7 July 2022

Mr Charles Popple
Chair
AEMC Reliability Panel

Dear Mr Popple

2022 Reliability Standard and Settings Review – Draft Report

Hydro Tasmania appreciates the opportunity to respond to the Reliability Panel's *2022 Reliability Standard and Settings Review* Draft Report.

Throughout this review period, the AEMC and the Reliability Panel have demonstrated a keenness to engage in meaningful consultation with industry about the ongoing suitability of the NEM's reliability framework. We commend the AEMC for their transparent and highly consultative approach, and greatly appreciate the robust analysis that has been conducted by IES to inform this review process.

Hydro Tasmania is broadly supportive of the Panel's observations and draft recommendations contained in the *2022 Reliability Standard and Settings Review* Draft Report.

Appendix A to this submission contains Hydro Tasmania's views on the Reliability Standard and Settings. This appendix also contains Hydro Tasmania's views on the current reliability settings in relation to the recent Administered Price Period (APP) and Market Suspension. Hydro Tasmania also provides some commentary regarding the IES modelling approach and assumptions in **Appendix B**.

If you wish to discuss any aspect of this submission, please contact me on (03) 8612 6443 or at Colin.Wain@hydro.com.au.

Yours sincerely,

Colin Wain
Manager Policy Development

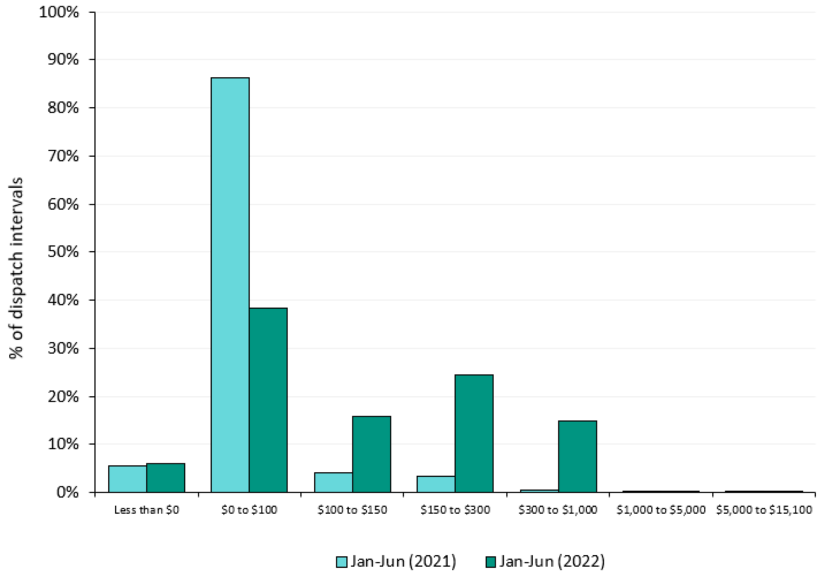
Appendix A – Hydro Tasmania comments on the Draft 2022 Reliability Standard and Settings

1. Relationship between the market settings and the 2022 energy crisis

Given the disruption to the energy market this year, there will naturally be greater attention on energy policy and regulatory settings. The timing of this Review may bring more questions from stakeholders and the community about how the market settings could have contributed to or prevented the high prices, market suspension and financial strain on market participants.

While we note that the energy crisis this year has affected retailers, we do not consider that alternative market settings such as a lower market price cap (MPC) would have alleviated financial stress in this instance. The figure below shows the counts of dispatch intervals by price bin across NEM regions (excluding TAS) in the first half of 2021 and 2022. In 2022, there has been a significant increase in dispatch intervals priced at $150 to $1,000 compared to 2021. The share of dispatch intervals priced above $5,000 is mostly unchanged in 2022 at 0.17% compared to 0.13% in 2021.

In this case, a lower MPC would not have protected retailers from financial stress. Instead, a lower MPC could have reduced the incentive for retailers to buy cap contracts, leading to even more financial strain from exposure to sustained high prices. We consider that energy constraints (see Section 2 below), rather than capacity constraints, are leading to persistently high, but not extreme prices, which in turn are affecting retailers.



