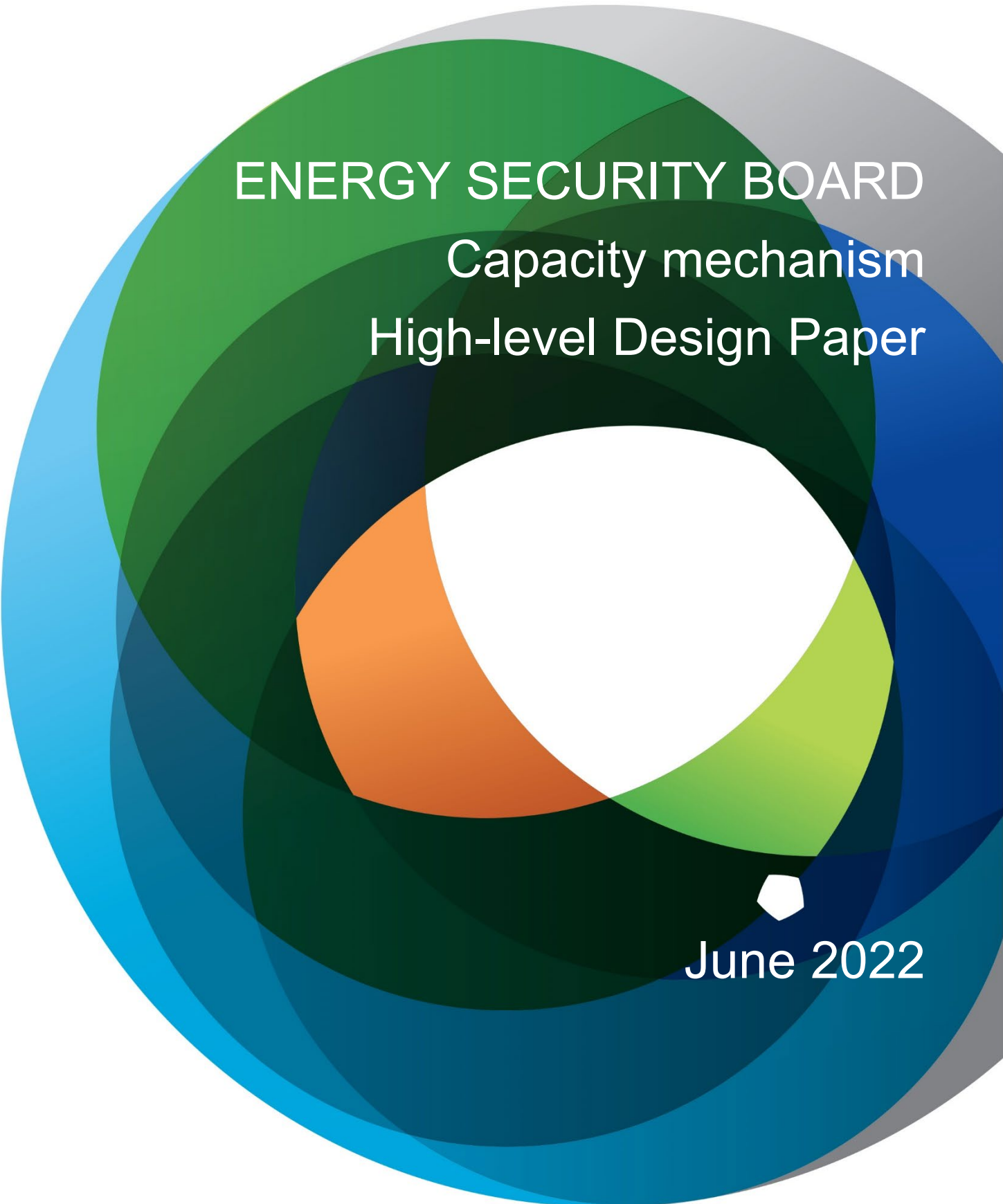




ENERGY SECURITY BOARD

Capacity mechanism
High-level Design Paper

June 2022



Anna Collyer

Chair

Australian Energy Market Commission and
Energy Security Board



Clare Savage

Chair

Australian Energy Regulator



Daniel Westerman

Chief Executive Officer

Australian Energy Market Operator

Table of Contents

Executive Summary	i
1. Introduction.....	1
2. Approach	2
3. Case for change.....	7
4. Participation of new and existing capacity in the mechanism	17
5. Forecasting demand and the building blocks for a mechanism	21
6. Procuring capacity and auction design	38
7. What are the obligations on capacity providers?	47
8. How will costs be allocated?.....	57
9. How is transmission capacity reflected in the capacity mechanism design?	59
10. Assessment of high-level design	67
11. Next steps and implementation	73

List of Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CMM	Congestion management model
COAG	Council of Australian Governments
CONE	Cost of New Entrant
DR	Demand response
ELCC	Equivalent Load Carrying Capacity
ESB	Energy Security Board
ESS	Essential System Services
GW	Gigawatt
ISP	Integrated System Plan
MW	Megawatt
MLO	Market Liquidity Obligations
NEM	National electricity market
NEO	National Electricity Objective
NEL	National Electricity Law
OEMC	Orderly exit management contract
PV	Photovoltaic
PRRO	Physical Retailer Reliability Obligation
REZ	Renewable Energy Zone
RRO	Retailer Reliability Obligation
VRE	Variable renewable energy
WEM	Wholesale electricity market

Executive Summary

The National Electricity Market (NEM) is going through a once-in-a-century transformation as Australia moves towards net-zero emissions by 2050. This transition will see ageing fossil fuel plants that once made up most of the NEM replaced with new, clean energy resources and a more responsive demand-side.

This transition needs to be carefully managed. The stakes have never been higher. Coal generators, which currently account for over half the NEM's generation output, are ageing, and several have announced early retirement dates. Most market participants consider AEMO's Step Change scenario to be the most likely – which implies 14 GW of coal-fired generation may retire by 2030, and all coal-fired generation will cease generating by 2043. At the same time, AEMO has forecast that electricity demand could at least double by 2050. AEMO's Step Change scenario estimates about 122 GW of additional wind and solar (collectively variable renewable energy (VRE)) firmed by approximately 45 GW of new dispatchable storage capacity, 7 GW of existing dispatchable hydro and 9 GW of gas-fired generation will be required by 2050 to meet demand as coal-fired generation withdraws.¹

Coordinating exit and entry, including the mix of resources to ensure an orderly transition, is an enormously complex task.

The uncertainties facing investors have never been greater. Demand uncertainties include the speed of post-covid recovery, the longevity of major users such as smelters, and the timing and scale of trends like electrification of gas and transport. On the supply side, investors are grappling with the disruptions and uncertainties in the supply chain due to the pandemic, and now war in Ukraine. More fundamentally, despite notice of closure provisions, the exact closure timing of the large, thermal plant closure is uncertain. In a market where demand has been relatively stable for several years, it is difficult to make a case for new investment until a clear gap in the market has been established. A 'wait and see' approach from investors is a rational response to such uncertainty. But widespread 'waiting and seeing' will risk too little capacity being available and new capacity arriving too late. It also increases the likelihood that jurisdictions will feel forced to intervene – which, in turn, can create another source of uncertainty for investors.

The result is that it is hard to be confident that we will 'stick the landing' of the energy market transition. We could get the timing wrong (too little, too late) or the mix wrong (not enough dispatchable capacity, including long-duration storage, to firm VRE). The results would mean high prices (driven by scarcity and uncertainty-inflated costs of capital) and poor reliability outcomes. None of these outcomes would be in the long-term interests of consumers – the anchor point of the National Electricity Objective and the pole star for the work of the ESB. Evidence of the lack of confidence that the current arrangements will deliver can be found throughout the NEM. Jurisdictions are intervening in various ways, such as the NSW Energy Roadmap, including its storage targets, the Victorian Big Battery, the Commonwealth's investment in gas-fired generation and Snowy 2.0.

A capacity mechanism, in which providers of capacity are paid to have their capacity available during certain periods, will help reduce the risk of a disorderly transition. It is a more direct, more certain way of ensuring we have the right amount and the right mix of capacity that we need, to deliver affordable and reliable power as our system decarbonises.

¹ AEMO. Draft 2022 Integrated System Plan. Page 36 and 46.

It puts an explicit value on capacity and provides a clear route to purchasing it. It leaves less to chance.

In arriving at this conclusion, the Energy Security Board (ESB) notes that the vast majority of electricity markets around the world already explicitly value capacity and pay for it directly. Australia is one of very few 'energy only' markets remaining. Even in Australia, the bulk of resources built by the private sector have been underpinned in some way by government policies. The practical reliance on the energy-only market to drive investment in dispatchable capacity has been limited.

From an investor's point of view, a capacity mechanism would reduce reliance on wholesale market outcomes that are becoming increasingly difficult to predict. It would provide an alternative revenue source that would be potentially more predictable and secure, rewarding the capacity service that the market needs.

From a customer point of view, the risks of a disorderly transition would be reduced, including avoiding elevated high prices due to scarcity and the disruption and costs of load shedding. The ESB is aware of concerns that a capacity mechanism could cause customers to pay more for the same level of service. This is clearly not the intent, and it will be avoided through careful design. In particular, as part of the development of its detailed design proposal, the ESB will focus on the role that the market price cap would play in the presence of a capacity mechanism, and assess the scope for any reductions in its level to ensure customers pay no more than is necessary. It will also give careful thought to auction design and the scope for different rules and support arrangements for existing and new participants. The ESB's intent is to design a mechanism that balances the income that capacity providers would earn between capacity and energy sources to promote lower cost investment while at the same time ensuring payments are only made where benefits to consumers can be demonstrated.

Designed well, the capacity mechanism will enable a swifter, less risky and more orderly transition to a net zero emissions energy system. To this point, the ESB is seeking further guidance on the principle of continued emissions reduction of electricity supply to allow the principle to be operationalised in the design in a way that guides the transition without impacting jurisdiction's ability to determine technology that is eligible for participation. The mechanism will allow jurisdictions to proceed with greater confidence, knowing that reliability is being explicitly managed in the process. It means less reliance on other government interventions or emergency, out of market measures.

To keep pace with the speed of the transition, the capacity mechanism will need to be operational by 1 July 2025. Therefore, the design of the capacity mechanism needs to be straightforward to start with, and it can be refined over time, as has occurred in the energy market since the NEM commenced. This report presents the ESB's High-Level Design of a proposed capacity mechanism prepared in response to a request by Energy Ministers in October 2021 and following consultation on the Initiation Paper in December 2021. The ESB has looked at a range of design options to develop this high-level design, drawing on international examples and the Western Australian wholesale electricity market (WEM). The Board has also consulted with stakeholders, including the Advisory and Technical Working Groups and jurisdictions. This paper sets out the next steps for the design, including the issues to resolve and further analysis required in each of these key design areas. The ESB seeks stakeholder feedback on these issues to inform the detailed design of the capacity mechanism.

The high-level design at a glance

The ESB's preferred high-level design centres around some fundamental design choices:

- who is eligible to participate
- the degree of centralisation of forecasting and procurement
- the nature of the obligation placed on capacity providers in return for a capacity payment
- the role of interstate trade
- how costs are passed through to customers.

Who is eligible?

The ESB proposes that all resources contributing to capacity requirements be eligible to participate in the capacity mechanism. This would include demand-side resources, which will have an important role to play in a decarbonised grid.

While some stakeholders have proposed that only new resources should be eligible to participate, in the ESB's view, the capacity mechanism should not exclude existing resources. This is so the mechanism can:

- access the most efficient mix of resources to ensure reliability
- avoid over-building new capacity before it is required
- discourage premature exit of existing capacity before alternative resources are in place.

It is also critical to note that existing capacity does not equate directly to thermal plant. For example, there are existing batteries, hydro and pumped hydro storage already in the NEM that should be able to participate.

However, the ESB recognises that new and existing capacity have different requirements. Existing capacity faces sunk costs, while new investors require sufficient certainty that their capital costs, as well as their operating costs, will be recovered.

The ESB intends that the mechanism will consider the challenges faced by new capacity and provide it with additional support. This may take the form of longer-tenure contracts, like those in the Great Britain market, and potentially different auction participation rules.

The degree of centralisation of forecasting and procurement

The ESB proposes a centralised approach to forecasting capacity requirements and purchasing what is required. The ESB considers this approach offers the greatest likelihood that sufficient capacity will be procured to give jurisdictions confidence in the path forward.

The ESB notes stakeholder concerns that a centralised scheme could be more likely to over-insure the NEM if the Australian Energy Market Operator (AEMO) takes a conservative approach to forecasting and procurement. To ensure costs for consumers are minimised, the ESB will continue to explore further opportunities for market participants to have a role in forecasting. The ESB will explore potential hybrid models where retailers take on some role in forecasting their own needs and procuring for them, from a pool of capacity procured by AEMO. This hybrid approach could increase the transparency of retailers' forecasts relative to AEMO's and the associated differences in costs to consumers.

De-rating

Another essential element of the forecasting process is how a capacity provider's capacity is 'de-rated'. De-rating is the process by which a capacity provider's nameplate capacity is scaled down to the level of expected output during reliability compliance events.

The period over which capacity providers are de-rated (referred to in this paper as the 'at risk period') is an important consideration. Options considered include a pre-defined period (e.g., summer weekday evenings between 4 pm to 9 pm) and modelled occurrence of reliability events. A pre-defined period is a more straightforward approach. However, a model based on the occurrence of the reliability event is more likely to reflect the changing nature of reliability. The ESB is seeking feedback on the most appropriate approach to de-rating.

The capacity providers' obligation

For the capacity mechanism to achieve its stated objectives set out in this paper, it is vital that capacity providers meet the requirements of the capacity certificates. The design of the obligation sets out what capacity providers awarded with a capacity certificate must do in return for their capacity payment, and what happens if they fail to meet their obligations. The ESB proposes that the performance obligation should be principally tied to availability across the delivery year and bidding during periods of system stress (such as lack of reserve (LOR) 2 or LOR3) with weighted payments tied to both these obligations.

This means that the capacity obligation covers all periods of system stress throughout the year, rather than just peak periods.

