FORM OF THE RELIABILITY STANDARD

PREPARED FOR THE AUSTRALIAN ENERGY COUNCIL

FINAL REPORT

Endgame Economics

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Executive summary

Australia's National Electricity Market (NEM) is going through profound change. The energy transition may pose new operational challenges and introduce new risks. One of these new risks is the possibility that the distribution of unserved energy (USE) changes such that 'tail-risk' USE (i.e. very large USE events) make up a bigger share of total USE over time.

In this context, the Reliability Panel is undertaking a review of the form of the reliability standard to investigate whether the form should be amended to include a tail-risk metric in addition to the current expected USE metric.

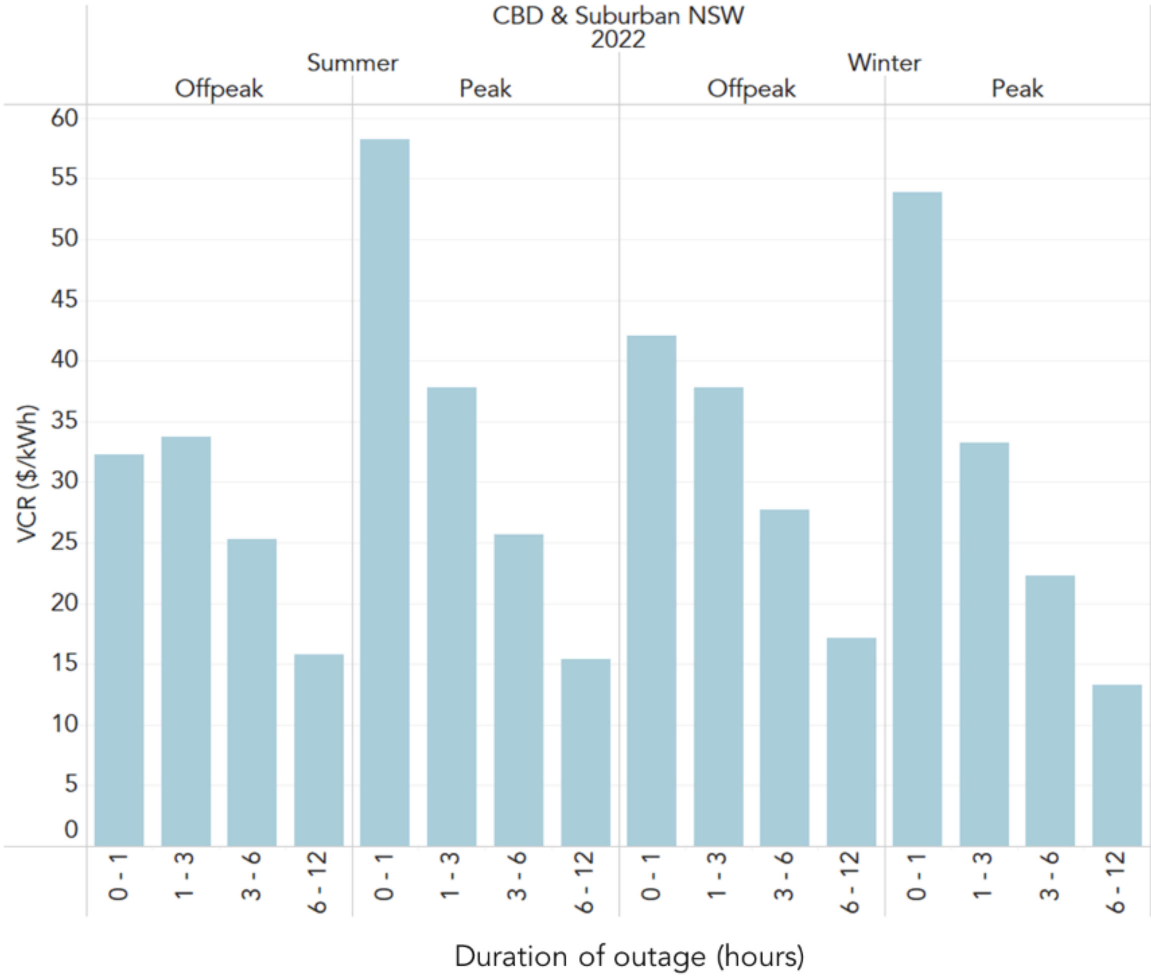
The form of the standard is central to the reliability framework and plays a key role in determining market intervention triggers and the reliability settings which guide billions of dollars of investment. The form of the standard allows a trade-off to be made between the cost of unserved energy and the system cost of reducing unserved energy. Considering the importance of the form of the reliability standard, strong evidence is required to justify a change. As we will show in this report, we do not believe the case for change has been made.

While we agree that the energy transition may change the distribution of unserved energy, this *by itself* does not change the underlying economics and therefore does not justify a change in the form of the standard. The current form of the reliability standard, expected unserved energy, captures tail-risk and weights it according to its modelled probability of occurrence.

To make the case for change, the Reliability Panel must show that there is a change in how customers value reliability. In particular, the Reliability Panel is required to show that the change in the distribution of USE changes the marginal cost of USE. In other words, the Reliability Panel must show that customers exhibit risk aversion, or an increasing marginal value of customer reliability, in terms of $/kWh unserved, for larger USE events.

In its Issues Paper, the Reliability Panel has not provided evidence that customers exhibit risk aversion towards larger USE events. In fact, the Australian Energy Regulator's Value of Customer Reliability study provides evidence in the *opposite* direction, that is that the value of customer reliability is *declining* for longer duration events, as shown in Figure 1.

Figure 1: Value of customer reliability for residential customers by duration



Note: Presented for residential customers in CBD & suburban NSW. Calculated from AER Annual Update VCR – Appendices A – E. December 2022.

These findings are consistent with several international studies which similarly show a declining marginal cost of unserved energy for longer duration events.

Furthermore, in 2019, the Australian Energy Market Commission engaged The Brattle Group (Brattle) as part of the Enhancement to the Reliability and Reserve Trader rule change to undertake a comprehensive review of whether customers in the NEM exhibit risk aversion (and loss aversion) in relation to high-impact, low-probability reliability events. Brattle were unable to find any evidence to support the case of risk aversion or loss aversion. The Commission, considering Brattle's findings and the overwhelming majority of stakeholder submissions found that it was unlikely that customers in the NEM exhibit loss aversion.

There is limited evidence available on the marginal cost of repeat outages, but our international research found a similar relationship, i.e. a declining marginal value for successive outages. This accords with our expectation, customers "learn from experience" and adapt to multiple outages such that the marginal impact of successive outages for most customers is likely to be the same, or lower.

Theories of risk aversion and loss aversion depend critically upon the reference point or baseline against which customers compare a loss. Even if one were to assume risk aversion, the value of a tail-risk reliability event must be considered in the context of *all* outages, of which over 99% are not related to reliability.

In other words, if customers do exhibit risk aversion to tail-risk reliability events, they must place an exceptionally high value on distribution outages which can last for several hours, or even days, for e.g. following a severe flooding event.

However, we know through the experience of distribution network 'gold-plating' that this is not the case. In 2017, the Australian Competition and Consumer Commission (ACCC) launched the Retail Electricity Price Inquiry investigating the drivers behind the sharp increase in customer bills. The final report found that increases in network costs driven by excessive distribution network reliability standards accounted for the largest source of increase in customer bills over the period 2007-08 to 2017-18.

The ACCC notes in relation to distribution network reliability standards (but which could equally apply to wholesale reliability standards):[1]

> *"We consider that reliability standards should be informed by deep understanding of consumer preferences and the careful examination of the costs and benefits of particular standards or changes to those standards."*

The consumer backlash to increasing distribution costs due to gold-plating is not consistent with consumers exhibiting increasing marginal cost of reliability.

Moreover, given reliability events are managed through rotational load shedding, it is not sufficient to show that there is risk aversion towards tail-risk *region-wide* USE events. Each region-wide USE event needs to be allocated to consumers (i.e. through rotational load shedding) and the consumers must

[1] See p. 192, ACCC Retail Electricity Pricing Inquiry – Final Report.

be shown to be risk-averse towards the allocation of USE that they actually experience.

Rotational load shedding creates a significant problem for any risk averse metric. Under the current 'risk-neutral' expected USE metric, the cost of USE can be linearly added up across customers to the regional level. However, moving to a risk averse reliability metric creates a preference aggregation problem. Under risk aversion, the customer's value of reliability is a non-linear function of the size of the unserved energy that they experience. This means that that there is no longer a one-to-one relationship between the value of region-wide USE and the value of USE actually experienced by the customer. In the context of rotational load shedding, the 'value' of region-wide USE no longer represents the value of USE to customers.

This issue rules out the Reliability Panel's straw person composite reliability metric. The composite metric is a weighted average of the current risk-neutral expected USE approach and a tail-risk CVaR metric defined at a predefined level at the *region-wide* level. Therefore, the straw person metric is internally inconsistent as it implicitly assumes risk-neutrality. Even if the CVaR metric was instead based on tail-risk actually experienced by customers, it would require an incredibly sophisticated understanding of consumer preferences in order to deliver the efficient level of reliability.

In its submission to the review, the Australian Energy Market Operator (AEMO) proposes its own metric based on average USE outcomes above the worst 1-in-10-year outcomes. AEMO notes that this is statistically equivalent to the CVaR component of the Reliability Panel's straw person approach but would be more transparent and simpler to implement. AEMO has not provided evidence for how this standard, set at a very conservative level, could deliver the efficient level of reliability.

In addition to the theoretical challenges, the straw person approach poses a number of modelling challenges. It is not clear from the Reliability Panel's proposed modelling methodology how the straw person metric can be operationalised in practice. There will likely be material computational and empirical challenges, that require additional methodological design than running an ISP-style or ESOO-style market model.

In our view, the case has not been made for changing the form of the reliability standard to include a tail-risk metric. Such a change risks over-estimating the value to consumers of unserved energy and will likely deliver an inefficiently high level of reliability, with the costs ultimately borne by consumers.

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1. Introduction

Endgame Economics ('Endgame') has been engaged by the Australian Energy Council ('AEC') to investigate whether the form of the reliability standard should be changed to include a tail-risk metric to account for the changing distribution of unserved energy in the future power system.

1. Introduction

Endgame Economics (Endgame) has been engaged by the Australian Energy Council (AEC) to provide advice on the Reliability Panel's *Review of the form of the reliability standard and Administered Price Cap* (APC). Our engagement is limited to the form of the reliability standard, we are not providing advice on the APC.

Specifically, we have been tasked with producing a report on:

- Fundamental theoretical issues around the existing form of the standard in the context of the energy transition.
- Consideration of the alternative forms of the standard that we are aware of, or that have been proposed by the Reliability Panel.
- Recommendations of matters that the Reliability Panel should take into account in their review.
- Our view on the Reliability Panel's approach to its modelling.

Our advice on the review is primarily based on the Issues Paper for the Review of the form of the reliability standard and APC (hereafter the 'Issues Paper').[2] However, we may also provide comment on related publications, for example, the Final Report of the 2022 Reliability Standards and Settings Review and a submission by Professor Pierluigi Mancarella which provides the basis for the Reliability Panel's straw person reliability standard.[3]

We have also conducted a wide-ranging review of the relevant Australian and international literature and evidence on matters that relate to the review.

1.1. Background

The Reliability Panel's 2022 Reliability standards and settings review included a recommendation to investigate whether the form of the reliability standard should be amended to include a 'tail risk' metric in addition to the expected unserved energy metric in the current form of the reliability standard.

[2] Issues Paper, Review of the form of the reliability standard and APC.
[3] These two documents can be found here: https://www.aemc.gov.au/market-reviews-advice/2022-reliability-standard-and-settings-review

In response to this recommendation the Australian Energy Market Commission has issued terms of reference to the Reliability Panel which has enabled the review.[4]

1.2. Framework for our advice

In conducting this review, the Reliability Panel must be guided by the National Energy Objectives (NEO) and the General Assessment Principles from the Reliability Panel's Final Guidelines Review of the Reliability Standard and Settings Guidelines.[5]

The NEO is:

> *to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
>
> (b) *the reliability, safety and security* of the national electricity system.