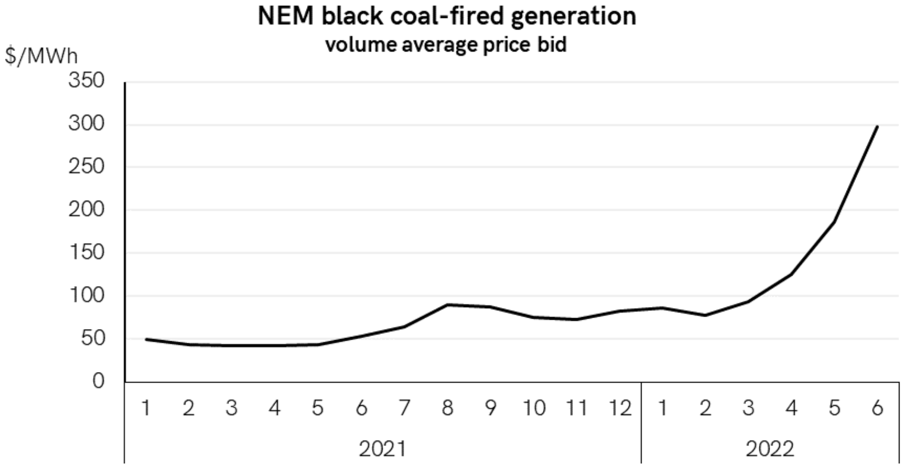
Source: Hydro Tasmania analysis of Australian Energy Market Operator (AEMO) data

While a lower cumulative price threshold (CPT) would have pushed the market into an APP more quickly, as discussed below, this is likely to have hastened the market suspension as generators took action to avoid dispatching at the APC (and at a loss relative to their short-run marginal cost (SRMC)).

Hydro Tasmania appreciates the hardship the 2022 NEM energy crisis is causing to the industry as whole, and in particular, smaller retailers and consumers. We consider the failure of smaller retailers as an undesirable outcome as it will lead to reduced competition in the sector. However, as noted above, our view is that market settings have not contributed to these hardships. Instead, we believe current challenges in our market will be better addressed by government and policy measures outside the scope of this review.

2. Administered Price Cap (APC)

The APC plays an important role in our market by protecting and sustaining electricity trading during periods of sustained high prices. Since the commencement of this review process, the NEM has experienced a particularly turbulent period and volatile prices, driven predominantly by high gas prices (capped at $40/GJ), sustained high levels of unplanned thermal plant outages, and record high international coal prices (coupled with domestic coal supply issues) which have led black coal-fired generators to substantially increase the prices of their market offers. The chart below shows the significant increase in volume-weighted average price bid by black coal-fired generators[1], rising from $42/MWh in early 2021 to $298/MWh in June 2022.



Source: Hydro Tasmania analysis of Australian Energy Market Operator (AEMO) data

This combination of factors has resulted in the application of an APP period across all NEM regions from Monday 13 June to Wednesday 22 June 2022, followed by a prolonged and unprecedented spot market suspension. This series of events provides important context to consider the ongoing suitability of the current APC setting.

There are four key variables that determine the Short-Run Marginal Cost (SRMC) of Open-Cycle Gas Turbine (OCGT) generation: availability of gas, the gas price; the OCGT heat rate; and variable operating expenditures (inc. transportation costs). Assuming gas is available, given its price cap of $40/GJ; a heat rate of approximately 12[2]; and a variable operating expenditure of between $2.49/MWh and $3.12/MWh[2], the SRMC of OCGT sits somewhere in the order of $480/MWh to $500/MWh. This is significantly higher than the administered price cap of $300/MWh. This effectively means that OCGT operators were likely unable to recover their operating costs under the recent APP.

We also note that while market caps and suspension can provide short-term relief to market participants through lower spot prices, higher costs associated with fuel and market tightness will still be recovered from the market through compensation processes, as well as any costs associated with Reliability and Emergency Reserve Trader (RERT) activations. This may result in a similar level of overall

[1] Bid date adjusted to exclude bids below $20/MWh and bids above $1,000/MWh.
[2] https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/inputs-assumptions-and-scenarios-workbook.xlsx?la=en

costs for end-consumers, but with a re-balancing of costs to occur outside of the market. In this case, retailers that have prudently hedged against high spot prices are no longer capable of managing these out-of-market risks. Already this year (as at end of June), costs associated with RERT activations and dispatch total $136 million, at an average cost $23,062/MWh. This is well above the current MPC of $15,100/MWh.