Transmission capacity

Transmission network constraints may limit the ability of capacity providers in one part of the grid to meet demand in another location. Therefore, the capacity mechanism design needs to account for transmission constraints when determining which capacity resources can be procured to ensure both reliability of supply and efficient investment in capacity.

The ESB considers that the benefits of interconnection should be realised through the mechanism. The ESB has considered two approaches to doing this:

- expected interconnector flows during periods of system stress would inform the amount of capacity purchased within a single region, but there would be no explicit participation in neighbouring region capacity auctions
- capacity providers and market interconnectors² can participate in neighbouring region capacity auctions.

Allowing interstate resources to participate adds to the complexity of the design, and there are several options for how it could be achieved. The ESB has not yet formed a view on each of these options. The ESB seeks feedback on the most appropriate approach to realise the benefits of an interconnected NEM in the capacity mechanism.

Cost allocation

Under a centralised procurement approach, AEMO would hold capacity auctions, award contracts, and make payments to capacity providers. It would then need to allocate these costs to consumers – either through networks or retailers.

The ESB considers that cost allocation through retailers using actual demand is the preferred approach. The basis for sharing costs among retailers needs to be transparent and well-understood so that retailers can build in expected costs into tariffs in advance. Using

² For a market interconnector (currently, only Basslink) a decision would need to be made whether the market interconnector is the capacity market participant, or the generator(s) behind the interconnector (Hydro Tasmania). In either case, the parties would need to contract among themselves to enable participation.

actual demand will provide retailers the incentive to manage demand, particularly at peak periods.

Next steps

Following the publication of this paper, the ESB will consult on the high-level design and issues set out in this paper.

The ESB will return to Energy Ministers with a draft detailed capacity mechanism design by December 2022, which will be put to stakeholders for further consultation. Following this, the ESB will present its final detailed capacity mechanism design to Energy Ministers in February 2023.

Submissions to this paper are due on 25 July 2022 and can be sent to info@esb.org.au.

1. Introduction

1.1. Purpose of this paper

This paper puts forward the Energy Security Board's (ESB's) high-level design of a capacity mechanism for the national electricity market (NEM). It outlines the ESB's proposed direction on fundamental design decisions and the key considerations which informed these positions. The positions in this paper narrow the field of possible options and progress discussion to detailed design questions. This paper also sets out what these decisions mean regarding the issues to resolve and further analysis required in each of these key design areas. We are seeking stakeholder views on the issues identified throughout this paper.

1.2. How to make a submission

The ESB will publish submissions on the Energy Ministers website, following a review for confidentiality claims. All submissions should be sent to info@esb.org.au.

Submission information	
Submission close date	25 July 2022
Lodgement details	Email to: info@esb.org.au
Naming of submission document	[Company name] Response to Capacity Mechanism Project High-level Design Paper
Form of submission	Clearly indicate any confidentiality claims by noting "Confidential" in document name and the body of the email.
Publication	The ESB will publish submissions on the Energy Ministers website, following a review for confidentiality claims

2. Approach

2.1. Context

In March 2019, the then COAG Energy Council tasked the ESB with advising on a long-term, fit-for-purpose NEM design. This has become known as the Post 2025 Market Reform Project. This request reflected a general concern about reliability, security and affordability in the NEM as the rapid uptake of renewable generation occurs and the existing ageing generation fleet progressively retires.

The ESB provided its final advice to Ministers on the Post 2025 Market Reform Project in July 2021. The advice included a recommendation for Ministers to provide in-principle support for a capacity mechanism for the NEM and, in recognition of significant stakeholder concerns, to instruct the ESB to work with stakeholders and jurisdictions to develop the detailed design of a capacity mechanism for Ministers' agreement.

The ESB's final advice to Ministers included a straw proposal for a physical retailer reliability obligation (PRRO), a form of decentralised capacity mechanism. However, the ESB also proposed it would first answer a series of structural questions posed by stakeholders, which would include whether it would be preferable to centrally determine the volume of required capacity and other more centralised design choices.

In September 2021, Energy Ministers agreed at the Energy National Cabinet Reform Committee to progress further design work on a mechanism that specifically values capacity in the NEM.

In December 2021, the ESB published an initiation paper for the Capacity Mechanism Design Project. The initiation paper outlined the approach the ESB proposed to take in progressing the design project and sought stakeholder feedback on high-level design choices, including how centralised or decentralised the capacity mechanism should be. Recognising that there are variations within this choice, the ESB proposed a further three straw proposals to guide stakeholder feedback:

- a fully decentralised approach where liable entities (retailers and other market customers) are responsible for procurement of capacity, forecasting and determining demand
- a hybrid decentralised approach where liable entities are responsible for procuring capacity according to a forecast determined and allocated to them by a central body (Australian Energy Market Operator (AEMO))
- a centralised model where a central body (AEMO) is responsible for procurement of capacity and forecasting and determining demand.

The ESB also stated that the energy market with the current financial retailer reliability obligation (RRO) (including other proposed minor amendments) will be considered further as part of the base case against which the benefits of a proposed capacity mechanism will be considered.

2.2. Scope

The four Post 2025 reform pathways are a package of interrelated reforms and actions to deliver the necessary design changes in the NEM for 2025 and beyond. The capacity mechanism design project is just one aspect of the Post-2025 reforms.

In the December 2021 initiation paper, the ESB summarised the aim of the capacity mechanism as comprising two limbs, informed by Ministers' principles:

- Ensuring investment in an efficient mix of variable and firm capacity that meets reliability at the lowest cost by:
 - facilitating the timely entry of new generation, storage and flexible resources
 - facilitating or complementing the orderly retirement of ageing thermal generation
 - complementing other market arrangements addressing resource adequacy.
- Increasing government and community confidence that the market will deliver resource adequacy and thereby reducing the need for interventions over the longer term.³

The ESB expects its preferred capacity mechanism design will have implications for various aspects of NEM design and operation, such as the contract market. These areas will be identified and their impacts considered during the design process.

The ESB also recognises that its preferred capacity mechanism design will have implications for the other work programs and that those work programs have a range of potential implications for the capacity mechanism design. Capacity within the power system will only provide benefits to reliability where the transmission system has the ability to deliver that capacity to customers. There are then important linkages between the capacity and energy markets and both the development and utilisation of the transmission system.

The ESB's Post 2025 recommendations identified a way forward for essential system services. This recognised that there is significant value where resources can provide flexibility and essential capabilities, allowing system needs to be met through a different mix of resources to what is used today. The work of the market bodies is largely progressing these recommendations through rule changes and subsequent implementation programs.

The ESB recognises that solar PV located at the customer's premises provides a large and growing portion of supply to the NEM. Distributed battery storage is now also growing strongly, while new technologies offer opportunities to derive benefits from more flexible demand. The ESB's program is addressing a range of issues to unlock the potential benefits of integrating demand-side resources into the market and this will extend to the capacity mechanism. There are options as to how that integration could be achieved, which could both provide efficient resources to the capacity mechanism and benefit customers.

Information is critical to the success of the capacity mechanism, both for predicting the level and profile of demand and the nature and capability of resources to meet that demand. Better data and advances in technology can improve the accuracy of these assessments and help to reduce the costs of delivering the required level of reliability. This is particularly important in a transitioning power system where changes in consumer demand and customer take-up of distributed resources and flexible demand opportunities are critically important.

The ESB recognises that the parallel work programs will have implications for a capacity mechanism, and will consider the crossovers during detailed design. Where these are complementary, the ESB will carefully consider the issues alongside each other.

At the same time, the Reliability Panel is carrying out its four-yearly Reliability Standard and Settings Review (RSSR). In its Review, the Panel will recommend the appropriate level of the reliability standard and market price cap required under the current market arrangements. The ESB is keeping across this work as it progresses.

³ ESB, Capacity Mechanism Project Initiation Paper, Dec 2021

2.3. How we assessed options

2.3.1. The National Electricity Objective

The ESB is guided by the National Electricity Objective (NEO) in developing and assessing capacity mechanism design options. The NEO, as stated in the National Electricity Law (NEL), 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:

- *price, quality, safety and reliability and security of supply of electricity*
- *the reliability, safety and security of the national electricity system.”*

To order to consider the NEO, the ESB has developed the following assessment criteria:

1. Achieving the optimal level of reliability: a mechanism should achieve the target level of reliability that consumers and governments value.
2. Appropriate allocation of risk: a mechanism should efficiently and appropriately allocate risks.
3. Technological neutrality: a mechanism should be technologically neutral while recognising the rapid pace of change, noting there are design principles which relate to these criteria that will be addressed during the process.
4. Minimise regulatory burden: a mechanism should minimise the regulatory burden for market participants.
5. Emissions reduction: a mechanism should be compatible with emissions reduction targets set out by state and federal governments.

We have developed the high-level design with reference to these assessment criteria. A discussion of how the design performs against the assessment criteria is in section 10. These criteria will continue to inform the ESB's work during the detailed design phase.

2.3.2. Minister's design principles

In September 2021, Energy Ministers set out a series of design principles to inform ESB's capacity mechanism work. These are set out in Box 1 below. The principles have been an important input for the ESB in its consideration of a preferred high-level design. To facilitate decision-making, and to ensure the principles are met, the ESB captured Energy Ministers' principles in the form of the assessment criteria outlined above. In addition, some of the principles will require careful consideration to ensure they can be met in the design, for example, the ability of jurisdictions to opt in and opt out of the mechanism. How the ESB intends to address these issues in the detailed design process is discussed in section 10.

Box 1 Energy Ministers' principles to guide capacity mechanism development

The detailed design work on a capacity mechanism will be guided by the following principles agreed by Energy Ministers:

1. be consistent with the **National Electricity Objective**
2. focus on **affordability, reliability, security, and continued emissions reduction** of electricity supply
3. provide a **signal to value capacity** that best supports the needs of the NEM
4. **complement existing energy only market design** and well-functioning **markets for financial contracts**, and other reforms in development
5. **minimise regulatory burden** for market participants
6. **safeguard energy consumers**. In particular:
 - a. ensure costs and revenues are efficiently and fairly allocated; and
 - b. avoid duplication of costs to secure reliability
7. ensure sharing of resources across the NEM by **supporting inter-regional contracting**
8. provide **greater certainty around closure dates** of exiting generation
9. **mitigate** reliability risks presented by **unexpected closures** of existing capacity
10. encourage the **timely replacement** of existing capacity through driving commitments to new investment within reasonable notice periods of closure of existing capacity
11. to the extent it does not conflict with state and territory policies, be **technology neutral** to ensure a focus on the ability of each resource to deliver generation on demand, for the periods when it is most needed
 - a. Jurisdictions must be able to determine, via their regulation, provided for in the National Electricity Law framework, which technologies are eligible for participation in a capacity mechanism in their region
12. recognise relevant **state and territory policies and investment schemes** to account for bespoke arrangements to retain and replace existing capacity
13. enable jurisdictions to **opt out**, via the National Electricity Law framework
14. enable jurisdictions to **opt in**, through triggered thresholds for the mechanism

2.3.3. ESB analysis and design work

The ESB's approach to developing the preferred high-level design has been to identify the critical design questions that shape the core of a capacity mechanism design. The ESB has then sought to provide its preferred answer to these questions to set out the type of capacity mechanism that, in its view, is most appropriate for the NEM.

Some of these questions align with the core design areas that the ESB consulted on in the December 2021 Initiation Paper, such as:

- the definition of capacity (and other core building blocks)
- how capacity requirements are forecasted
- how capacity is procured
- the nature of the obligation on liable capacity providers
- whether inter-regional capacity is captured.

The ESB also identified further questions through stakeholder feedback, such as whether all capacity should be eligible to participate in the scheme or whether the scheme should be restricted to new capacity only.

This paper provides the ESB's view on these key design questions.

Several overseas markets have capacity mechanisms, as does Western Australia. To learn from these examples, the ESB commissioned NERA to examine five international capacity mechanism examples: Great Britain (GB), France, Ireland, and PJM and CAISO in the US. Relevant findings from this work are summarised in this report. The ESB's preferred high-level design also recognises that the NEM has several unique characteristics and is a product of the specific Australian context in which it operates. As a result, approaches that have worked overseas may not always be appropriate to apply to the NEM.

2.3.4. Governance and stakeholder engagement

To ensure stakeholders' views are reflected in the project, the ESB's governance arrangements for the capacity mechanism project include the following:

- ESB – the Chairs of the Australian Energy Market Commission and Australian Energy Regulator, and the Chief Executive Officer of the Australian Energy Market Operator
- Internal Working Group (IWG) – senior representatives of the three market bodies
- Advisory Group – senior nominated representatives of market participants, including generators, retailers, energy consumers, financial institutions, and project developers
- Technical Working Group (TWG) – nominated representatives of market participants, including generators, retailers, energy consumers, financial institutions and project developers
- Senior Officials Group – senior representatives of state, territory and Commonwealth energy agencies.

This document reflects the input of these diverse stakeholders.

Stakeholder feedback was critical in informing the ESB's proposed high-level design. The ESB recognises that a capacity mechanism is a significant change to the NEM and that many stakeholders have concerns about the introduction of one. The ESB has therefore sought to maximise stakeholder engagement in the process. This has included establishing an Advisory Group and TWG that provides a formal avenue for stakeholders to participate in the design process. These groups have acted as a sounding board for the ESB's thinking on design decisions.

The ESB also engaged on the Capacity Mechanism Initiation Paper, which occurred throughout December 2021, and January and February 2022. The ESB received 35 written submissions on this paper, published on the Energy Ministers' website found [here](#).

This paper includes summaries of the feedback stakeholders provided on the key design questions and how this informed the ESB's thinking.

3. Case for change

3.1. The NEM needs unprecedented investment in the coming years

Our electricity sector is undergoing a once-in-a-century transformation, as ageing fossil fuel generators are replaced by modern, clean energy sources. This transformation is happening quickly, in response to both market forces and jurisdictional climate change and energy policy measures. This transition needs to be carefully managed. The stakes are high: electricity is an essential service, central to our modern economy and way of life. Governments, acting on behalf of consumers, understandably want to be confident that there will be reliable and affordable supply as the NEM is decarbonised.

