

Assessment of potential market impacts associated with moving to a higher reliability standard

Australian Energy Market Commission
on behalf of Energy Security Board

6 May 2020

Release Notice

Ernst & Young ("EY") was engaged on the instructions of the Australian Energy Market Commission on behalf of Energy Security Board ("Client") to provide an assessment of potential market impacts associated with moving to a higher reliability standard to support a reliability standard review ("Services"), in accordance with the Order dated 14 January 2020 in accordance with the Panel contract with the AEMC dated 19 April 2018 (the "Agreement").

The work completed for the preparation of this Report applies the fundamental principles and modelling methodology described in detail in the 2018 Reliability Standards and Settings Review (RSSR) EY modelling report (Available at <https://www.aemc.gov.au/markets-reviews-advice/reliability-standard-and-settings-review-2018>). This Report must be read in conjunction with the 2018 Reliability Standards and Settings Review modelling report to gain the complete details and context about the contents of this Report. You should read this Report in its entirety including any disclaimers and attachments.

Our work commenced on 14 January 2020 and was completed on 17 March 2020. Therefore, our Report does not take account of events or circumstances arising after 17 March 2020 and we have no responsibility to update the Report for such events or circumstances. The results of EY's work, including the assumptions and qualifications made in preparing the report, are set out in EY's report dated 6 May 2020 ("Report"). A reference to the Report includes any part of the Report. Minor editorial changes have been made to the Report at the request of the Client in early May 2020 to enable the Report to be published. No further work has been undertaken by EY since completion of the work on 17 March 2020.

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Our conclusions are based, in part, on the assumptions stated and agreed upon on 19 February 2020, as well as on information provided by the Client and other information sources used during the course of the engagement. The modelled outcomes are contingent on the collection of assumptions as agreed with the Client and no consideration of other market events, announcements or other changing circumstances are reflected in this Report. Neither Ernst & Young nor any member or employee thereof undertakes responsibility in any way whatsoever to any person in respect of errors in this Report arising from incorrect information provided by the Client or other information sources used.

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1. Executive summary

The 2019 ESOO found that the existing reliability standard is expected to be met in 2023-24. However, it is also noted that there is sizeable tail risk of the annual unserved energy (USE) exceeding 0.002% of energy demanded. To reduce this risk, the 2019 ESOO proposed an alternative reliability standard where the annual USE would be expected to be less than 0.002% in 9 out of 10 years.

The AEMC on behalf of the ESB has commissioned EY to undertake a market modelling study to explore potential market impacts of moving between the existing reliability standard and the alternative, tighter reliability standard as proposed by AEMO in the 2019 ESOO. This study explores a single scenario for the year 2023-24 to consider the following key questions:

- ▶ What is the additional generation capacity required to achieve the alternative reliability standard?
- ▶ If the alternative standard were to be achieved by increasing the market price cap (MPC), by how much would the MPC need to be increased?
- ▶ What is the impact on retail electricity prices that may result from increasing the MPC?

The scope is to analyse the difference between meeting the existing and alternative reliability standards in New South Wales (NSW), Victoria (Vic) and South Australia (SA) since these are the regions forecast in the 2019 ESOO to be most at risk of experiencing USE in the coming years. Since it is more common that one region experiences breaching the reliability standard at a time than multiple regions simultaneously, and to allow the regions to be considered separately, we built separate models to explore the implications of tightening the reliability standard for each region. As a result, we modelled six cases, considering the existing and alternative reliability standards for each of these three regions.

1.1 Summary of outcomes

Table 1 presents a summary of the outcomes that answer the key questions above. The differential assessment compares the relative impact on these metrics between a future year in which the existing reliability standard is just achieved, or the alternative reliability standard is just achieved. For the avoidance of doubt, the outcomes presented here are not relative to a baseline or expected market condition in the 2023-24 year. A material reduction in the expected installed generation capacity in the 2023-24 year was applied in the modelling to first achieve a situation in which the existing reliability standard is only just met. Table 1 summarises the relative change in market capacity and reliability settings to achieve the alternative standard. A full description of the applied methodology is provided in the main report in section 3 and resulting capacity adjustments are shown in Table 6 within section 5.

Table 1: Summary of key outcomes

Region	Additional capacity to achieve the alternative standard*	Required increase in the MPC to achieve the alternative standard	Impact on wholesale component of average retail electricity bills from increasing the MPC
NSW	510 MW	2.5x	+\$2/MWh (+2%)
VIC	420 MW	3x	+\$3.50/MWh (+3%)
SA	130 MW	4x	+\$4/MWh (+4%)

* This number presents an upper bound for the specific region.

Additional capacity

The additional capacity required to meet a higher standard could be provided by demand side response, by pumped hydro or battery storage or by a range of generating plant. At this time, technology cost data favours open cycle gas turbine (OCGT) or reciprocating engine plant for very low utilisation duties. For simplicity, a standard OCGT technology was assessed to estimate the theoretical maximum additional capacity required to achieve the higher alternative reliability standard relative to the existing reliability standard, i.e., if the expected USE was somewhere between the two standards, the additional OCGT capacity required to reduce USE to the alternative standard would be less than the number in Table 1.

The case of two or more regions having USE close to the existing reliability standard simultaneously was not modelled. It is expected that the additional capacity required to reduce USE in such situations would be less than the sum of the additional capacity required for each region individually. As such the sum of the three capacities for the three regions (1,060 MW) is an upper bound on the total capacity required across those three regions to meet the alternative standard. Based on the assumed capital cost of \$1,225/MW, this represents an upper bound capital cost of approximately \$1.2b.

Required increase in the MPC

To incentivise investment in the required plant through the NEM's energy only market design, the market price cap and/or related measures would need to rise. If the alternative reliability standard were to be achieved by increasing the MPC alone, the study found this increase would need to be a factor of approximately three. This increase reflects achieving the break-even (full economic cost recovery) point of a marginal OCGT. Moving to the tighter alternative standard reduces the frequency of high-priced periods, including periods priced at the MCP. With fewer periods to provide the marginal OCGT a high revenue, those periods need to have a higher price for the generator to earn enough revenue to still break-even.

To estimate the required MPC to achieve the existing or alternative reliability standards, we used the same methodology as was applied in the 2018 RSSR. This involves establishing a model where the reliability standard is just met with a new entrant OCGT and adjusting the reliability settings (MPC, Cumulative Price Threshold (CPT) and Administered Price Cap (APC)) to find the point where the expected market revenue of the OCGT is enough to break even against its annualised costs. In this study we maintained the CPT at 15 times the MPC and the APC remaining at the present setting of \$300/MWh and explored adjusting the MPC. It is noted that different CPT and APC settings may also be explored as a future part of this review which would lead to different MPC outcomes.

The modelled MPC required to meet the existing and the higher standard in each region for the year analysed are shown in Table 8. The difference between the two MPCs for each region is indicative of the scale of change in MPC required as shown in Table 1 above. The analysis suggests that all else being equal, the MPC would need to increase by a factor of approximately three (treble).

Impact on retail electricity bills

It is important to point out that the wholesale market price impact presented is between the modelled cases that are just achieving the existing and alternative reliability standards. However, in years where there is little expected USE, increasing the MPC would apply to fewer periods and the price increase may be smaller. Conversely, depending on the level of competition in the market, a higher MPC may allow the market to settle at prices higher than the present market price cap at times, despite having surplus capacity available.

Whilst the change in MPC required to achieve a higher level of reliability is significant, this modelling suggests this may lead to a relatively small increase in average wholesale electricity prices. The wholesale market component on average retail electricity bills is proportional to the demand-weighted wholesale electricity market price as this represents the average price for each megawatt-hour of demand. Table 1 presents the difference in the modelled demand-weighted wholesale

market prices between the cases where each reliability standard is just met and using the required reliability settings (MPC, CPT and APC). With an increase of \$2-4/MWh across the three regions, this outcome reflects that the higher MPC periods are occurring when the demand is higher than for other periods where the additional (OCGT) capacity available in the market reduces prices.