To this end, it may be prudent for the Panel to consider re-adjusting the APC to a range of between $500-$600/MWh. Had the APC been set in this range, Hydro Tasmania considers it likely that we would not have observed OCGT operators bidding their assets unavailable, and we would have seen the market continue to clear efficiently during the recent APP.

We believe there is an urgent need to increase the APC given present market dynamics.

3. Market Price Cap (MPC) and Cumulative Price Threshold (CPT)

Hydro Tasmania has long held the view that amendments to the RSS can provide the basis for maintaining a secure and reliable supply of energy in the NEM. We commend the Reliability Panel and IES for the rigorous and transparent approach to the modelling and the approach to base the consideration of market settings on the outputs of the modelling.

Hydro Tasmania's view is that maintaining the status quo could result in a range of undesirable outcomes, including: insufficient incentivises for efficient investment in flexible and dispatchable generation and storage assets; a heightened risk of market interventions (including RERT activations, generator directions and market suspensions); and ultimately, a heightened risk of reliability shortfalls across the review period. The remainder of this section covers Hydro Tasmania's views on:

i. A clear transitionary pathway to a higher MPC/CPT;
ii. Trade-offs between the MPC and CPT;
iii. Implications for contract market liquidity; and
iv. The relationship between the CPT and APC.

i. A clear transitionary pathway to higher MPC/CPT settings

Unlike the urgency surrounding the need for an increase in the APC, we support the approach proposed by the Reliability panel to stagger increases to the MPC and CPT over the Review Period (FY2025-FY2028). We consider that this approach balances the need for strengthening investment signals for new entrants and allowing sufficient time for consumers and market participants to adjust to the new market settings. Given the level of new investment expected during the next decade and during the Review Period, we also caution against a major delay in transition to appropriate market settings, as this would risk delaying the investment required to replace ageing thermal plant, resulting in high market costs and undesirable reliability outcomes.

ii. Trade-offs between the MPC and CPT

We note that IES modelling indicates that short-duration storage will likely be sufficient to cover the first two-hours of unserved energy (USE) events. As has also been noted in this review however, there is a heightened focus on tail-risk reliability events as the reliability risk profile changes in the NEM. These events are typically high-impact and prolonged events, and as such, it may be prudent to opt for a combination of MPC/CPT settings that will also incentivise investment in a broad set of technology options capable of generating throughout extended shortfalls, such as pumped storage hydropower, or OCGT gas peaking plant. Assets such as these will provide valuable insurance against the increasing risk of high impact and enduring reliability shortfalls. Further, given current uncertainties about technology cost reduction, it remains prudent to have market settings that provide appropriate incentives for a broader range of technologies, rather than focussing too narrowly on one option.

iii. MPC/CPT settings and implications for contract markets

We consider that an MPC and CPT setting in the range proposed in the draft report will have significant impact on the contract market including:

Cap contract liquidity – Hydro Tasmania considers that increases to the MPC and CPT would increase the incentive for retailers to hedge against volatility and therefore increase aggregate demand for cap contracts. For example, retailers will consider the hourly risk/cost of being short/exposed to an MPC event against the cost of purchasing a cap contract. A worked exampled is provided below for a Queensland retailer looking to cover a 20 MW position for Q4 2023.

- QLD Q4 2023 cap price: $45/MWh. Cost of 20 MW cap contract = $45/MWh x 20MW x 24(hours) x 92(days) = $1,987,200 cap premium per quarter.
- Cost per hour of a MPC event with a cap of $15,100 = 20 x 15,100 = $302,000/hour.
- Cost per hour of a MPC event with a cap of $30,000 = 20 x 30,000 = $600,000/hour.

In deciding whether to purchase a cap, the retailer will come to a view of the likelihood of MPC events and whether it is a better option to buy a cap contract or remain short to the market. A higher MPC means they will be more likely to buy a cap contract due to a higher cost per hour of being short to the spot market.

Increased cap contract demand and price, along with the higher potential spot market revenues will provide a strong investment signal for dispatchable generation. We would also note the converse of this may be true. In other words, reacting to the energy challenges of this year by lowering the MPC would risk reducing the level of retailer contracting and ultimately, could leave some smaller retailers more exposed to high prices in the future.