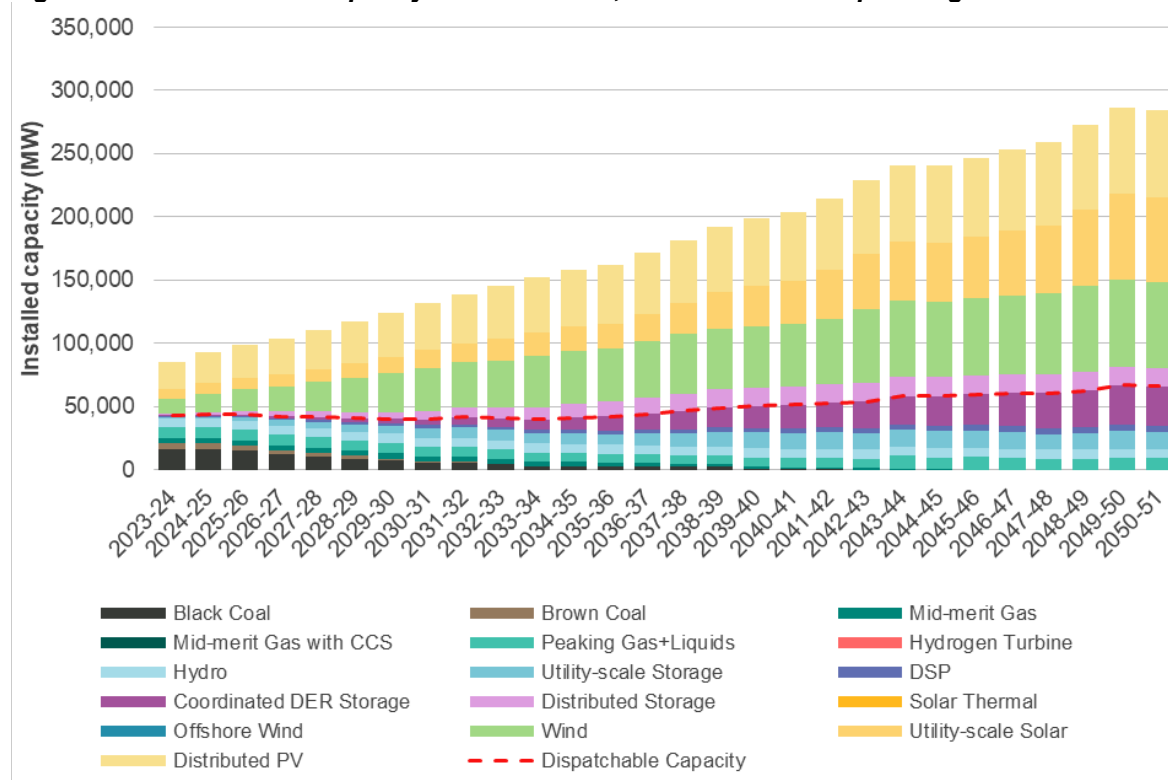
The necessary scale of investment to maintain reliability over the coming decades is dramatic. Coal generators, which currently account for over half the NEM's generation output, are reaching the end of their technical lives. At the same time, AEMO has forecast that electricity demand could at least double by 2050.⁴ AEMO's Step Change scenario estimates approximately 122 GW of new wind and solar firmed by approximately 45 GW of new dispatchable storage capacity, 7 GW of existing dispatchable hydro and 9 GW of gas-fired generation will be required by 2050 to meet demand as coal-fired generation withdraws. The new capacity required over the next 28 years is more than seven times that built over a similar time frame since the NEM commenced 24 years ago and around fifty times the amount built by the Snowy Hydroelectric Scheme.

As Figure 1 shows, the majority of new investment in the coming decades is expected to be in wind and solar (collectively variable renewable energy (VRE)), which are now the cheapest sources of new generation on a levelised cost of electricity basis.⁵ However, these technologies have a number of technical attributes which make maintaining a secure, reliable electricity supply more challenging in a system dominated by VRE.

⁴ Under AEMO's Integrated System Plan Step Change scenario, considered most likely.

⁵ CSIRO 2021, GenCost 2020-21, Final Report

Figure 1 - NEM installed capacity mix 2024-2051, Draft 2022 ISP Step Change Scenario



Source: Draft 2022 ISP - Step Change scenario

One primary consideration is that VRE is variable in its output, based on the weather. Because electricity supply and demand must remain precisely in balance in real time, VRE must be complemented and backed up by 'dispatchable' capacity providers that can output electricity on demand when VRE generation is low. The Draft 2022 ISP Step Change forecasts the NEM will require approximately 60 GW of dispatchable capacity in 2050, and significant further investment in transmission, to maintain reliability in a VRE-based system.⁶

There is much that could go wrong if the resources required to keep our system reliable and affordable are not built in a timely manner to replace existing assets. Existing assets, each of which can represent a significant proportion of generation in their region, might close before replacement capacity is in place. A single coal generation facility can account for as much as a third of a state's power needs.⁷ After an abrupt closure, price impacts can be similarly substantial – wholesale prices in Victoria jumped 85 per cent following the sudden closure of the Hazelwood power station before any replacement capacity could be built.

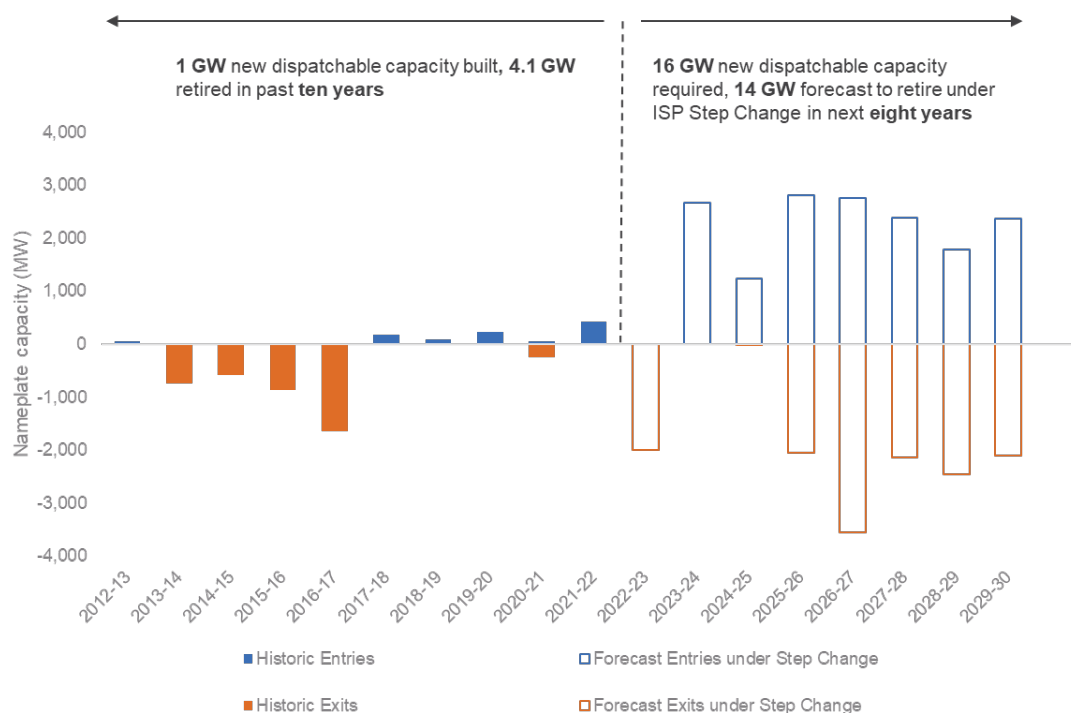
The economic viability of many coal generators is under increasing pressure due to ongoing investment in VRE and rising fuel costs. As capacity factors and margins fall, there is an increased risk of the disorderly exit of these facilities, without the ability to plan for and construct replacement capacity.

⁶ AEMO. Draft 2022 Integrated System Plan. Page 46

⁷ In 2020 for example Loy Yang A produced approximately 16TWh/a, or 36 percent of Victoria's electricity consumption of 44.3TWh.

While 5 GW of coal capacity has already announced it will close by 2030, as much as 14 GW may become uneconomic by that time.⁸ 14 GW represents around one-third of the NEM's dispatchable capacity, a significant amount to exit over an eight year period. Replacement would require the equivalent of another Snowy 2.0 to be connected every year from now until 2030. Figure 2 shows the scale of the investment task expected under ISP Step Change, relative to the investment in dispatchable capacity over the past decade.

Figure 2 - Dispatchable capacity entry and exit – historic and forecast under ISP Step Change scenario



Note: Includes exit of Liddell in FY2023 and entry of Hunter Power Project in FY2024, which aren't included in Draft 2022 ISP Step Change

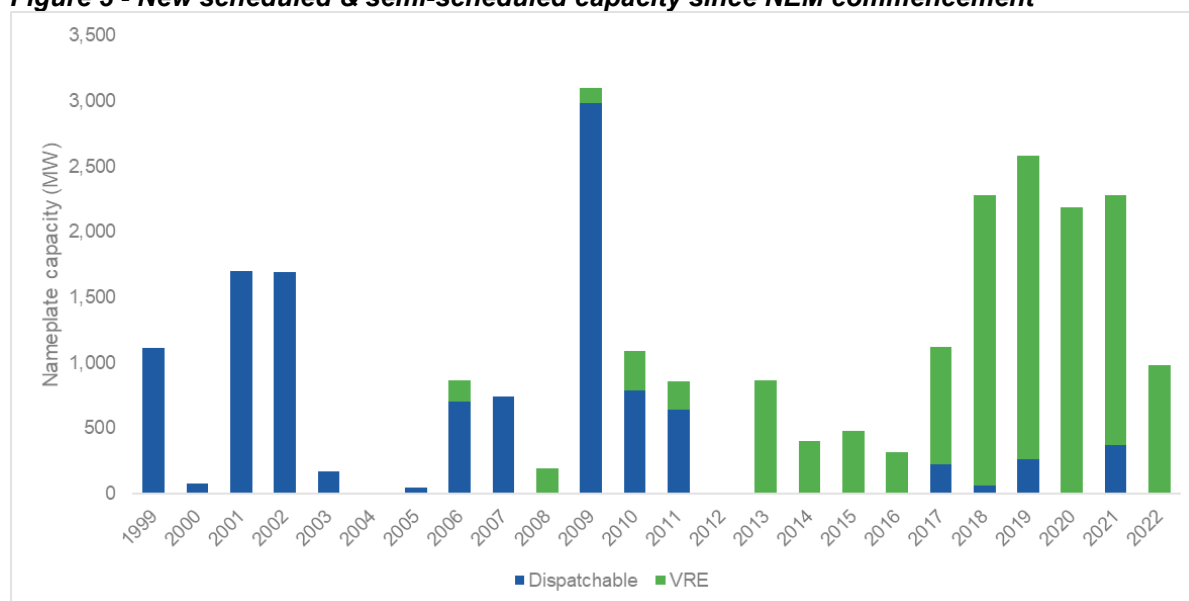
Source: AER State of the Energy Market 2018 and 2021; AEMO NEM Generation Information May 2022; AEMO Draft 2022 ISP - Step Change scenario

Replacement capacity needs to be built before coal-fired power stations close.

Since the NEM's start, market participants have delivered around 11,600MW of investment in new scheduled dispatchable capacity. Only around 900 MW – eight per cent – of that took place in the past ten years (see Figure 3).

⁸ AEMO 2022 Draft ISP - Step Change scenario

Figure 3 - New scheduled & semi-scheduled capacity since NEM commencement

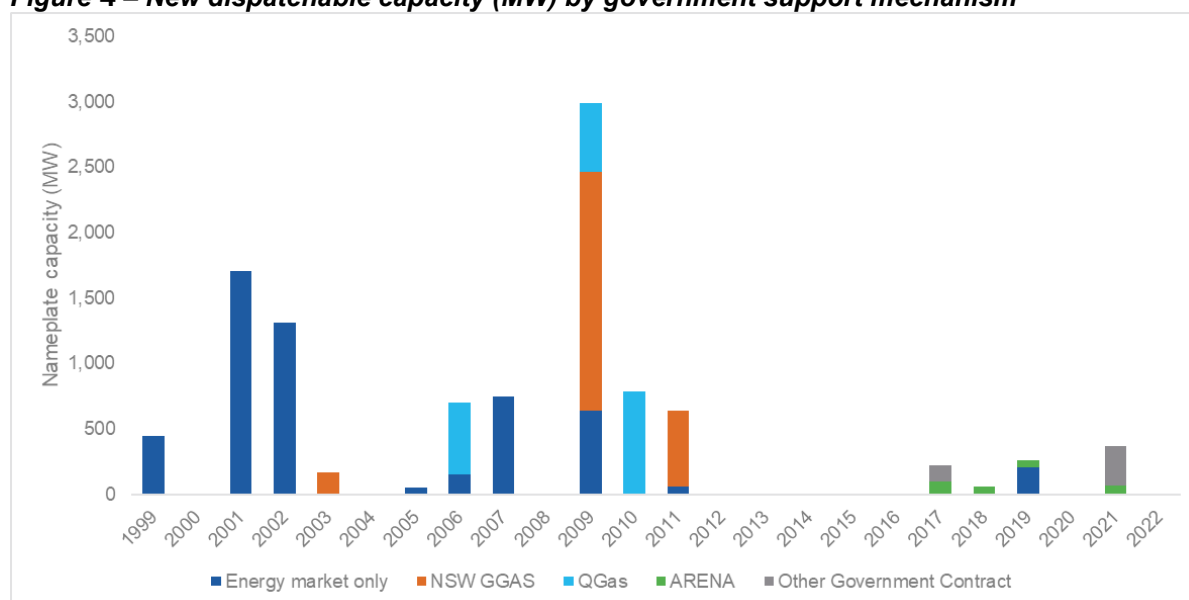


Note: Calendar year basis

Source: AEMO NEM Generation Information May 2022, individual company websites

Furthermore, governments have provided some level of support for most investments in dispatchable capacity over the past decade. This has taken many forms, including grant funding (ARENA, state governments), legislated obligations (Queensland Gas Scheme, NSW GGAS), and government-initiated contracts (e.g. Snowy 2.0 and the Hunter Power Project and Victorian Big Battery). Figure 4 shows most investments in dispatchable capacity over the past decade received some form of government support.

