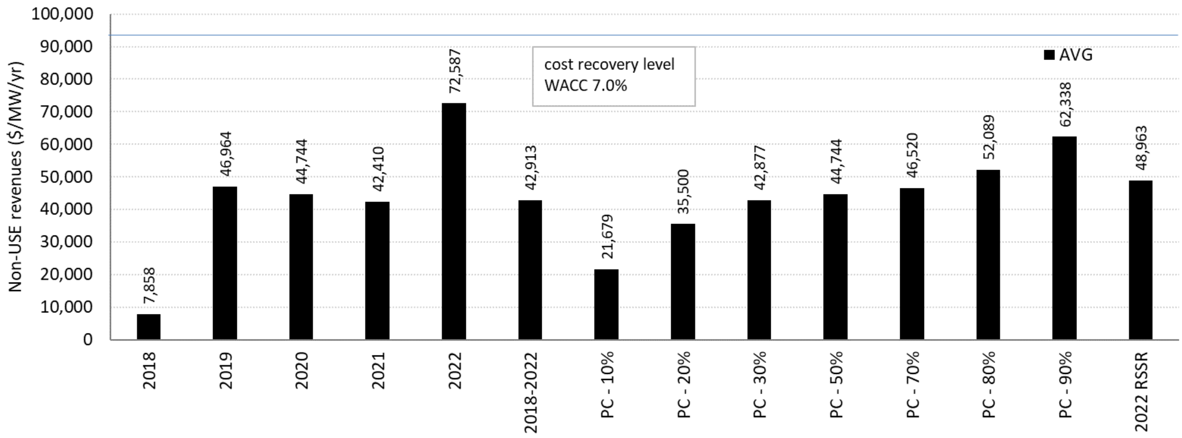
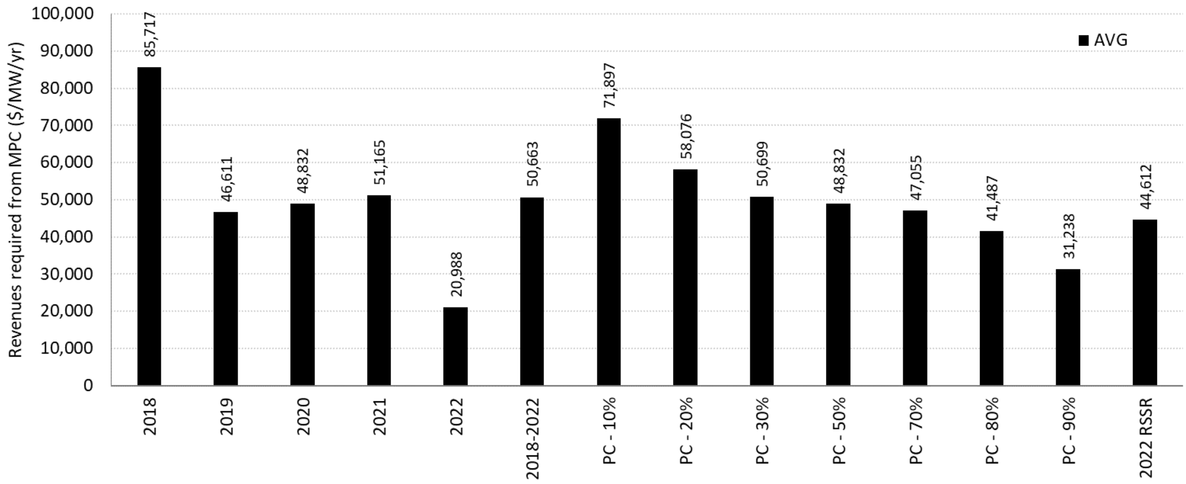


Figure 19 Revenue recovery requirements during reliability periods (large OCGT, NSW)



The large OCGT scenarios, with and without DR, based on various historical revenue percentiles are plotted in Figure 20 and Figure 21 respectively. At a CPT of 8.5 hours, the range of MPC levels for the large OCGT range from $22,000/MWh to $31,000/MWh and reduces by up to $2,000/MWh when DR is included (Table 15).

Figure 20 MPC/CPT combinations (large OCGT and revenue sensitivities)

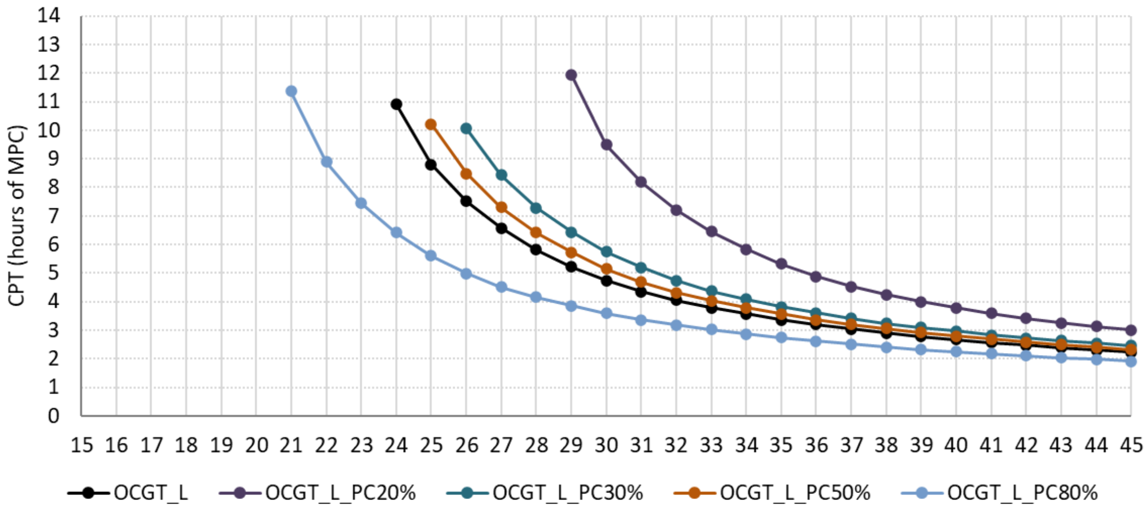


Figure 21 MPC/CPT combinations (large OCGT with DR and revenue sensitivities)

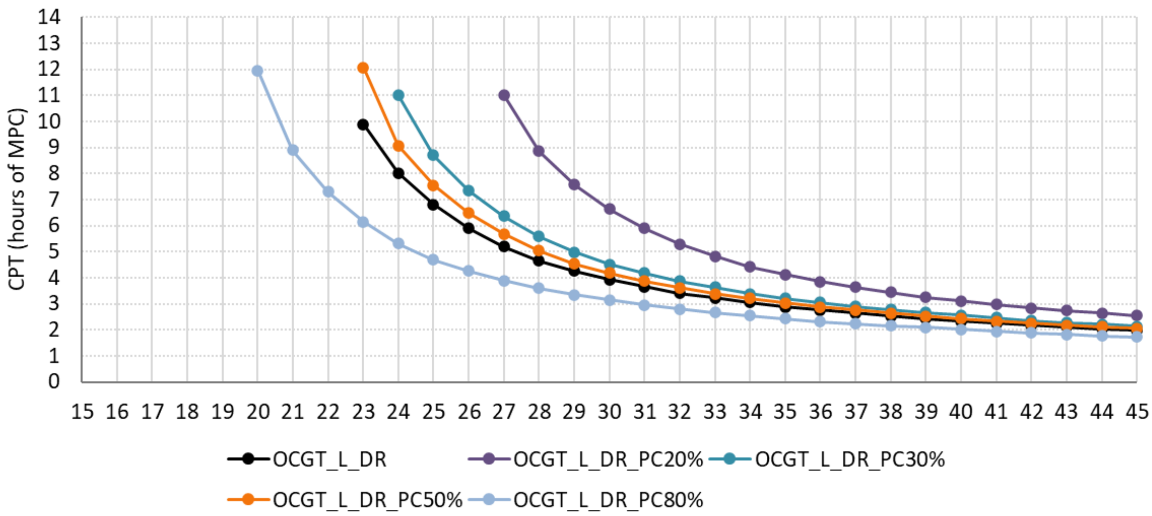


Table 15 Corresponding MPC at 8.5-hour CPT – revenue sensitivities ($/MWh)

Revenue level	OCGT_L	OCGT_L_DR
PC20%	30,755	28,280
PC30%	26,955	25,146
PC50%	25,991	24,379
2022 RSSR revenue assumption	25,239	**23,747**
PC80%	22,267	21,247

Note: All the figures in this table are based on updated cost and revenue assumptions.

4.1.3 Weighted average cost of capital

Table 16 provides a summary of the WACC sensitivities for the large OCGT using updated assumptions, both with and without demand response. The frontiers resulting from these WACC sensitivities are illustrated in Figure 22 and Figure 23. Notably, a reduction in the required MPC to approximately $17,500/MWh is observed when assuming a WACC of 5%. The inclusion of demand response has an impact on the MPC but is less pronounced at lower levels of MPC. This effect can be attributed to the distribution of demand response volumes across offer prices of $15,000/MWh, $20,000/MWh, and $25,000/MWh. The range of MPC levels at an 8.5-hour CPT is summarised in Table 17.

Table 16 MPC/CPT – WACC sensitivities

CHART_LABEL	WACC	DR MW	CAPEX $/MW/YR	REVS $/MW/YR	NET $/MW/YR
OCGT_L	7.0%	0	93,826	46,250	47,576
OCGT_L_WACC5.0%	5.0%	0	79,487	46,250	33,237
OCGT_L_WACC5.5%	5.5%	0	82,958	46,250	36,708
OCGT_L_WACC6.0%	6.0%	0	86,507	46,250	40,257
OCGT_L_DR	7.0%	30.1	93,826	46,250	47,576
OCGT_L_WACC5.0%_DR	5.0%	30.1	79,487	46,250	33,237
OCGT_L_WACC5.5%_DR	5.5%	30.1	82,958	46,250	36,708
OCGT_L_WACC6.0%_DR	6.0%	30.1	86,507	46,250	40,257

Note: The DR equivalent cases have the same unitised fixed costs as the non-DR cases, but would have additional variables costs associated with dispatching DR.