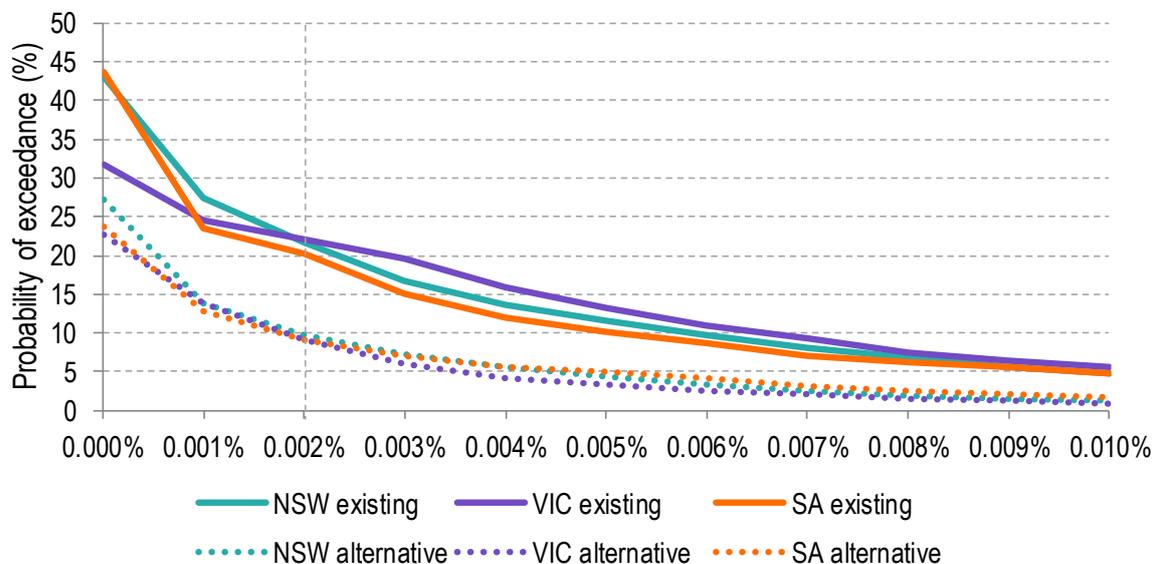
Based on a representative household customer using 4,000 kWh per year¹ (4 MWh), an increase of \$2-4/MWh in the wholesale market price translates to \$8-\$16/year for each household. This estimate may change if customer energy consumption increases (EV charging for example) or decreases (larger rooftop PV installations for example). It also assumes a simple flat electricity tariff whereas future customers may have access to more flexible tariff arrangements such as time of use to improve their annual electricity cost exposure.

For the wholesale market in the NSW, VIC and SA regions with an operational sent-out energy of approximately 120,000,000 MWh this translates to \$240-\$480m per year in wholesale energy traded².

Unserviced energy outcomes

Figure 1 shows the modelled probability of USE exceeding different levels to compare the regions and the two standards.

Figure 1: Probability of exceedance of expected annual USE (%) for all regions and each reliability standard



The figure shows that while the curve is broadly similar between the three regions modelled for each of the reliability standards there are some differences in cases modelled, such as for the probability of annual USE > 0, which is referred to as the loss of load probability (LOLP). Table 2 presents the USE outcomes for the modelled scenarios that meet each of the reliability standards, in terms of the measures on which each standard is defined and the LOLP.

¹ Based on NSW and Victoria in Table 3.1 of the AEMC's 2019 Retail Electricity Price Trends report <https://www.aemc.gov.au/sites/default/files/2019-12/2019%20Residential%20Electricity%20Price%20Trends%20final%20report%20FINAL.pdf>

² Across the whole NEM including Queensland and Tasmania the operational sent-out energy is approximately 180,000,000 MWh translating to \$360-720m per year in energy traded.

Table 2: USE outcomes for all regions when meeting each reliability standard

Region	NSW	VIC	SA
Reliability standard	Expected annual USE (% of energy)		
Existing	0.0020%	0.0019%	0.0018%
Alternative	0.0007%	0.0006%	0.0008%
Reliability standard	Probability of annual USE > 0.002% of energy		
Existing	21.6%	22.0%	20.2%
Alternative	9.8%	9.1%	9.3%
Reliability standard	Probability of annual USE > 0% of energy (LOLP)		
Existing	43.1%	31.8%	43.7%
Alternative	27.3%	22.6%	23.7%

Table 2 shows that, compared to the existing reliability standard, the alternative standard:

- ▶ represents reducing the expected unserved energy to approximately one third,
- ▶ represents approximately half the probability of USE being > 0.002%, and
- ▶ would reduce the probability of any USE in a year or LOLP by approximately one third.

Based on the modelling scenario and methodology applied, the modelling outcomes in this study provide the following answers to the key questions explored:

- ▶ Tightening the existing reliability standard to the alternative reliability standard in NSW, VIC and SA would require an upper bound of 1,000 MW of additional dispatchable capacity or demand side reduction across those regions.
- ▶ To use the existing market framework reliability settings to incentivise sufficient generation to meet the alternative standard would require increasing the present MPC and CPT by a factor of approximately three.
- ▶ Tripling of the MPC and CPT to achieve the alternative reliability standard would result in increasing the wholesale electricity component of retail bills by \$2-4/MWh (2-4%), compared to a market achieving close to the existing reliability standard. The actual impact on wholesale electricity prices depends on the level of expected USE with the existing reliability settings and competition between generators. All else being equal, this would flow through to increase an average residential retail electricity customer bill by less than \$20 per annum.

EY advises that the outcomes provided are based on many detailed assumptions underpinning the scenarios, and the key assumptions are described in the Report. Where indicated, the methodology for preparation of data was informed by previous work completed for the 2018 RSSR³. The modelled scenarios represent one possible future for the development and operation of the NEM, and it must be acknowledged that many alternative futures exist. We encourage the Client to ensure that they develop a thorough understanding of the sensitivity of the key assumptions to outcomes and consider these assumptions with due care before acting on the outcomes presented in this Report.

³ See EY's report at <https://www.aemc.gov.au/markets-reviews-advice/reliability-standard-and-settings-review-2018>

2. Introduction

The 2019 ES00 found that the existing reliability standard is expected to be met in 2023-24. However, it is also noted that there is sizeable tail risk of the annual USE exceeding 0.002% of energy demanded. To reduce this risk the 2019 ES00 proposed an alternative reliability standard where the annual USE would be expected to be less than 0.002% in 9 out of 10 years.

The AEMC on behalf of the ESB has commissioned EY to undertake a market modelling study to explore potential market impacts of moving between the existing reliability standard and the alternative, tighter reliability standard as proposed by AEMO in the 2019 ES00. This study explores a single scenario for the year 2023-24 to consider the following key questions:

- ▶ What is the additional generation capacity required to achieve the alternative reliability standard?
- ▶ If the alternative standard were to be achieved by increasing the market price cap (MPC), by how much would the MPC need to be increased?
- ▶ What is the impact on retail electricity prices that may result from increasing the MPC?

The scope is to analyse the difference between meeting the existing and alternative reliability standards in New South Wales (NSW), Victoria (VIC) and South Australia (SA) since these are the regions forecast in the 2019 ES00 to be most at risk of experiencing USE in the coming years. Since it is more common that one region experiences breaching the reliability standard at a time than multiple regions simultaneously, and to allow the regions to be considered separately, separate models were built to explore the implications of tightening the reliability standard for each region. As a result, six cases were modelled, considering the existing and alternative reliability standards for each of these three regions.

The MPC is a mechanism with which AEMO ensures an appropriate level of reliability in the electricity market. Building generation assets capable of meeting the entirety of consumer demand for all periods would be very costly, and the reliability standard is intended to represent a balance between the cost of electricity supply and the cost of the demand being unmet occasionally. The MPC aims to provide a price signal to incentivise generators and loads to meet the reliability standard while limiting market participant's exposure to high prices. Therefore, moving from the existing standard to the tighter alternative standard would require an increase to the MPC setting.

This Report is structured as follows:

- ▶ Section 3 describes the modelling methodology,
- ▶ Section 4 lists the key modelling assumptions,
- ▶ Section 5 presents the outcomes, answering the study's key questions above, and
- ▶ Section 6 discusses the modelling limitations.

All prices in this Report refer to real June 2019 dollars unless otherwise labelled. All annual values refer to the fiscal year (1 July - 30 June) unless otherwise labelled.

We note that the assumptions have been selected by the Client in consultation with EY. We acknowledge that there is a significant range of alternative assumptions that, in isolation or in aggregate, could transpire to produce outcomes that will differ to those that have been modelled. These possible alternative futures have not been considered in this engagement.