Figure 4 – New dispatchable capacity (MW) by government support mechanism



Note: NSW GGAS provided some generators with only modest revenues that may not have had a material impact on investment decisions. Some generators commissioned prior to GGAS and QGas subsequently received revenue through these schemes – these revenues are not included in the Figure. Calendar year basis.
Source: AEMO generator information page, ARENA website, GGAS registry, QGas Registry, individual company websites.

For the current framework to deliver the investment in new capacity required over coming decades, policy makers would need to be confident the private sector can and is willing to finance the vast amounts of necessary generation, in a timely way that is coordinated with other generators' exit decisions. Policy makers would also need to be confident that large energy users would be willing to enter into long-term contracts to underpin new capacity. Market participants, on the other hand, would need to be confident that governments would allow wholesale prices to stay very high for a sufficient length of time to enable the market to make investment decisions, without intervening as they have in the past. The challenges in realising these outcomes are discussed below. The scale of the transformation will test the adequacy of the existing investment framework.

3.1.1. How the NEM currently achieves electricity reliability

The NEM is an *energy-only* market. Generators are paid only for their energy, without a formal mechanism valuing their *ability* to produce energy (their 'capacity'). Prices in the wholesale market are permitted to move within the Market Price Cap (MPC) of \$15,100/MWh and a Market Price Floor of -\$1,000/MWh.⁹ The NEM's MPC is one of the highest in the world, with periods of very high prices providing an incentive for generators which are only required a few times per year (during very high demand events) but are critical to achieving reliability objectives.¹⁰

Underlying the spot market is a financial contract market that enables electricity retailers to hedge their exposure to very high price events. The contract market also provides opportunities for generators to obtain a degree of revenue certainty and, in some cases, be remunerated for the insurance value they provide. In this way, the contract market enables generators to extract value for their capacity. However, this value is limited by the market price settings and short-term nature of contracting in the NEM, discussed below. Under the existing market framework, incentives for new capacity to enter and existing capacity to remain in the system are driven by the spot and contract markets.

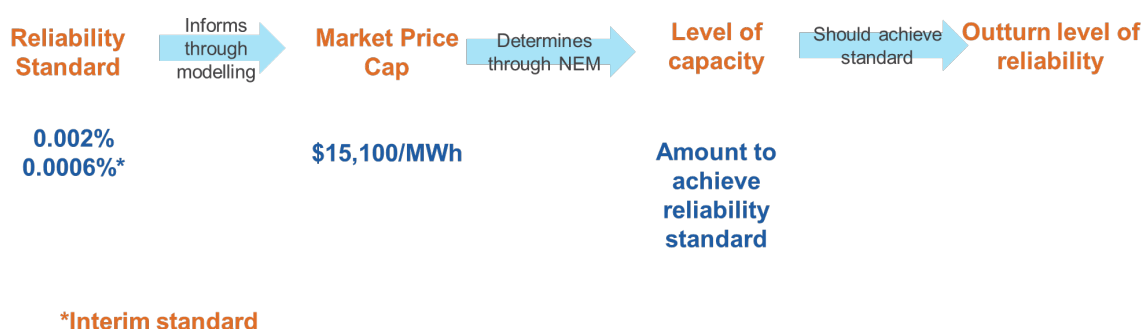
The target level of reliability in the NEM (the reliability standard) is set at the level estimated to be lowest cost to consumers from a whole-of-system perspective. The level at which the reliability standard is set represents the tradeoff between the whole-of-system costs to achieve higher reliability (i.e. the cost of incentivising more generation to remain in the market) and the value customers place on electricity reliability (the 'value of customer reliability' (VCR)). The current reliability standard in the NEM is that no more than 0.002 per cent of electricity demand should be unmet ('unserved energy' (USE)). In 2020, Energy Ministers implemented an additional Interim Reliability Measure standard of no more than 0.0006 per cent USE.

The mechanism by which the reliability standard is currently achieved in the NEM is through the market price settings (the MPC, market price floor and cumulative price threshold), which collectively constrain generators' earnings (or losses) in the wholesale market (see Figure 5). The MPC has been set at a level estimated to be high enough to incentivise generation capacity into the market, sufficient to meet the reliability standard.

⁹ In FY2022. Source: AEMC 2022, Schedule of Reliability Settings

¹⁰ In addition, periods of high prices enable other generators to recover their fixed operating costs.

Figure 5 - The Reliability Standard is achieved by setting incentives through the MPC.



In an energy-only market, if the MPC is set too low, not enough generation will be present in the market and customer value will be lost in the form of USE. If the MPC is set too high, customers will pay more than the level required for new entry consistent with the reliability standard. The level at which the MPC is set, therefore, determines both the reliability outcomes in the NEM as well as overall costs to consumers. The Reliability Panel assesses the ongoing suitability of the reliability standard and the market price settings every four years through the RSSR process.

Box 2 Should the current reliability standard be changed?

In response to the ESB's *Capacity Mechanism Initiation Paper*, several stakeholders raised the need to clarify what reliability objective a capacity mechanism should target.

The ESB considers that the form of the reliability standard (e.g. unserved energy, loss of load probability, or other) and the exact reliability target (e.g. 0.002 per cent, 0.0006 per cent, or other) is ultimately a matter for Energy Ministers, informed by expert advice from the Reliability Panel and the Australian Energy Market Commission (AEMC).

A review of the suitability of the current reliability standard is currently being undertaken by the Reliability Panel as part of the 2022 RSSR.

3.2. The market faces enormous uncertainties, making it riskier to rely on an energy-only market for capacity

Implicit in the NEM's energy-only design is that commercial investors will respond to incentives and therefore maintain reliability. Provided incentives from the wholesale and derivatives markets are sufficient, commercially motivated market participants should invest in enough generation to maintain a reliable system. However, there are several reasons the required investment may not be forthcoming when and where it is needed and in line with the expectations of governments:

- the market faces significant uncertainties, making it difficult to predict future revenues
- opportunities to 'lock in' revenues through contracting are short-term, at least with respect to the life of an asset
- governments feel obliged to step in during periods of sustained high prices, but high prices are required to deliver the necessary investment in new capacity.

These issues are discussed below.

3.2.1. Incentives to invest may not be sufficient under conditions of high uncertainty

Levels of uncertainty in the market today are extremely high. Demand uncertainties include the speed of post-covid recovery, the longevity of major users such as smelters, and the timing and scale of trends like the electrification of gas and transport. On the supply side,

despite notice of closure provisions, the exact timing of the closure of large existing thermal plant is uncertain. In a market where demand has been relatively stable for several years now, it is difficult to make a case for new investment until a clear gap in the market has been established. A 'wait and see' response from investors is a rational response to such uncertainty. But widespread 'waiting and seeing' will risk too little capacity being available, and new capacity arriving too late. It also increases the likelihood that jurisdictions will feel forced to intervene – which, in turn, can create another source of uncertainty for investors.

These sources of uncertainty make predicting future revenues challenging. Greater uncertainty of returns increases the risk involved in making an investment and requires higher prices and stronger incentives for investment to be forthcoming. Because they are uncertain, investors are also likely to discount the probabilities of future high-priced events when considering their future cashflows, particularly where there is a risk of government intervention that would increase supply-side resources. Under the current framework, higher market uncertainty necessitates higher costs to consumers for reliability objectives to be met. Under the current framework, there is a tangible cost imposed by uncertainty.

In its current review of the NEM's reliability standard and settings, the Reliability Panel has noted the uncertainty in future market conditions. To account for this uncertainty, it has considered a range of sensitivities and scenarios in its modelling. The wide range of scenarios considered is indicative of the range of uncertainties facing investors currently. While the Reliability Panel's work is continuing, its Draft Report¹¹ and, in particular, the IES modelling outcomes suggest that the existing MPC is materially too low to give a high likelihood of meeting the current reliability standard, and a substantial increase in the MPC is likely to be warranted in the absence of a revenue stream outside the energy-only market.

As the Reliability Panel has previously shown, the required market price cap to meet the reliability standard is extremely sensitive to new entrant assumptions. For example, the 2018 RSSR process found that the MPC needed to meet the reliability standard varied from \$1,500/MWh to >\$50,000/MWh depending on changes to assumptions about the cost of new entrant plant.¹²

It is fundamentally challenging to achieve a precise investment outcome (enough capacity to meet the reliability standard) through a relatively static and indirect investment incentive (the MPC) in a highly dynamic and uncertain investment environment.

3.2.2. The NEM provides limited long term investment signals

As noted above, a variety of factors are making it extremely difficult to predict longer-term revenues. In addition, there are limited opportunities for investors to lock-in long-term revenues. Both these factors increase uncertainty and risk to investors and make investment in the current market challenging.

Electricity derivatives contracts do provide some certainty, but are exchange-traded only three years out. This is an insufficient tenor to underwrite long term projects. Bilateral contracts ('over the counter') also tend to match those timeframes or are often linked to floating benchmarks like exchange-traded products so provide limited long-term revenue certainty.

¹¹ Reliability Panel AEMC 2022, 2022 Review of the Reliability Standard and Settings, Draft Report

¹² Key new entrant assumptions included the weighted average cost of capital (WACC), length of asset life and fuel cost.

Renewable power purchase agreements (PPAs) do provide longer-term certainty but have generally only been available for VRE technology types.¹³

Large commercial and industrial (C&I) customers (such as aluminium smelters) previously had a role in underwriting new investment through long-term offtake agreements. However, such long-term agreements are no longer widely available in the market as a source of underwriting new investments.¹⁴

Retailers have little incentive to enter long-term agreements with external entities given they pass costs on to customers on a short-term variable basis (costs are reset around annually). Retailers who lock in long-term wholesale prices through a long-term bilateral contract could find themselves 'out of the money' relative to the rest of the market and their competitors.

Additionally, a retailer's demand can be significantly affected by customer churn. C&I customers often contract with a retailer on a shorter-term basis and switch retailers regularly given their price sensitivity. This provides a further disincentive for retailers to contract with generators over a longer-term horizon given the loss of a few large customers may materially impact the amount of electricity they require to cover their customer base.

The primary mechanism by which new investment can be financed without government support is by large, vertically integrated generator-retailer entities using their retail customer load to in effect self-secure a long-term offtake agreement. These entities and others with a very large asset base can also utilise their balance sheets to secure competitive financing ('corporate finance' as opposed to 'project finance'). Entities that are not vertically integrated or do not have a substantial balance sheet to borrow against have limited ability to secure financing on competitive terms without some form of government support.

Given the present market dynamics and lack of long-term investment signals, investment in new generation is predominantly possible only by a few large entities. It is questionable whether these relatively few entities will finance the vast levels of investment required over coming decades. Absent long-term investment signals, other financiers are likely to require a substantial premium to invest in the NEM, requiring prices to remain higher for longer, all else equal.

3.2.3. Sustained high wholesale prices are required to incentivise new investment – but put upward pressure on consumer costs

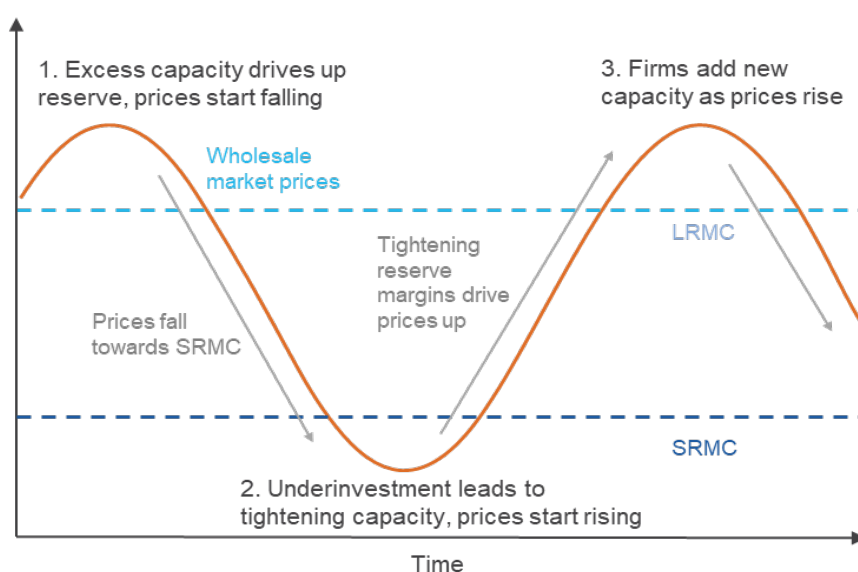
By design, the existing NEM-framework requires elevated prices to incentivise new investment. Scarcity pricing – resulting from tight supply-demand conditions – results in elevated prices which provide a signal and incentive for new investment. For new investment to occur, price expectations into the future must be at a level sufficient to make a return for investors.

Additional capacity entering the market in turn places downward pressure on prices which removes the incentive for additional investment. In this way, scarcity pricing drives an alternating cycle of structural undersupply with higher prices to structural oversupply with lower prices. This dynamic is shown in Figure 6. Of course, many other factors have a bearing on the underlying price, notably fuel prices, short- and long-term electricity demand profiles and out-of-market investment schemes.