Figure 22 MPC/CPT combinations (large OCGT and WACC sensitivities)

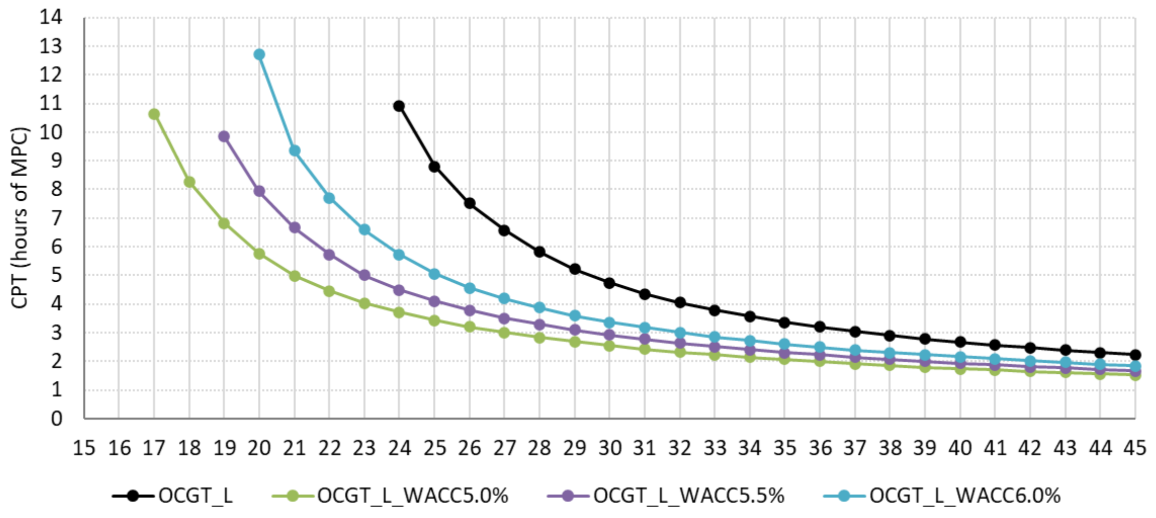


Figure 23 MPC/CPT combinations (large OCGT with DR and WACC sensitivities)

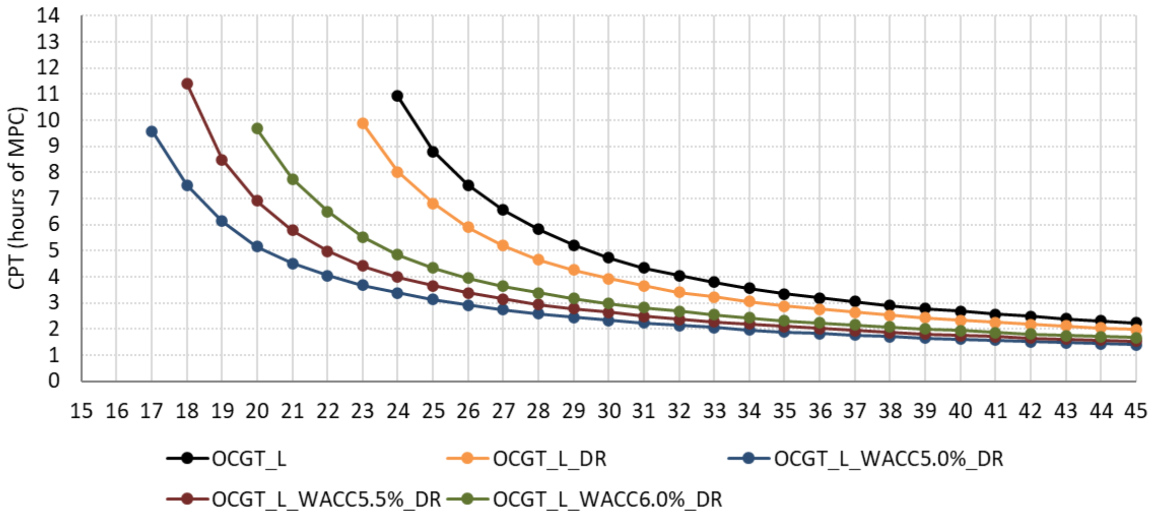


Table 17 Corresponding MPC at 8.5-hour CPT – WACC sensitivities ($/MWh)

WACC	NO DR	WITH DR
5.0%	17,905	17,522
5.5%	19,702	18,997
6.0%	21,518	20,612
7.0%	25,239	**23,747**

Note: The Panel recommendation was based on the large OCGT with DR at 5.5% WACC but falls to $18,997/MWh with the updated (lower) build costs. The reduction in build cost is entirely offset by the updated higher central WACC assumption of 7%.

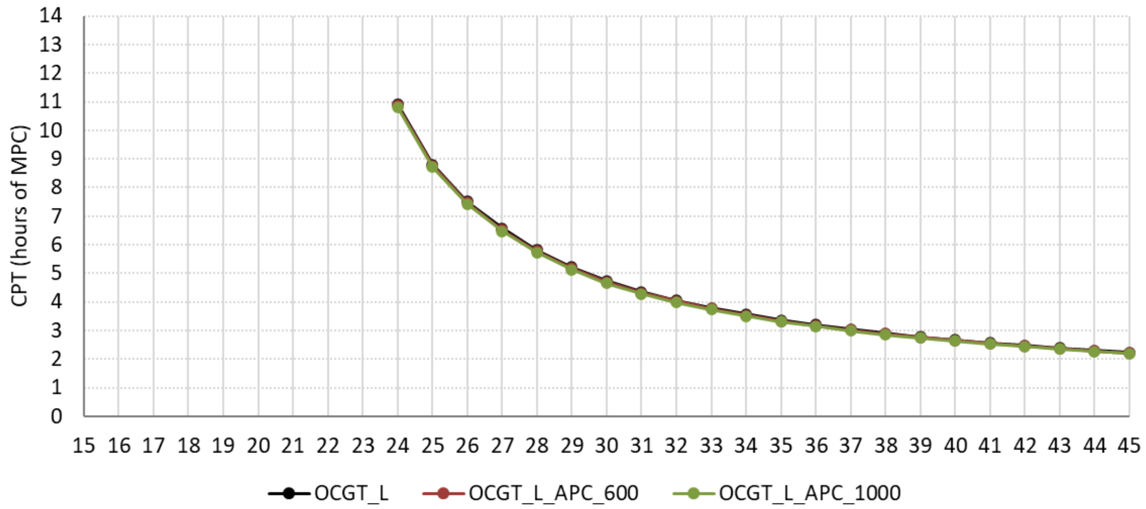
4.1.4 APC levels

MPC/CPT impacts from a change in APC levels is consistent with the 2022 RSSR modelling work and shows a negligible difference. Under high MPC and low CPT combinations where the APC is most relevant, the revenue derived from APP constitutes less than 2.5% of total revenues recovered from reliability periods. Information of the APC sensitivities modelled can be found in Table 18, while Figure 24 plots the MPC/CPT frontiers.

Table 18 MPC/CPT – APC sensitivities

CHART_LABEL	WACC	APC $/MWh	CAPEX $/MW/YR	REVS $/MW/YR	NET $/MW/YR
OCGT_L	7.0%	500	93,826	46,250	47,576
OCGT_L_APC_600	7.0%	600	93,826	46,250	47,576
OCGT_L_APC_1000	7.0%	1000	93,826	46,250	47,576

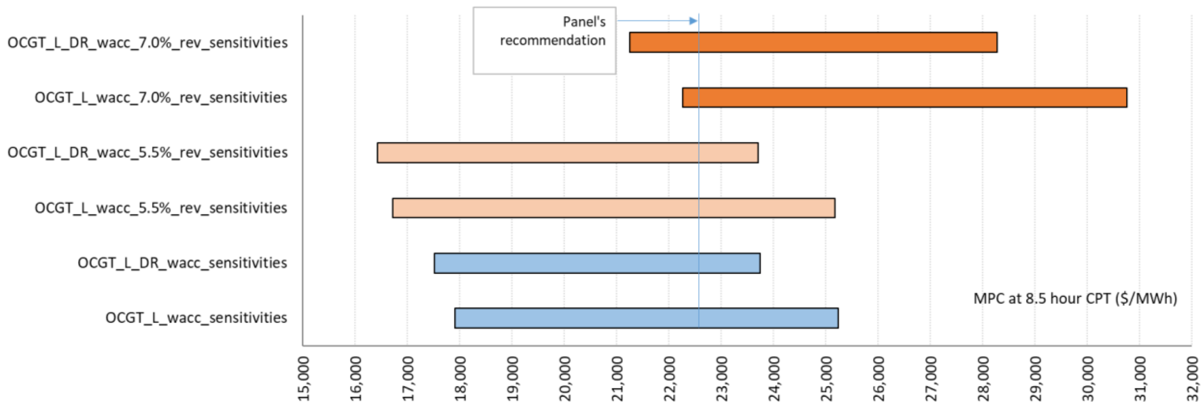
Figure 24 MPC/CPT combinations (APC sensitivities)



4.1.5 MPC/CPT summary

The range of MPC/CPT outcomes varies significantly depending on the input assumptions used. Figure 25 presents an overview of the range of MPC levels associated with a CPT of 8.5 hours for the different sensitivities assessed. The Panel's recommendation, when adjusted to 2022 dollars, falls within the scope of the considered ranges.

Figure 25 MPC/CPT range summary



Note: the revenue sensitivities are based on the historical 20th to 80th percentiles.

4.2 Task B: Consumer cost assessment

Re-profiled prices based on the last 5-year and median 5 of last 7-year average price levels for each of the regions to MPC levels of $22,000/MWh and $25,000/MWh were used to assess consumer cost impacts.[30] These costs were then compared to outcomes based on the existing settings.

Figure 33 illustrates the NSW frontier that represents cost outcomes linked to optimal hedging arrangements for a specific level of risk (standard deviation) under the current MPC and CPT settings and higher price settings. This approach facilitates standardised cost comparisons accounting for risk.

For retailers that are entirely exposed to spot prices, the average cost and standard deviation of cost outcomes increase, as highlighted in grey. On the other hand, outcomes for a risk-averse retailer, which hedges the load to minimise cost variations, as shown in green, also experience cost increases, but the increase in risk is managed. The overall cost impact is primarily driven by the rise in spot costs borne by all retailers. Additionally, the risk-averse retailer incurs increased costs related to the rise in contract risk premiums due to the added price volatility from a higher MPC. For retailers with varying risk profiles and optimal hedging strategies, their costs would fall between these two bounds, depending on their specific risk exposure and hedging practices.