The General Assessment Principles set out in the 2021 Guidelines are:

1. *Allowing efficient price signals while managing price risk.*
2. *Delivering a level of reliability consistent with the value placed on that reliability by customers.*
3. *Providing a predictable and flexible regulatory framework.*

We have developed our advice using the same framework, with a particular focus on economic efficiency.

1.3. Structure of the report

The remainder of this report sets out our findings and proceeds as follows:

- **Section 2** provides an overview of the current reliability framework.
- **Section 3** describes how the power system is changing and what this may mean for the distribution of unserved energy.

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[4] The terms of reference are available at: https://www.aemc.gov.au/market-reviews-advice/review-form-reliability-standard-and-apc
[5] The 2021 Guidelines can be found at: https://www.aemc.gov.au/market-reviews-advice/review-reliability-standard-and-settings-guidelines-0

- **Section 4** provides our assessment of the Reliability Panel's approach.
- **Section 5** concludes by summarising our main arguments.

2. The current reliability framework

In this section we will outline how the current reliability framework is designed to target the efficient level of reliability. This will include a brief overview of how the scope, the form and the level of the reliability standard jointly determine the level of reliability settings that target the level of reliability that consumers value.

Understanding how the different elements of the reliability framework relate to each other is important for assessing whether there should be a change to the form of the reliability standard.

2.1. The different elements of the reliability framework

2.1.1. The scope of the reliability standard

The scope of the reliability standard defines what is included and excluded from the calculation of unserved energy. The Issues Paper states that the scope of the reliability standard is outside this review.[6] This allows us to agree on the definition the scope of the reliability standard. Clause 3.9.3C (a) of the National Electricity Rules (NER) defines the reliability standard as follows:

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

From the following clauses, 3.9.3C (b) and (c), it is clear that the reliability standard must only consider unserved energy due to *reliability* events, that is due to insufficient generation and/or inter-regional transmission capacity. The reliability standard explicitly *excludes* unserved energy due to multiple credible contingencies, non-credible contingencies or other power system security events.[7]

As will become clear in this report, the focus on reliability events is important because any assumption of risk aversion on behalf of customers towards tail-risk USE events should include *all* outages as a reference point (or baseline).

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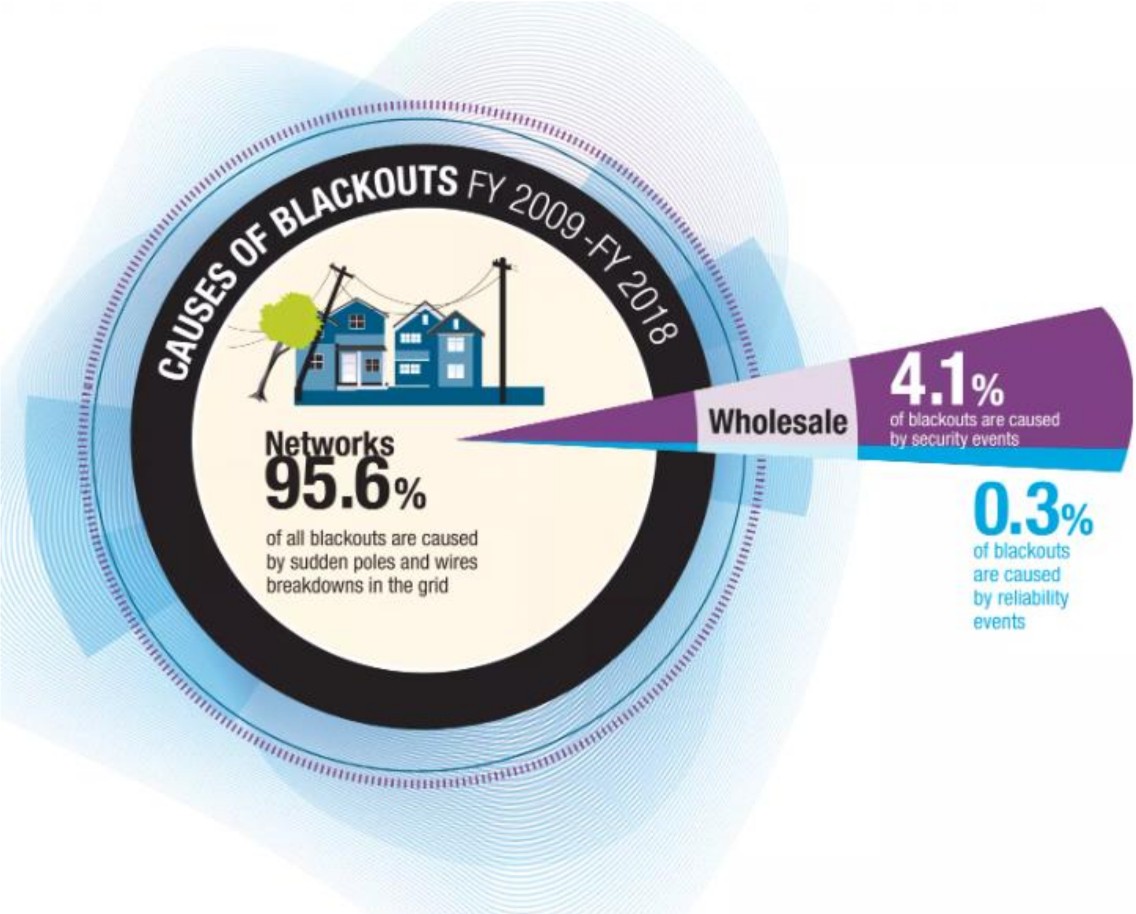
[6] See p. 2, Issues Paper, Review of the form of the reliability standard and APC.
[7] See Clause 3.9.3C of the NER and also p. iii and p. 9 of the Issues Paper.

The Reliability Panel's analysis shows that reliability events constitute less than 1% of customer outages, as shown in Figure 2.

Figure 2: Cause out NEM outages (2009/10 – 2018/19)



Source: AEMC, reliability fact sheet.

2.1.2. The form of the reliability standard

As set out in the NER definition above, the current form of the reliability standard is an ex-ante metric, defined as the maximum *expected* USE in a region in a financial year. The expected USE is calculated from a weighted average of unserved energy from a number of different simulations of the future power system, reflecting different generator outages, different demand profiles and different profiles of wind and solar. The weights reflect the probabilities of each scenario occurring.

Crucially, in relation to the Reliability Panel's review, the current expected USE approach can be considered to be 'risk neutral' with respect to different USE events. Under the current approach, customers are assumed to have a constant value of customer reliability (VCR) within each region.[8] This means that customers in each region are implicitly assumed to only care about the expected USE, without regard to the distribution of the expected USE.

A consequence of a risk neutral standard is that customer preferences over outages can be aggregated to the regional level. As we will show in this report, preference aggregation is an important feature of the reliability standard as it allows trade-offs between system cost and the cost of expected unserved energy to occur at the regional level.

Through its review, the Reliability Panel is investigating whether the form of the standard should change to reflect 'risk aversion' on behalf of customers. In other words, are customers willing to pay more (per kWh unserved) to avoid very large USE events. If so, the Reliability Panel suggests that a change in the form of the reliability standard (e.g. to include a tail-risk metric) may be required to properly reflect customer risk aversion.

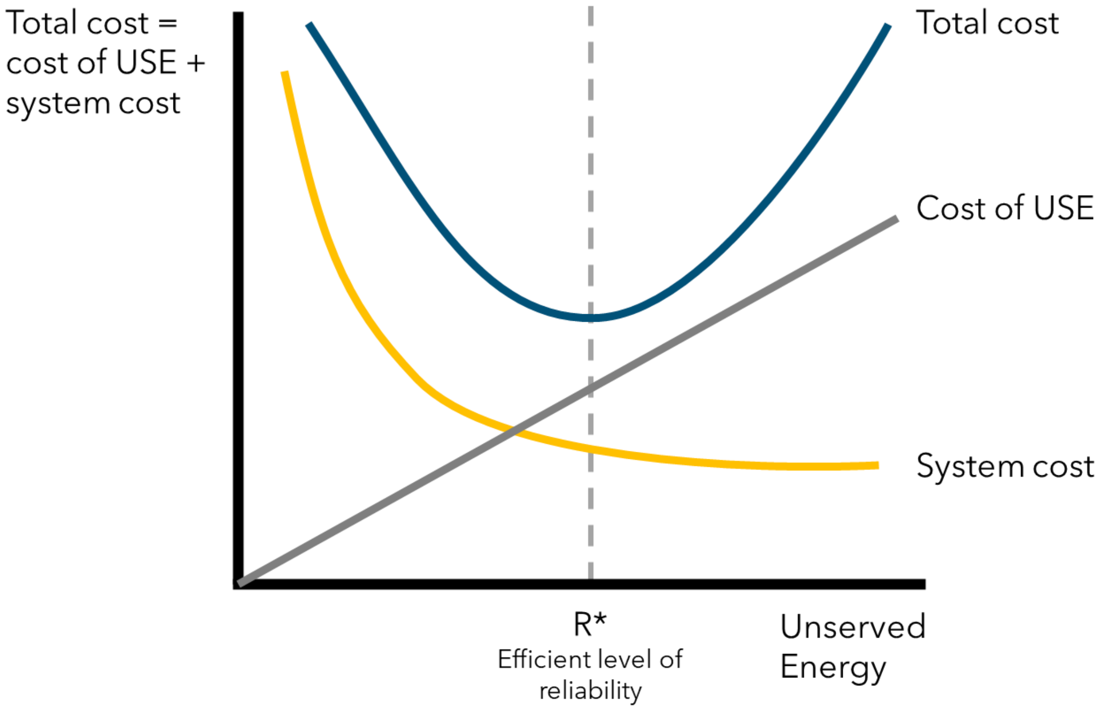
2.1.3. The level of the reliability standard

The current framework takes the scope and the form of the standard as defined above, and determines the level of the reliability standard, i.e. the maximum expected USE, represented as a percentage of total demand, in a region in a financial year (currently set to 0.002%). The level should be set efficiently, in line with the customer value of reliability, i.e. the level of the reliability should be set so that total cost, including both the cost of unserved energy and system costs, is minimised. In practice, the same level for the reliability standard is set across all NEM regions even where modelling results may imply different levels should apply in different regions. Similarly, the reliability settings are set consistently across all regions. This reflects some practical and operational realities of the interconnected power system.

Figure 3 illustrates the trade-off between the cost of USE and system costs. The cost of USE rises linearly (equal to VCR multiplied by USE) while system costs fall non-linearly as USE increases reflecting the sharply increasing system costs as USE approaches zero. The sum of these costs gives the U-shaped total cost curve. The efficient level of reliability, R*, is where the total cost is minimised.

[8] However, as we will explain later in the report, the single VCR number for each region is a weighted average valuation across a number of different dimensions of outages including outage duration.

Figure 3: The efficient level of reliability minimises total cost



A consequence of the current risk-neutral reliability standard is that the cost of USE is a linear function of the level of expected USE, as shown in Figure 3.

Adopting risk aversion in the standard would change this assumed relationship:

1. Given reliability outages are managed through rotational load-shedding, it is no longer possible to represent a single relationship between the cost of USE and the amount of region-wide USE. The cost to consumers depends upon the *allocation* of a given region-wide USE event (e.g. assuming risk aversion, 500 MWh of unserved energy will be valued differently if its allocated as a 10-hour outage for one group of consumers compared to if it is rotated as a one-hour outage for 10 different groups of customers).
2. For a given *allocation* of a USE event, the cost to consumers increases non-linearly (i.e. the cost increases at an increasing rate) as unserved energy increases.