3. Methodology

3.1 Overview

The modelling methodology used to answer the primary questions in this study can be summarised in the following steps:

1. Build a half-hourly dispatch and price model of the NEM in 2023-24 where the expected USE in the target region is just under 0.002%, i.e., the existing reliability standard is just met (Case 1).
2. Find the MPC setting that results in a marginal new entrant OCGT breaking even, in terms of its expected wholesale market revenue being enough to cover its annualised costs.
3. Adjust Case 1 to find the amount of additional OCGT capacity that reduces the modelled USE outcomes to just under the alternative reliability standard (Case 2).
4. Repeat step 2 to find the MPC setting that results in the marginal new entrant OCGT breaking even in the case of meeting the alternative reliability standard.
5. Calculate the average demand-weighted price outcomes for the two cases and compare to estimate the impact on retail electricity bills.

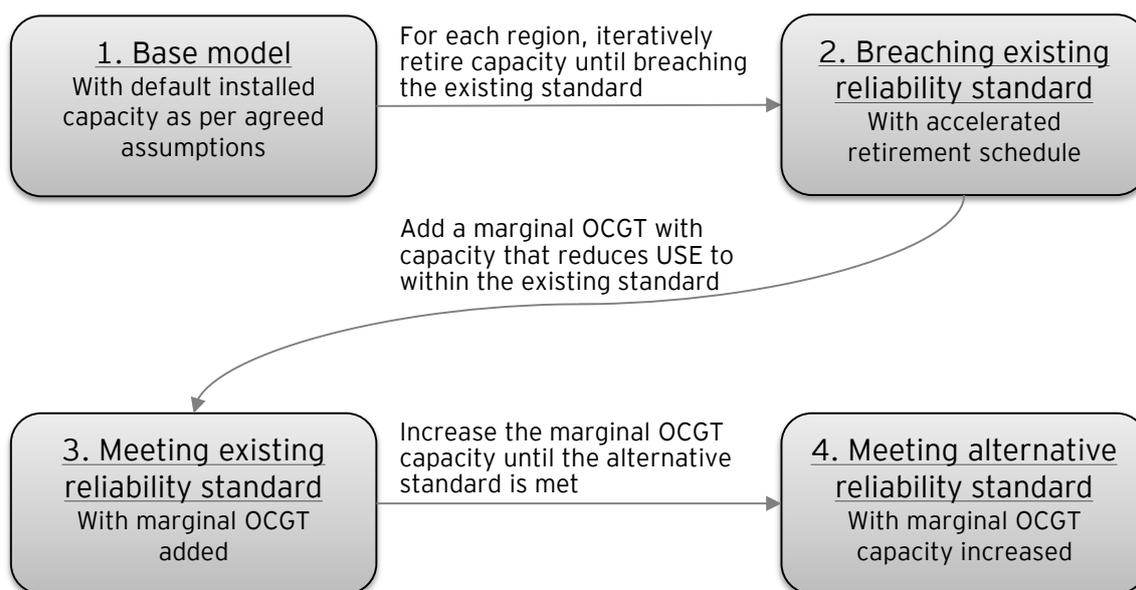
The above process was performed separately for New South Wales (NSW), Victoria (VIC) and South Australia (SA). These regions were selected by the Client as they are the regions forecast in the 2019 ESOO to be most at risk of experiencing USE in the coming years. Since it is more common that one region experiences breaching the reliability standard at a time than multiple regions simultaneously, and to allow the regions to be considered separately, separate models were built to explore the implications of tightening the reliability standard for each region. As a result, we modelled three scenarios with two cases each, considering the existing and alternative reliability standards for each region.

This modelling methodology was discussed with and agreed to by the Client and is described in more detail in the following section.

3.2 Methodology in detail

Figure 2 summarises the modelling steps undertaken for each region.

Figure 2: Flowchart of the modelling process undertaken for each region



Each of the boxes in the diagram represents a key market simulation⁴ of 2023-24 in the modelling process. Table 3 provides further explanations of key steps of the modelling methodology and the outcomes of each step.

Table 3: Modelling methodology and outcomes from individual steps

Step	Description
1. Base model	Developing the base model for the National Electricity Market in 2023-24
	<p>Method: Establish a model that reflects the agreed assumptions for 2023-24 to simulate the dispatch of each generating unit and the price in half-hourly time-steps.</p> <p>Outcome: Baseline of expected USE for each region. This same model is used for each region in the subsequent modelling steps.</p>
2. Breaching existing reliability standard	For each region, develop a plausible early retirement of capacity that results in the forecast USE breaching the existing reliability standard
	<p>Method: Retire demand-side response and then thermal generators based on their age or announced closure date, and iteratively simulate 2023-24 until the expected USE in the target region exceeds the existing reliability standard.</p> <p>Outcome: Three scenarios, one for each region, where the existing reliability standard is breached in that region.</p>

⁴ For more detail on how a market simulation was conducted for this Report, see Section 3.3.

Step	Description
3. Meeting existing reliability standard	Adding marginal OCGT capacity to bring USE outcomes just under the existing reliability standard
	<p>Method: For each scenario, add a marginal new entrant OCGT in the target region and find its minimum capacity that reduces the expected USE to meet the existing reliability standard.</p> <p>We then adjusted the MPC setting to find the point where the expected market revenue of the OCGT is enough to break even against its annualised costs. This is considered the MPC setting required to achieve meeting the reliability standard from the market in the scenario. More on this methodology is described following this table.</p> <p>Outcomes: For each region/scenario, the probability of different levels of annual USE, the MPC setting required to achieve the existing reliability standard; annual demand-weighted pool price.</p>
4. Meeting alternative reliability standard	Adding further marginal capacity to meet alternative standard
	<p>Method: Increase the capacity of the marginal OCGT generator until the alternative reliability standard is met.</p> <p>Outcomes: For each region, the additional OCGT capacity required to move the expected USE from the existing reliability standard to the alternative reliability standard; the probability of different levels of annual USE; the MPC/CPT settings required for the marginal generator to break even; annual demand-weighted pool price.</p>

Estimating the required MPC

As stated in the 2018 RSSR⁵ report, setting the level of the MPC involves making a trade-off on behalf of consumers between:

- ▶ market participants' exposure to high prices, and
- ▶ providing efficient price signals to incentivise generators and loads to meet the reliability standard.

As per the second point above, provided the MPC is sufficiently high, it provides a market mechanism to achieve the reliability standard. For the 2019-20 financial year the MPC is \$14,700/MWh and is currently set to rise in nominal terms each future financial year in line with changes in the consumer price index (CPI).

To estimate the required MPC to achieve the existing or alternative reliability standards, we used the same methodology as was applied in the 2018 RSSR⁵. In this Report, this involves establishing a model where the reliability standard is just met with a new entrant OCGT and adjusting the reliability settings to find the point where the expected market revenue of the OCGT is enough to break even against its annualised costs. This provides a theoretical optimal MPC, which is at the minimum level needed to incentivise enough OCGT capacity to achieve the reliability standard. If the OCGT capacity were to be increased, this would reduce unserved energy and prices in the market, and the OCGT would no longer earn enough revenue to cover its annualised costs.