Figure 27 provides a summary of the wholesale cost impact relative to current settings, focusing on the outcomes for a risk-averse retailer. Key findings include:

- The most significant impact is in QLD, with cost increases ranging from $7.8/MWh to $13.4/MWh (8-11%) across both median 5 of 7-year and 5-year average pool conditions. NSW and VIC would experience increases of $4.8/MWh to $8.0/MWh (5-8%), while SA would see increases between $8.6/MWh to $10.4/MWh (7-8%). TAS, on the other hand, would be relatively unaffected, experiencing an increase of less than 1%.
- These outcomes are heavily influenced by spot price volatility and prices that are close to the MPC in the underlying pricing samples. The overall cost increase aligns relatively well with the findings from the 2022 RSSR work, which focused on NSW and reported an increase of $7.5/MWh or 8%.[31]
- Raising the MPC and CPT will lead to higher pool volatility and increased costs, which all retailers will face, regardless of their hedging strategies. However, hedged retailers will also incur additional contract risk premiums, with the magnitude of this cost being higher for more risk-averse retailers. For example, shifting from current settings to a $25,000/MWh MPC and 8.5-hour CPT, consistent with 5-year average pool conditions, would result in an average cost increase of $9.9/MWh across NSW/QLD/VIC/SA.[32] This increase comprises an uplift of $7.3/MWh in energy costs and $2.6/MWh relating to additional contract premiums. Additionally, there are increased risks for the risk-averse retailer.

[30] See Appendix C for further details
[31] Based on $22,800/MWh and 8.5-hour CPT (converted to 2022 dollars).
[32] Simple average.

- As a sensitivity, doubling the assumed risk premium assumption would lead to a further average cost increase of \$2.4/MWh or 1.6% across NSW/QLD/VIC/SA.

In summary, the proposed changes in MPC and CPT settings would have varying impacts on wholesale costs across regions, with QLD being the most affected. Risk-averse retailers would face additional costs related to higher contract risk premiums; however, the risk can be managed and the overall cost increase would depend on the specific price conditions and risk profile of each retailer.

Figure 26 Frontier under different pool conditions and MPC/CPT combinations (NSW)

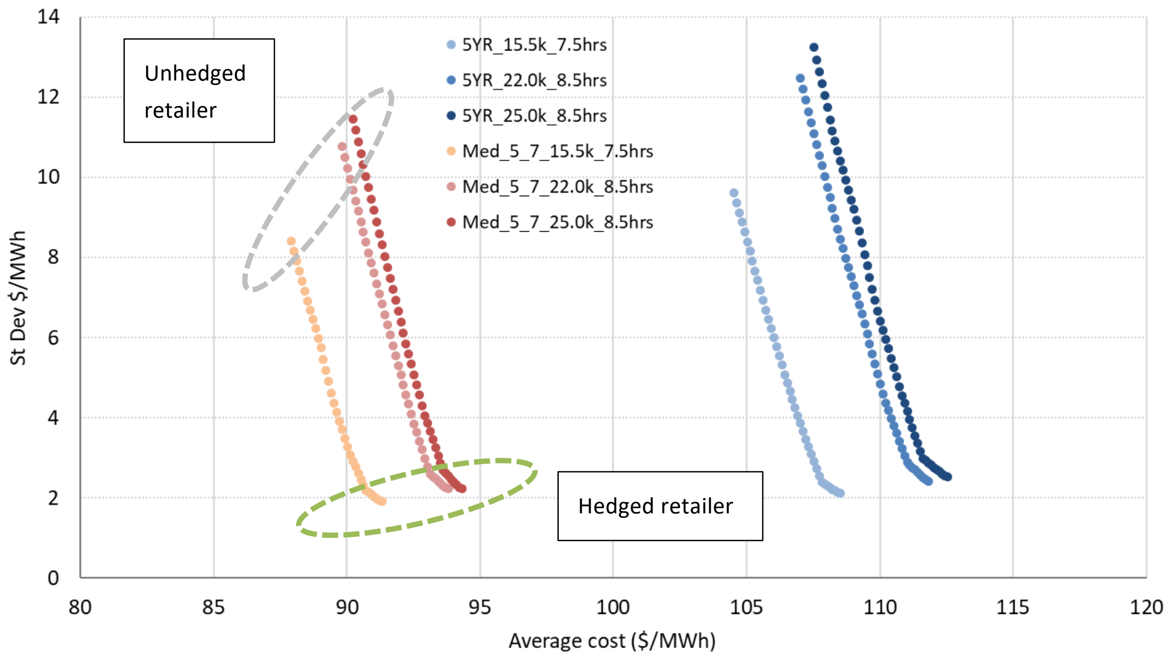
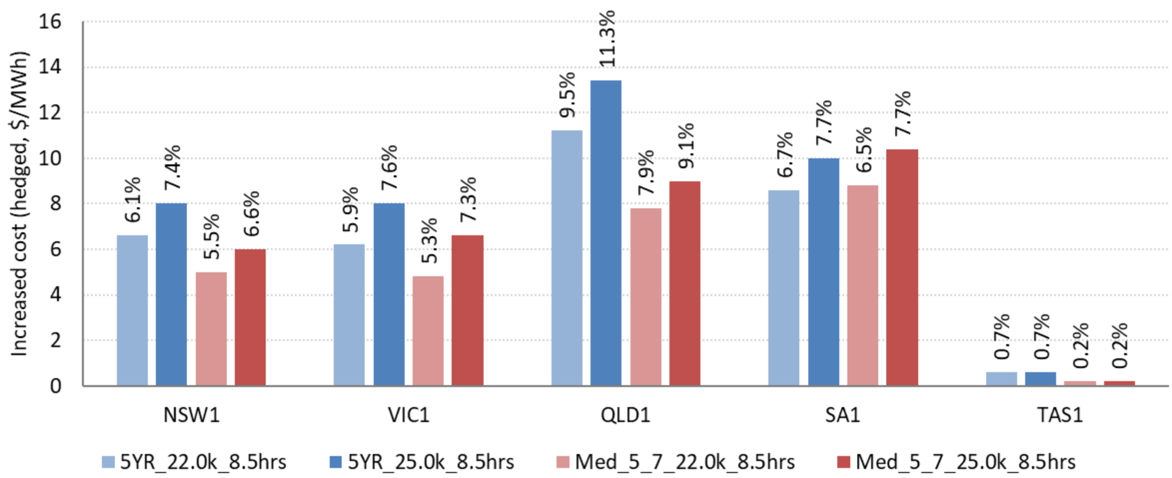


Figure 27 Increased consumer costs relative to current settings



4.3 Task C: Various

4.3.1 Carbon cost impact on MPC/CPT

Table 19 presents the simulated outcomes for a large OCGT under two carbon scenarios: $20/t and $50/t. It is essential to note that the new entrant OCGT plant would only experience additional pool revenues if a higher carbon-intensity plant, located higher up in the merit order, is setting the electricity price. Consequently, the extent of the additional net revenues from a carbon impost is contingent upon two factors: (a) the relative carbon intensity of the large OCGT and higher SRMC plants, and (b) the number (or total capacity) of SRMC plants and the frequency at which they set the electricity price.

Figure 28 and Figure 29 plots the relevant metrics for NSW and VIC, respectively, and the blue line corresponds to the large OCGT carbon intensity. The charts show that new entrant OCGTs in VIC have more opportunities to earn additional revenue compared to those in NSW. The corresponding incremental net revenues are illustrated in Figure 30. VIC shows more revenue-earning potential for new entrant OCGTs, particularly under the $50/t carbon scenario, while the impact in NSW is comparatively modest.

Table 19 Carbon cost sensitivity summary

Metric	Units	NSW1	VIC1	AVERAGE
Net Revenues, Base sens	$000	128.28	83.07	105.68
Net Revenues, Base sens + $20/t carbon	$000	128.44	84.39	106.41
Net Revenues, Base sens + $50/t carbon	$000	128.68	95.44	112.06
SRMC, Base sens	$/MWh	170.53	131.44	150.99
SRMC, Base sens + $20/t carbon	$/MWh	182.15	143.06	162.60
SRMC, Base sens + $50/t carbon	$/MWh	199.58	160.49	180.03
Incremental net revenues ($20/t)	$000	0.16	1.31	0.74
Incremental net revenues ($50/t)	$000	0.40	12.36	6.38

Figure 28 Carbon intensity against SRMC (NSW, thermal plants)

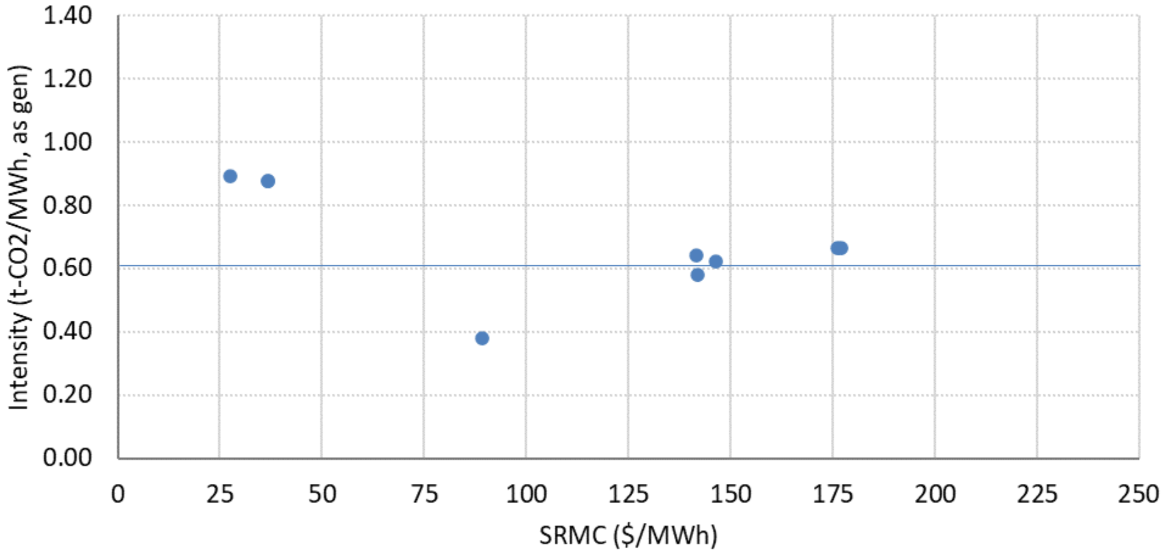


Figure 29 Carbon intensity against SRMC (VIC, thermal plants)