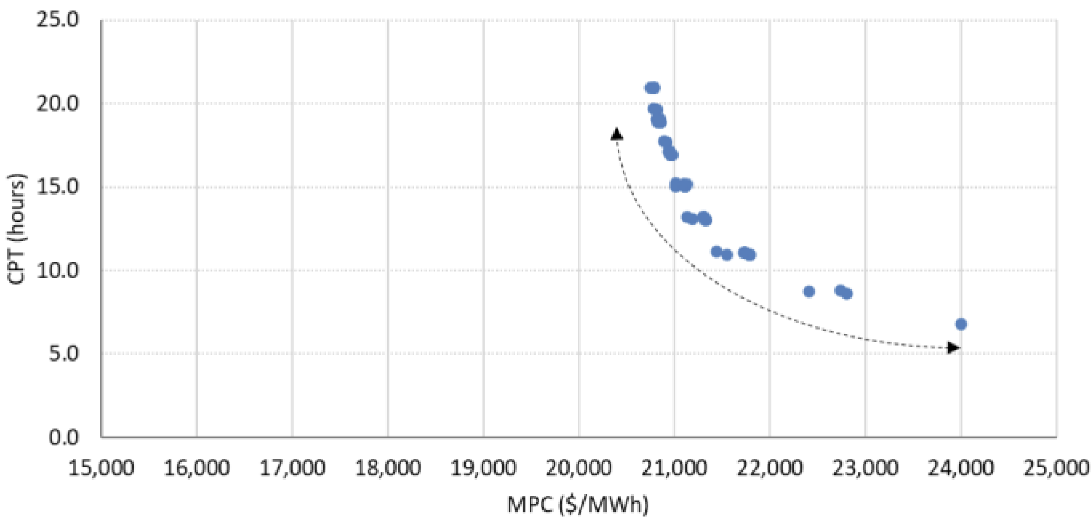
As we will show in this report, point (1) effectively rules out the proposed straw person metric as it implicitly assumes risk-neutrality on behalf of consumers. Regarding point (2), we will show that the Australian Energy Regulator's (AER) Value of Customer Reliability (VCR) survey points in the *opposite* direction, i.e. that the value of customer reliability (in $/kWh) is declining for longer duration events.

2.1.4. The reliability settings

Together the scope, form, and level of the reliability standard play an important role in informing the reliability settings, in particular the Market Price Cap (MPC) and the Cumulative Price Threshold (CPT). Every four years, as part of the Reliability Standard and Settings Review (RSSR), the Reliability Panel undertakes (or commissions) modelling to determine the level of the MPC and CPT to incentivise investment in the resource mix required to meet the reliability standard.

In practice, the modelling approach will find a 'frontier' of plausible MPC and CPT combinations for a given marginal entrant for a given region. Figure 4 presents modelling from Intelligent Energy Systems (IES) for the 2022 RSSR showing the frontier of MPC and CPT combinations to deliver the reliability standard in New South Wales (NSW) with an open-cycle gas turbine (OCGT) as the marginal entrant.

Figure 4: IES modelled CPT and MPC combination for NSW OCGT



Source: Figure 3, IES Final Modelling Report, 2022 Reliability Standard and Settings Review.

2.2. The form of the standard is the linchpin of the reliability framework

Considering the links between the different elements of the reliability framework, it is clear that the form of the reliability standard plays an important role in informing the cost of USE that is used to determine the efficient trade-off against system costs which in turn determines the reliability settings which ultimately drive investment decisions in the National Electricity Market (NEM).[9]

The Reliability Panel considered whether the form of the standard is appropriate in 1998, 2007 and 2016 and each time found that the existing metric was fit for purpose.[10] A change in the form of the standard was also considered by the AEMC in the Enhancement to the Reliability and Emergency Reserve Trader rule change in 2019 in the context of high-impact, low-probability events. The Commission similarly found that the form of the standard was fit for purpose.[11]

Given the importance of the form of the standard, any change should be based on rigorous evidence that the change will deliver a more efficient outcome for consumers than the status quo. As we will show in this report, we do not believe that the case has been made for a change in the form of the reliability standard.

[9] The Reliability Panel also notes that a change in the form of the reliability standard may mean that "complementary measures" can better deliver the new standard (section 6.5 of the Issues Paper). This argument is a version of the Tinbergen Rule and, in our view, is likely to be the case for any composite standard which includes a tail-risk metric.
[10] Reliability Panel, Determination on reserve trader and direction guidelines, June 1998; Reliability Panel, Comprehensive Reliability Review, 2007; Reliability Panel, RSSR Guidelines 2016.
[11] AEMC, Enhancement to the Reliability and Emergency Reserve Trader, Rule determination, 2 May 2019.

3. The changing power system

The energy transition will likely involve change in the distribution of USE. However, this does not change the economics of reliability which involves a trade-off between the cost of unserved energy and the cost of new resource entry.

3.1. The shift from a capacity-constrained to an energy-constrained system

The NEM has historically been dominated by thermal and hydro generators with large generating units. In this system, reliability risks primarily arose due to unplanned outages during peak demand periods. In other words, we can think of reliability risks in the traditional power system as arising due to capacity constraints.

However, as the energy transition continues, the resource mix is rapidly changing. The system is seeing increasing penetration of renewable generators (i.e. solar PV and wind generators) and storage. These new generators have different operational characteristics to thermal and hydro generators. The availability of renewable generators is largely outside of the control of the system operator and depends upon local weather conditions (i.e. solar irradiation and wind speed). This creates a new source of reliability risk arising during periods of sustained low variable renewable energy (VRE) generation, i.e. VRE droughts (sometimes called ‘dunkelflaute’ or ‘dark doldrums’). These reliability risks can be thought of as arising due to energy constraints.

3.2. This could lead to a change in the distribution of USE

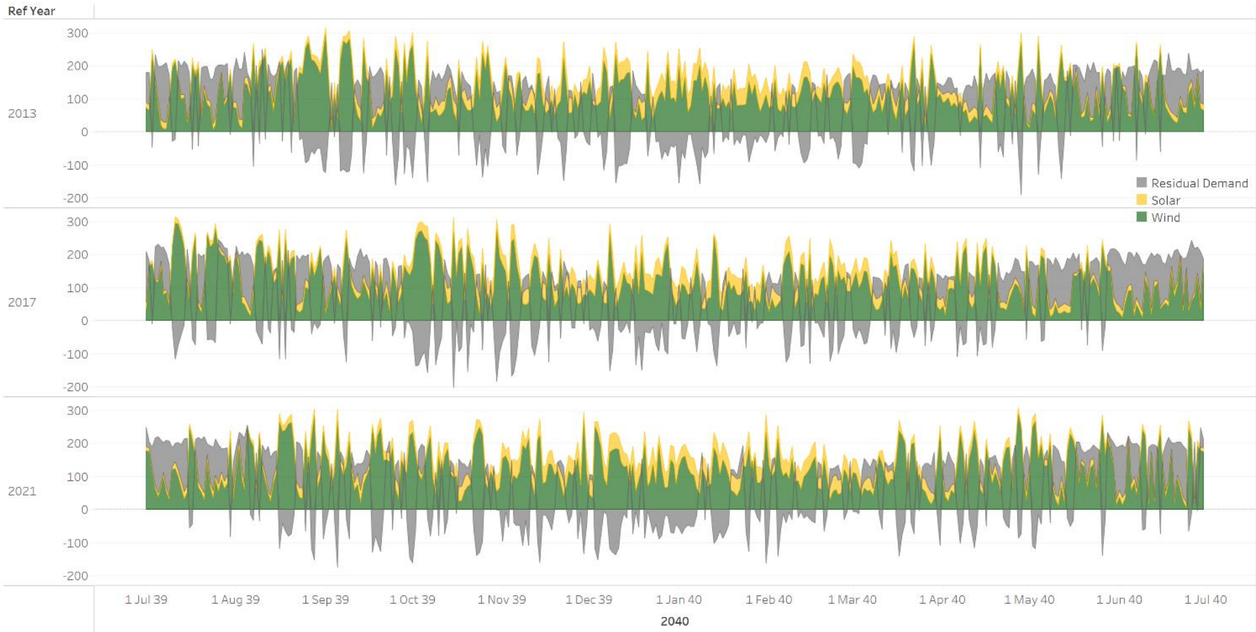
The energy transition may bring about changes in the distribution of USE. A shift in the reliability risk from capacity constraints to energy constraints may lead to larger USE events, i.e. “fatter” tails in USE distributions. On the other hand, the exit of large thermal units will reduce the size of contingency events due to forced outages, which could *reduce* the likelihood of some large USE events.

3.2.1. VRE droughts will become more important

In the future system, periods of low VRE output will become more important to the operation of the power system.

Figure 5 shows financial year 2040 projection for Victoria of operational demand, decomposed into solar and wind generation and residual demand[12], for different reference years (i.e., weather patterns) under AEMO's 2022 Integrated System Plan (ISP). In all reference years, Victoria experiences long low-VRE periods in winter (e.g., June – August), during which its sustained high residual demand must be met by local generation and interconnector imports. Other states also exhibit similar features although to a lesser extent. As traditional thermal generators leave the market in the future, additional storage, interconnection or other 'firm' sources will required to manage the duration issue.

Figure 5: 2040 Victorian ISP forecasts of residual demand against wind and solar



Source: Endgame Economics analysis of ISP data

This illustrates the transition from traditional capacity limitations towards ensuring sufficient energy to last VRE droughts. Periods of low VRE output require dispatchable resources with long duration (whether storage or thermal).

[12] Residual demand is operational demand (demand excluding BTM generation and storage) subtracted by utility solar and wind output.

3.2.2. The size of contingencies could decrease

On the other hand, the shift in the resource mix away from large thermal units will decrease the reliability risk associated with random forced outages during periods of high demand. This may reduce the likelihood of some large USE events.

3.3. The changing distribution of USE doesn't change the economics of reliability

While the distribution of USE will likely change with the energy transition, this does not change the underlying economics which inform the reliability standard.

As explained in Section 2.1.3, the reliability standard should be set at the level which efficiently trades off the cost of USE against the cost of new resource entry, i.e. the reliability standard should be set at the level of expected USE such that:

$$Marginal\ cost\ of\ E(USE) = marginal\ system\ cost\ of\ reducing\ E(USE)$$

Where the cost of USE can be expressed as:

$$Cost\ of\ E(USE) = VCR * E(USE)$$

Therefore, a change in the *distribution* of USE by itself is irrelevant for determining the efficient level of reliability. The Reliability Panel must show that the change in the distribution of region-wide USE changes the *marginal cost of USE*, as experienced by customers. In other words, the Reliability Panel must demonstrate that customers exhibit risk aversion, or an increasing value of customer reliability for larger USE events.

Furthermore, given reliability events are generally managed through rotational load shedding, it is not sufficient to show that there is risk aversion towards tail-risk region-wide USE events. Each region-wide USE event needs to be allocated to consumers (i.e. through rotational load shedding) and the consumers must be shown to be risk-averse towards the allocation of USE that they experience.

Therefore, while the investigation of different distributions of USE is interesting and informative from an operational perspective, the Reliability Panel has not, in our view, made the case for change to the form of the standard.