¹³ Long-tenor PPAs remain available in the market due to corporate demand for renewable energy offsets

¹⁴ See, for example, ACCC 2018, *Retail Electricity Pricing Inquiry*, p. 98-99

Figure 6 - Energy only market is characterised by periods of structural over and under-supply

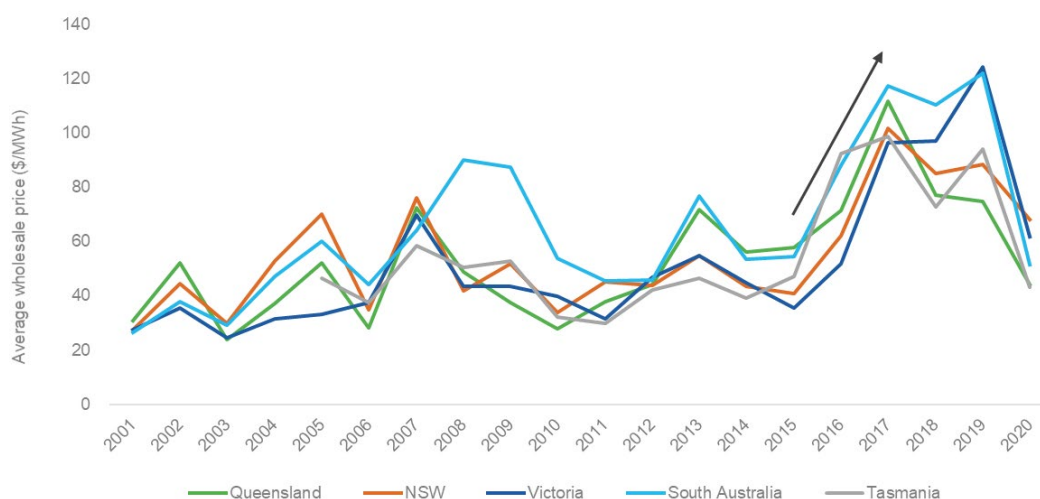


Note: LRMC = Long-run Marginal Cost; SRMC = Short-run Marginal Cost

Source: Reproduced from Grattan Institute 2017, *Power Struggle: Short term responses in a climate of uncertainty*, p. 18

However, tightening supply conditions which create the incentives for private investment are also experienced by consumers as a rapid increase in electricity bills. For example, between 2015 and 2017 the wholesale price increased, on average, 127 per cent, shown in Figure 7.

Figure 7 - Spot prices increased steeply between 2015 and 2017 in all regions.



Source: AER State of the Energy Market 2021

High prices are required to elicit market-led investment. However, sustained high wholesale prices lead to consumer cost pressures. The AER's Better Bills research also highlighted that customers value stability in their energy bills, with small business customers raising the importance of price predictability, due to budgeting and cashflow management requirements.¹⁵ To protect customers, governments have acted to prevent high wholesale

¹⁵ AER, Small to Medium Business Owners Better Bills Guideline Research Report – December 2021

prices by supporting new generation into the market. Such recent actions have sought to align generator closure and replacement capacity. Examples include the Yallourn battery, Hunter Power Project and Warratah battery in response to the closures of Yallourn, Liddell and Eraring respectively.

This apparent mismatch between the expectations of governments and market operations has led to government investment occurring ahead of a market-led response. This creates two issues: it does not give commercial investors a chance to determine and then respond to incentives; and it heightens market participants' perception of market risk given government intervention can have detrimental impacts on their own investment decisions. Taken together, these dynamics create a cycle whereby market participants are less likely to invest, governments have less confidence that market participants will invest, and further government support becomes necessary for new investment to occur.

3.3. Capacity mechanisms provide a more direct way of ensuring capacity requirements are met

The NEM has performed well against its reliability objectives since the NEM started. There have only been five instances of any load-shedding since 2005 related to reliability – twice in Victoria and three times in South Australia.¹⁶ However, recently, emergency reserves have increasingly been required to maintain reliability, with the Reliability Emergency and Reserve Trader (RERT) deployed 15 times in the last five years, and never before that.

The NEM's investment framework too is under increasing pressure. At the commencement of the NEM, change in the generation mix was gradual and investment requirements were incremental. In such circumstances, the reliability framework provided sufficient certainty that reliability outcomes would be met.

The investment task now facing the NEM is many multiples larger than that of recent decades. The market dynamics outlined above highlight at least three challenges with the existing reliability framework: uncertainty weakens incentives to invest in line with reliability objectives, only a limited number of market participants are likely to finance investment in new generation, and a misalignment between the expectations of governments and needs of investors perpetuates a requirement for further government support for new investment.

The ESB is of the view that, while these factors do not guarantee poor reliability and price outcomes, there is sufficient uncertainty over the current reliability framework's ability to drive the levels of investment needed in coming years to warrant consideration of an additional mechanism that provides greater certainty that reliability will be maintained.

A capacity mechanism rewards capacity providers for their ability to output electricity or reduce demand. It would provide a more direct way of ensuring capacity requirements are met. Depending on design, it could provide greater control over when and how much capacity is commissioned and would provide much greater certainty reliability will be maintained as the NEM transitions.

The ESB also notes that almost all markets in the world (including in Western Australia) have some reward for capacity that is separate from dispatched energy. Considering a capacity component would enable Australia to benefit from this wealth of experience, as we jointly tackle the task of transitioning our energy systems to net zero emissions.

¹⁶ AEMC 2020, *Information Paper: The Reliability Standard: Current Considerations*, p8 found [here](#).

4. Participation of new and existing capacity in the mechanism

Summary

The ESB considers all capacity (both new and existing) rather than just new capacity should participate in the capacity mechanism. This incorporates stakeholder feedback and the ministerial design principles.

As outlined in the case for change, investment in new resources is a key issue for the capacity mechanism to address. A capacity mechanism could focus directly on this problem by restricting eligibility to new capacity providers, which would avoid paying capacity providers that already exist for services they could already provide. However, all resources that participate in the market contribute to reliability, and a mechanism where all capacity is eligible to participate should encourage a more efficient mix and utilisation of resources.

The ESB proposes that all resources that contribute to capacity requirements should be eligible to participate in the capacity mechanism. The ESB also intends that the mechanism will consider the challenges faced by new capacity and provide it with additional support. Key reasons included:

- accessing and incentivising the most efficient mix of resources to ensure reliability
- discouraging premature exit of existing capacity before alternative resources are in place
- avoiding over-building new capacity before it is required.

However, the ESB recognises that new and existing capacity have different commercial and technical requirements and that the benefits of different technologies entering the market may evolve.

Issues for detailed design include designing support for new capacity that does not overcompensate existing capacity providers. This issue is considered further in section 6.

As outlined in the case for change, a key reason for introducing a capacity mechanism is to create more targeted incentives to guide investment in new capacity, in line with the needs of the system. Therefore, the ESB considers a critical issue is whether the mechanism should target only new capacity or whether a whole-of-market approach should be taken.

Several stakeholders also proposed designs that would only support new capacity.

In the ESB's view, both new and existing capacity should be eligible to participate in a capacity mechanism. Key reasons for this decision included that a whole of market mechanism would:

- access and incentivise the most efficient mix of resources to meet reliability
- enable co-ordinated incentives between entry and exit decisions making timely replacement of capacity more likely
- maintain a consistent regulatory framework across the market.

These issues are discussed below.

4.1. Utilising an efficient mix of capacity

The ESB considers a whole-of-market mechanism beneficial because it enables all capacity options to be assessed and the lowest cost options procured. A mechanism that only supports new capacity has only one lever to address a forecast reliability gap – supporting investment in new capacity. In some cases, paying to retain existing capacity may be more efficient than incentivising a new entrant into the market following an exit.

For example, without the inclusion of existing capacity in the scheme, the exit of an economically marginal capacity provider, such as a fast-start gas generator, could trigger a requirement for investment in new capacity, which risks coming at a high cost to consumers. Here, it would be more efficient to pay to keep the existing generator in the market to minimise costs for consumers.

An additional concern from an efficiency perspective would be the potential impact of a 'new only' mechanism on the existing generation fleet. Providing payments to only new capacity would, all else being equal, give them a competitive advantage while at the same time reduce revenues for all capacity providers (through increased competition, which will drive prices down) and potentially make some uneconomic, thereby increasing the risk of a disorderly transition to net zero.

In response to stakeholder feedback, the ESB acknowledges that holding new capacity that has been supported through the capacity mechanism out of the market may reduce the potential for impact on existing capacity providers. Indeed, the ESB's workstream relating to a jurisdictional strategic reserve relates directly to out-of-market resources (while the capacity mechanism workstream is directed at ensuring capacity is directly rewarded in the market itself). However, the Board considered that it could have other undesirable effects:

- capacity payments to support new capacity may need to be higher if the out of market capacity providers cannot recover any of their costs in the energy market
- consumers and government may not support paying for new resources to sit idle instead of actively participating in the market
- less efficient and higher emissions capacity providers may continue operating while new, more efficient and lower emissions capacity providers sit on the sidelines.

For the avoidance of doubt, the purpose of a capacity mechanism is not to extend the lifespan of ageing coal generators. These generators face several structural challenges as the NEM transitions to a VRE based system. This is primarily driven by these generators' technical incompatibility with high levels of VRE, resulting in reduced capacity factors and increased maintenance costs. The capacity mechanism would not and cannot address these challenges. Instead, the capacity mechanism would provide more targeted incentives to ensure replacement capacity arrives when it is needed, giving greater assurance that the exit of these generators will be well managed.

Procuring capacity on a whole of system basis also allows for new and existing capacity to compete on a technical basis, to procure technologies that can best meet the reliability needs of the system. For example, the de-rating methodology (see section 5) will assess both existing technologies in the NEM and new or emerging ones for their expected contribution to reliability, and appropriate auction design (see section 6) will enable various technologies to compete on a cost-basis.

Therefore, the result of a whole of market approach is to arrive at an efficient mix of capacity that is both technically suitable and cost-effective, versus an approach where incentives and competition is limited to new capacity only.

4.2. Coordination of entry and exit decisions

Participation of both new and existing capacity could allow better coordination of entry and exit decisions at lower overall cost. Auction prices revealed through the proposed centralised auction processes should reflect the costs to capacity providers of remaining in, or entering, the market. For example, a capacity provider may decide to factor in refurbishment or retrofitting costs into their bid, and if this is cost-competitive against new capacity, then customers receive the reliability benefit of this asset remaining in the market.

Participation of existing capacity would also enable these capacity providers to obtain better visibility of their expected forward revenue, which could then inform retirement decisions. The timing of auctions is discussed further in section 6.5.2 but could be designed to align

with existing notice of closure requirements. This would give further confidence that a capacity provider's economic incentives and notice of closure obligations are aligned. For example, a capacity provider that is unable to secure an economic price for its capacity to remain in the market in 3 to 4 years' time can then make an informed decision about a potential exit.

A whole of market approach would therefore enable the costs and benefits of supporting existing capacity versus new capacity to reflect a variety of commissioning, operational, and decommissioning factors. This would therefore lead to more efficient procurement decisions as the true cost of each capacity can be weighed against the others.

4.3. Adjustment of other market settings would be constrained

A final consideration for a mechanism that supports only new capacity would be how it impacts decisions to change other regulatory or market price settings. A mechanism that supported all capacity providers in the market would also be more compatible with whole of market reform instruments, such as potential changes to the MPC. One intention of introducing a capacity mechanism is for better coordination of the NEM, and therefore compatibility with existing regulatory instruments is an important consideration.

4.4. Stakeholder feedback

Industry stakeholders raised the following key issues during consultation on the Initiation Paper, which will be directly addressed in detailed design:

- Capacity should be remunerated for their performance and contribution towards reliability outcomes, and therefore a mechanism should support a range of technologies and types of capacity.
- The mechanism should consider excluding ageing thermal generators, so as not to extend the operational life of these assets beyond what is economically or technically reasonable. Emissions thresholds should also be in place to ensure integration with net zero targets.
- While being technology neutral, the mechanism design should recognise the advancements in new technologies and their ability to participate, including emerging types of capacity such as DER and demand response.

There were several alternative capacity mechanism models suggested by stakeholders. Full details of each of these options is available in the proponents' submissions on the Energy Ministers' website.

A theme in some of the industry models was a focus on the entry of new capacity to fill an identified reliability gap. The ESB acknowledges this feature and has addressed this by considering the possibility of longer tenor contracts for new capacity only (existing capacity providers would only be eligible for single-year contracts) and potentially allowing different clearing prices for old and new resources as explained below.

4.5. Considerations for detailed design

In detailed design, the ESB will consider the role for all capacity in a range of design elements including:

- auction design including the contract duration eligibility for new capacity
- market power mitigation measures that may be needed especially for existing capacity.

4.5.1. Interaction between new and existing and auction design

Another key consideration is the different levels of support required for existing generation to remain in the market relative to new generation to enter the market. For example, new generation may require more support over a longer time period to make the investment

viable. An auction design that takes into account the differences between new and existing capacity, and their differing requirements, is an important issue to be considered in the detailed design phase.

4.5.2. Delivery risk and eligibility of new capacity

A framework will be developed during detailed design to mitigate the risk that some new capacity providers, who are successful at auction, will not deliver the required capacity due to development, construction, or commissioning issues.

Due to the range of hurdles that need to be overcome, a framework is intended not to place significant burden on new capacity providers, but rather allow for visibility of progress for the procurer. This way, delays can be known far ahead of time, with impacts on planning and reliability understood, and replacement capacity procured where necessary.

Eligibility criteria will also be developed to ensure a level of project maturity and feasibility prior to auction, and appropriate milestone requirements will be in place to track and incentivise the timely delivery of awarded new capacity.

5. Forecasting demand and the building blocks for a mechanism

Summary

A fundamental design choice is who should forecast and determine the capacity requirement. The ESB considered centralised and decentralised options.

A centralised approach would see a central body (AEMO, given their existing role) forecast demand and determine the capacity requirement. A decentralised approach would see retailers procure sufficient capacity to meet their actual demand, with penalties if their actual demand ended up higher than what they had procured.

The ESB proposes forecasting and determination of the capacity requirement be centralised. Key reasons include:

- This aligns with AEMO's existing forecasting role and will ensure that the capacity mechanism is aligned to the reliability outlook contained in the NEM Electricity Statement of Opportunities (ESOO).
- AEMO is likely to be better positioned to forecast system demand over the long-term.
- The capacity requirement could leverage the pre-existing ESOO process which incorporates stakeholder input and forecast accuracy reporting. A decentralised approach would run the risk of creating a disconnect between the capacity requirement estimated by AEMO (through the ESOO) and that targeted by retailers.

Issues for detailed design include:

- Should the capacity zones align with the NEM regions or some other grouping?
- How are capacity providers de-rated for the purpose of forecasting the capacity requirement and awarding capacity certificates under the scheme?
 - Over which time periods are capacity providers de-rated and how are these periods determined (referred to in this paper as the 'at risk periods')?
 - Should de-rating be at a technology level or at a station or even unit level?
- How is the capacity target defined?

5.1. Forecasting the capacity requirement

A fundamental design choice is who should be responsible for forecasting the capacity requirement under the capacity mechanism. The Board has considered both centralised and decentralised approaches to forecasting.