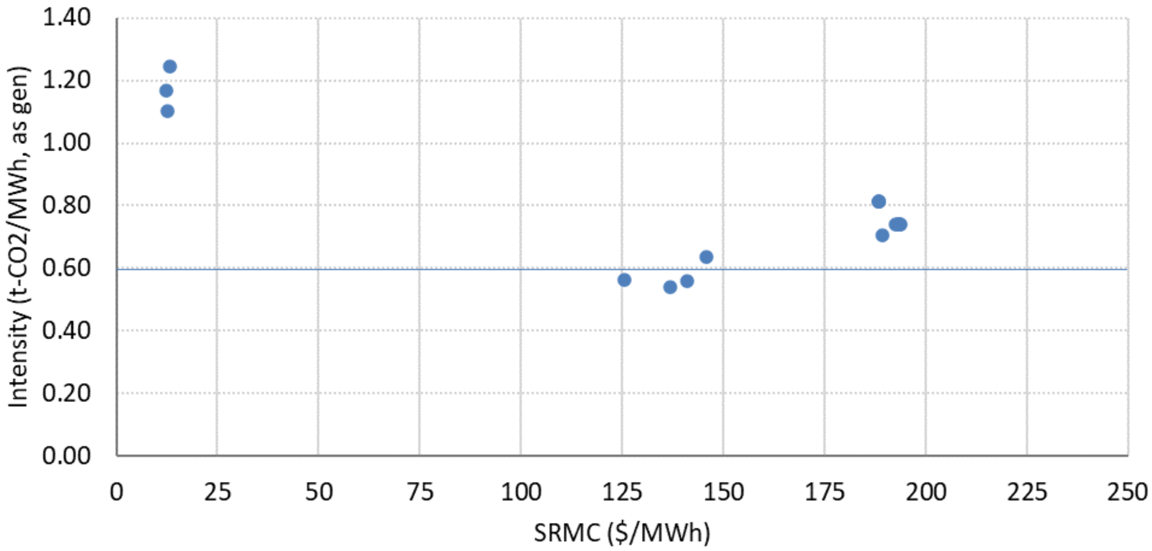
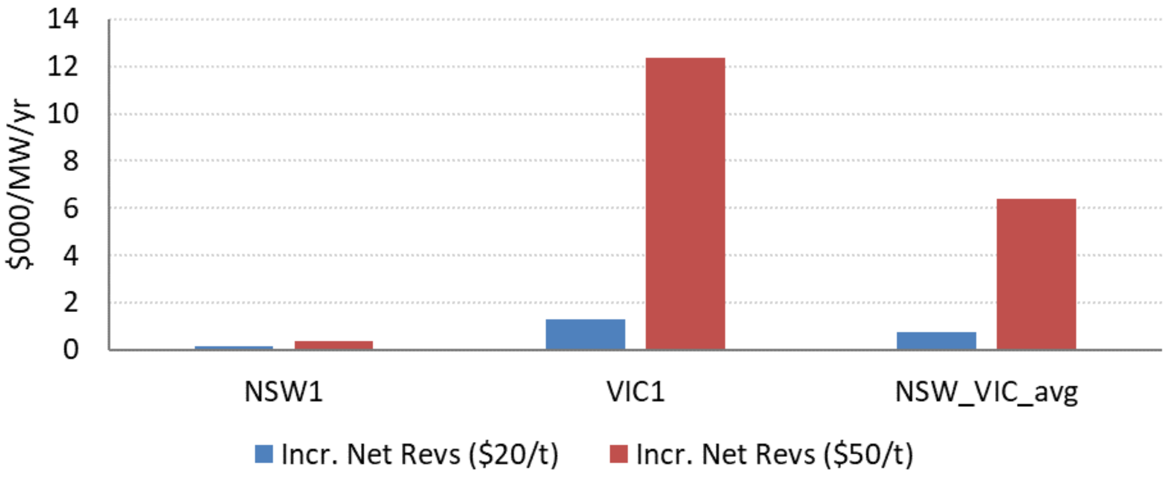


Figure 30 Carbon cost impact on net revenues (large OCGT)



The analysis above considered standalone regions; however, the dispatch dynamics of NSW can and is frequently influenced by VIC. Due to this interdependence, the impact of additional revenues accruing to the NSW OCGT has been based on the average of both NSW and VIC ($6,380/MW/year under the $50/t scenario). This increase in net revenues leads to a reduction in the MPC at 8.5 hours by approximately $3,500/MWh (Table 20).

Table 20 MPC/CPT base scenario with and without carbon ($/MWh)

Revenue level	WACC5.5%	WACC7.0%	WACC 5.5% with DR	WACC 7.0% with DR
PC20%	25,172	30,755	23,702	28,280
PC80%	16,725	22,267	16,431	21,247
PC20%_C50	21,910	27,498	20,935	25,602
PC80%_C50	Below 15,000	18,970	Below 15,000	18,472

Note: C50 = $50/t carbon cost assumption.

4.3.2 Counterfactual assessment

The counterfactual assessment leverages the 2022 RSSR modelling effort and encompasses several steps to effectively compare (a) the counterfactual case based on the current settings, and (b) the sufficient settings case based on a $25,000/MWh MPC and 8.5-hour CPT.[33] The process and outcomes of this comparison are summarised in Table 21. The analysis interpolates between points and is based on a polynomial of order 2, however, for simplicity the interpolation has been presented as a linear relationship in the charts below.

[33] Higher bound of the range of MPC/CPT combinations.

Table 21 Counterfactual assessment steps and outcomes

Process	Description	Method and outcome
1. [Counterfactual] Identify the equilibrium amount of unserved energy and additional new entrant OCGT capacity for an unreliable system before capacity investment (0.005%).	An unreliable system is likely to exhibit high spot prices and spot volatility due to capacity shortfalls. Even with an insufficient MPC to drive reliability down to 0.002%, there is likely some capacity that is still incentivised to enter because of the high underlying prices corresponding to a higher structural level of USE.	Figure 31 plots the gross revenue levels for different levels of OCGT capacity investment corresponding to a reliability level. The equilibrium level of investment is where the OCGT is revenue neutral, i.e., where revenues meet its fixed costs of \$93,000/MW/year as indicated in Figure 32. The total OCGT capacity corresponding to this point is 935 MW which delivers long-term reliability of approximately 0.004%.
2. [Sufficient settings] For the same unreliable system (0.005%), identify the amount of OCGT capacity required to meet the reliability standard.	An unreliable system with sufficiently high settings will result in higher levels of new entrant (OCGT) investment which results in reliability brought back to the level of the reliability standard (0.002%).	It can be inferred from Figure 32, that the required OCGT capacity corresponding to a long-term reliability of 0.002% is 1287 MW. The points from steps 1 to 2 are shown in Figure 34.
3. Generate price samples consistent with steps (1) and (2).	Prices corresponding to (1) and (2) are required to feed into the wholesale cost model to carry out the counterfactual comparison. However, only pricing outputs from the 2022 RSSR modelling corresponding to the OCGT 800/1100/1400 MW points is available.	The annual cap settlement prices are inferred for the reliability points of interest (0.004% and 0.002%) from Figure 33 which plots the cap values against reliability levels. A simple price elasticity function based on the incremental OCGT capacity, targeting the annual cap values is used to calibrate the price samples from the 2022 RSSR modelling.[34] The prices for the sufficient settings cases requires an additional step – prices close to the existing MPC are set to the higher MPC level and capped for CPT.

[34] Prices are only reduced/adjusted if (i) prices are greater than the OCGT SRMC, and (ii) if the incremental OCGT MW (derated for average availability) reduces USE to zero, otherwise it stays at MPC.

Process	Description	Method and outcome
		The pricing outcomes for the 0.004% and 0.002% reliability points are plotted in Figure 35 and shows: - 935 MW of OCGT capacity (0.004%) results in higher swap and cap prices than pool conditions corresponding to 1287 MW of OCGT capacity (0.002%) with an MPC at \$25,000/MWh. - The target cap value for the 1287 MW OCGT point was \$7.6/MWh (Figure 33) but was scaled to a higher MPC of \$25,000/MWh which lifted the cap price to \$10.3/MWh.
4. Run wholesale cost model using the price samples corresponding to the data points above	The inputs are fed into the wholesale cost model to compare the counterfactual and sufficient settings costs for a typical residential customer. The cost needs to also consider the additional USE in each of the cases.	The wholesale costs associated with the counterfactual and sufficient settings for an unreliable and reliable system is summarised in Figure 36. There is an additional USE component that has been included and is based on the expected USE volume x cost of USE (priced at the Value of Customer Reliability) spread across the total residential load.

Figure 31 Inferring the equilibrium level of USE (counterfactual case)