Incentives for cap contract sellers – Hydro Tasmania considers that where the CPT is set too low, short duration storage technologies such as batteries may be incentivised to oversell cap contracts relative to their actual physical availability. During a sustained period of high prices where a battery's stored energy is likely to be depleted, the APC will provide artificial protection to these parties. In the long term, there is a risk that a relatively low CPT will artificially support the contract position of short duration technologies and may not deliver the most efficient mix of generation technologies to meet reliability needs in all future market conditions – particularly with increasing VRE and tail risk for USE outcomes.

Noting that the IES modelling shows that USE events lasting at least 10 hours account for roughly 5% of USE events, we illustrate an example of the spot market losses from a 10-hour USE event the table below for different CPT levels. In this example, we assume that prices are at MPC of $21,000/MWh during the 10-hour USE period and calculate the spot market losses of different generation technologies selling 100% versus 67% of their capacity in the cap contract market.

	% capacity under cap contract	2hr CPT	8hr CPT	12hr CPT
2hr storage	100%	$\text{Spot market losses} = 300MW \times \$21,000 \times (\text{hours exposure})$ $= 300MW \times \$21,000 \times 0hrs$ $= \$0M$	$\text{Spot market losses} = 300MW \times \$21,000 \times (\text{hours of exposure})$ $= 300MW \times \$21,000 \times 6hrs$ $= \$37.8M$	$\text{Spot market losses} = 300MW \times \$21,000 \times (\text{hours of exposure})$ $= 300MW \times \$21,000 \times 8hrs$ $= \$50.4M$
	67%	$\text{Spot market losses} = 200MW \times \$21,000 \times (\text{hours of exposure})$ $= 200MW \times \$21,000 \times 0hrs$ $= \$0M$	$\text{Spot market losses} = 200MW \times \$21,000 \times (\text{hours of exposure})$ $= 200MW \times \$21,000 \times 6hrs$ $= \$25.2M$	$\text{Spot market losses} = 200MW \times \$21,000 \times (\text{hours of exposure})$ $= 200MW \times \$21,000 \times 8hrs$ $= \$37.8M$
8hr storage	100%	$\text{Spot market losses} = 300MW \times \$21,000 \times (\text{hours of exposure})$ $= 300MW \times \$21,000 \times 0hrs$ $= \$0M$	$\text{Spot market losses} = 300MW \times \$21,000 \times (\text{hours of exposure})$ $= 300MW \times \$21,000 \times 0hrs$ $= \$0M$	$\text{Spot market losses} = 300MW \times \$21,000 \times (\text{hours of exposure})$ $= 300MW \times \$21,000 \times 2hrs$ $= \$12.6M$
	67%	$\text{Spot market losses} = 200MW \times \$21,000 \times (\text{hours of exposure})$ $= 200MW \times \$21,000 \times 0hrs$ $= \$0M$	$\text{Spot market losses} = 200MW \times \$21,000 \times (\text{hours of exposure})$ $= 200MW \times \$21,000 \times 0hrs$ $= \$0M$	$\text{Spot market losses} = 200MW \times \$21,000 \times (\text{hours of exposure})$ $= 200MW \times \$21,000 \times 2hrs$ $= \$8.4M$
OCGT	100%	$\text{Spot market losses} = 300MW \times \$21,000 \times (\text{hours of exposure})$ $= 300MW \times \$21,000 \times 0hrs$ $= \$0M$	$\text{Spot market losses} = 300MW \times \$21,000 \times (\text{hours of exposure})$ $= 300MW \times \$21,000 \times 0hrs$ $= \$0M$	$\text{Spot market losses} = 300MW \times \$21,000 \times (\text{hours of exposure})$ $= 300MW \times \$21,000 \times 0hrs$ $= \$0M$
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The table shows that under lower CPTs, 2hr storage incurs lower spot market losses from selling cap contracts above its physical capabilities during a 10hr USE event. On the other hand, higher CPTs encourage market discipline by exposing generators overselling cap contracts to risk, without precluding them from doing so, should their risk appetite allow for this. This example also shows that higher CPTs send the appropriate investment signal for generation technologies able to supply during this USE event by allowing them to sell more cap contracts than short duration technologies.

iv. The relationship between the APC and the CPT

We note that where the APC and CPT (in equivalent hourly terms) are close together, the protection from an APP when spot prices only slightly exceed the CPT would be minimal. As such, Hydro Tasmania considers that, if the APC increases, so too should the CPT. We encourage the Reliability Panel to consider the market settings holistically and in particular, the significant regulatory burden and market uncertainty (through opaque pricing outcomes) arising from an APP that is not appropriately tuned to the prevailing market conditions.