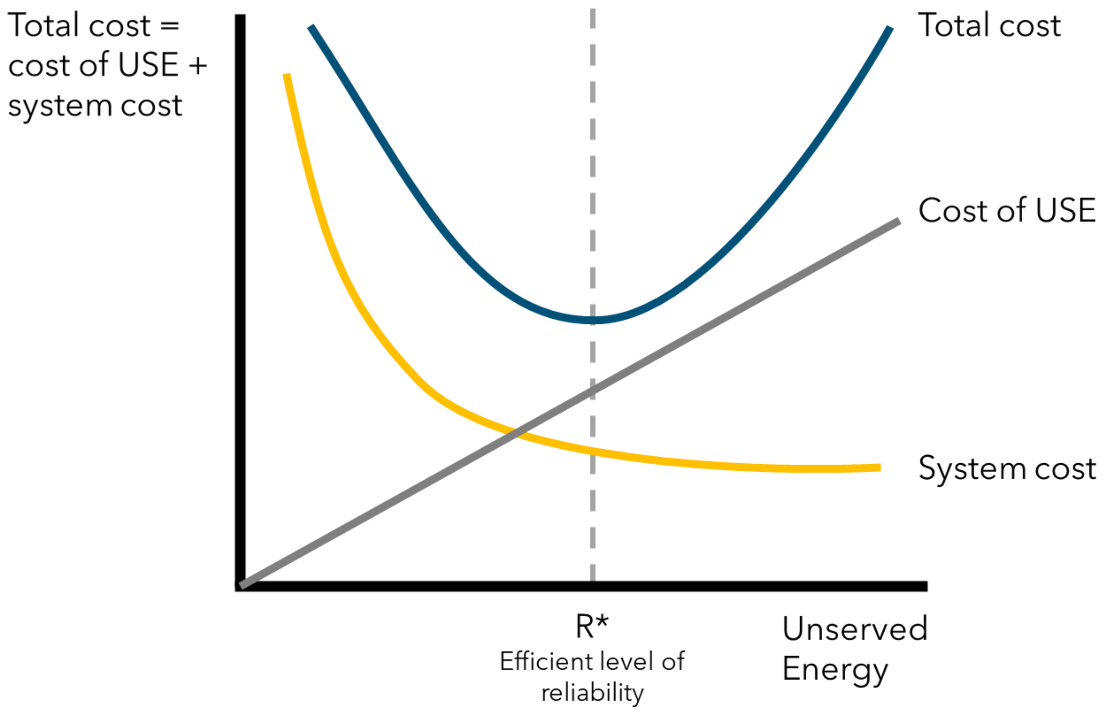
We explore each of these points in detail in Section 4.

4. Assessment of the proposed approach

4.1. The reliability standard should deliver the efficient level of reliability

The form of the reliability standard should allow a trade-off to be made between the cost of expected unserved energy to consumers and the total system costs. This would allow the level of the reliability to be set at the efficient level where total cost, including the cost of unserved energy and system costs, is minimised. Figure 6 illustrates the trade-off.

Figure 6: The efficient level of reliability minimises total cost



Understanding the cost to consumers of unserved energy is therefore key to determining the form of the reliability standard that can, along with the other elements of the framework, deliver an efficient level of reliability.

While the Reliability Panel has completed rigorous and informative analysis of the changing nature of the *distribution of USE*, they have not, in our view, undertaken the work necessary to understand customer preferences over reliability.

The Reliability Panel must show that consumers have a higher *marginal* valuation, in terms of $/kWh unserved, for larger reliability USE events. If this case is not established, either through risk aversion or otherwise, there is not a case for changing the form of the standard to include tail risk.

As we will show in this section, we do not believe that the case has been made that consumers place a higher marginal valuation for larger USE events. In our view, a change in the form of the reliability standard to include a tail-risk metric risks over-estimating the value to consumers of unserved energy and will likely deliver an inefficiently high level of reliability, with the costs ultimately borne by consumers.

4.2. There must be a focus on the end-customer's experience

The reliability framework must necessarily make trade-offs on behalf of customers at an aggregate level (e.g. region-wide). This involves the aggregation of customer preferences by some method so that the value of outages can be balanced against total system costs.

While aggregation is inevitable, we feel that the Issues Paper has inadvertently conflated two distinct aspects of a given reliability event:

- the outage as experienced by the individual customer, and
- the outage as experienced by the system operator (e.g. USE aggregated across an entire region).

It is important to remember that reliability events do not impact a region as a single unit, they are experienced by individual customers. There must therefore be a tight connection between the estimation of the value of reliability outages at the region level and the *actual* experience of customers.

4.2.1. Larger USE events do not necessarily translate into longer customer outages

AEMO will generally manage outages due to reliability events through rotational load shedding by issuing directions to the relevant network service providers.[13] The network service providers then implement load shedding in their region by disconnecting and reconnecting load on a rotational basis according to a pre-determined schedule from the Jurisdictional System

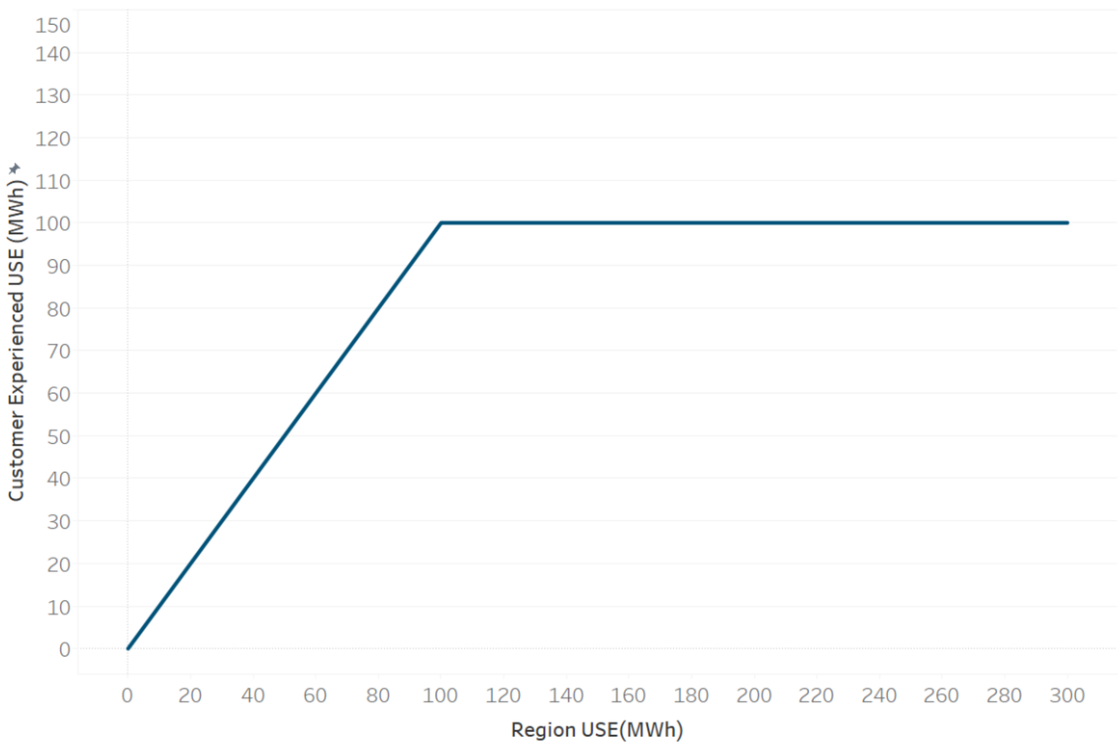
[13] See https://aemo.com.au/en/learn/energy-explained/energy-101/explaining-load-shedding

Security Co-ordinator. Individual customers would generally be disconnected for 30-60 minutes at a time.[14]

Consequently, there is not a one-to-one relationship between region-wide USE and the length of individual customer outages. A large 'tail-risk' USE event would generally be rotated around different groups of customers so that the duration of the outage to any individual customer will be a fraction of the duration of the total event across the region.

Figure 7 presents a simplified example for how rotational load shedding breaks the one-to-one relationship between region-wide USE and USE experienced by an individual customer (or group of customers).

Figure 7: Stylised relationship between region-wide USE and customer experienced USE



[14] See p. 75, AEMC, *Enhancement to the Reliability and Emergency Reserve Trader*, Rule determination, 2 May 2019. Different distributors cite different outage durations. E.g. in South Australia the target appears to be 45 minutes: https://www.sapowernetworks.com.au/outages/load-shedding/ while CitiPower in Victoria states "one to two hours": https://media.powercor.com.au/wp-content/uploads/2021/07/07130816/Loadshedding-Fact-Sheet.pdf

In this example, suppose that a reliability event requires 100 MW of load shedding for three consecutive hours (resulting in total unserved energy of 300 MWh). The system operator rotates the outages each hour around three different groups of customers. This figure shows the relationship between region-wide USE and the first group of customers that experience load shedding. After the first hour, the first group of customers have their power restored, breaking the relationship between region-wide USE and the individual customer's experience of USE.

This point was made by the AEMC in the *Enhancement to the Reliability and Emergency Reserve Trader* rule change with respect to high-impact, low-probability (i.e. tail-risk) events:[15]

> *The Commission considers that generally speaking, reliability events, due to their nature of being managed through rotational load shedding, are unlikely to be "high impact" events, unlike system-wide blackouts or more widespread blackouts.*

It is critical to understand this point as the Reliability Panel is required to show that customers have risk aversion to outages that they *actually experience*, not region-wide USE as experienced by AEMO or the network service providers.

This point is acknowledged by the Reliability Panel in the Issues Paper but this does not appear to have been incorporated into the key arguments about tail-risk and risk aversion.[16]

For example, the straw person composite reliability metric put forward in the Issues Paper includes a 'tail risk' conditional value at risk (CVaR) metric based on the probability distribution function of USE at the region level.[17]

Rather than focusing on the distribution of USE at the regional level the Reliability Panel should consider the actual experience of customers.

4.2.2. Most customer outages are not related to reliability

We are not aware of any evidence that customers care about the *source* of outages. Most customer outages are caused by distribution network outages

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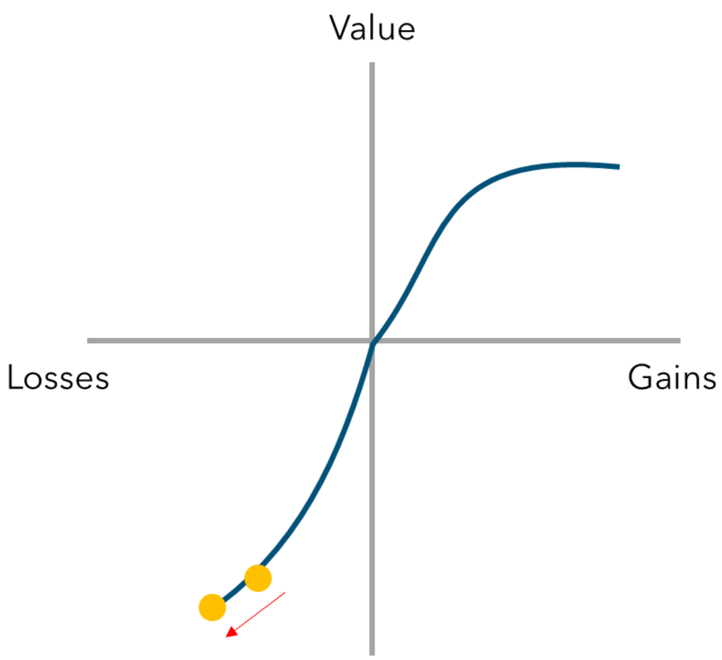
[15] See p. 75, AEMC, Enhancement to the Reliability and Emergency Reserve Trader, Rule determination, 2 May 2019.
[16] See p. 16 of the Issues Paper.
[17] See p. 31 of the Issues Paper and P. Mancarella, Briefing Note for the AEMC in support of the 2022 Reliability Standards and Settings Review, August 2022

and less than 1% of outages are caused by reliability events (see Figure 2 in Section 2.1.1).

This must be considered because the value of losses under risk aversion or loss aversion depend on the customer's reference point. Under loss aversion, the marginal subjective valuation of loss is diminishing as the size of the loss increases. Figure 8 illustrates the subjective value of losses and gains from the classic *Prospect Theory* article by Kahneman and Tversky.

Figure 8: Reference points are important for estimating the value of losses under loss aversion



Source: Adapted from Daniel Kahneman and Amos Tversky. Prospect theory: An analysis of decision under risk. Econometrica: Journal of the econometric society, pages 263–291, 1979.

In our context, this means that the valuation of reliability tail-risk events must consider *all* outages expected to be experienced by the customer.

4.3. The current approach already captures tail risk

The previous subsection explained why larger region-wide USE events does not necessarily translate one-for-one into longer outages for customers. However, even if it were the case that there was a perfect correlation between region-wide USE and the end-customer's actual experience, the current form of the reliability standard is based on expected USE and therefore already incorporates and values tail-risk events.