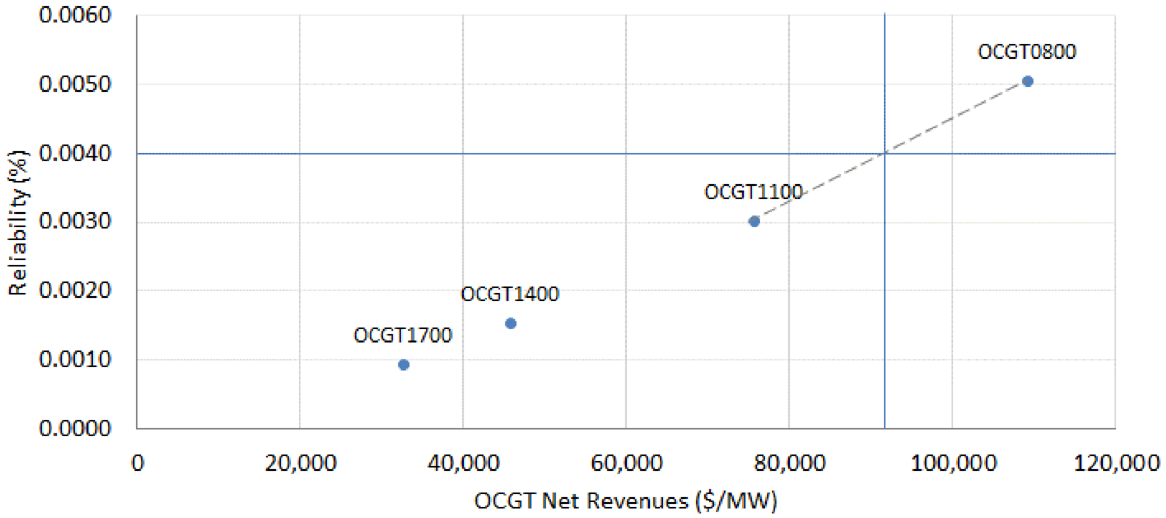


Figure 32 Level of OCGT capacity and corresponding reliability levels

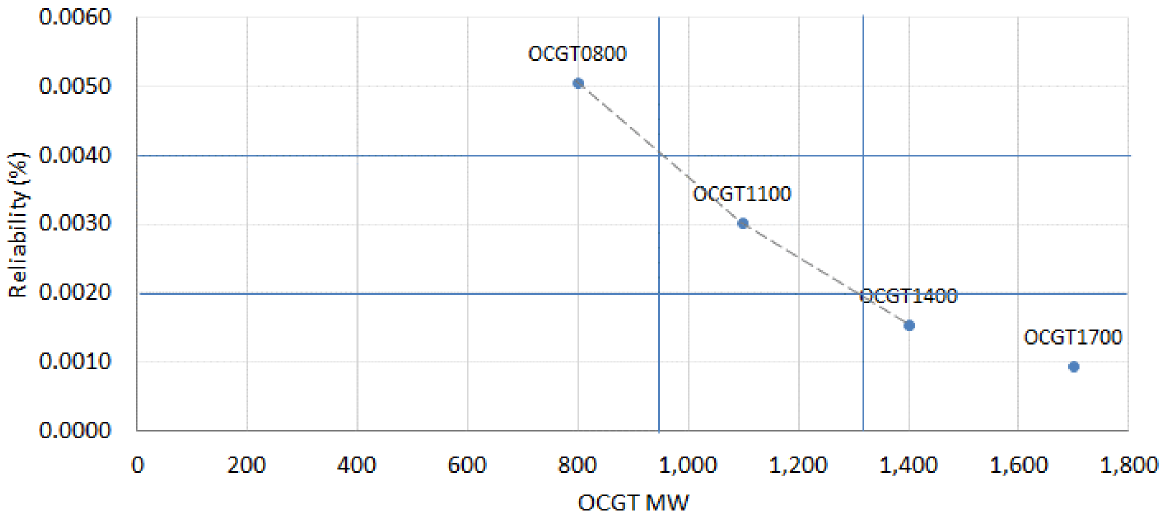
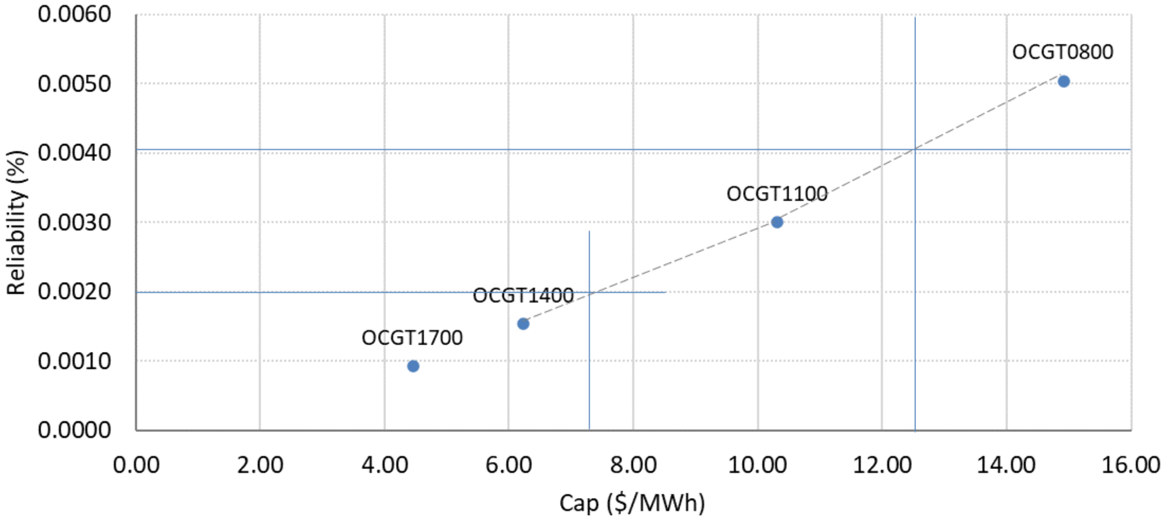


Figure 33 Cap settlement values and reliability levels



Note: These are the targeted cap settlement values based on the current price settings. The prices close to the current MPC in the sufficient settings cases are subsequently set to the higher settings.

Figure 34 Summary of reliability equilibria

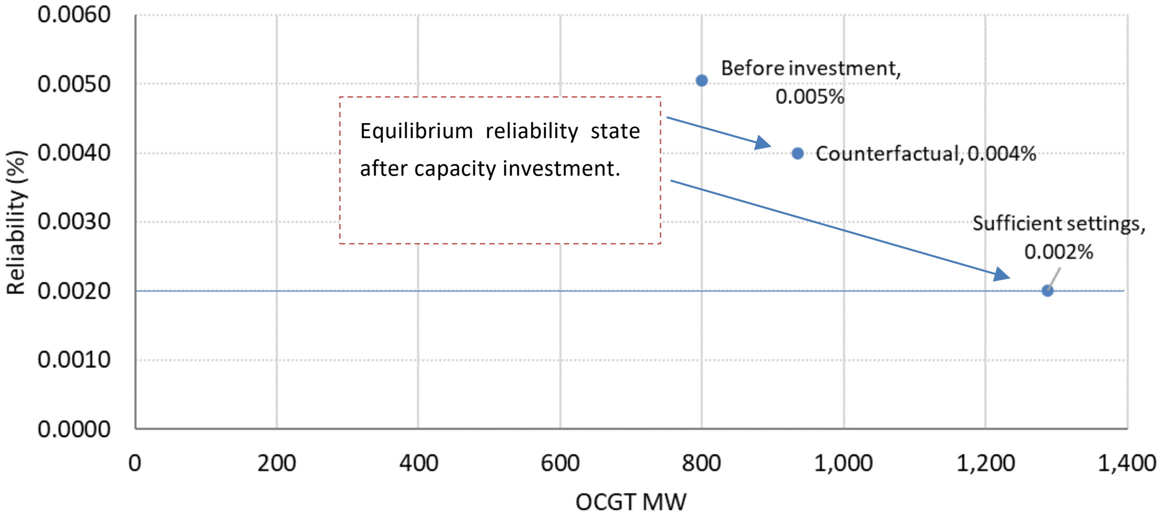


Figure 35 Simulated energy and cap settlement values

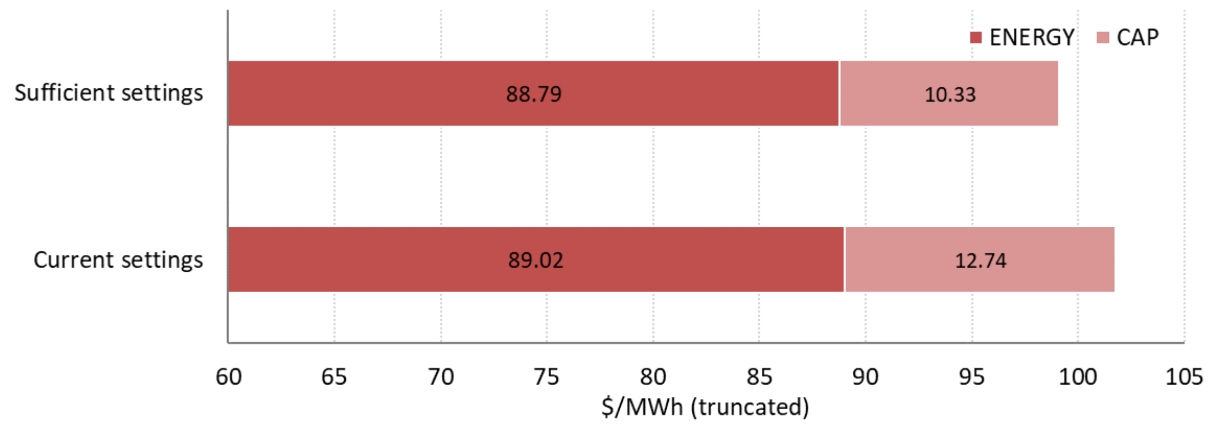
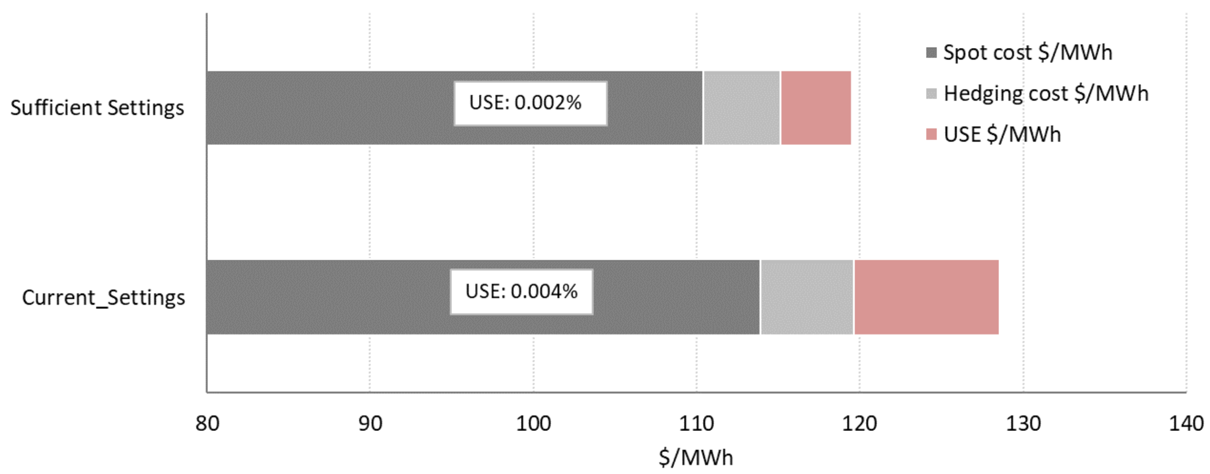


Figure 36 Consumer costs (current and sufficient settings)



The counterfactual assessment against the sufficient settings based on an MPC of $25,000/MWh and CPT of 8.5 hours is summarised in Table 22. The equilibrium level of reliability under the current settings is structurally higher at 0.004%, double the current 0.002% reliability standard. The sufficient settings case results in lower pool prices and wholesale costs compared to the counterfactual. The higher level of USE under the current settings also adds $4.5/MWh to the residential wholesale cost. The overall cost increase, when compared to the sufficient settings case, is $9/MWh or 7.5% higher.