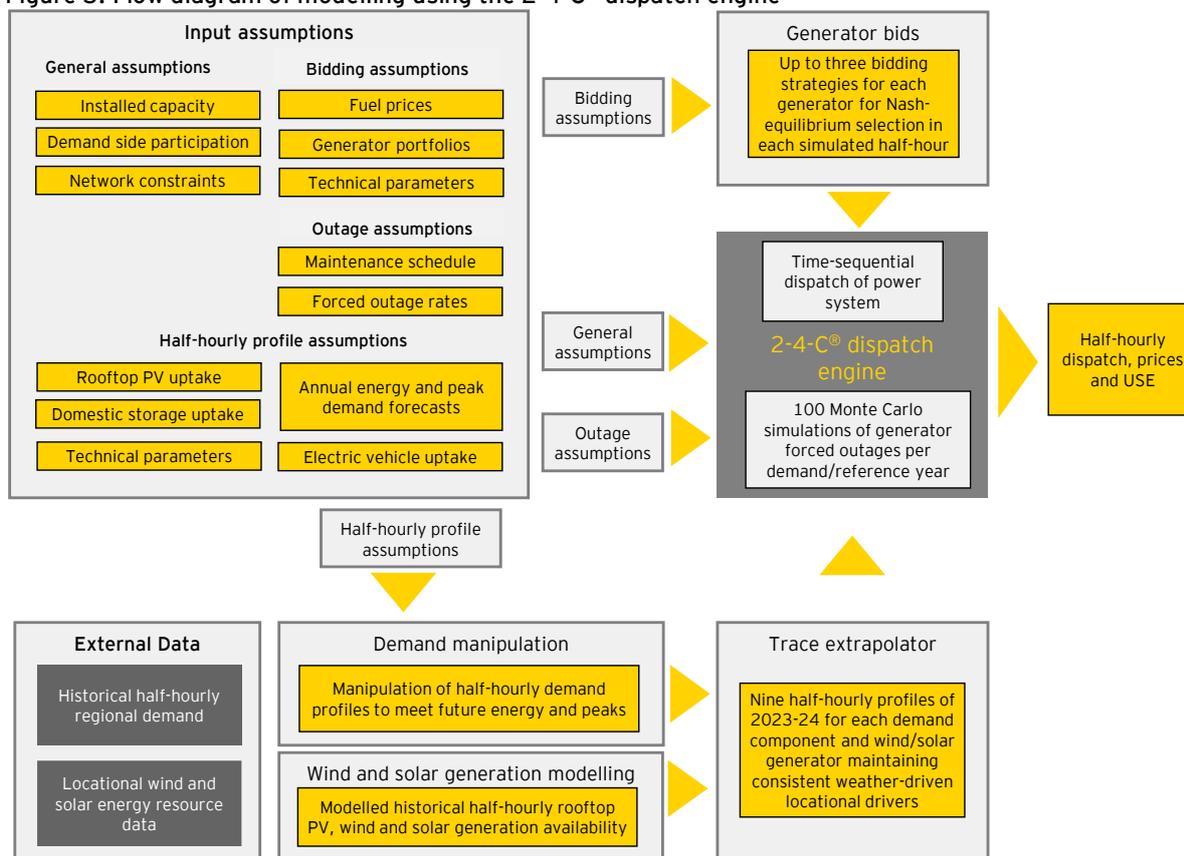
The three key reliability settings that impact an OCGT's revenue are the MPC, Cumulative Price Threshold (CPT) and Administered Price Cap (APC). In this study we maintained the CPT at 15 times the MPC and the APC at the present setting of \$300/MWh and explored adjusting the MPC only. For more details on what the reliability settings represent, and for outcomes exploring different combinations of those settings see the EY 2018 RSSR report⁵.

⁵ See EY's report at <https://www.aemc.gov.au/markets-reviews-advice/reliability-standard-and-settings-review-2018>

3.3 Market simulations

The market simulations are conducted using EY's in-house market dispatch modelling software, 2-4-C[®]. Figure 3 shows a flow diagram depicting the input assumptions and data processing used for the market simulations in this study.

Figure 3: Flow diagram of modelling using the 2-4-C[®] dispatch engine



Refer to Chapter 7 of the 2018 RSSR report for further detail on the individual elements in the diagram.

3.4 Generator bidding

Generator bidding behaviour is conducted in this study using EY's dynamic bidding module which finds the Nash-equilibrium across all portfolios of generators for each half-hour simulated. Three different bidding strategies are allocated to each generating unit in a portfolio and the Nash-equilibrium outcome is a selection of one of those strategies for each half-hour. The three strategies typically consist of one with no capacity above the generators SRMC, one with some capacity withheld to higher prices and another with more capacity withheld.

Contracting is not considered in this study, an assumption that was also made in the 2018 RSSR. Contracting was not included as part of the dynamic bidding selection process due to the lack of transparency around currently contracted positions for generation portfolios. Hence, all generators portfolios were modelled as receiving all their revenue directly from wholesale spot market.

As stated in the assumptions, the marginal OCGT is assumed to always bid all its available capacity at its SRMC. Its net revenue outcome is also considered directly from the wholesale market outcomes as a weighted expectation over 1,800 simulations. Contracting for the OCGT is not considered in the net revenue calculation as such contracts are used to hedge against the potential variability in outcomes, which is captured across the 1,800 simulations.

Whilst this study has endeavoured to capture a range of likely bidding behaviours, there may be other bidding behaviours that are not captured in this study. Alternative bidding strategies and generator portfolio contracting positions could produce significantly different absolute outcomes for the theoretical MPCs. However, these considerations are unlikely to change the key conclusion on the relative difference between the MPCs with the two reliability standards.

3.5 Calculation of USE outcomes

The basis for measurement of the existing and alternative reliability standard has been agreed:

- ▶ In all cases the denominator for the percentage USE calculation will be measured on a regional basis against the “native sent-out energy” as defined by AEMO
- ▶ For each Monte Carlo iteration the USE is the measured sent-out shortfall within each simulation year
- ▶ For the existing standard the expected USE is calculated as a 30/70 weighting on the annual USE outcome from each Monte Carlo simulation of the 10%/50% PoE peak demand forecast cases over nine historical reference weather years (2010-11 to 2018-19):

$$Expected\ USE = \frac{\sum_{r=1}^9 \sum_{i=1}^{100} (0.3 * USE_{10\% POE(r,i)} + (0.7 * USE_{50\% POE(r,i)})}{r * i}$$

Where:

USE is expressed as a percentage of the native sent-out energy

r = historical weather reference years

i = Monte Carlo iterations

Expected USE should be less than 0.002%

- ▶ The alternative standard to be assessed is that there is at least a 90% chance that annual USE will be less than 0.002%. As prescribed by AEMO, the formulation of this standard includes the assumption that there would be no USE in any 90% POE peak demand forecasts. The 90% POE demand would be weighted with 0.3 but it was not modelled and does not appear in the formula. This leaves a weighting of 0.4 for the 50% POE demand and 0.3 for the 10% PoE demand. The probability that USE exceeds 0.002% in any year is measured as:

$$Probability = \frac{\sum_{r=1}^9 \sum_{i=1}^{100} 0.3 * if(USE_{10\% POE(r,i)} > 0.002\%, 1, 0) + 0.4 * if(USE_{50\% POE(r,i)} > 0.002\%, 1, 0)}{r * i}$$

Where:

USE is expressed as a percentage of the native sent-out energy

r = historical weather reference years

i = Monte Carlo iterations

Probability should be less than 10%

4. Scenario development and data sources

Table 4 summarises the key assumptions used for this study, which were provided by the Client in consultation with EY and other industry stakeholders. These assumptions reflect one possible scenario of the market in 2023-24.

Table 4: Overview of key assumptions

Assumption	Source
Assumptions affecting demand / energy consumption	
Load - energy and peak demand, rooftop PV, domestic storage, industrial demand	2019 ISP Central scenario.
Demand for unserved energy % calculation	Native (sent-out) energy.
Assumptions affecting market supply	
New renewable generation	Agreed list of advanced projects assumed to proceed and meet the renewable energy targets.
Thermal generation retirements	Announced retirements, plus end of technical life retirements based on AEMO's Generating Unit Expected Closure Year - 8 November 2019.
Fuel prices	2019 ISP Neutral for gas and coal.
Existing generator bidding assumptions	Generators assigned to portfolios use a dynamic bidding approach where one of three bidding strategies are selected by the model in each time-step based on the Nash-equilibrium. no specific contracting assumptions are applied (as per 2018 RSSR). Other generation facilities bid into the market based on observed common, highest frequency bidding behaviours.
Forced outage rates	2019 ISP, except EY-adjusted coal reliability.
Network constraints	AEMO ESOO 2018 constraint set.
Network augmentation	ISP Group 1 network augmentations included.
Marginal OCGT cost assumptions	
Economic life, auxiliaries, FOM, VOM, capex, heat rate, summer derating, full forced outage rate, maintenance rate	Aurecon report ⁶ .
WACC	Pre-tax, real WACC of 10% (as per 2018 RSSR).
Bidding strategy	Bid all capacity at SRMC (calculated from fuel price and VOM). Profitability based on market revenue relative to annualised cost in 2023-24 (calculated based on capex, economic life, WACC and FOM). No contracting assumed.

A material set of assumptions for the MPC outcomes is the marginal OCGT parameters. These are outlined below in Table 5.