Expected USE is calculated as the weighted average of USE from many modelling simulations of the future power system. Each simulation includes random generator forced outages, demand profiles, and wind and solar traces reflecting variability in VRE output. The expected USE calculation takes the probability weighted average USE from each scenario.

Therefore, if a large 'tail-risk' USE event occurs in a particular simulation, it will be captured by the current approach and weighted according to its probability.

In order to find that the current expected USE approach does not adequately represent the customer's valuation of tail-risk events, it must be demonstrated that customers have an increasing marginal willingness to pay for longer duration events, for example, that customers are willing to pay more (per kWh) to avoid a 12-hour outage than what they would be willing to pay to avoid two separate 6-hour outages.

The Issues Paper does not provide evidence that customers are willing to pay more at the margin for longer duration events. In fact, the available evidence appears to show the *opposite*, that is, based on the AER's latest VCR survey, customers have a declining marginal willingness to pay for longer duration outages as explained in Section 4.4.1.

The Issues Paper argues that a potential source of increasing marginal valuation of tail-risk events with reference to the concept of risk aversion. However, The Reliability Panel have not provided evidence that consumers exhibit risk-aversion towards tail-risk USE events. Furthermore, an extensive investigation by Brattle commissioned by the AEMC in 2019 did not find evidence for risk aversion, as we will show in Section 4.4.3.

4.4. Valuation of customer reliability for different durations

4.4.1. AER's value of customer reliability study

The Australian Energy Regulator (AER) has the responsibility of reviewing and updating the Value of Customer Reliability (VCR) every 5 years. [18] The VCR is used to trade off the value of unserved energy against the cost of new entry to determine the efficient level of reliability.

[18] This responsibility was transferred from AEMO to the AER under National Electricity Rule 8.12 following a rule change in 2018.

In particular, the VCR represents the amount that customers would be willing to pay to avoid one kilowatt hour of unserved energy. It is expressed in $/kWh and is determined through a combination of contingent valuation and choice modelling survey techniques of customers.[19]

The AER surveys collect responses from residential and business customers of different sizes on the value of outage events across multiple different dimensions including:

- Different durations
- Different geographic areas
- Severity (e.g. local vs. widespread)
- Different times of day (e.g. peak vs. off-peak)
- Season (e.g. summer vs. winter)
- Weekdays vs. weekends

The valuations of outages across these dimensions are weighted to give an overall $/kWh VCR for each region that reflects the value across each dimension.

Of most interest for our purposes is the value customers place on outages of different *durations*. The AER publishes the VCR in $/kWh for different durations for residential and business customers.[20] The AER also publishes the outage probabilities (or weights) for different durations that are used to calculate the overall VCR by customer type.[21]

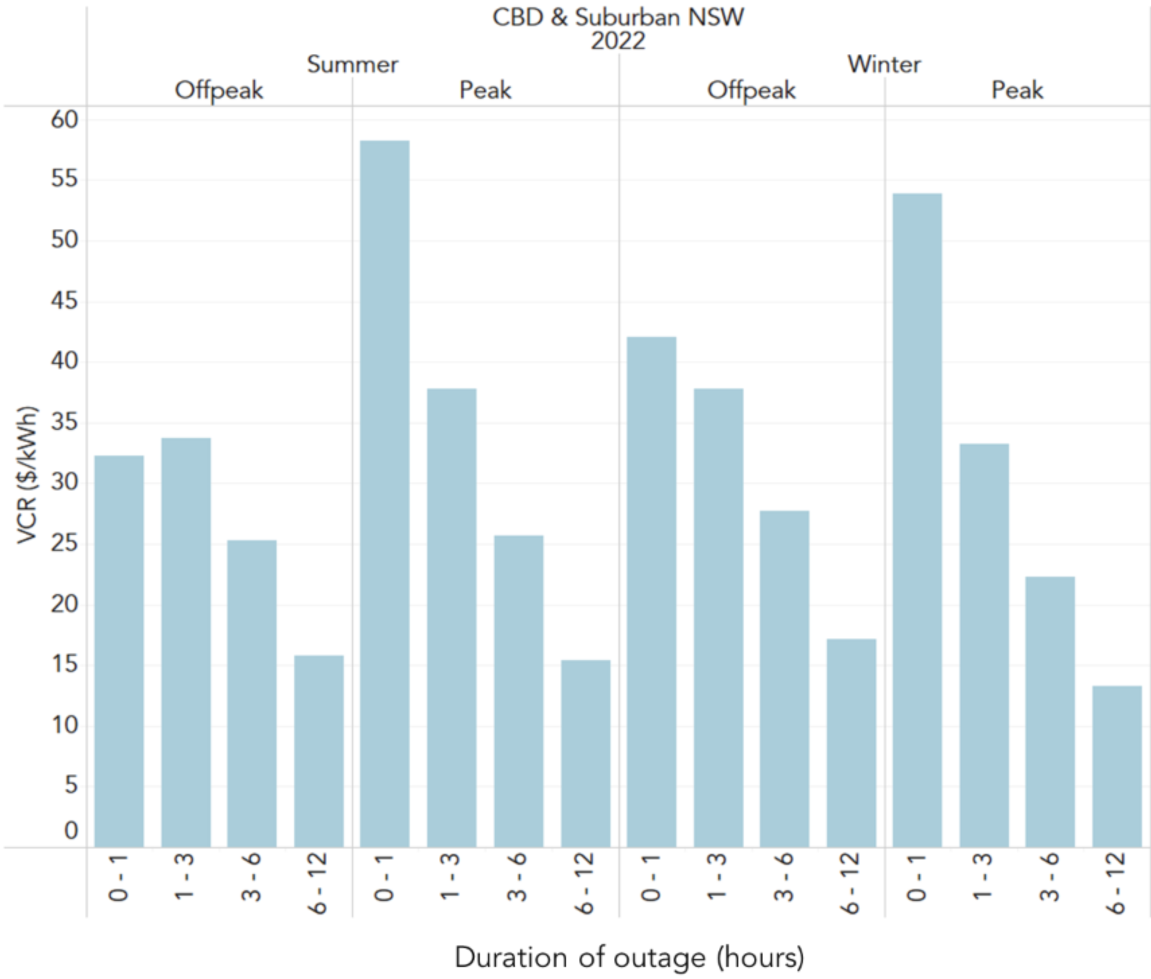
The results show that the marginal VCRs are generally declining with duration. In other words, the amount that consumers are willing to pay per kWh of unserved energy decreases as the duration of outages increases.

Figure 9 shows the residential VCR by duration of event for CBD & Suburban NSW. This shows that the VCR (in $/kWh) declines as the duration of outages increases. The relationship is consistent between summer and winter, and

[19] For a summary of the method undertaken by the AER see Section 1.4, AER, Value of Customer Reliability – Final report on VCR values, December 2019.
[20] For the full set of VCRs by event duration and customer type see AER - Annual update - VCR review final decision - Appendices A to E - December 2022.
[21] See the tabs beginning 'App B' in the same workbook as the previous footnote for the full set of weightings of different outage durations.

during peak and off-peak periods, though the value of the first hour of outages is much higher during peak times, as expected.

Figure 9: Value of customer reliability for residential customers by duration



Note: Presented for residential customers in CBD & suburban NSW. Calculated from AER Annual Update VCR – Appendices A – E. December 2022.

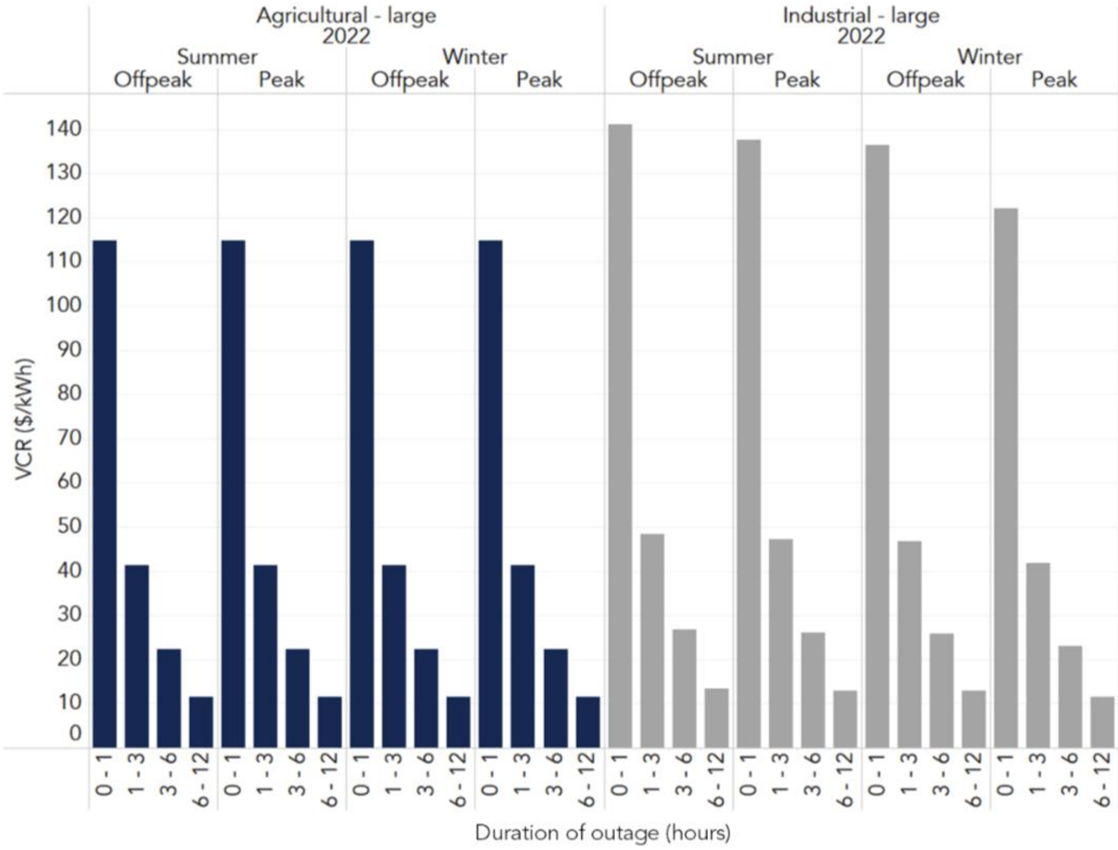
We present the results for NSW here as it covers the largest population, but the results are consistent across different geographic areas as can be seen from the public VCR data.[22]

These results are also consistent across the different types of business customers surveyed. In fact, the decline in VCR by duration is much more

[22] See previous footnote for the reference.

rapid for large business customers. Figure 10 shows the VCR by duration for agricultural and industrial customers.

Figure 10: Value of customer reliability for business customers by duration



Note: Presented for agricultural and industrial business customers. Calculated from AER Annual Update VCR – Appendices A – E. December 2022.

This may be counter-intuitive but becomes clearer when considering the problem at the margin. The initial interruption is likely to be disruptive, imposing significant costs on both residential and business customers. As reflected in the figure, large businesses (e.g. commercial, industrial and agricultural businesses) experience a large sudden loss in output as their processes are halted.

However, as the outage persists, the *additional* cost borne by customers for each kWh unserved is falling. Residential customers will generally find substitutes for the services normally provided by their energy supply (e.g. preparing meals that do not require cooking or ordering take-away) while business customers (particularly commercial, industrial and agricultural) may continue to suffer marginal losses in output but at a decreasing rate.[23]

The AER made this point in the latest VCR review noting:[24]

> *"Most respondents however, indicated costs growing at a slower rate the longer the outage persisted, suggesting that after accounting for the initial fixed costs of an outage, costs incurred for lost production are more limited. This results in lower VCRs the longer the outage duration."*

A similar point is made in the AER's 2020 Widespread and Long Duration Outage review:[25]

> *"In our 2019 VCR review, we found that for 'standard' localised outages of up to 12 hours, the VCR decreased as duration increased… this is because respondents to the survey were generally not willing to pay three, six or twelve times more to avoid localised outages that lasted three, six or twelve times longer than a one hour outage."*

The AER findings are the *opposite* of what would be required to justify the inclusion of a tail risk metric in the form of the standard. If the Reliability Panel is concerned that longer duration outages are becoming more likely, this can be reflected in the VCR calculation by updating the weights used for different duration outages. However, this will likely result in a *lower* overall VCR as customers have a declining marginal valuation of USE duration.