Important factors not considered in the counterfactual assessment include:

- While the 2022 RSSR modelling work did not reveal any reliability gaps over the review period, it is essential to recognise that the supply and demand modelling was not revisited in this update. Moreover, significant market developments since the 2022 RSSR PLEXOS modelling work has the potential to threaten the reliability standard over the Review Period.
- Higher price settings can act as a hedge against adverse changes in the supply and demand balance, which could potentially threaten reliability outcomes. While higher prices may lead to

increased costs for periods with no reliability gaps, they can also provide a buffer to manage sudden shifts in demand or supply constraints in the future.

- The analysis was based on a single year to represent the long-term equilibrium of reliability and stability of investment. Decisions on the reliability settings should also take into account the long-term implications for ensuring reliable electricity supply and encouraging sustainable investment.

Table 22 Counterfactual assessment comparison ($/MWh)

Reliability state	Current settings	Sufficient settings	Difference (Current – sufficient settings)
Unreliable state before capacity investment (above 0.005%)	Wholesale: 119.6 USE: 8.9 Total: 128.5 Equilibrium USE: 0.004%	Wholesale: 115.1 USE: 4.4 Total: 119.5 Equilibrium USE: 0.002%	+$9.0/MWh (+7.5%)

4.3.3 Efficacy of higher price settings

The efficacy of higher price settings was assessed for NSW in a historical context, to answer (a) whether long-term historical cap prices have been below that of the cost of new entrant OCGT and therefore resulted in insufficient capacity investment and (b) whether a higher MPC would have materially addressed the shortfall. Analysis based on historical cap settlement values against the equivalent cap settlement values based on an MPC of $22,000/MWh and $25,000/MWh are presented in Figure 38.[35] The cap values are compared to the historical cost of a large OCGT. Key observations pointing to low cap values and insufficient investment include:

- Historical OCGT costs, predominantly driven by build costs and the WACC, has fluctuated between $13/MWh and $15/MWh. The latest cost assumption updates point to the upper bound of this range (see Figure 37).
- The cap values over the 2021-2023 period are outliers and are not representative of long-term conditions, however, even when included over a 10-year period (2014-2023) the level has been below the cost of OCGT.[36]
- Apart from Barker Inlet Power Station which replaced AGL's Torrens Island A, there have been no new peaking capacity commissioned in the NEM since 2010 on a pure commercial basis.[37] This is consistent with the low cap settlement values.

It has been noted that the average historical level of USE in NSW has been low, and the case could be made that cap settlement values would also be low because peaking capacity was not required over this timeframe. Instead, the 2022 RSSR Base case sensitivity outcomes in NSW are used to

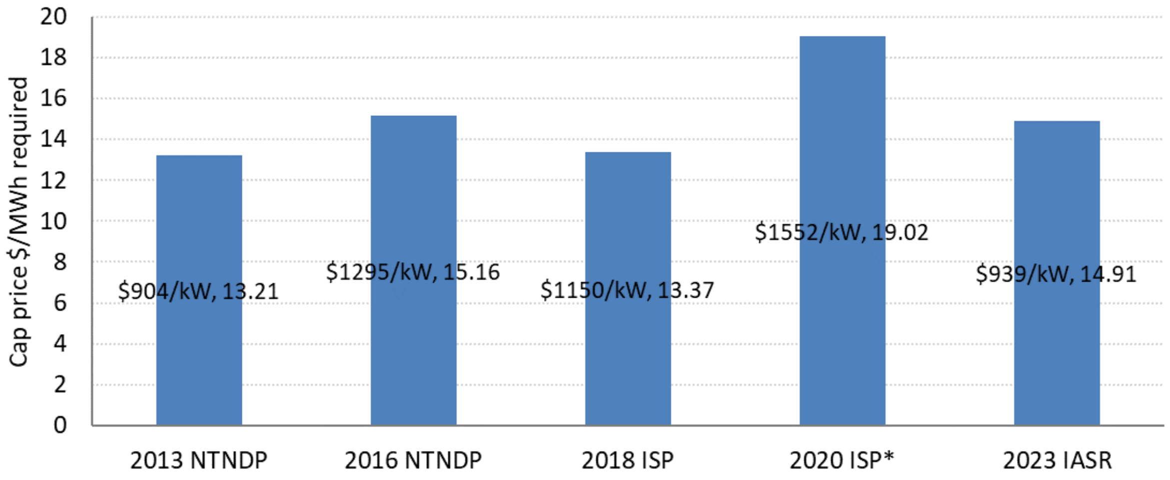
[35] Cap settlement values is a sufficient indicator of OCGT revenues given the majority of spot revenues are derived from spot prices above $300/MWh. The analysis is static and ignores potential supply-side responses to higher price settings.
[36] Average levels without 2021-2023 are also presented in the charts.
[37] Capacity mechanism High-level Design Paper, Energy Security Board (June 2022).

assess pricing conditions associated with reliability gaps. The corresponding cap values based on the existing MPC and higher settings are also included in Figure 38. The impact of higher price settings for NSW is discussed below:

- The modelling produces a cap value of approximately $10/MWh under the current settings however, this would fall short of actual OCGT requirements of $15/MWh. If the MPC were to be set at $22,000/MWh this would bring the cap settlement value in line with the cost of OCGT, i.e., investment in OCGT capacity would be sufficiently incentivised to meet the reliability standard. At the current MPC level, this would lead to underinvestment and a structurally higher level of USE (see Section 4.3.2 for the counterfactual assessment). An MPC of $25,000/MWh would likely over-compensate new entrant OCGTs or produce more reliable outcomes than the current 0.002% standard.

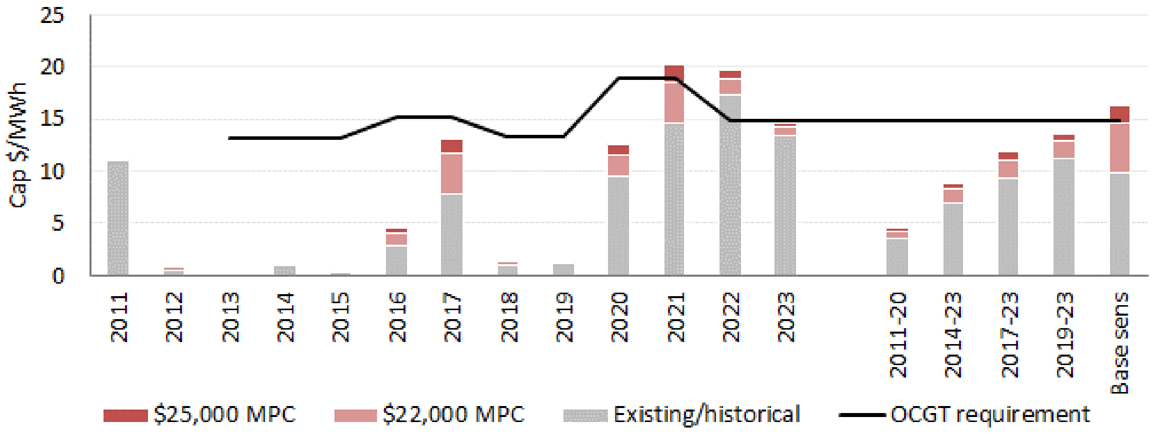
Table 23 below explains how spot market dynamics and cap values influence contract values and long-term reliability investment.

Figure 37 OCGT cost assumptions and recovery requirement



Assumptions: average OCGT costs across the NEM based on large OCGT (where the distinction is made) and the equivalent central scenario. Build costs ($/kW as per data labels) are based on the prospective 5 years, and fuel costs based on FY2028 and OCGT capacity factor of 2.5%. The 2020 ISP point is based on a small OCGT.

Figure 38 Cap settlement values (NSW)



Note: The Base case sensitivity has a reliability gap, and therefore needs further new entrant investment to maintain the reliability standard.

Table 23 Efficacy of higher price settings

Factor	Relevance
Importance of contracts in the context of investment	The NEM is an energy only-market which exhibits high variability in OCGT spot revenue outcomes due to the nature of its design. The annual cap settlement values can be as low as $0/MWh or exceeding $20/MWh in more recent years. The standard deviation of outcomes from 2011 to 2023 ranges between 60%-100% across regions. See NSW as an example in Figure 38 . While the commercial feasibility of capacity investment should be assessed over the project lifespan which can be 15 years or more, the certainty of project cashflows are paramount in the context of meeting year-on-year equity and debt commitments. Wholesale contracts, including swaps and caps, serve as effective tools for mitigating the impacts of revenue variability in an energy-only market. This is important when seeking financing for prospective projects, as lenders typically demand some certainty around cashflows. The contracts underpinning the project cashflows would need a contract price aligning with the fixed and variable costs of the project accounting for risk.
Impact of increased volatility	Within the existing framework, volatility in spot outcomes is necessary to foster a functioning contracts market. Increased volatility, under equivalent conditions, correspondingly motivates both power generators and retailers to actively hedge its exposure to provide revenue and cost certainty. Price volatility predominantly emerges from supply constraints or shortages. Any imbalance persisting in a structural manner poses a potential threat to the reliability standard unless adequate investment is made. Price volatility, subject to an

	appropriate level of the MPC, assumes the price signalling role for peaking capacity. Its primary function is to stimulate the requisite investment needed to address the supply-demand disparity and maintain the equilibrium necessary to ensure the reliability standard can be met.
Impact of higher spot prices on contract prices	Contract prices are settled from spot prices and are therefore set based on the expectation of spot pricing outcomes, including both the level and volatility of outcomes. Therefore, the higher or more volatile the spot price expectation the higher contract prices would be set to, and the more likely projects become 'in the money' resulting in investment. The resulting impact on supply and demand dynamics in the NEM are self-regulating in that high prices would incentivise supply which in turn reduces prices until an equilibrium is reached. The equilibrium in the context of the reliability framework depends on the MPC which is driven by the reliability standard. The modelled cap values, whereby additional capacity is required under the Base case sensitivity and based on the current settings, are lower than levels required for OCGT cost recovery.

A summary of a higher MPC/CPT and its implication for capacity investment is provided below:

- All else being equal, an appropriate level of the MPC and CPT will the incentivise necessary investment to maintain the reliability standard over the long term.
- The historical trend of low cap values aligns with the lack of peaking capacity investment although reliability may not have been an issue over this timeframe. If the objective were to facilitate more capacity investment, it becomes evident that the historical and current levels of MPC/CPT would have fallen short of meeting this objective.
- The present MPC/CPT levels do not adequately incentivise prospective investment in peaking capacity, with OCGT representing the most economically viable option at present (see Section 4.1.1).
- Raising the MPC to $22,000/MWh will raise spot volatility, cap values and contract prices to levels commensurate with the cost of building OCGT capacity when supply is needed to meet potential reliability gaps.