Hydro Tasmania considers that under an APP, the CPT should be calculated based upon the APC, rather than shadow pricing. As demonstrated through recent events, spot market prices under an APP may not accurately reflect supply and demand conditions, nor what counterfactual price outcomes may be were the market in normal operation, as participants are not exposed to shadow pricing. Generators may bid themselves at much higher than normal prices to avoid generating at a loss under an APC, leading to spot market prices remaining high. In this case, the APP would be prolonged unnecessarily even after tight supply and demand conditions have eased, leading to greater disruption, regulatory burden and out of market costs.

4. The Reliability Standard

We agree with the Reliability Panel that a change to the form of the reliability standard is needed to reflect the changing reliability risk profile and risk attitudes to long-tailed events. We note that the IES modelling of USE distribution indicates that approximately 15% of USE events are long duration and that these events are associated with high depth USE. To the extent that consumers are disproportionately averse to high depth and long duration USE, the reliability standard should put some additional weight on these high impact events. Noting that discussions on the form of the reliability standard are ongoing, we consider that a lowering of the existing reliability standard (below 0.002% USE) could be a reasonable interim approach to accounting for risk aversion.

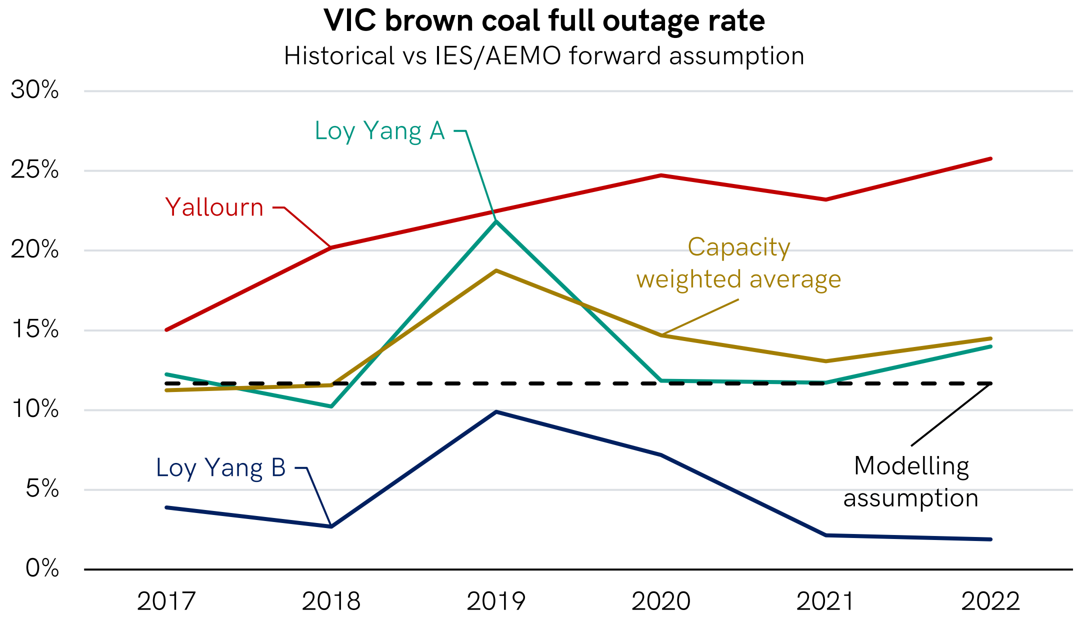
Appendix B – Hydro Tasmania's comments on IES modelling approach and inputs

Hydro Tasmania supports the robust and transparent approach that IES have employed for this review process. We are broadly supportive of IES's findings, but have some general observations we wish to raise in relation to a number of inputs and assumptions used to inform this work.

Our internal modelling base case view sees a greater risk of USE exceeding the reliability standard than presented in IES's base case. This is likely due to:

- **Forecast outages assumptions** – we assume a higher level of coal generator forced outages than IES (which draws heavily on AEMO assumptions). Our forced outage assumptions are based on detailed analysis of historical data which reveals that the actual level of forced outages in recent years has exceeded the level in AEMO assumptions.