The AER is due to complete the next review of VCRs by 31 December 2024.

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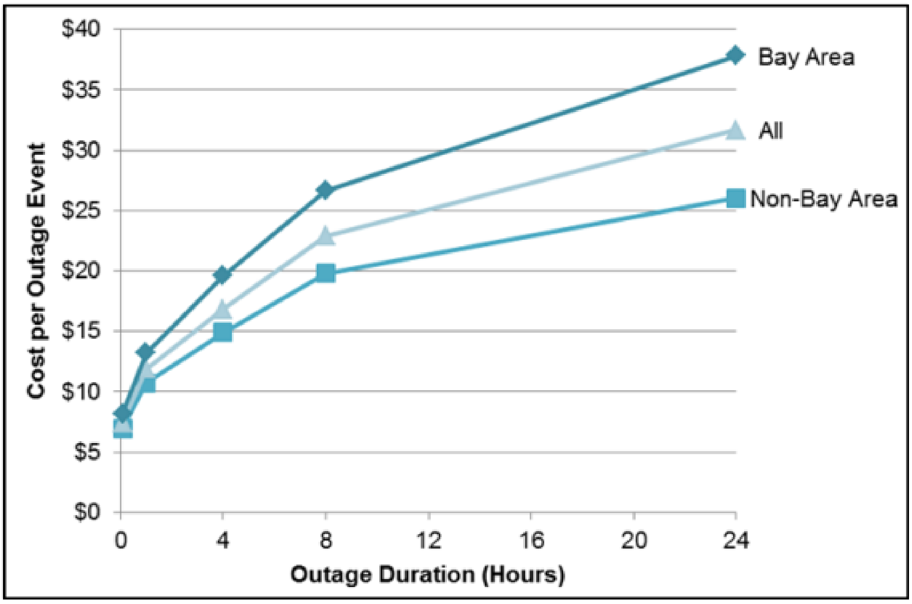
[23] A declining VCR for longer duration events is also found in a 2012 VCR study for New South Wales by Oakley Greenwood for the AEMC. See NSW Value of Customer Reliability. May 2012. See Tables 50 – 61. They find a declining value of customer reliability (in $/kWh) for longer duration events for all customers (residential, small and large business) and across all three distribution networks in NSW.
[24] See p. 65, AER - Values of Customer Reliability – Final Decision. December, 2019.
[25] See p. 17, AER - Widespread and Long Duration Outages - Values of Customer Reliability - Final Conclusions

4.4.2. Other jurisdictions also find marginal value of customer reliability decreasing with outage duration

The AER VCR findings are consistent with studies from other jurisdictions which similarly find a declining marginal valuation of outages by duration. Figure 11 shows the residential value of outages in California in 2012. The relationship displayed here is consistent with the AER VCR, the marginal value of unserved energy is decreasing with longer duration outages.

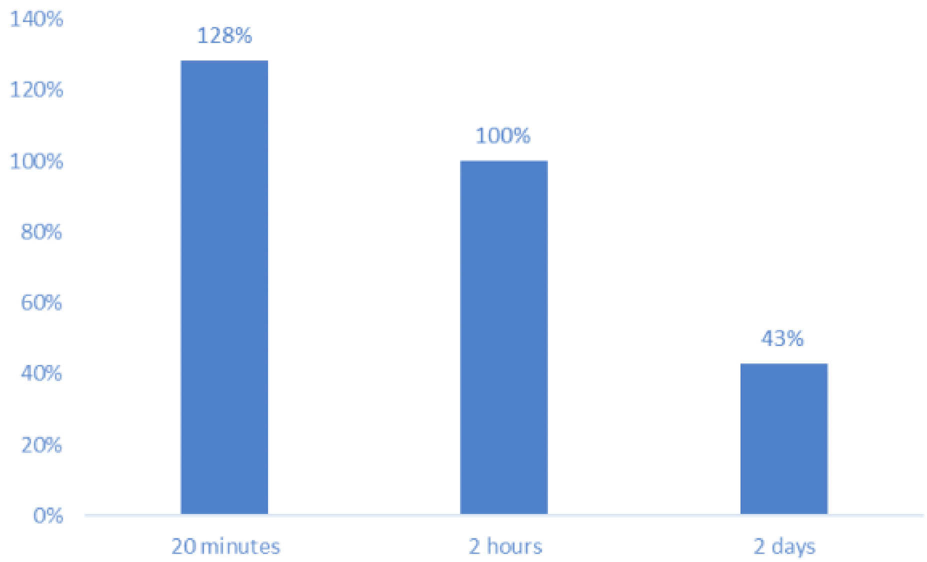
Figure 11: Residential value of outage events in California (2012)



Source: p. 44, Estimating Power System Interruption Costs – A Guidebook for Electric Utilities.

Similarly, a comprehensive study by Cambridge Economic Policy Analysis (CEPA) found that the value of outages in EU member states is declining in duration. Figure 12 shows customer willingness to accept an outage (per hour), relative to a 2-hour outage in Europe.

Figure 12: Domestic willingness-to-accept per hour relative to a 2-hour outage (European Union)



Source: p. 44, Study on the estimation of the value of lost load of electricity supply in Europe. Cambridge Economic Policy Associates. July 2018.

4.4.3. Risk aversion

In its Issues Paper, the Reliability Panel suggest that the current risk-neutral approach does not account for customers exhibiting risk aversion to "severe, but low probability, tail risk reliability events"[26]. Risk aversion is again used as the justification for the Reliability Panel's 'straw person' composite metric including a contingent value-at-risk (CVaR) tail metric based on advice received from Professor Pierluigi Mancarella.[27] The Issues Paper does not provide evidence that customers exhibit risk aversion over tail-risk reliability events.

As we have already established in this section, we do not think that the case for assuming risk aversion has been made. To summarise our reasons:

- Larger reliability USE events do not translate 1-for-1 into longer outages due to rotational load shedding.

[26] See p. 1, Reliability Panel, Review of the Form of the Reliability Standard and Administered Price Cap, Issues Paper, 30 March 2023.
[27] See p. 31 of the Issues Paper and P. Mancarella, Briefing Note for the AEMC in support of the 2022 Reliability Standards and Settings Review, August 2022

- Most customer outages are not related to reliability events so that even significant increases in the size of reliability events are likely to be a small proportion of outages experienced by customers.
- Even if customers did experience longer outages relating to tail-risk reliability events, the AER VCR study shows that the customer's marginal valuation of outages decreases with longer duration events.

Furthermore, previous studies have not found evidence of risk aversion to tail-risk reliability events.

In 2019, the AEMC investigated whether there was evidence for risk aversion (and loss aversion) as part of the Enhancement to the Reliability and Emergency Reserve Trader rule change. The AEMC engaged economic consultancy The Brattle Group (Brattle) to examine the concept of risk aversion and loss aversion and consider whether these concepts imply whether expected USE is not adequately capturing consumers preferences for wholesale reliability.[28] In particular, Brattle was engaged to advise whether 'high impact, low probability' (HILP) reliability events were adequately captured by the expected USE metric.

After a comprehensive investigation, Brattle concluded that:[29]

> *"We do not know whether consumers in the NEM are risk averse in relation to wholesale-level reliability. It might be possible to assess consumer preferences through surveys and directly asking about willingness to pay for insurance against wholesale-level reliability events, but we are not aware of any such surveys."*

In addition, Brattle noted that even if one were to assume risk aversion, the impacts of HILP reliability events under risk aversion or loss aversion depend critically on:

- The size of the harm relative to a consumer's overall wealth or income, and
- The reference point (or 'baseline') against which the consumer is comparing the outage.

[28] The Brattle Group. *High-Impact, Low-Probability Events and the Framework for Reliability in the National Electricity Market*. December 2019. Available on the Enhancement to the RERT rule change page: https://www.aemc.gov.au/rule-changes/enhancement-reliability-and-emergency-reserve-trader

[29] See p. vi of the Brattle report.

Regarding the first point, Brattle argues that HILP reliability events are unlikely to cause a significant amount of harm to consumers (in relation to their overall income or wealth) so that the risk-neutral, expected USE forecasting approach is consistent with expected utility theories of risk aversion in relation to reliability.[30]

In relation to the second point, Brattle notes that over 99% of customer outages relate to factors other than reliability, and that the relatively small number of reliability outages are generally rotated around different customers. Therefore, the value that a consumer places on HILP reliability events (or tail-risk events) under loss aversion "should be expressed relative to the baseline of total customer outages".[31]

Considering Brattle's findings and the overwhelming majority of stakeholder submissions, the AEMC concluded:[32]

> *"In light of the significant feedback that consumers do not wish to pay more for electricity, it does not appear to the Commission that there is much evidence of (loss aversion) in the NEM."*

This is an important point for the Reliability Panel to consider in the current review. There has been no evidence presented to suggest that consumers have different valuations for difference *sources* of outages (e.g. distribution outages vs. reliability events).

Therefore, under an assumption of risk aversion (or loss aversion), we must consider the marginal value of an outage in relation to all expected outages. If it is the case that customers exhibit risk aversion or loss aversion in relation to HILP reliability events, then they must also place an extremely high value on avoiding distribution outages which can last for many hours or even days (e.g. after an extreme weather event). This would justify very large investments in the distribution network to reduce the probability of outages. However, the experience of distribution network 'gold-plating' showed that large network investments significantly over-estimated the value that consumers place on reduced outages.

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[30] See p. 41 of the Brattle report.
[31] See p. 46 of the Brattle report.
[32] See p. 54, AEMC, *Enhancement to the Reliability and Emergency Reserve Trader*, Rule determination, 2 May 2019

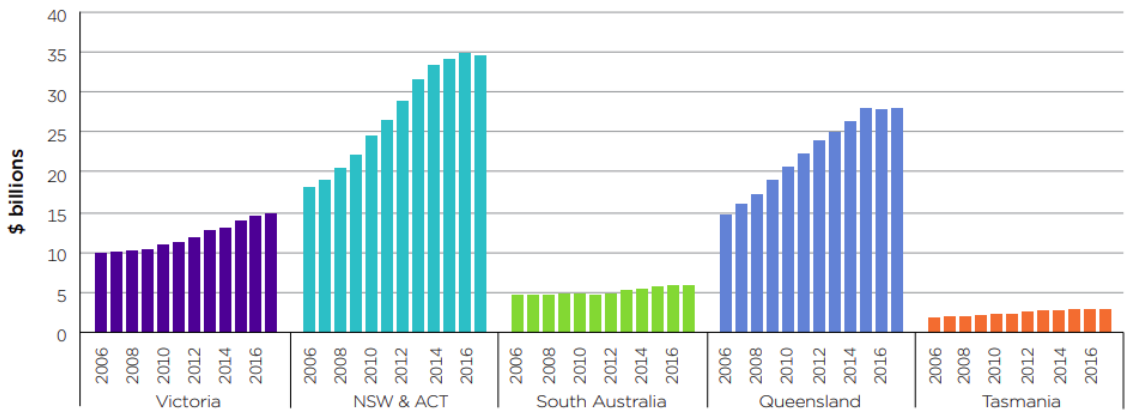
4.4.4. Experience with excessive distribution network reliability standards

The consumer response to distribution network 'gold-plating' is an informative case study for consumer preferences for outages.

In the early 2000s, distribution outages in New South Wales and Queensland led the state governments to impose excessive distribution network reliability standards. This led to significant investment in additional redundancy in these networks resulting in a significant increase in cost to consumers.