4.4 Key findings

Table 24 summarises the key findings across the various modelling tasks.

Table 24 Key findings

Category	Key findings
MPC/CPT combinations	- The required MPC levels for small OCGT and BESS (2 and 4-hour), and its related sensitivities, continues to be significantly higher than that of a large

Category	Key findings
	OCGT due to the difference in underlying capital costs and energy constraints associated with BESS. - The WACC and the assumption of non-reliability revenues play a significant role in determining the required MPC for large OCGTs. The outcomes show a wide range of MPC values at a CPT of 8.5 hours, ranging from $16,500/MWh to $31,000/MWh, depending on the WACC and revenue sensitivities considered. - The level of the APC is not material in determining the MPC/CPT combination as the revenues derived from Administered Pricing Periods comprise a negligible share of the OCGT's revenue. - The Panel's recommendation of $22,800/MWh sits firmly in the middle of the MPC sensitivity ranges explored.
Carbon cost impact on the MPC/CPT	- The net revenues for a large OCGT plant under the two carbon scenarios are influenced by its carbon intensity relative to other plants and the total capacity of higher SRMC plants setting the spot price. - The impact of a $20/t carbon cost was found to be negligible, indicating that it has minimal influence on the required MPC/CPT for a large OCGT. However, the sensitivity analysis with a $50/t carbon cost shows a material impact. The additional revenues associated with a $50/t carbon cost corresponds to $6,380/MW/year, which reduces the required MPC by approximately $3,500/MWh at the 8.5-hour CPT level. - The additional net revenues potentially accruing to a large OCGT located in NSW are limited compared to VIC. This is because VIC has a higher number of generators that are positioned above the new entrant OCGT SRMC and have significantly higher carbon emissions intensity.
Consumer cost assessment	- In QLD, the impact of higher price settings would be the most significant, with wholesale cost increases ranging from $7.8/MWh to $13.4/MWh (8-11%) under both median 5 of last 7-year and 5-year average pool conditions. NSW and VIC would experience cost increases of between $4.8/MWh and $8.0/MWh (5-8%). SA would see increases ranging from $8.6/MWh to $10.4/MWh (7-8%). TAS would be relatively unaffected, with a minimal increase of less than 1%. - The average increase across all regions, except TAS, is $9.9/MWh under a $25,000/MWh MPC and 8.5-hour CPT. This is comprised of $7.3/MWh in energy costs and an additional $2.6/MWh related to contract premiums for the higher MPC and CPT settings. Risk-averse retailers would face increased, but manageable, risks. - The doubling of the assumed risk premium assumption would lead to an average cost increase of $2.4/MWh or 1.6% across NSW/QLD/VIC/SA.
Counterfactual assessment	- For an unreliable state, the current price settings (counterfactual) would lead to a structurally higher equilibrium level of reliability at 0.004%, which is double the current reliability standard of 0.002%. The counterfactual case would also result in higher pool prices and wholesale costs compared to the sufficient settings case. The overall cost increase is $9/MWh, including $4.5/MWh in additional USE costs, or 7.5% higher than the sufficient settings case.

Category	Key findings
Efficacy of higher price settings	- The historical trend of low cap values aligns with the lack of peaking capacity investment. If the objective were to facilitate more capacity investment, it becomes evident that the historical and current levels of MPC/CPT would have fallen short of meeting this objective. - The present MPC/CPT levels do not adequately incentivise prospective investment in peaking capacity, with OCGT representing the most economically viable option at present. - Raising the MPC to $22,000/MWh will raise spot volatility, cap values and contract prices to levels commensurate with the cost of building OCGT capacity when supply is needed to meet potential reliability gaps.

Appendix A Abbreviations

Abbreviation	Term
2022 RSSR	2022 Reliability Standard and Settings Review
AEMO	Australian Energy Market Operator
APC	Administered Price Cap
APP	Administered Pricing Period
BESS	Battery energy storage system
CPT	Cumulative Price Threshold
ESOO	2021 Electricity Statement of Opportunities
FCAS	Frequency control ancillary services
FOM	Fixed operating and maintenance costs
IES	Intelligent Energy Systems
IASR	Inputs, Assumptions and Scenarios
ISP	Integrated System Plan
MFP	Market Floor Price
MPC	Market Price Cap
MW	Megawatt
MWh	Megawatt hours
NEM	National Electricity Market
NEO	National Electricity Objectives
NER	National Electricity Rules
NSW	New South Wales
OCGT	Open cycle gas turbine
POE	Probability of exceedance
QLD	Queensland
SRMC	Short-run marginal cost
TAS	Tasmania
USE	Unserved energy
VCR	Value of customer reliability
VIC	Victoria
VRE	Variable renewable energy
WACC	Weighted average cost of capital

Appendix B Reliability framework definitions

The definitions for the various components of the reliability framework are summarised in Table 25.

Table 25 Definitions of reliability framework components

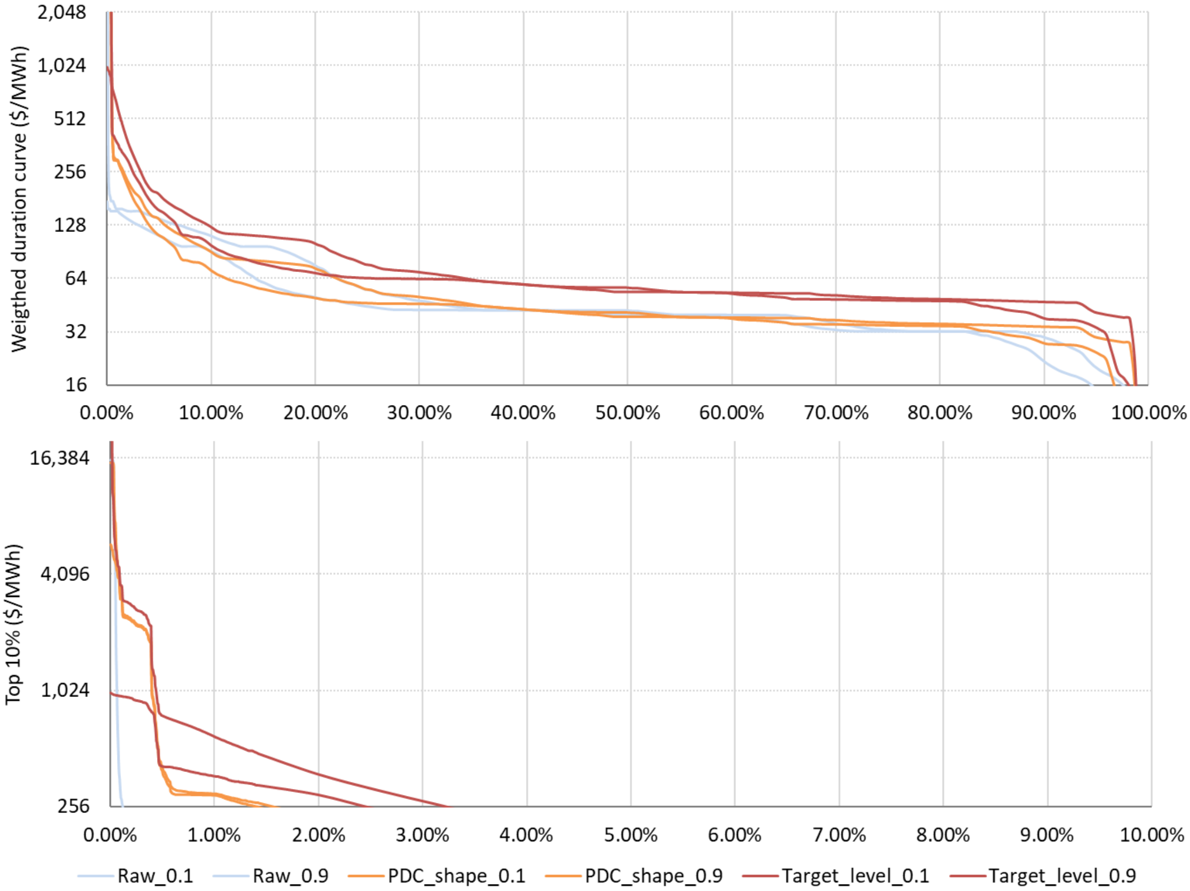
Components	Definition/purpose
Reliability standard	The current reliability standard is expressed in terms of outputs. It expresses the maximum expected amount of energy demand that can be unmet in each NEM region in a year. It is expressed as a proportion — 0.002 percent of the total energy demanded 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: Reliability Panel, 2022 Reliability Standard and Settings Review, Issues Paper, 27 January 2022.

Appendix C Re-profiled prices

Figure 39 provides a series of snapshots illustrating the interval-level re-profiling process. The lines labeled "raw" represent the 10th and 90th percentiles of the raw price duration curves, derived from all 1100 price samples.[38] The "PDC_shape" lines depict the prices after undergoing the shaping step, aligning them with the FY2021 price duration curve shape. Subsequently, the "Target_level" lines indicate the final price duration curve shape after scaling to the target price levels and adjusting prices near the current MPC to a higher price setting.

Figure 39 Re-profiled price duration curve (NSW, log-2 scale)



Note: Based on 2021 PDC shape and Median_5_of_7 target price level. y-axis has been truncated.

The re-profiled price scenarios are summarised in Table 26 and the outcomes are plotted for each region in Figure 40 to Figure 44. The historical values presented in grey are provided for additional context. The term "energy" refers to settlement values up to and including $300/MWh, where the

[38] Weighted 30/70 across the P10 and P50 samples, respectively.

energy and cap value together correspond to the annual (swap) settlement value. Key observations from the re-profiling process are as follows:

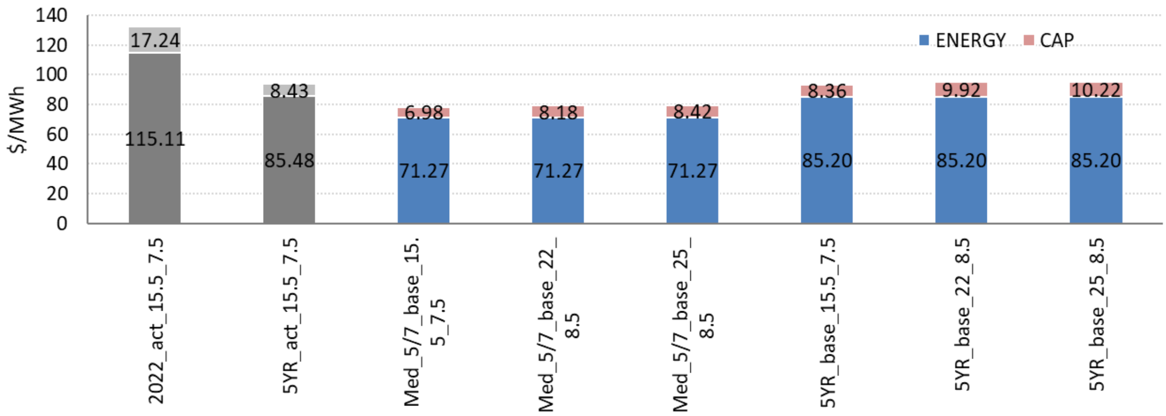
- The energy values closely correspond to the target level, i.e., either the 5-year average or median 5 of the last 7 years average.[39]
- However, the cap value differs due to the scaling of underlying prices to higher MPC levels. The increase in the cap value concerning current settings is influenced by the underlying price duration curve. For instance, all regions except TAS show an increase in the cap value up to $2.5/MWh when the MPC is set to $22,000/MWh.