⁶ See Aurecon's report at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Aurecon-2019-Cost-and-Technical-Parameters-Review-Draft-Report.PDF

Table 5: Overview of marginal OCGT cost assumptions

Parameter	New entrant OCGT parameters			Source
	NSW (NCEN)	VIC (LV)	SA (ADE)	
Gas price scenario	Neutral outlook - ISP 2019			General modelling assumption of ISP 2019 Neutral fuel prices.
Gas price for OCGTs in 2023-24 (\$/GJ)	\$11.46	\$10.93	\$11.11	
Economic life (years)	25			Aurecon report
Auxiliaries (%)	2			
FOM (\$/MW)	\$12,348	\$12,348	\$12,348	
VOM (\$/MWh sent-out)	\$4.02	\$4.02	\$4.02	
Capex (\$/kW)	\$1,225	\$1,225	\$1,225	
WACC (pre-tax real)	10%			
Heat rate (GJ/MWh as-gen)	11.28			Aurecon report, same number selected for winter and summer for simplicity
SRMC (\$/MWh as-gen)	\$133.20	\$127.23	\$129.26	Calculation based on fuel price and VOM.
Annualised fixed costs (\$/MW installed)	\$147,304	\$147,304	\$147,304	Calculation based on capex, economic life, WACC and FOM.
MLF	1.0			Assume MLF of 1 for simplicity.
Summer derating (% nameplate)	89.7			Aurecon report
Full forced outage rate (%)	2.0			
Maintenance rate (days per year)	3			
Bidding strategy	Bid all capacity at SRMC			Profitability based on the market revenue relative to annualised cost in 2023-24; no contracting assumed.

More detail on the key input assumptions can be found in Appendix A.

5. Outcomes

5.1 Capacity

Using the agreed baseline installed capacity, transmission upgrades and other market assumptions for 2023-24, the base model produced a materially lower expected USE than the existing reliability standard. This is less than forecast in AEMO's 2019 ES00⁷, which is primarily driven by additional transmission upgrades and a total of approximately 1,500 MW additional solar PV and wind capacity assumed to be operational by 2023-24 compared to the 2019 ES00. In total, the modelling in this study assumes a NEM-wide collective solar PV and wind capacity of approximately 14,000 MW.

With the relatively low USE outcomes from the base model, some existing capacity is required to be removed from the model (effectively retired early) to achieve a model that breaches the existing reliability standard. As a first step we removed the assumed market-price-responsive demand-side capacity in the model on the basis that this capacity is less certain to be available to the market than conventional generation capacity.

Table 6 presents the subsequent existing capacity that was required to be removed to exceed the existing standard, as well as the for the changes in generator capacity between the other modelling steps for each scenario.

Table 6: Changes in capacity (MW) between the modelling steps for each scenario

Between modelling steps	Description	NSW	VIC	SA
1-2	Generator capacity retired early to exceed the existing standard*	660	1,990	600
2-3	Marginal OCGT capacity added to just achieve existing standard	70	460	170
3-4	Additional OCGT capacity required to just achieve alternative standard	510	420	130

* In addition to assuming no market-price-responsive demand-side participation is active.

Generator capacity retired early to exceed the existing standard

Thermal generators selected for retirement are based on how early their announced closure dates are to reflect a plausible scenario. The existing generator units retired in each scenario are:

- ▶ **NSW:** Vales Point coal power station (one of two units, 660 MW)
- ▶ **VIC:** Yallourn coal power station (1,480 MW) and Newport gas power station (510 MW)
- ▶ **SA:** Torrens Island B (three of four units, 600 MW)

Marginal OCGT capacity added to just achieve present existing standard

The marginal OCGT capacity required to reduce the expected USE back to just under 0.002% (meeting the existing standard) is a function of the size of the last unit that was selected to be retired in the previous step and the resulting expected USE. Apart from its impact on the resulting capacity mix, this OCGT capacity is inconsequential to the MPC outcomes as it is only the marginal additional capacity that influences the OCGT revenue outcomes.

⁷ https://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ES00/2019/2019-Electricity-Statement-of-Opportunities.pdf

Additional OCGT capacity required to just achieve alternative standard

In each region in turn, the marginal OCGT capacity was increased further until the alternative standard was met. The additional marginal OCGT capacity required to reduce the expected USE from just meeting the existing standard to just meeting the alternative standard ranges from 130 MW to 510 MW across the three regions. This capacity is approximately proportional to the energy demand in the respective regions, which make sense considering annual USE being defined as a proportion of the energy demand in both reliability standards.

The case of two or more regions having USE close to the existing reliability standard simultaneously was not modelled. It is expected that the additional OCGT capacity required to reduce USE in such situations would be less than the sum of the additional capacity required for each region individually. As such the sum of the three capacities for the three regions (1,060 MW) is an upper bound on the total capacity required across those three regions to meet the alternative standard. Based on the assumed capital cost of \$1,225/MW, this represents an upper bound capital cost of approximately \$1.2b.

5.2 Unserved energy

Table 7 presents the USE outcomes for the modelled scenarios that meet each of the reliability standards, in terms of the measures on which each standard is defined and the Loss of Load Probability (LOLP).

Table 7: USE outcomes for all regions when meeting each reliability standard

Region	NSW	VIC	SA
Reliability standard	Expected annual USE (% of energy)		
Existing	0.0020%	0.0019%	0.0018%
Alternative	0.0007%	0.0006%	0.0008%
Reliability standard	Probability of annual USE > 0.002% of energy		
Existing	21.6%	22.0%	20.2%
Alternative	9.8%	9.1%	9.3%
Reliability standard	Probability of annual USE > 0% of energy (LOLP)		
Existing	43.1%	31.8%	43.7%
Alternative	27.3%	22.6%	23.7%

The table shows that, compared to the existing reliability standard, the alternative standard:

- ▶ represents reducing the expected unserved energy to approximately one third,
- ▶ represents approximately half the probability of USE being > 0.002%, and
- ▶ would reduce the probability of any USE in a year or LOLP by approximately one third.

USE outcomes by region

Figure 4 shows the probability that USE exceeds a certain value in any sample year. Under the existing reliability standard (expected USE 0.002%) the figure shows the shape of the probability curve is similar across regions, and there is a probability of around 20% of exceeding 0.002% USE.

Figure 4: Probability of exceedance of expected annual USE (%) for all regions and each reliability standard

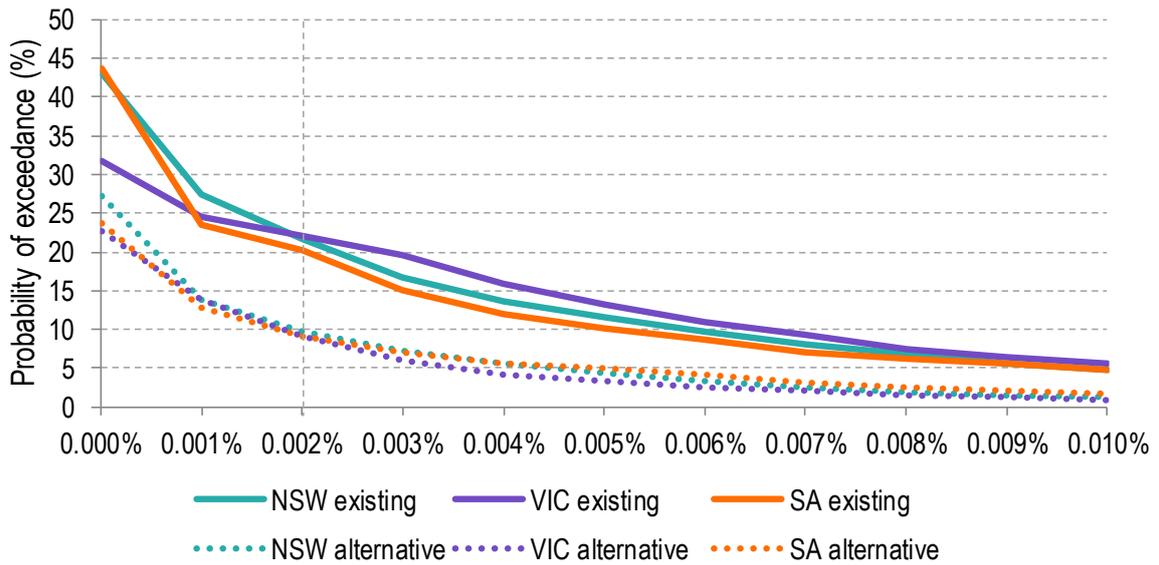


Figure 5 shows how the probability of occurrence of expected USE for NSW changes when moving between the reliability standards. The labels of expected USE should be viewed as bands showing the sum of annual USE less than or equal to the value and greater than the previous value. Moving from the existing standard to the alternative standard represents a shifting lower (to the left) of all probability outcomes for an expected USE of greater than 0.002%.