In 2017, the Australian Competition and Consumer Commission (ACCC) launched the Retail Electricity Price Inquiry investigating the drivers behind the sharp increase in customer bills. The final report found that increases in network costs accounted for the largest source of difference in customer bills over the period 2007-08 to 2017-18, accounting for 35% of the total increase.[33] Figure 13 shows the increase in regulatory asset base in the different NEM regions over the period 2006 to 2017.

Figure 13: Regulatory asset base 2006 to 2017, real $2016-17



In their review, the ACCC notes:[34]

> *"(The) increased expenditure on networks was driven by reliability standards for some networks that were set too high, without due regard for consumers' willingness to pay for marginal increases in reliability."*

The ACCC made a number of recommendations to address this misalignment and reduce network costs and subsequent reforms have resulted in a

[33] See p. v and chapter 7 of ACCC - Retail Electricity Pricing Inquiry–Final Report. June 2018.
[34] See p. iv, ACCC Retail Electricity Pricing Inquiry – Final Report.

reduction of network costs to be more in line with customer preferences over reliability.

This experience has relevance to the current review being undertaken by the Reliability Panel. Any changes to the form of the reliability standard should be based on a rigorous analysis of consumer preferences over reliability including the customer experience of tail-risk events. As the ACCC notes in relation to distribution network reliability standards:[35]

> *"We consider that reliability standards should be informed by deep understanding of consumer preferences and the careful examination of the costs and benefits of particular standards or changes to those standards."*

The consumer backlash to increasing distribution costs due to gold-plating is not consistent with consumers exhibiting increasing marginal cost of reliability whether through risk aversion or otherwise.

4.4.5. Marginal cost of repeat outages

One final possibility is that during tail-risk USE events, extended periods of rotating outages mean that individual consumers experience repeat outages and that each successive outage has a higher marginal cost to the consumer.

In our view it is unlikely that customers in the NEM have higher marginal costs for repeat outages.

Firstly, the Issues Paper provides no evidence that this is the case. We are not aware of any literature in Australia, but there is some international literature regarding the customer value of more frequent outages. A study into the value of outages in the Netherlands found decreasing marginal value of repeat outages for both residential and business customers.[36] Figure 14 shows the average compensation required by customers by the frequency of outages in a year for Dutch households. This figure shows, for a given outage duration (21 minutes), there is a logarithmic relationship between the frequency of outages and the average compensation required, i.e. the marginal cost of successive outages is decreasing.[37]

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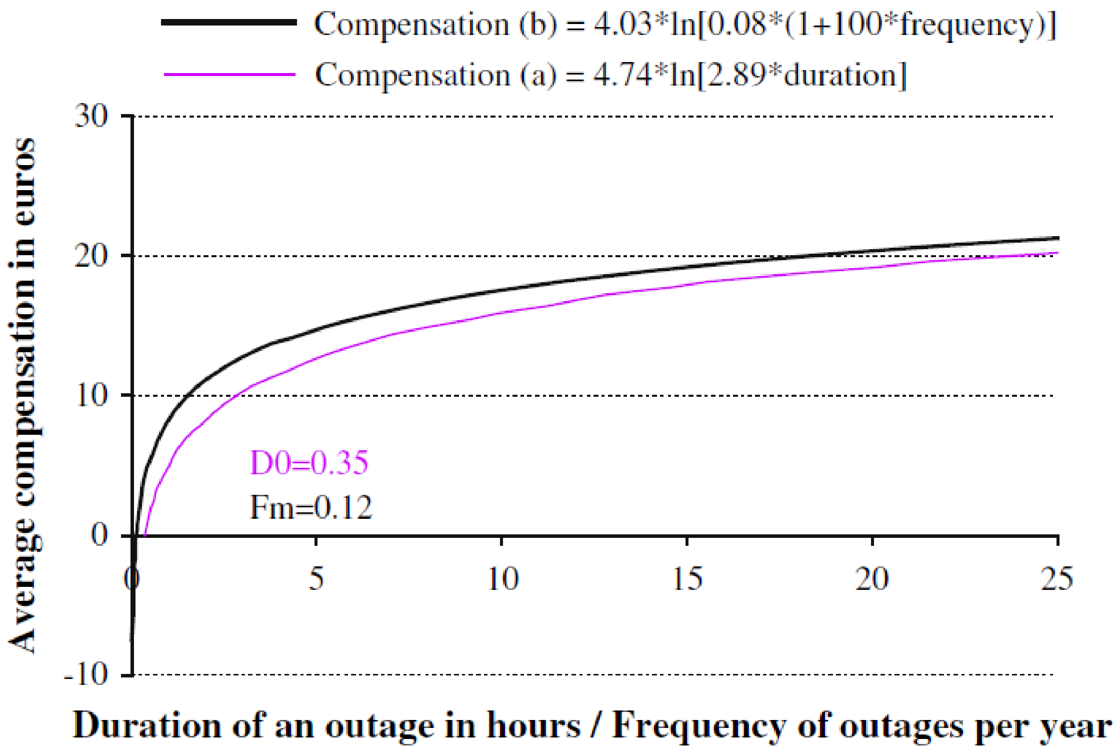
[35] See p. 192, ACCC Retail Electricity Pricing Inquiry – Final Report.
[36] Baarsma and Hop, 2009. Pricing power outages in the Netherlands. Energy. https://doi.org/10.1016/j.energy.2009.06.016.
[37] Table 8 in the study above also shows the average willingness to pay for two-hour outages ranging from 1 to 12 outages per year for residential and

Figure 14: Compensation required for Dutch households for different frequency of outages



Source: Figure 1, Baarsma and Hop (2009). Energy. The black curve shows the willingness to pay to avoid outages by frequency of outages in a year.

Secondly, for NEM customers, the initial outage is generally the most disruptive part of an outage and has the highest marginal cost for most customers (see Section 4.4.1). In our view, it would seem to be the case that each successive outage will likely have the same, or lower impact on customers.

Thirdly, we would expect that there is a certain degree of "learning through experience" for customers experiencing repeat outages. With each outage, consumers gain experiential knowledge, learning to better manage without power and finding alternative solutions or substitutes over time. This learning and adaptation process is even more likely if customers have advance warning of outages. There is evidence from international studies that the cost of USE to customers declines when notice of the outage is communicated in advance. For example, the CEPA study mentioned in Section 4.4.2 found that the cost of outages declined when customers are notified ahead of an

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business customers. These results also show a declining marginal cost of repeat outages.

outage.[38] Considering these factors, we think it's likely that each successive outage would impose at most the same, and likely lower, marginal cost on customers.[39]

4.5. Challenges associated with proposed tail-risk metric approaches

In our view, the case has not been made that customers place higher marginal value on tail-risk USE events, whether through risk aversion or otherwise.

However, assuming that this case was established, any proposed change to the form of the reliability standard must carefully balance the marginal cost of USE against the marginal system cost to achieve the efficient level of reliability.

Undertaking this trade-off will involve a sophisticated understanding of consumer preferences which will likely require extensive and detailed surveys.[40]

In this subsection we outline the challenges we see around how two proposed changes to the form of the reliability standard can achieve an efficient level of reliability:

1. The Reliability Panel's 'straw person' approach including a contingent value-at-risk (CVaR) tail metric based on advice received from Professor Pierluigi Mancarella.[41]
2. The multi-metric proposal put forward by AEMO.[42]

While both of these submissions should be commended for their investigation into the changing distribution of USE, they do not in our view

[38] See p. 44-45, Study on the estimation of the value of lost load of electricity supply in Europe. Cambridge Economic Policy Associates. July 2018.
[39] In economic terms: elasticities are generally higher the longer the time period that is being considered. In our context, consumers learn from experience of outages, adapt and find substitutes.
[40] We note that a similar review was undertaken by the AER, the Widespread and Long Duration Outage review but was ultimately discontinued. See AER - Widespread and Long Duration Outages - Values of Customer Reliability - Final Conclusions.
[41] See p. 31 of the Issues Paper and P. Mancarella, Briefing Note for the AEMC in support of the 2022 Reliability Standards and Settings Review, August 2022
[42] See AEMO's submission at: https://www.aemc.gov.au/market-reviews-advice/review-form-reliability-standard-and-apc

demonstrate how customer value of reliability can be traded off against system costs to achieve an efficient level of reliability.

4.5.1. The Reliability Panel's straw person approach

The 2022 Reliability Standard and Settings Review put forward a straw person composite reliability standard based on advice received from Professor Pierluigi Mancarella. The composite metric is a weighted average of the current risk-neutral expected USE approach and a tail-risk CVaR metric defined at a predefined level.

The composite metric could be defined as follows:[43]

$$R_{ENS} = w \cdot EENS + (1 - w) \cdot \alpha\%CVaR_{ENS}$$

In effect, the composite metric would determine a 'budget' to be allocated to investment to address tail-risk reliability events, based on customer risk-aversion. This approach will involve setting two coefficients, α and w. The coefficient α sets the level of contingent value at risk, i.e. α = 95% represents the expected unserved energy in the worst (1 – 95%) = 5% of cases. The coefficient w sets the weighting between the two metrics e.g. w = 0 would represent complete risk aversion, i.e. the composite metric collapses to the CVaR metric and w = 1 would represent complete risk neutrality which would be equivalent to the current risk-neutral approach.

The composite metric does not explain how simulations of region-wide USE are translated into expected outages for the end consumer. As noted in this report and in the Issues Paper, reliability events are generally managed through rotational load shedding so that there is not a one-for-one relationship between region-wide USE and the duration of customer outages.[44]

Under the straw person proposal, the tail risk CVaR component of the metric only considers the distribution of aggregate USE, it does not distinguish between different allocations of load shedding. For example, a tail risk event of 100 MW of load shedding for 10 hours would lead to the same CVaR calculation whether the USE was borne by a single group of customers for 10 hours as if it was borne by 10 different groups of customers for one hour each. In other words, the aggregation of customer preferences under the

[43] See p. 33 of the Mancarella briefing note cited above for a complete explanation.
[44] See p. 16 of the Issues Paper.

straw person approach implicitly assumes risk neutrality, i.e. a constant value of customer reliability for any number and duration of outages. This is clearly inconsistent with the assumption of risk aversion and, in our view, calls into question the internal validity of the straw person approach.

Even if a fixed relationship between each customer's USE and region-wide USE could be assumed, the composite metric would require complex modelling and a very sophisticated understanding of consumer preferences over different distributions of unserved energy.

Any reliability standard must have a basis for trading off customer value of reliability against system costs. Determining α requires an accurate understanding of customers' appetite for tail-risk and appears to only be relevant for a specific allocation of rotational load shedding. Similarly, coefficient w determines the budget allocated to tail risk and needs to be based on the relative importance to consumers of expected USE and tail risk.

In our view, while the straw person put forward in the Issues Paper is elegant, the informational and computational requirements of the approach mean that it is unlikely to be able to achieve an efficient level of reliability in practice.

4.5.2. AEMO's proposed approach

In its submission to the Review, AEMO sets out its preferred metric for addressing tail-risk.[45] AEMO proposes a multi-metric reliability standard which takes into account the depth, duration and frequency of USE.

AEMO expresses an example of their proposed metric as:[46]

> *The average annual outcomes that are at or above a one-in-10-year probability may not be greater than x% of average regional load shed for 4 hours, or equivalent.*

AEMO does not suggest a basis on which their proposed metric would trade-off customer value of tail-risk against system costs. AEMO's proposed approach based on average outcomes at a one-in-10-year probability would significantly overestimate customer value of reliability because it effectively discards the USE outcomes in the bottom 90% of simulation years.

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[45] See AEMO's submission here: https://www.aemc.gov.au/market-reviews-advice/review-form-reliability-standard-and-apc

[46] See p. 14 of AEMO's submission.

To use an analogy, consider if an insurance company set their home insurance premiums based on a one-in-10-year flooding event occurring every single year. In this situation, almost all homeowners would forego the insurance as it dramatically overstates their willingness to pay. However, according to AEMO's proposed metric, this premium would represent fair value for consumers and AEMO would purchase this insurance on the customer's behalf.

In our view, adopting the proposed AEMO metric as the reliability standard would result in an inefficiently high level of reliability that significantly overstates the value customers place on reliability.