Under a centralised forecasting approach, a single central party is responsible for forecasting and determining the capacity requirement. In the case of the NEM, the central body would be AEMO given its existing role. A centralised forecasting approach is taken in the WA wholesale electricity market (WEM), GB, Irish, PJM and CAISO capacity mechanisms.

A decentralised forecasting approach places the obligation on retailers to procure capacity to meet their forecast future demand. To incentivise accuracy, decentralised forecasting requires an 'ex post' compliance framework whereby a retailer's procurement of capacity is assessed against their actual demand, after the event. Decentralised forecasting is a feature of the French capacity market and the RRO.

The ESB's view is that AEMO should have responsibility for centrally forecasting the capacity requirement for the NEM. The ESB's consideration of the trade-offs between the two approaches is outlined below.

5.1.1. Centralised Forecasting Approach

A centralised approach in which AEMO is responsible for forecasting the capacity requirement for the NEM as a whole and on behalf of liable entities would leverage the existing responsibilities of AEMO, namely in the production long term demand forecasts as part of its annual modelling efforts for the ESOO.

Box 3 How the ESOO forecasts reliability

The ESOO measures reliability using expected USE, and compares forecast USE against both the:

- IRM of 0.0006 per cent of the total energy demanded in a region for a financial year
- reliability standard of 0.002 per cent of the total energy demanded in a region for a financial year.

For the purposes of the RRO, the IRM of 0.0006 per cent USE is the standard until 30 June 2025, after which the reliability standard reverts to 0.002 per cent USE. AEMO reports on both standards for information purposes.

The ESB considers AEMO is likely to have the best whole of system view of electricity demand over the long term and recognise the ESOO as the primary source of information to signal an impending reliability gap to market participants and governments. Given that the capacity mechanism operates on a long-term scale, consistent with generation investment and construction timeframes, forecasting accuracy over the long term is crucial.

The ESB consider governments are likely to have greater confidence that gaps identified in the ESOO will be resolved if there is alignment between the ESOO and the mechanics of the capacity mechanism.

However, several stakeholders have raised concerns that a central body (such as AEMO as system operator, with responsibility for system reliability, may take a conservative approach to forecasting capacity requirements. Stakeholders argued that while this may increase confidence for governments that reliability gaps will be addressed, it could also lead to increased costs for consumers if it results in over-procurement.

The ESB notes that AEMO has developed measures to address stakeholder concerns with its forecasts, including establishing the Forecasting Reference Group (FRG) and publishing its annual Forecasting Accuracy Report. Many of these process improvements were made as part of the package of reforms accompanying the implementation of the RRO, and AEMO continues to be open to ways to strengthen this process. The ESB also note AEMO's commitment to engage with industry and interested parties (e.g. through such forums as the FRG) before, during and after the determination of reliability forecasts as well as its commitment to continuously improve its forecasting processes.

Questions for stakeholders

- Q1 What measures could be put in place to improve AEMO's forecasting process and to access the best information from retailers and large customers on their likely demand?

5.1.2. Decentralised Forecasting Approach

A decentralised forecasting approach would oblige individual retailers to procure sufficient capacity to meet their actual demand. When paired with an ex-post compliance regime, retailers would be incentivised to forecast accurately but not over-forecast their capacity requirement.

Market customers may have a better understanding of their own electricity demand than AEMO, for example in the short term over the operational window when a reliability event may occur. This would particularly be the case if the obligation is based on actual demand rather than forecast demand. However, it can be difficult for retailers to accurately forecast their expected demand over a longer period - several years in advance - for example due to customer churn. This is particularly the case if a large C&I customer was to switch as this could materially affect a retailer's overall demand. This was a significant issue that was considered in the development of the RRO, and addressed through two mechanisms:

- allowing large C&I customers to opt in to manage their RRO obligations directly
- allowing retailers 'top up' contract amounts throughout the T-1 year to account for new C&I customers that were not customers of that retailer at the T-1 contract submission point.

The ESB considers a decentralised approach would run the risk of creating a disconnect between the capacity requirement estimated by AEMO (through the ESOO) and that targeted by retailers. For example, retailers could under-forecast (procure) in aggregate, creating the possibility that a reliability gap is not sufficiently addressed. Ultimately, a decentralised approach may not provide additional certainty that reliability gaps will be identified and addressed compared to current arrangements.

Placing a requirement on market customers to forecast their load over the long-term may add an additional compliance burden on retailers (noting they already forecast their load over the shorter term). Additionally, AEMO may still be required to play a verification role under a decentralised approach, as well as the AER to verify compliance in forecasting.

In addition, as discussed further in section 6, the ESB is interested in exploring hybrid centralised/decentralised models with stakeholders, with a view to incorporating the strengths of both centralised (whole of market, long term view) and decentralised forecasting (closer relationship to customers, potential ability to influence demand, and commercial incentives not to over-forecast) into the mechanism.

5.1.3. Stakeholder Feedback

Of the stakeholders who indicated a preference in approach in response to the Initiation Paper, the majority (75 per cent, including Hydro Tasmania, Stanwell and Origin) favoured a centralised forecasting approach with a view that AEMO is better placed to model the resource adequacy requirement for the system. Stakeholders noted the challenges for retailers to forecast future needs due to customer churn (for example, C&I customers) and recognised a centralised approach could provide a longer-term investment signal.

Other stakeholders preferred a decentralised approach allowing retailers to forecast and meet their own needs (for example, EnergyAustralia and Shell). The Australian Energy Council recognised that a decentralised mechanism is closer to the existing market arrangements but noted that all options discussed in the Initiation Paper involve a move towards centralisation.

When discussing the decentralised approach, TWG members noted that retailers are best placed to manage the risks of under/over forecasts and market participants would have a strong incentive (including consideration of any compliance or penalty regime) to forecast their capacity requirements accurately. TWG members considered decentralised forecasting would allow for short term optimisation and management of reliability risks closer to real-time, as well as more adaptive consideration of demand-side participation and facilitating greater innovation.

Nevertheless, TWG members also recognised the risk that a decentralised approach may not provide governments with sufficient confidence. A decentralised approach may provide low certainty to policymakers that the market will take the actions needed to support resource adequacy.

Members of the TWG acknowledged such a centralised approach is likely to provide greater confidence that reliability gaps will be addressed, particularly when linked to the ESOO outcomes. However, this could come at high costs for consumers and loss of competition and market dynamism. Members similarly raised concerns associated with a single point of failure should forecasts be wrong and AEMO's ability to adapt forecasts to changing policy, technology, and market conditions.

Despite these risks, members also recognised a centralised approach would provide greater visibility of the whole-of-system requirements and make it easier for governments to make policy decisions and better align with the ISP/transmission development. It would also provide greater transparency on costs.

5.2. De-rating capacity

A key issue for the detailed design is how each resource's capacity is de-rated. De-rating is the process by which a resource's nameplate capacity is scaled down to the level of expected output during at-risk periods. De-rating enables each MW of capacity across the system to be considered interchangeably (i.e. 'fungible'). Whilst the ESOO explicitly models the performance of different capacity providers across each season and time of day under a range of weather scenarios, it produces a stochastic distribution of outcomes. A capacity mechanism requires that this be translated into a single deterministic number for each resource.

The alternative would be to treat each type of capacity (thermal, wind, solar or batteries) separately and for the procurer of capacity to specify how much of each technology type it requires. This would create many challenges, including:

- specifying the optimal technology mix
- ensuring sufficient competition in each procurement process
- dealing with multiple capacity prices.

The de-rated capacity is an input to AEMO's reliability forecast and determines the maximum amount of capacity certificates that could be awarded to each capacity provider in an auction.

5.2.1. Specification of Capacity Unit

Capacity has a physical and a deliverability dimension – physical generation capacity must be adjusted for weather and for outages reflecting what will likely be available on the day. Therefore, most capacity mechanisms define a capacity unit in terms of a resource being continuously available to provide 1 MW to meet demand during certain at-risk periods of a delivery year.

The definition of capacity also needs to refer to a location and time period. A capacity mechanism may be system-wide (WEM, GB, France and Ireland) or provide for multiple zones or regions (PJM, NYISO, MISO). The NEM was designed on a regional model. This is reflected in the reliability standard, which specifies a maximum proportion of USE over a financial year in a NEM region. Hence, the capacity mechanism should ensure there is capacity in each region to meet the reliability standard.

Questions for stakeholders

- Q2 Do you agree that the capacity mechanism should provide for multiple zones being the existing NEM regions?

5.3. At-Risk Periods

A key issue for detailed design is the period over which technologies should be de-rated. The period which is used to de-rate capacity is important because the season and time of day can have a material impact on different resource's expected performance, as well as implications for network congestion.

The period over which technologies are de-rated, the at-risk periods (see Box 4), can be defined in two ways:

- as discrete time periods of the year e.g. summer evenings on workdays
- on the forecast occurrence of a defined event e.g. if there is USE.

Box 4 'At-risk periods' vs 'compliance periods'

At-risk periods: The time periods which are used to de-rate capacity. A primary consideration for de-rating is the expected weather conditions (temperature, humidity, solar radiation, wind etc) during these periods.

Compliance periods: The time periods where the compliance obligation is assessed. Under the compliance approach currently proposed (see section 7), these periods would be the actual occurrence of LOR events.

Ideally, there should be alignment between how the 'at risk periods' are defined for the purposes of de-rating and how the actual compliance events are defined. A significant disconnect between the definition of the at-risk periods and compliance periods could result in capacity providers being assessed for compliance on a different basis to how their capacity was certified.

If compliance events are defined as the occurrence of a USE event, the at-risk periods would be based on a forecast of when these events are expected to occur. This requires a model to simulate the distribution of events throughout the year and to determine the performance of different technologies whenever these events occur. In this approach, the forecast at-risk periods are contained within the model and may be less transparent than if they are explicitly defined in advance.

On the other hand, there may be benefits to adopting a more simplified approach to determining at-risk periods – for example using pre-defined time periods. Defining the at-risk periods based on discrete time periods provides a more transparent approach that will allow each technology provider to understand their rating and the value of their technology.

The choice is also influenced by how well reliability events can be forecast in advance and how concentrated they are throughout the year. If the compliance events are hard to predict or spread throughout the year, then an event-based definition would be more appropriate. These dynamics in the NEM are discussed below.

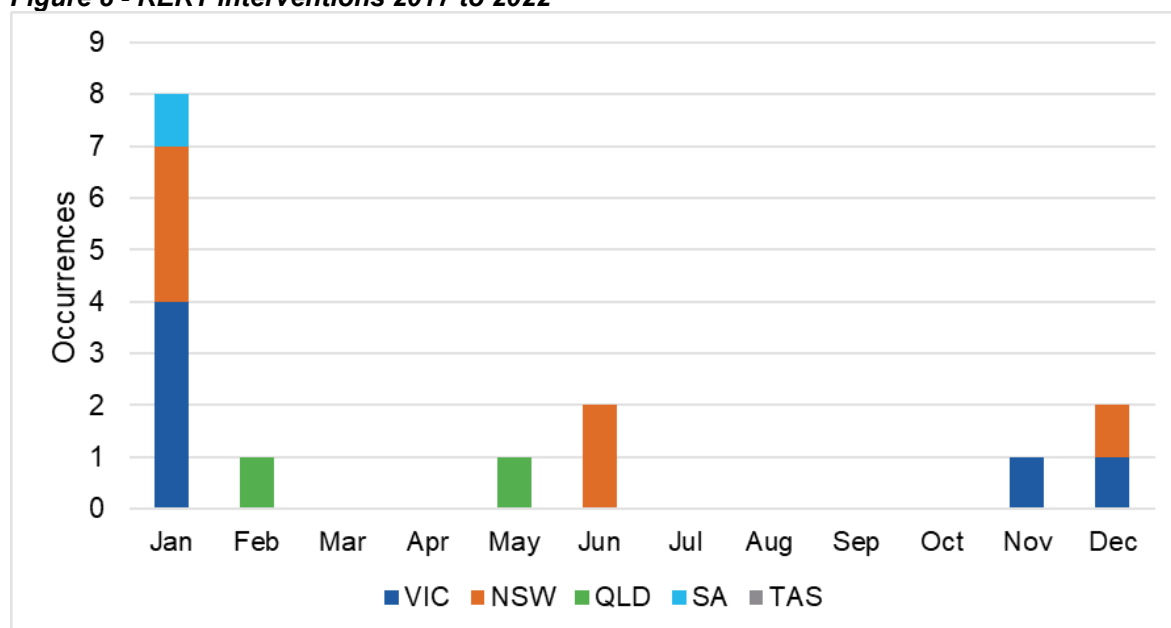
5.3.1. When is reliability most at risk?

A review of historical data provides a useful starting point for determining which periods of the year reliability is most at risk.

RERT Interventions

Given that the NEM has historically experienced very little USE, AEMO's deployment of the RERT could indicate when the power system is most likely to be under stress. Over the last few years, AEMO has used RERT on 15 occasions as shown in Figure 8 below.

Figure 8 - RERT interventions 2017 to 2022



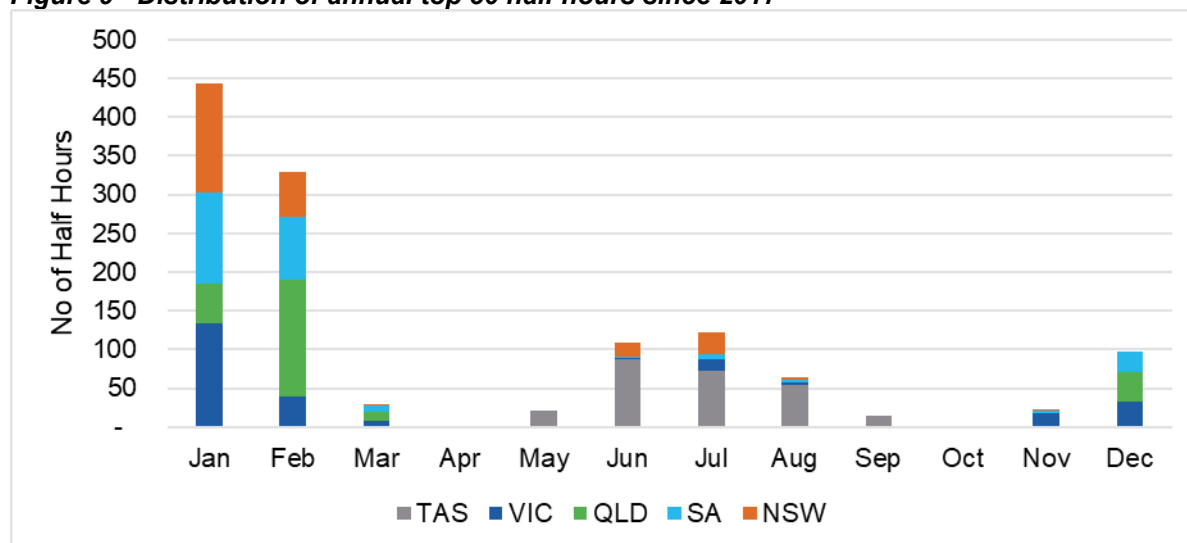
Source: AEMO data on RERT interventions.