Figure 5: Probability of occurrence of expected USE (%) for NSW when meeting either reliability standard (x-axis labels represent the maximum for each band of width 0.001%)

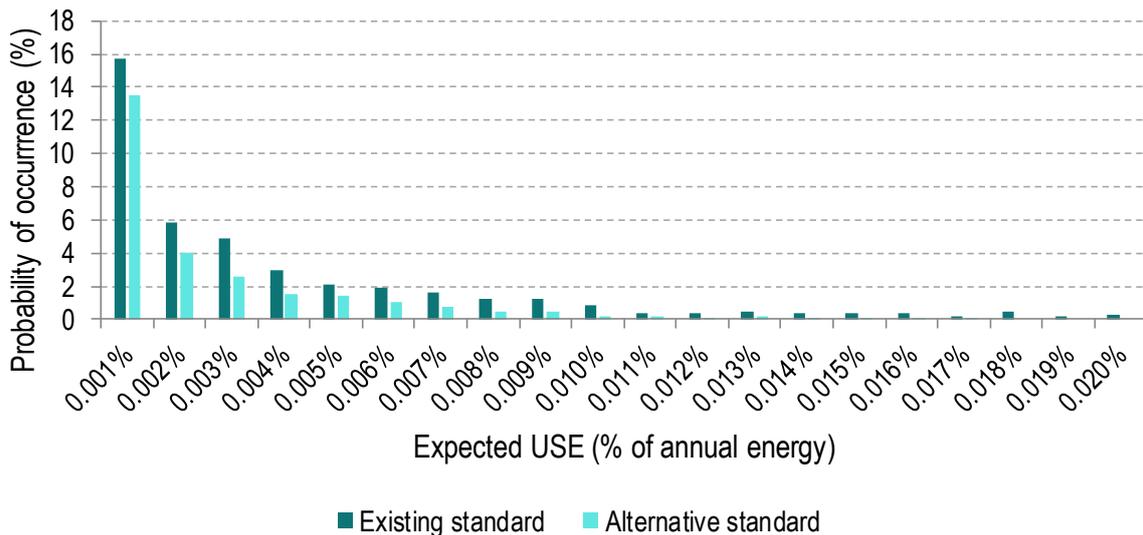


Figure 5 is also shown for the purpose of comparing directly with Figure 33 in the 2019 ES00 report, where the expected USE in NSW is similarly modelled to be close to the existing standard. The distribution of USE in each band of USE is broadly similar to the 2019 ES00 outcome.

5.3 Market Price Cap

Table 8 shows the outcomes for the theoretical optimum MPC, along with the achieved capacity factor of the marginal OCGT. As stated earlier, the CPT setting was maintained at 15 times the MPC setting as per the present settings in the market. This means that any increase in the MPC presented in this Report is accompanied by a proportional increase in the CPT.

Table 8: Theoretical optimum MPC and the outcomes for key MPC drivers in each case

Region	Standard	Theoretical optimum MPC (\$/MWh)	OCGT capacity factor (%)	Proportion of periods with prices > \$1,000/MWh
NSW	Existing	48,000	4.4	0.05%
	Alternative	130,000	2.4	0.02%
VIC	Existing	28,000	9.5	0.09%
	Alternative	85,000	8.6	0.09%
SA	Existing	8,000	9.3	0.20%
	Alternative	33,000	7.8	0.14%

The MPC outcomes presented for the existing reliability standard are different to the present MPC setting of \$14,700/MWh and are also quite different between the regions. This is an outcome of the assumptions used in this study, including the dynamic bidding assumptions and the marginal OCGT parameters.

These outcomes do **not** necessarily suggest that a change should be made to the present reliability settings for meeting the existing reliability standard and addressing that question is outside the scope of this study. However, the outcomes present three different scenarios under which the theoretical optimal MPC is quite different allowing the study to explore the range of comparative outcomes when tightening to the alternative reliability standard.

The MPC outcomes presented for the alternative reliability standard tell a consistent story with the MPC (and CPT) being required to be increased by approximately a factor of three compared to the existing reliability standard.

There are a few key factors that influence the market revenue of the marginal OCGT and in turn, the theoretical optimal MPC. These are:

- ▶ The frequency of prices above the OCGT's SRMC
- ▶ How frequently the prices are very high (e.g., >\$1,000/MWh)
- ▶ The assumed summer derating for the OCGT (89% in this study) as high prices tend to occur in the summer months

Since the OCGT incurs variable costs at the SRMC whenever it generates, when the price is only a little higher than its SRMC it can only earn a comparatively small revenue net of those costs. As such, much higher prices are more influential in contributing to recovering the fixed costs of the OCGT.

As indicated in Table 8, the proportion of periods with prices > \$1,000/MWh has a much stronger relationship to the MPC outcomes than the achieved OCGT capacity factor. However, only the full distribution of prices can tell the full story on where the OCGT is earning its revenue.

Table 9 presents the modelling outcomes in terms of the number of hours per year with the price at the MPC, with the APC being the market price cap applied (due to the CPT triggering) and the hours per year that the price is capped at the APC.

Table 9: MPC and APC statistics showing the annual average hours where price caps were triggered

Region	Standard	Hours per year at MPC	Hours per year with APC as cap	Hours per year where APC caps price
NSW	Existing	2.6	14.0	1.7
	Alternative	1.1	3.9	0.4
VIC	Existing	2.5	16.2	1.6
	Alternative	1.4	4.2	0.4
SA	Existing	13.3	203.1	10.3
	Alternative	1.0	6.6	0.5

The table shows that the number of MPC-priced periods and APC periods is generally reduced when USE is reduced to meet the alternative reliability standard. The table also illustrates that there are many more MPC-priced hours in SA compared to the other regions with the existing standard. This is because the MPC setting in the SA case is \$8,000/MWh and the bidding profiles used have a comparatively high capacity between \$8,000/MWh and the present MPC setting of \$14,700, resulting in a high number of periods being capped by the MPC.

Impact on demand-weighted price

The wholesale market component on average retail electricity bills is proportional to the demand-weighted wholesale market price as this represents the average price for each megawatt-hour of demand. Table 10 shows the forecast annual demand-weighted price (\$/MWh) and annual time-weighted price (\$/MWh) for each scenario and case.

Table 10: Annual average pool prices for each reliability standard across the three regions

Region	Standard	Demand-weighted price (\$/MWh)	Percentage increase (demand-weighted)	Time-weighted price (\$/MWh)	Percentage increase (time-weighted)
NSW	Existing	92.74	2%	76.67	0.6%
	Alternative	94.92		77.16	
VIC	Existing	95.69	3%	80.17	0.4%
	Alternative	99.04		80.46	
SA	Existing	94.80	4%	76.44	1.3%
	Alternative	98.79		77.41	

This outcome reflects that the higher MPC-priced periods are occurring when the demand is higher than in other periods where the additional OCGT capacity is reducing prices. Based on a representative household customer using 4,000 kWh per year⁸ (4 MWh), an increase of \$2-4/MWh in the wholesale market price translates to \$8-\$16/year for each household. This estimate may change if customer energy consumption increases (EV charging for example) or decreases (larger rooftop PV installations for example). It also assumes a simple flat electricity tariff whereas future customers may have access to more flexible tariff arrangements such as time of use to improve their annual electricity cost exposure.

⁸ Based on NSW and Victoria in Table 3.1 of the AEMC's 2019 Retail Electricity Price Trends report <https://www.aemc.gov.au/sites/default/files/2019-12/2019%20Residential%20Electricity%20Price%20Trends%20final%20report%20FINAL.pdf>

For the wholesale market in the NSW, VIC and SA regions with an operational sent-out energy of approximately 120,000,000 MWh this translates to \$240m-\$480m per year in wholesale energy traded⁹.

The percentage increases for demand-weighted prices are higher than for time-weighted average price. The summer derating factor limits the contribution of the marginal OCGT, by just over 10% of its nameplate capacity during the largest USE events, which largely occur in the summer months. This is the primary reason the time-weighted price increases in the alternative standard cases as the OCGT needs to recover proportionately more revenue during the majority of MPC-priced periods in summer as its capacity is de-rated during those times

This price increase presented is between the modelled cases that achieve the existing and alternative reliability standards. However, in regions where there is little expected USE, increasing the MPC would apply to fewer periods and the price increase would be smaller.