AEMO notes that their proposed approach is statistically equivalent to the CVaR component of the Reliability Panel's straw person approach set at a 90% CVaR (but assuming full risk-aversion i.e. with $w = 0$). AEMO considers that while the two approaches would deliver very similar outcomes, AEMO considers that their proposed metric is simpler and more tangible for customers.[47]

We consider the equivalence drawn by AEMO between the two proposed approaches is further evidence that the straw person model, which is less intuitive to understand, is inefficiently conservative.

4.6. Comments on the Reliability Panel's modelling approach

The Reliability Panel discussed its proposed modelling approach in the Issues Paper. Based on our understanding, the Reliability Panel proposes to use an ISP-style generation expansion modelling, combined with an ESOO-style time-sequential dispatch model to work out the distribution of USE and the impact of different reliability outcomes on the system cost under different generation mixes.

4.6.1. Lack of clear linkage between market modelling and the form of the standard

As we have argued in the previous sections, the Reliability Panel must first establish that customers do actually exhibit risk aversion towards reliability load shedding. However, even if we assume risk aversion is true, it is not clear how the proposed market modelling approach and output will inform the decision on the form of the standard. Under risk aversion, the consumer is

[47] See p. 15 – 17 of AEMO's submission on the close relationship between the straw person metric and AEMO's proposal.

willing to accept a higher level of expected USE in exchange for a lower level of reliability risk. Introducing an additional risk metric would involve the following:

- Determining the form of the additional metric.
- Determining the trade-off between the additional metric and the existing expected USE metric (i.e. coefficient w in the straw-person formulation: $w \cdot EENS + (1-w) \cdot \alpha\% CVaR_{ENS}$.).

The above appears to be purely related to consumer preference, rather than the underlying system cost. The Issue Paper has not explained why the underlying distribution of USE should affect the form of the additional risk metric or its trade-off with expected USE.

In addition, the presence of an additional risk metric in the standard appears to introduce a few significant technical challenges to market modelling at a later stage when the Reliability Panel will determine the level of the reliability standard. We will explore the modelling challenges further in the next subsection as an intellectual exercise, but note the Reliability Panel must first establish risk aversion, as experienced by the end customer.

4.6.2. Challenges of modelling an additional metric in the standard

Under the current expected USE metric, the level of standard is determined by finding the level of reliability that minimises the total cost consisting of the cost of unserved energy and the cost of generation. This can be expressed as:

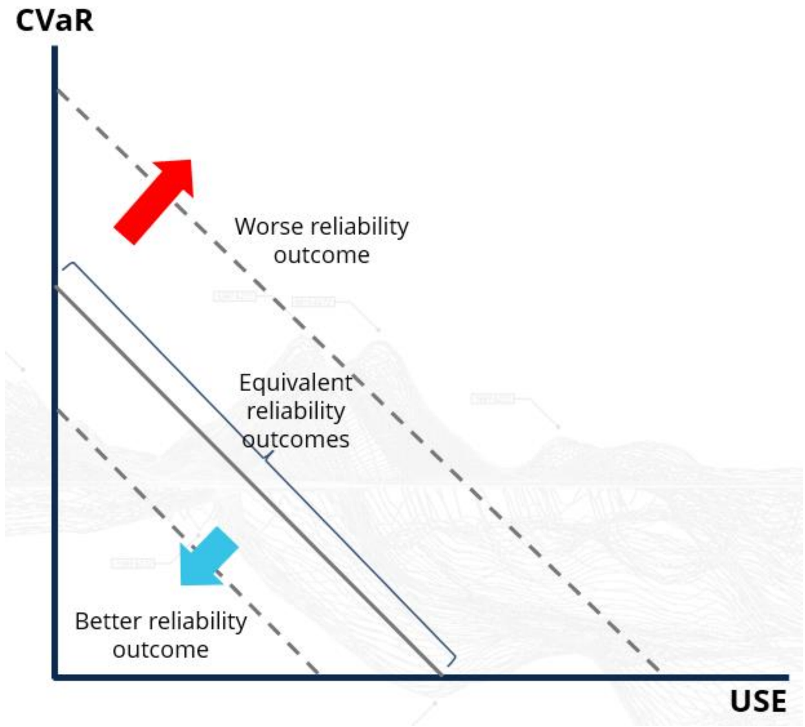
$$Total\ cost = VCR * E(USE) + System\ cost$$

The expected USE measure of the current standard means that the cost of unserved energy can be transparently compared against the generation cost using the VCR.

This is less straightforward with an additional metric in the standard. Using the straw person composite metric, even if the weighting parameter, w, has been determined, the efficient level of the standard must consider the interaction between expected USE and the risk metric. That is, the consumers might be indifferent between two reliability outcomes (e.g., outcome A with a higher USE and a lower CVaR, versus outcome B with a lower USE and a higher CVaR), despite the two outcomes having different system cost implications. As shown in Figure 15 below, each line shows the combinations of expected USE and CVaR outcome that leads to equivalent reliability outturn to consumers (as they are willing to incur a higher expected USE to reduce the

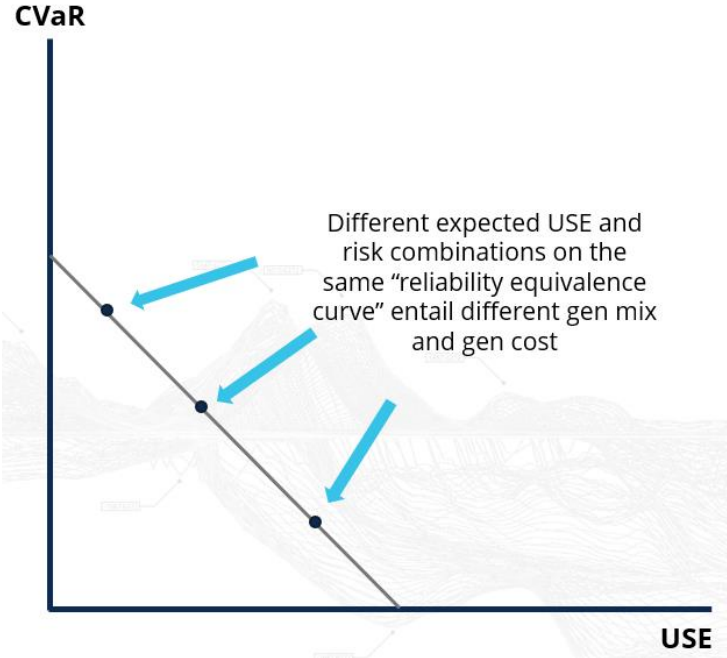
CVaR). The consumer would be worse off (i.e. experience a worse reliability outcome) if the line shifts outward and would be better off (i.e. experience a better reliability outcome) if the line shifts inward, as shown by the two dashed lines.

Figure 15: Illustration of reliability equivalence curves



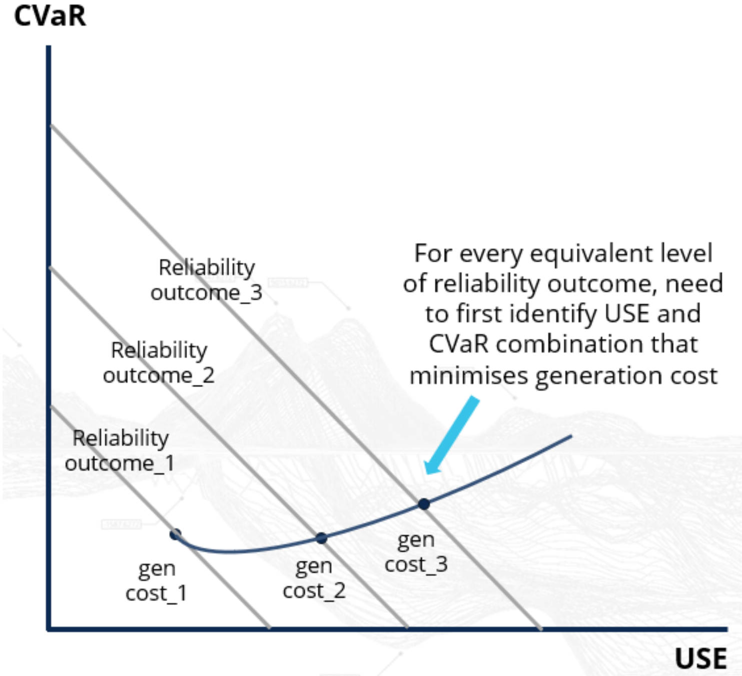
Each point on a given "reliability equivalence curve", however, will likely be the outwork of a different generation mix and hence entail a different system cost.

Figure 16: Different generation cost for equivalent reliability outcome



Given consumers view the reliability outcomes equally on each line, the modelling must first identify the minimum generation cost for each level of equivalent reliability outcome, as outlined in Figure 17.

Figure 17: Finding USE and CVaR that minimise generation cost for each equivalent reliability outcome



Having gone through the above exercise, one needs to convert each reliability outcome into a monetary equivalent, which can be added to the associated generation cost (minimised for this level) to obtain the total cost. Currently it is not clear how this can be done, given the presence of the CVaR metric. The efficient reliability level, defined by an optimal expected USE and optimal CVaR, is the reliability level that minimises the total cost, taking into account the optimised generation cost for the level.

While the above is a theoretical exercise, it highlights that there appear to be some gaps in the Reliability Panel's proposed modelling methodology to produce the outputs required in each step. It also shows that there might be material computational and empirical challenges, that require additional methodology design than running an "ISP-style" or "ESOO-style" market model in PLEXOS.

5. Conclusion

The form of the standard is central to the reliability framework and plays a key role in determining the reliability settings which guide billions of dollars of investment. The form of the standard allows a trade-off to be made between the cost of unserved energy and the system cost of reducing unserved energy. Considering the importance of the form of the reliability standard, strong evidence is required to justify a change.

A change in the distribution of USE does not by itself change the underlying economics and therefore does not justify a change in the form of the standard.

To make the case for change, the Reliability Panel must show that customers exhibit risk aversion, or an increasing marginal value of customer reliability, in terms of $/kWh unserved, for larger USE events.

In its Issues Paper, the Reliability Panel has not provided evidence that customers exhibit risk aversion towards larger USE events. In fact, the Australian Energy Regulator's Value of Customer Reliability study provides evidence in the *opposite* direction, that is that the value of customer reliability is *declining* for longer duration events.

In 2019, Brattle undertook a comprehensive study and did not find evidence of risk aversion or loss aversion. The AEMC agreed, after taking into account the overwhelming majority of stakeholder submissions which were primarily concerned with cost. Similarly, the experience of distribution network 'gold-plating' provided a clear lesson that regulators should carefully take into account customer preferences when setting reliability standards.

There is limited evidence available on the marginal cost of repeat outages, but our international research found a similar relationship, i.e. a declining marginal value for successive outages. This accords with our expectation, customers "learn from experience" and adapt to multiple outages such that the marginal impact of successive outages for most customers is likely to be the same, or lower.

Given reliability events are managed through rotational load shedding, it is not sufficient to show that there is risk aversion towards tail-risk *region-wide* USE events. Each region-wide USE event needs to be allocated to consumers (i.e. through rotational load shedding) and the consumers must be shown to be risk-averse towards the allocation of USE that they actually experience.

This creates a preference aggregation issue which rules out the Reliability Panel's straw person composite reliability metric. Similarly, AEMO has not made the case for how their 'equivalent' metric achieves the efficient reliability trade-off.

In addition to the theoretical challenges, the straw person approach poses a number of modelling challenges. It is not clear from the Reliability Panel's proposed modelling methodology how the straw person metric can be operationalised in practice. There will likely be material computational and empirical challenges, that require additional methodological design than running an ISP-style or ESOO-style market model.

In our view, the case has not been made for changing the form of the reliability standard to include a tail-risk metric. Such a change risks over-estimating the value to consumers of unserved energy and will likely deliver an inefficiently high level of reliability, with the costs ultimately borne by consumers.

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