The data shows that the summer period when electricity demand is highest contains the most RERT interventions, with January accounting for half of the total. There have also been three occasions when RERT has been used in winter, with none during the shoulder months. A similar seasonal pattern is observed when reviewing lack of reserve (LOR) conditions with the summer months, particularly January being the highest risk time of year.

Operational Demand Outcomes

Another perspective is provided by reviewing operational demand outcomes. Figure 9 shows the monthly distribution of the top 50 half-hourly demands in each calendar year for each region over the last five years.

Figure 9 - Distribution of annual top 50 half hours since 2017



Source: AEMO operational demand data

Figure 9 shows that December to February have the highest half-hourly demands of the year in the mainland regions, with Tasmania recording its highest demands through the winter months due to a cooler climate and the reliance on electricity for heating.

The dataset also highlights the time of day when demands are highest with the mainland peaking on summer evenings, typically around 4pm to 7 pm EST. Tasmania experiences its peak demand on winter mornings.

5.3.2. How will reliability events change over time?

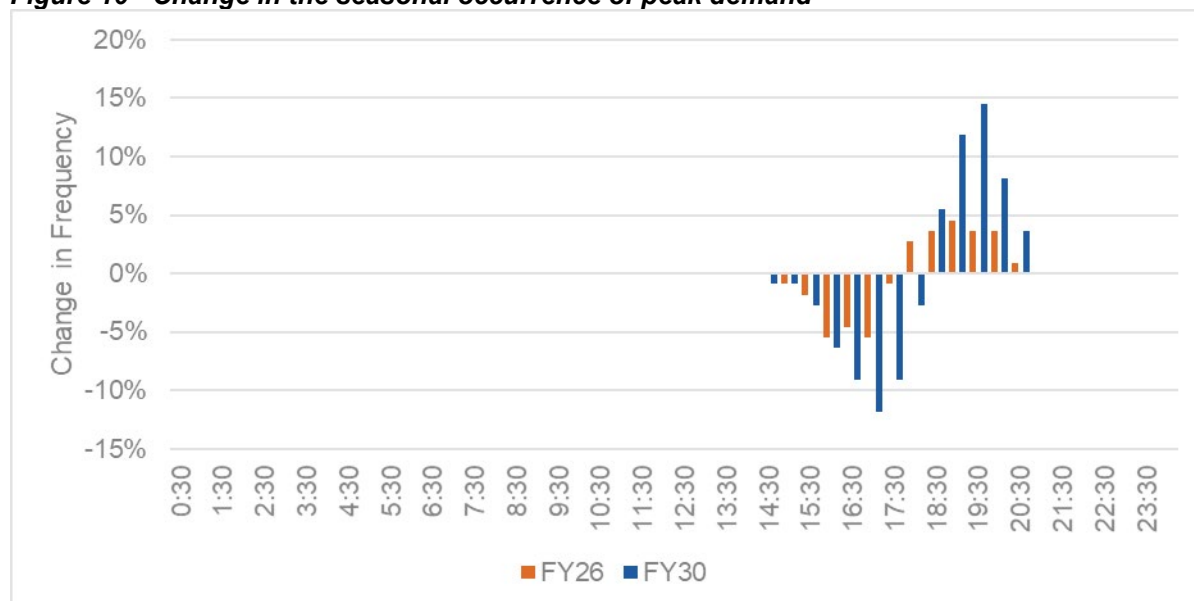
One of the objectives of a capacity mechanism is to promote investment to address future reliability risks. The focus is usually several years in advance to allow enough time to identify and mitigate capacity shortfalls. Therefore, it is essential to consider the drivers of future peak demand events and how these might change over time.

Change in time of day of peak

A key trend in the historical data is that the summer peak demand period has progressively shifted to later in the day driven by increasing distributed PV hollowing out the middle and afternoon demand. This is expected to continue to shape the future demand profile but other factors will also play a role such as the impact of electric vehicle charging.

Figure 10 shows how in New South Wales (which is representative of the mainland) summer peak periods used in the 2021 ESOO are expected to change over time compared to their forecast distribution in FY2022. The periods before 18:00 show a reduction in frequency to FY2026 and further reductions to FY2030, and this is offset by increases in frequency later in the evening.

Figure 10 - Change in the seasonal occurrence of peak demand



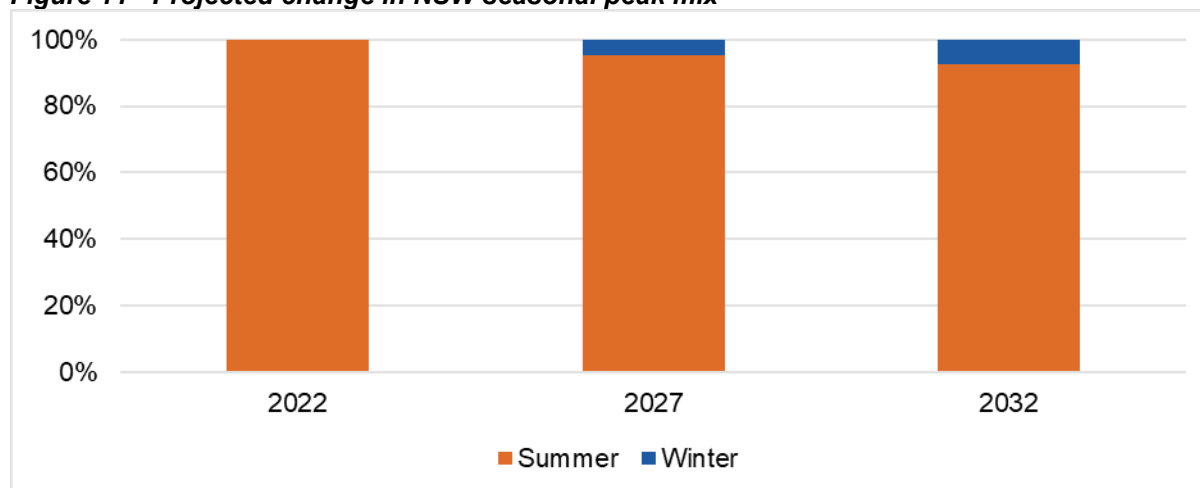
Source: Analysis of 2021 ESOO operational demand data

Change in the seasonal occurrence of peak demand

One concern with defining at-risk periods on a time-period basis is that the season when they occur will change over time. So, a mechanism that focuses on delivering capacity at one time of the year could miss reliability risks at other times.

New South Wales is the most likely to first change from summer peaking to winter peaking. Figure 11 shows that New South Wales remains predominantly summer peaking over the next decade, but the incidence of winter peaking will slowly increase over time. The expected gap between the summer peak and the winter peak is expected to remain steady around 700-1,000 MW. All other mainland states retain their summer peak, with Tasmania keeping its winter peak.

Figure 11 - Projected change in NSW seasonal peak mix



Source: Analysis of 2021 ESOO operational demand data

Change in the seasonal occurrence of USE

The 2021 ESOO forecast little USE over the 10-year planning horizon. It forecast a small amount of USE in Victoria and New South Wales in the latter part of the forecast and concentrated in December and January between 4 pm and 9 pm.

The 2021 ESOO Update contains higher USE driven by the closure of Eraring Power Station. However, summer continues as the main risk period.

Over time, as coal generators retire, the risk of USE will shift from summer to winter. This is because, with the exception of Queensland, most energy in the NEM is consumed in winter. This is likely to increase with the electrification of gas and transport. As coal generators are replaced with a combination of renewables, peakers and storage, the generation mix will become more flexible and therefore more able to handle the short, sharp demand spikes that are common in summer. However, in winter, the reduction in traditional base load generation will place more reliance on long-duration storage to cover extended runs of high demand during winter during wind droughts and this is where the risk of USE will increase.

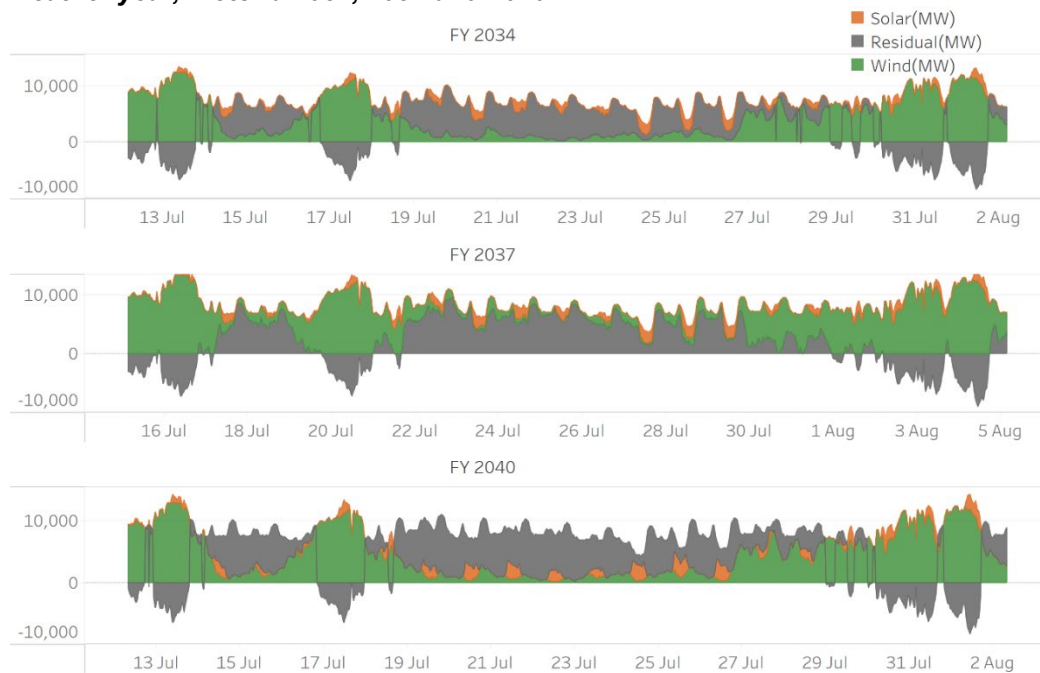
Consideration of ‘renewables droughts’

A final consideration for how system stress events might change over time is the impact of ‘renewables droughts’ on the ability to balance supply and demand across the system. A system where the bulk of electricity is produced by VRE, as is predicted for the NEM under AEMO’s ISP, could be adversely impacted by extended periods of coincident low wind and solar radiation.

Such periods are likely to be most severe in winter in southern latitudes, given these locations are subject to lower solar radiation and higher electricity demand resulting from greater heating requirements during winter months. When combined with extended low wind conditions, a significant and sustained gap between system demand and VRE generation output can be expected to emerge. Figure 12 shows the residual demand that must be met by non-VRE capacity providers in the worst¹⁷ weather year in Victoria under the ISP Step Change generation mix in 2034, 2037 and 2040. Under this scenario, around 1 TWh of electricity would need to be sourced from dispatchable generation, demand side resources or interconnection with other regions to bridge the VRE output deficit.

¹⁷ ‘Worst’ being the weather year resulting in the greatest residual demand, assessed on a one week basis

Figure 12 - System demand and VRE output, ISP Step Change generation mix under worst weather year, Victoria 2034, 2037 and 2040



Source:

Endgame Economics analysis of AEMO Draft 2022 ISP data

Renewables droughts could cause system stress events under a very high VRE generation mix if there is insufficient firm resources available to meet residual demand.

5.3.3. Dealing with multiple at-risk periods through the year

The data highlights that whilst the system stress events are mainly confined to one part of the year there is the potential in some regions for both summer and winter at-risk periods to emerge over time.

There are a few options for addressing this described below.

Focus on the higher demand period initially and evolve it over time

This approach works if the capacity mix that solves the higher demand period will also work to address the next highest period. In other words, if there is sufficient capacity to meet the summer peak then it should be able to meet the winter peak.

Given most of the work of the capacity mechanism is a year at a time auction (with auctions for capacity proposed a number of years in advance – see section 6.5) this approach can evolve over time to switch from a summer at-risk period to a winter at-risk period as the power system needs evolve.

Create two or more at-risk periods

Another approach is to create two or more at-risk periods throughout the year e.g. summer and winter at-risk periods. This would allow a more granular specification of the capacity requirement and a clearer distinction between the contributions of different technologies to meeting the different peak periods.

PJM provides participants with the optionality to 'deliver' capacity across the entire year or only for a specific season (summer or winter). While this option exists, only a small fraction of the total capacity procured through the PJM capacity mechanism relates solely to the winter or summer capacity period. Instead, most participants continue to offer or make

available their resource into the wider delivery year period. This may reflect the fact that renewable generation is still only a small proportion of the generation mix.

The challenge of operating a capacity mechanism with more than one period within a single delivery year is that it becomes considerably more complicated to administer. Most technologies will require different de-rating factors due to seasonal differences in ambient conditions, sunshine hours and the duration of USE events which will impact on storage. Specification of the capacity requirement will also become a problem because the reliability standard is specified over a whole year and not over seasons. Similarly, the capacity procurement process will also become more cumbersome.

Focus on event-driven at-risk periods

The alternative to defining a discrete time period as the at-risk period is to leave it to a model to determine when they occur. This has the advantage that the at-risk periods can be distributed throughout the year and can change over time as the assumptions in the model evolve.

Since the main purpose for defining at-risk periods is to set de-rating factors and the capacity requirement, an event-driven approach can integrate the modelling of these other elements without having to specify when the model predicted the events would occur. However, the risk of this approach is that the modelled events could still be primarily distributed in one season or another, but it would not be transparent as to when they are occurring.