These re-profiled price traces are incorporated into the wholesale cost model to evaluate the impacts on consumer costs, as detailed in Section 4.2.

Table 26 Summary of re-profiled price scenarios

			MPC	CPT	APC
LABEL	**TARGET_LEVEL**	**BASIS**	**$/MWh**	**hours**	**$/MWh**
2022_act_15.5_7.5	2022	Actual/historical	15,500	7.5	300
5YR_act_15.5_7.5	5YR_avg	Actual/historical	15,500	7.5	300
Med_5/7_base_15.5_7.5	Med_5_7	Base case	15,500	7.5	300
Med_5/7_base_22_8.5	Med_5_7	Base case	22,000	8.5	500
Med_5/7_base_25_8.5	Med_5_7	Base case	25,000	8.5	500
5YR_base_15.5_7.5	5YR_avg	Base case	15,500	7.5	300
5YR_base_22_8.5	5YR_avg	Base case	22,000	8.5	500
5YR_base_25_8.5	5YR_avg	Base case	25,000	8.5	500

Figure 40 Actual and re-profiled prices (NSW, FY2028)



[39] Median 5 of the last 7-years removes the lowest and highest years, generally FY2022.

Figure 41 Actual and re-profiled prices (VIC, FY2028)

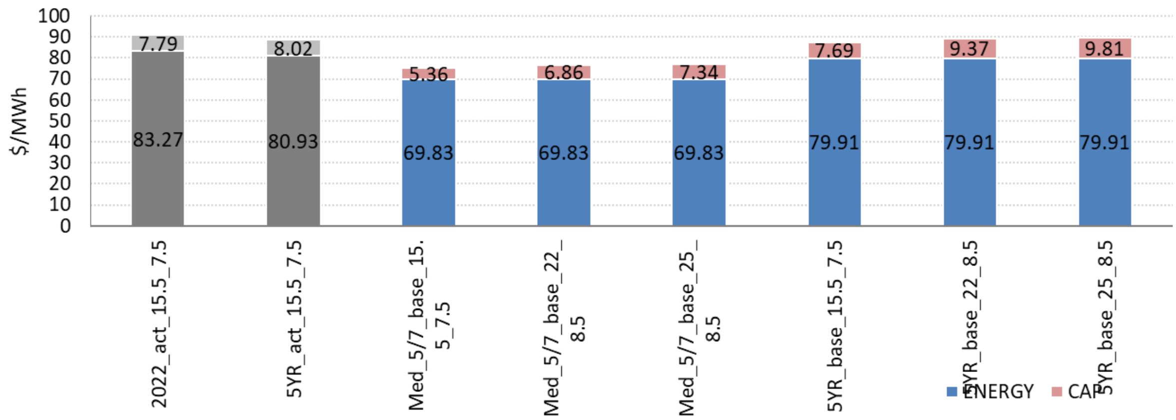


Figure 42 Actual and re-profiled prices (QLD, FY2028)

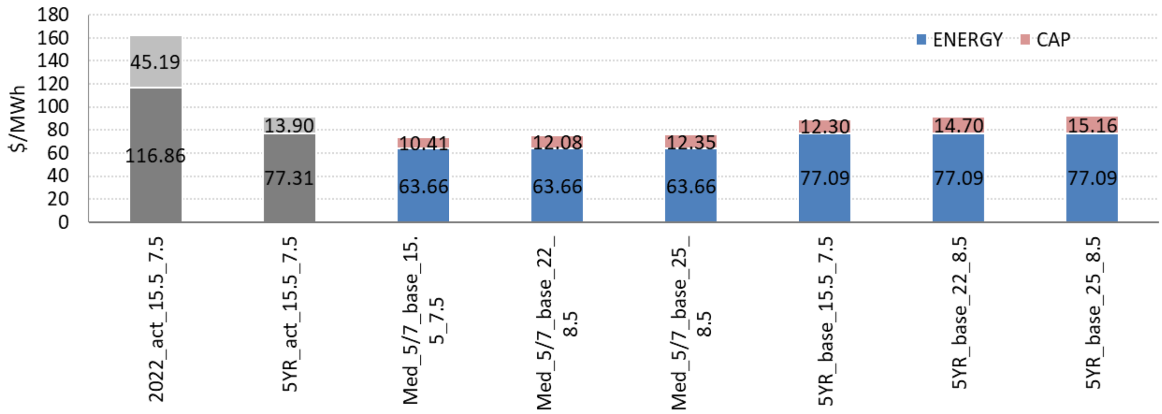


Figure 43 Actual and re-profiled prices (SA, FY2028)

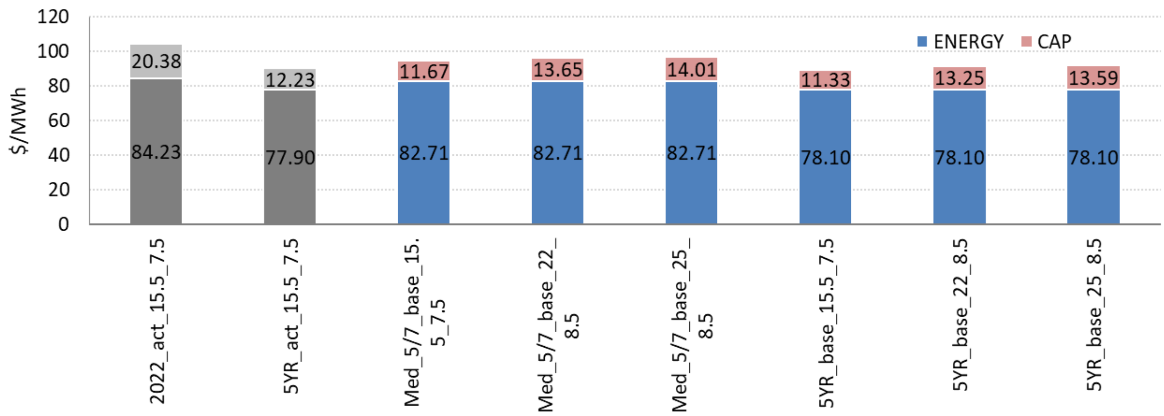
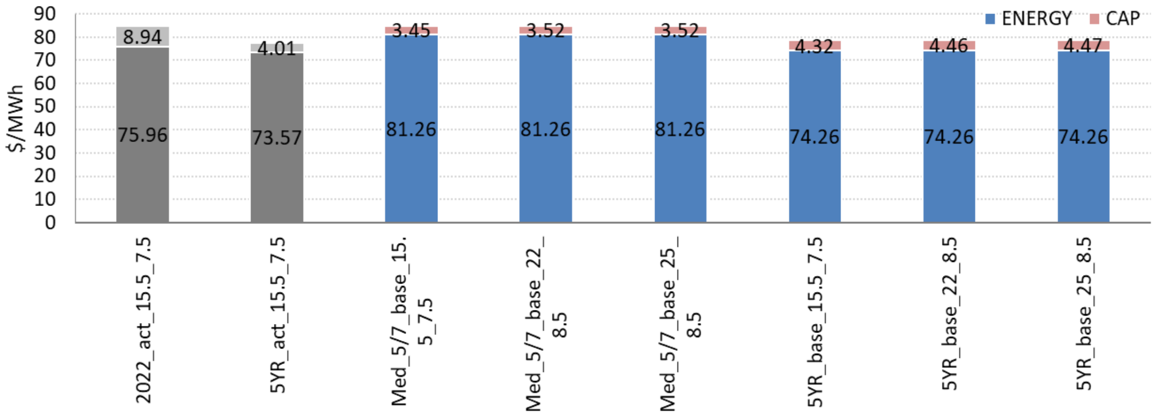


Figure 44 Actual and re-profiled prices (TAS, FY2028)



Appendix D Swap and cap settlement values

Swap and cap settlement values are based on what the instrument is expected to settle at. Swap and cap prices (different to settlement value) includes an additional risk premium for the underlying volatility in settlement values. This risk premium is only considered in the wholesale cost assessment component. This section details the calculation of the swap and cap settlement values.

D.1 Swap settlement calculation

The (annual) swap settlement value for a particular P50 and P10 samples is calculated as the time-weighted average of all half-hourly prices across the year. The weighted average cap settlement value is derived by weighting the average P10 and P50 cap settlement values, 30% and 70% respectively.

D.2 Cap settlement calculation

The (annual) cap settlement values are calculated based on a $300/MWh strike, and consistent with how cap contracts are settled in the market. The calculation is performed on a per-sample, per-interval basis, where the half-hourly cap payout is calculated as max(x(t) - 300, 0), where x(t) is the half-hourly price at interval t. The half-hourly cap payouts are then averaged across all 17568 intervals in the year (FY2028) to determine the per-sample cap settlement value. The weighted average cap settlement value is derived by weighting the average P10 and P50 cap settlement values, 30% and 70% respectively. Alternatively:

- Per sample (annual) cap settlement value ($/MWh) = $\sum_{t=1}^{17568} max(x(t) - 300{,}0)\,/17568$, where x(t) is the half-hourly price at interval (t).
- Average P50 cap settlement = $\sum_{i=1}^{n} annual\_cap\_settlement\_value(i)/n$, where i is the P50 sample number and n is the total number of P50 samples. Average P10 cap settlement is calculated in the same way with P10 samples.
- Weighted average (annual) cap settlement value ($/MWh) = *[average P50 cap settlement] * 70% + [average P10 cap settlement] * 30%*

D.3 Energy settlement calculation

This is the difference between the swap and cap settlement value.