5.4 Market price and revenue breakdown analysis

Figure 6 below illustrates the breakdown of regional wholesale market prices above the OCGT SRMC in different price ranges in each scenario. The height of each column represents the number of periods when the OCGT is dispatched as well as when the OCGT would have been dispatched if it wasn't on a forced outage. The proportion of time that prices are greater than \$1,000/MWh is relatively small. However, as discussed earlier, intervals of very high market prices provide a significant contribution to the marginal OCGT revenue.

Figure 6: Percentage occurrence breakdown of prices above OCGT SRMC in each region

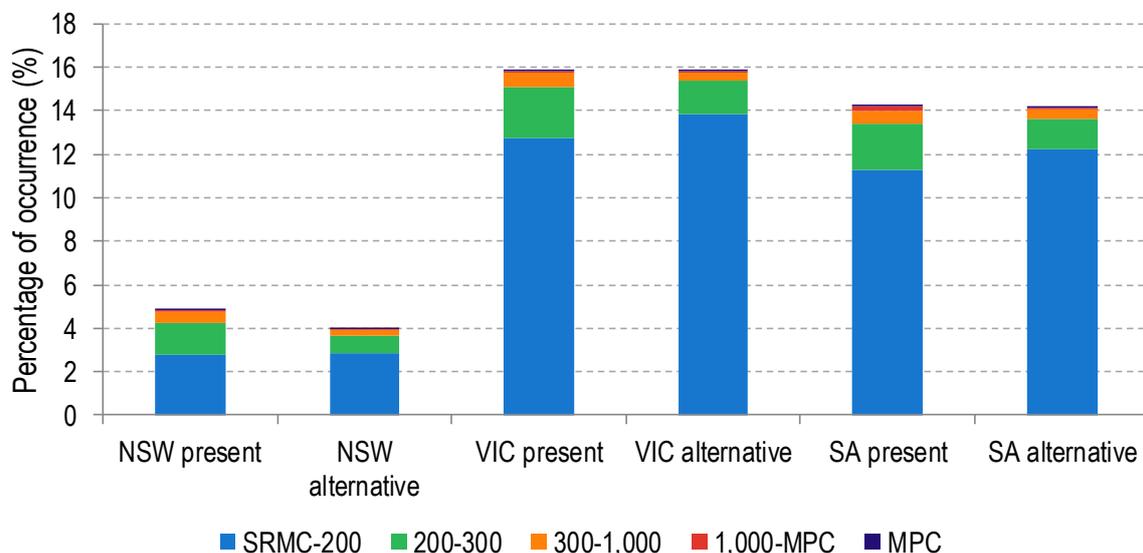


Figure 7 below shows the breakdown of the marginal OCGT revenue in the scenario where the existing reliability standard is just met with the existing reliability settings applied. The chart shows that the periods where prices are above \$1,000/MWh have the largest contribution to the net revenue and it is these periods that contribute the most to the differences in the OCGT net revenue between the regions. The chart also shows the required net revenue for the marginal OCGT to break even, indicating that the existing MPC is insufficient in NSW and VIC but higher than needed in SA.

⁹ Across the whole NEM including Queensland and Tasmania the operational sent-out energy is approximately 180,000,000 MWh translating to \$360-720m per year in energy traded.

Figure 7: The breakdown of net revenue for the marginal OCGT generator in each region for just meeting the existing reliability standard, with the existing reliability settings (MPC = \$14,700/MWh)

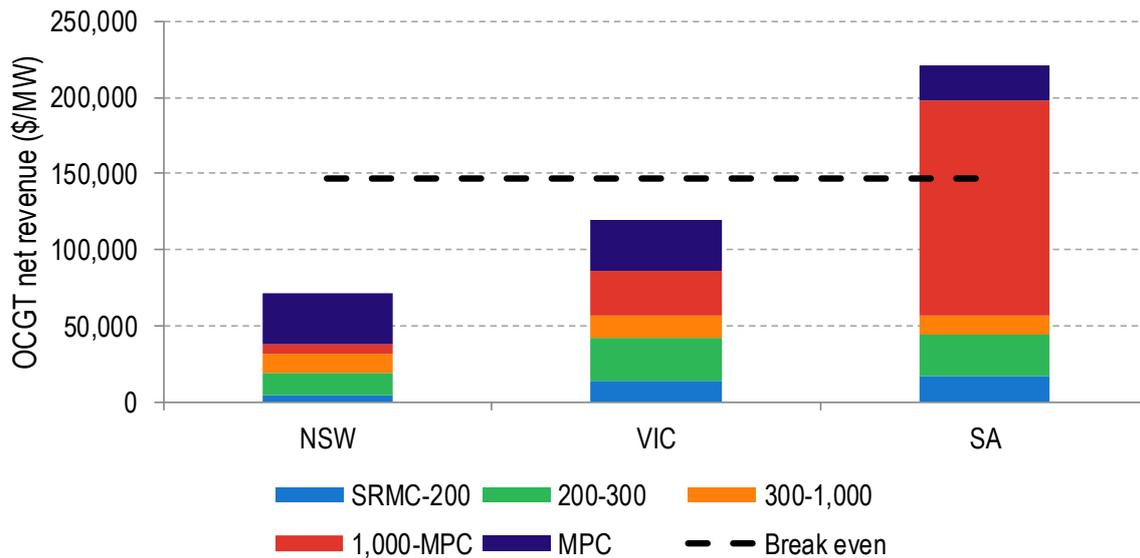
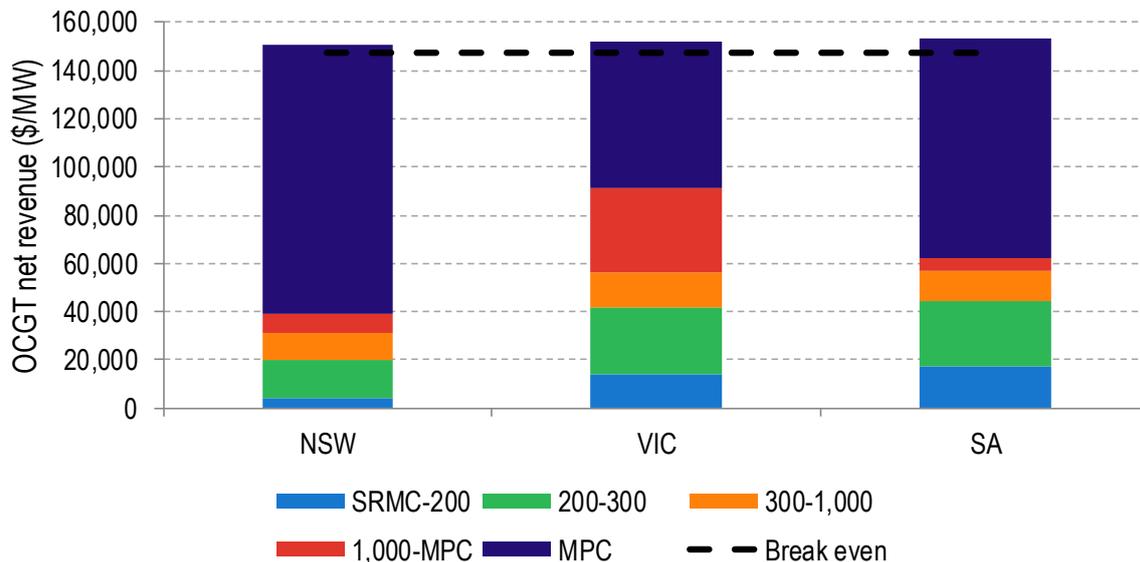


Figure 8 below shows the breakdown of the marginal OCGT revenue after adjusting the MPC (and CPT in proportion) so that the OCGT just breaks even under the existing standard.