  For example, as shown in the chart below, AEMO assumes a Victorian brown coal generator full outage rate[3] of 11.7%, while the actual capacity-weighted average from the period 2017-22 was 14%. In particular, Yallourn Power Station has consistently exhibited a very high forced outage rate which is also increasing over time. We observed similar trends in coal outage data in other NEM regions and other things being equal the expectation is that forced outage rates of ageing coal plant will increase over time.



- **Heightened risk of coal closures** – We note that AEMO's latest *Inputs, Assumptions and Scenarios* workbook has brought forward the retirements of major coal generators compared to the *2021 Inputs, Assumptions and Scenarios*. These include Bayswater and Loy Yang A power stations, now expected to retire two and three years earlier respectively, in addition to the

[3] Here we combine forced outages and maintenance outages due to difficulty assessing exact driver of outages in historical data.

early retirement of Eraring. We consider that the ongoing trend of expected closures being brought forward will continue as the transition of NEM accelerates.

- **Gas availability** – We note that AEMO's *2022 Gas Statement of Opportunities* identifies some gas shortfall risk for meeting peak daily demand in the short term to 2026 and that an option for address this risk as *"minimising electricity from gas at peak gas demand times"*. It identifies risk to both overall and peak gas demand in the longer term after 2026. We encourage the Reliability Panel to consider the potential risk to gas availability and its impact on USE outcomes.

While supportive of inputs and assumptions that have led to suggested ranges of MPC and CPT levels, we note there are plausible futures which would require higher MPC/CPT combinations to meet the reliability standard. Specifically:

- **Weighted Average Cost of Capital (WACC)** – We understand that IES has used a baseline assumption for pre-tax real WACC of 5.5% in line with the Central assumption in AEMO's *2021 Inputs, Assumptions and Scenarios*. We note that Synergies Economic Consulting's *Discount rates for use in cost benefit analysis of AEMO's 2022 Integrated System Plan*[4] report recommended a Central estimate of 5.5% discount rate to apply to ISP scenarios on the basis that scenarios contain a mix of network and generation/storage investments. For sensitivity analysis, it provided a lower bound discount rate of 2.0% which reflected *"recent regulated weighted average cost of capital (WACC) as determined by the AER for transmission and/or distribution networks"* and an upper bound discount rate of 7.5% which reflect a *"more risk-sensitive view about the required returns on private investments in the NEM, including generation and storage"*. Our view is that the use of a 5.5% WACC in the IES modelling could underestimate the revenue required for incentivising new entrants.
- **FCAS revenues** – We note that IES has identified greater investment in batteries in the NEM and Project EnergyConnect as increasing the supply of FCAS and consequently, reduce future FCAS revenues. The table below shows a list of major battery projects expected to come into the NEM within the next five years. Our view is that these events will have a more significant impact on FCAS markets than suggested in the IES report and recommend applying a greater reduction in the fixed FCAS revenue assumption.

Project	NEM region	Capacity / Storage	Commercial operation
Waratah Super Battery	NSW	700MW / 1,400MWh	Jul 2027
Central Renewable Energy Zone BESS	QLD	150MW / 150MWh	Dec 2024
Melton Renewable Energy Hub	VIC	600MW / 2,400MWh	Dec 2023
Eraring Big Battery Storage Stage 1	NSW	460MW / 920MWh	Nov 2023
Queanbeyan Battery	NSW	100MW / 200MWh	Oct 2022

[4] https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/synergies-discount-rate-report.pdf?la=en

Torrens Island BESS	SA	250MW / 250MWh	Jun 2023
Orana BESS	NSW	210MW / 800MWh	Jan 2025
Ulinda Park BESS	QLD	156MW / 300MWh	Jan 2024
Wooreen Energy Storage System	VIC	350MW / 1,400MWh	Dec 2025

We encourage the Reliability Panel to consider the long-term benefits of MPC and CPT settings which incentivise a broad range of technologies. Our view is that higher MPC and CPT settings will attract more diverse new entrants into the market competing to supply during potential USE events – leading to lower costs and increased reliability. Hydro Tasmania considers that competitive markets to be the primary mechanism for achieving the least-cost generation mix for addressing potential USE which will become increasingly unpredictable in timing, frequency, duration and depth.