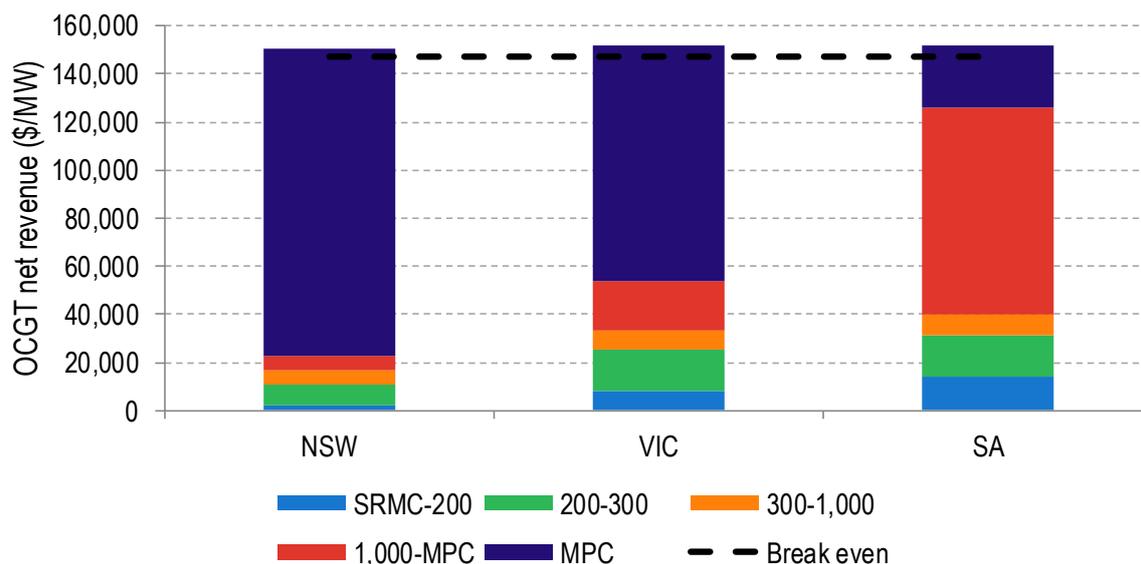
Figure 8: The breakdown of net revenue for the marginal OCGT generator in each region for just meeting the existing reliability standard, with the MPC at the breakeven value as shown in Table 8



Further analysis shows that in SA, prices that fall into the category of between \$1,000/MWh and MPC are occurring at the higher end of the range, frequently above \$10,000/MWh. Under the adjusted MPC of \$8,000/MWh these price intervals are capped to the adjusted MPC and therefore in Figure 8 the majority of the OCGT net revenue is shifted to the MPC category.

In the alternative standard case, more capacity is required to achieve a reduced unserved energy expectation. At the same time the higher quantity of capacity operates for a smaller proportion of the time. Therefore, a higher market revenue opportunity must be available to the marginal OCGT capacity in order to meet its fixed costs in a smaller amount of time. Figure 9 below shows the breakdown of the marginal OCGT revenue in the alternative standard case after adjusting the MPC (and CPT in proportion) so that the OCGT just breaks even.

Figure 9: The breakdown of net revenue for the marginal OCGT generator in each region for just meeting the alternative reliability standard, with the MPC at the breakeven value as shown in Table 8



The increased MPC in NSW and VIC has the effect of proportionally increasing the percentage of revenue gained from MPC periods. In SA the estimated optimal MPC was increased to \$33,000/MWh and therefore the proportion of market revenue between \$1,000/MWh and MPC returns to more similar levels to the existing MPC settings revenue breakdown shown in Figure 7.

6. Limitations

This Report only considers the scenarios modelled and presented. However, other plausible scenarios exist that are outside the scope of this Report.

The MPC outcomes presented are based on a set of assumptions on the technical and cost parameters for the marginal OCGT. In addition, the net revenue calculations are based on a single-year study and compare with the annualised costs of the OCGT. In the actual market an OCGT would likely need to consider a longer time horizon for making an investment decision. There are also a variety of other factors that may influence this investment decision and the associated cost assumptions used in this study. One example is the heightened level of uncertainty created by investments that are being underwritten under various government policies.

Moreover, the 2018 RSSR found an OCGT to be the marginal generator type to set the reliability settings for the existing reliability standard. Knowing this outcome and changes to technology cost assumption since then, it was considered unlikely that any other generator type would now be the marginal type and modelling of new entrant capacity to deliver reliability standards was limited solely to new entrant OCGT.

Additionally, this modelling does not deliver a baseline estimate of expected USE in the NEM in 2023-24 as AEMO has taken an approach to deliver this in the 2019 ESOO. Furthermore, this study does not set out to forecast the required MPC for the existing reliability standard. Instead, the modelling undertaken in this study involved modifying the expected capacity mix in 2023-24 to produce an outcome where the alternative reliability standards are explored and show the relative increase needed to move from the existing standard to the proposed alternative standard.

Appendix A Modelling assumptions

A.1 Thermal generation developments

Table 11 lists the retirements assumed in the scenario. These generator retirements are in line with the AEMO Generation Information resource¹⁰ that was available at the time of modelling.

Table 11: Retirements due to age or operational concerns

Power station	Region	Type	Capacity (MW)	Timing
Torrens Island A	SA	Gas - Steam	480/240 240/120	1/09/2020 (reduced capacity) 1/09/2021 (reduced capacity)
Mackay GT	QLD	OCGT	34	1/07/2021
Liddell	NSW	Black Coal	2,000	1 unit - 1/04/2022; Remaining 3 units - 1/04/2023
Osborne Power Station	SA	CCGT	172	On or before 1/07/2023
Tamar Valley CCGT	TAS	CCGT	208	Out of service

A list of announced new development (non-wind/solar) are shown in Table 12 and are also in line with the AEMO generation information resource that was available at the time of modelling.

Table 12: Announced and recently commissioned new developments (non-wind/solar)

Power station	Region	Capacity (MW)	Technology	Timing
Loy Yang B upgrade	VIC	40 MW 40 MW	Brown Coal	Commissioned 1/07/2020
Neoen Bulgana 20 MW battery	VIC	20 MW / 34 MWh	Storage	1/07/2020
Lake Bonney Battery	SA	25 MW / 52 MWh	Battery	Commissioned
Lincoln Gap Battery	SA	10 MW / 10 MWh	Battery	1/07/2020
Bayswater upgrade	NSW	25 MW 25 MW 25 MW 25 MW	Coal	Commissioned 1/07/2021 1/07/2022 1/06/2023

A.2 Assumed committed new wind and solar capacity

Table 13 lists the assumed new entrant renewable developments in the scenario assumed to be commissioned prior to the modelled year. These developments are based on public information with the criterion that the projects need to have obtained a power purchase agreement, financial close or are have achieved a more advanced stage as advised by the Client. The resulting list exceeds the LRET target of 33,000 GWh by 2020.

¹⁰ AEMO's Generation Information was taken from <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>

Table 13: Schedule of renewable energy generation development

Project	Region	Capacity (MW)	Technology
Bango	NSW1	240	Wind turbine
Berrybank Stage 1	VIC1	180	Wind turbine
Biala	NSW1	108.5	Wind turbine
Bomen Solar Farm	NSW1	100	Solar PV
Brigalow Solar Farm	QLD1	34	Solar PV
Bulgana	VIC1	194	Wind turbine
Carwarp	VIC1	100	Solar PV
Cattle Hill	TAS1	144	Wind turbine
Cherry Tree	VIC1	57.6	Wind turbine
Cohuna	VIC1	27.3	Solar PV
Crudine Ridge	NSW1	135	Wind turbine
Darlington Point Solar Farm	NSW1	275	Solar PV
Deakin University Geelong PV Plant	VIC1	6.59	Solar PV
Dundonnell	VIC1	336	Wind turbine
Goonumbla	NSW1	70	Solar PV
Granville Harbour	TAS1	112	Wind turbine
Kennedy Energy Park Solar	QLD1	15	Solar PV
Kennedy Energy Park Wind Stage 1	QLD1	43.2	Wind turbine
Kiamal Stage 1	VIC1	200	Solar PV
Lal Lal Elaine Section	VIC1	83.6	Wind turbine
Limondale Stage 1	NSW1	29	Solar PV
Moorabool Stage 1	VIC1	150	Wind turbine
Mortlake South	VIC1	157.5	Wind turbine
Nevertire Solar Farm	NSW1	120	Solar PV
Stockyard Hill	VIC1	536	Wind turbine
Sunraysia	NSW1	200	Solar PV
Warwick Solar Farm	QLD1	64	Solar PV
Winton	VIC1	85	Solar PV
Woolsthorpe	VIC1	72	Wind turbine
Yarranlea Solar Farm	QLD1	100	Solar PV
Yatpool	VIC1	81	Solar PV
Collector	NSW1	226.8	Wind turbine
Jemalong	NSW1	50	Solar PV
Limondale Stage 2	NSW1	220	Solar PV
Vales Point Solar	NSW1	55	Solar PV

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