Questions for stakeholders

- | | |
|----|--|
| Q3 | Is there sufficient evidence to say that the at-risk periods can be defined on a time-based definition? |
| Q4 | If there is a risk of the emergence of more than one at-risk period in the NEM how should that be addressed? |

5.4. Developing De-rating Factors

The approach taken for defining the at-risk periods has implications for how de-rating factors are then applied. The implications of a time period definition, an events based definition and a hybrid approach are discussed below. Consideration for the treatment of different technology classes are also discussed.

5.4.1. De-rating under a pre-defined period approach

The first issue to consider under a pre-defined period approach is whether the de-rating factor should be forward-looking or based on historical data or some combination of the two. Ideally, the de-rating factor should relate to the period for which capacity is being procured – typically three or four years into the future. This is because de-rating factors change over time for example as outage rates increase due to the ageing of a generator or because of the changing needs of the power system.

Whilst forward-looking estimates are preferred, they depend on modelled outcomes and are subject to the assumptions and dataset contained in the model at the time of evaluation. This can lead to volatility in de-rating factors when assumptions or modelling approaches change. A similar problem is possible when using historical data as new data is added to the dataset. However, at least with historical data the calculations are transparent and easily replicable.

For new capacity providers there may not be sufficient data available on which to base an assessment. This may require the review of data from similar, existing capacity providers, assessing technical specifications of the resource and modelling using relevant inputs such

as wind speeds. Some performance testing may also be required and there could be an initial allocation of a de-rating factor which is subsequently reviewed once there is sufficient actual data available to make a new assessment.

5.4.2. De-rating under an events-based definition

A group of methodologies has evolved in capacity mechanisms to determine de-rating factors consistent with an event based at-risk approach, known as Equivalent Load Carrying Capability (ELCC) in North America and Equivalent Firm Capacity (EFC) in GB. The basic concept in these methodologies is that the de-rated capacity of a resource is set to the equivalent performance of a hypothetical 100 per cent available unit during times of system stress.

The key features of the methodology are:

- **Simulation based** - forward-looking approach relying on simulations of supply and demand.
- **Assessment at the margin** – the de-rating factor is assessed based on its marginal contribution to meeting the reliability standard. This requires first calibrating the reliability outlook in each region until it just meets the reliability standard.
- **Comparison to a theoretically perfect capacity resource** – the impact of adding say, a 100 MW wind farm, on USE is compared to adding a 100 per cent available theoretical resource. When the USE reduction is equivalent the ratio of the perfect resource to the wind farm sets the de-rating factor.
- **Portfolio approach** - portfolios of technology types are assessed and then allocated to individual capacity providers typically using historical data.

5.4.3. Hybrid approach

The ELCC approach is computationally intensive and the results for some technologies are similar to the de-ratings determined using a time-period assessment. In some capacity mechanisms such as the GB capacity market a hybrid approach to de-rating is used where thermal generators are assessed based on the historical performance over the previous seven winter peaks and newer technologies like renewables and batteries are de-rated using the EFC approach.

Using historical data also provides an inbuilt mechanism to address under or over de-rating as the actual performance will contribute to future de-rating factors.

The GB mechanism also limits its de-rating methodology to determining a single de-rating factor for a class of technology. Thus, all onshore wind generation for instance receives the same de-rating factor. This provides for a simpler and more transparent de-rating methodology but may not accurately represent the performance of an individual resource.

5.5. De-rating factors for different technologies

5.5.1. De-rating Thermal Generation

The maximum output of a thermal generator at any time is subject to many factors including maintenance and condition of the plant, the availability of fuel and workforce scheduling, as well as the prevailing environmental conditions (particularly temperature) in which it needs to operate.

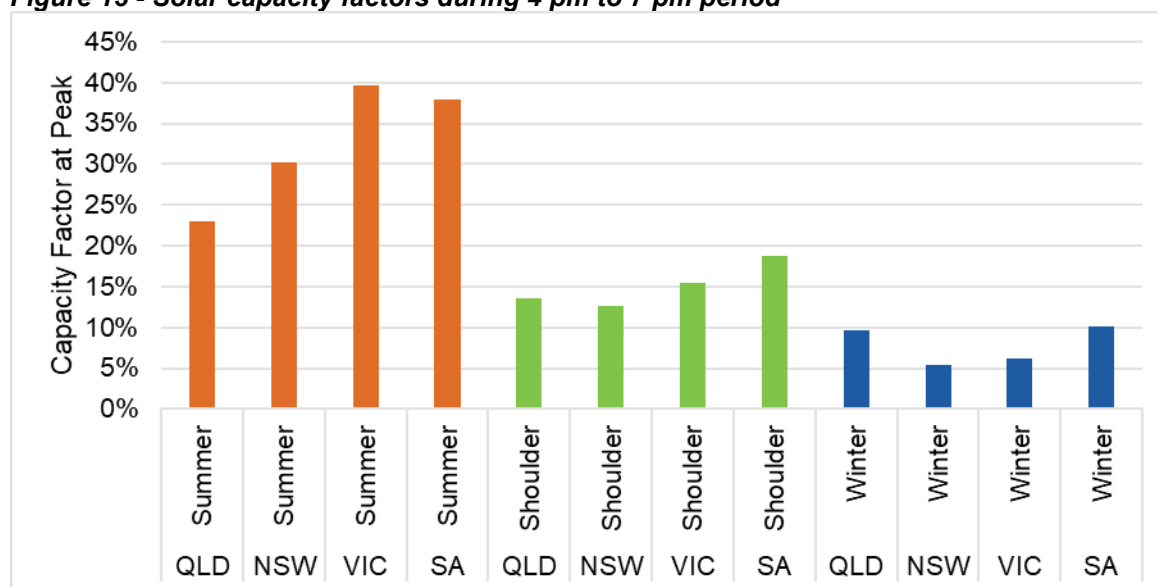
Focussing just on predefined at-risk periods allows this list to be narrowed down to the factors that the operator cannot control such as the impact of ambient conditions and forced outages. Here, it is assumed that the operator will not schedule planned outages during the at-risk times and will have the required fuel and workforce available to be able to operate at its full capacity.

It should be noted that temperature can have a material impact on generator output with AEMO's Generation Information showing that Somerton power station for instance has a summer peak capacity of 140 MW which is 82 per cent of its winter capacity of 170 MW.

5.5.2. De-rating Variable Renewable Generation

Whilst thermal generation exhibits some seasonal variation this is modest compared to the variability of wind and solar output which is highly dependent on the season and time of day. Focusing just on the evening peak hours of 4 pm to 7 pm EST the following chart shows that the location of the capacity provider is also important, particularly for solar. In southern Victoria summer daylight hours extend to 8 pm EST so solar can play a meaningful role in meeting the evening peak. By contrast in Brisbane, the sun sets before 7 pm in summer so the role of solar is much less.

Figure 13 - Solar capacity factors during 4 pm to 7 pm period

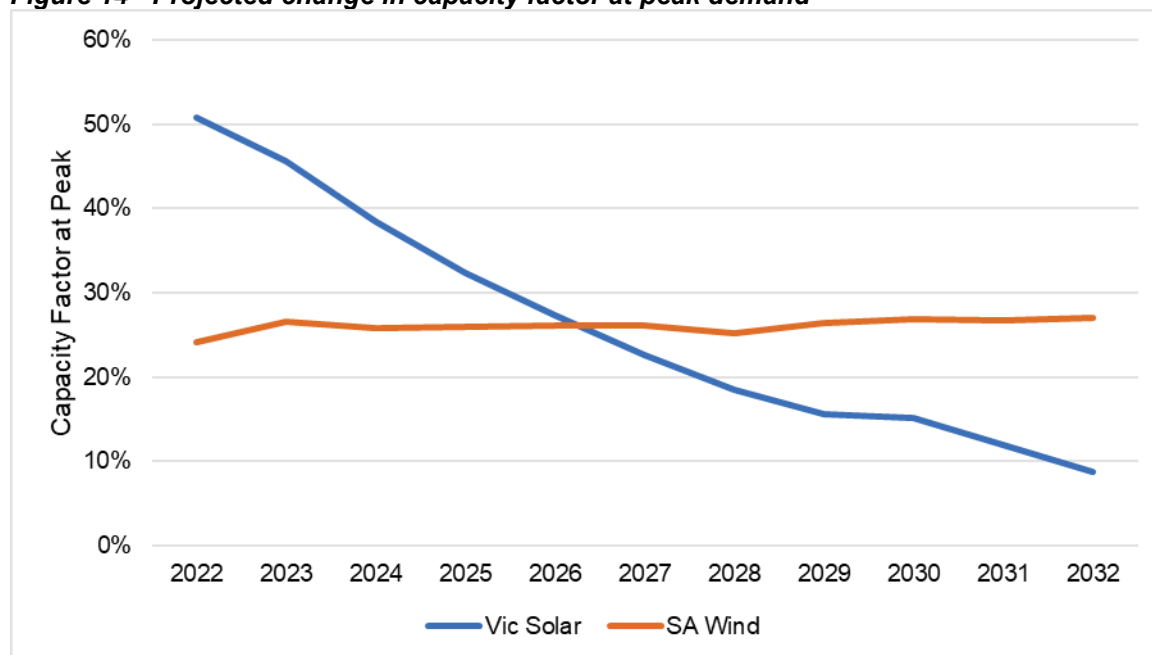


Source: Analysis of 2021 ESOO data

Wind also exhibits strong seasonal and regional trends with South Australia being the windiest state but also having older wind farms with smaller turbines (and therefore lower capacity factors) than are now commonly installed.

Another factor to consider with VRE is that the performance may change over time as the at-risk periods evolve. Figure 14 shows that focussing on the projected summer maximum demand time shows that South Australian wind is not expected to change much but Victorian solar shows a steep decline in effective capacity over time. This is because the operational demand peak is expected to continue to move later in the day due to the increased incidence of distributed PV hollowing out demand. This results in the projected contribution of grid solar to meeting the peak demand falling over time.

Figure 14 - Projected change in capacity factor at peak demand



Source: Analysis of 2021 ESOO forecasts for VRE

5.5.3. De-rating Hydro Generation

In theory hydro generation can be treated similarly to thermal generation where the capacity is assumed to be fully available during the at-risk periods with the risk of forced outages being the key driver of its de-rating factor.

However, hydro generation can be subject to operational limits of when it can run e.g. run of river hydro, or subject to energy constraints in the case of pumped hydro, or for traditional hydro during periods of drought. Also, the historical dispatch profile may be more reflective of contract positions rather than its potential generation.

Therefore, assessment of hydro de-rating factors is likely to require gathering a range of information to form a view of its potential output during the at-risk periods. However, for long duration pumped hydro and for dams that have sufficient water storage the de-rating factor will likely be close to 100 per cent adjusted for any forced outage risk.

5.5.4. De-rating Grid Batteries

As a relatively new technology, utility scale batteries can play an important role in contributing to the reliability of supply during at-risk periods due to their highly controllable output and quick response times. However, they are limited by their storage capacity (with most offering just one or two hours currently) and so their contribution will depend on their state of charge at the beginning of a reliability event and the duration of the event. They will also be impacted by any other services they are providing. Currently, batteries are an important source of Frequency Control Ancillary Services (FCAS) and other system services and may need to reserve a portion of their capacity for these.

Impact of at-risk periods

The NEM is characterised by short, sharp demand spikes in summer and a more consistent prolonged increase in energy consumption over winter. Given that system stress events are currently weighted towards hot summer evenings this means batteries with shorter storage durations can ensure they are fully charged and be able to play a role in delivering capacity in proportion to the length of the demand spike. However, as the role of thermal generation declines the system stress events will eventually shift to winter and the duration of the capacity requirement will increase. The mechanism will need to incentivise sufficient long duration storage to get through a run of cold, windless winter nights. Hence, the definition of at-risk periods will be an important determinant of the de-rating factor for batteries and is likely to change over time.

Linear de-rating

If a battery is assumed to be fully charged at the beginning of a reliability event (i.e. that the event can be anticipated) then its de-rating factor can be defined as the ratio of its storage duration at full capacity to the expected duration of the event. In the WEM, the at-risk period is defined as a continuous 4-hour period for assessing battery de-rating³. Hence, if a battery has only two hours of storage at full capacity, the de-rating factor is 50 per cent.

5.5.5. De-rating Demand Response

Demand response (DR) plays an important role in a capacity mechanism. Where DR participates in the mechanism it is common for the measured response on the day to be added back to the liable load calculation (as occurs in the RRO) to prevent double counting.

Participation by DR

Including DR will be an important feature of the capacity mechanism. The key issue for DR participation is that its ability to provide capacity is dependent on what its usage would have been during the at-risk period and so requires assessment of the hypothetical. This is particularly a challenge for providers with on-site generation who have discretion as to when they run their generator and for new sites with no historical data to go by.

Testing and baselining regimes are commonly used to provide the data points that allow DR to participate in a capacity mechanism. This may be supplemented with information about its operations and its physical connection to the electricity network to allow assessment of its potential.

Some forms of DR may not be well suited to making commitments to deliver if auctions are held up to 4 years in advance and so may prefer to defer committing until nearer the time say in a T-1 auction.

De-rating methodology

Given that DR is a function of usage this introduces a new concept into the de-rating approach which is separating out the capacity to which the de-rating is applied. For example, a 5 MW data centre may only have 1 MW of controllable capacity and that may have a 60 per cent de-rating factor (reflecting that it only available for a limited duration).

5.6. Summary of De-rating Factors

The following table illustrates the range of de-rating factors for different technologies in selected overseas capacity mechanisms.

Thermal generators receive the highest factors and tend to have a relatively small range of outcomes. Wind and solar on the other hand may make only a minimal contribution (PJM

solar is surprisingly high, reflecting a very low installed based and the receipt of some diversity benefit from storage. This is projected to fall as the installed base grows).

Storage and hydro can also receive a wide range of de-rating factors dependent on the level of storage and their controllability during the compliance periods e.g. run of river hydro may not be dispatchable.

Market	Coal	Gas	Hydro	Wind	Solar	Storage
CAISO	Equal to most recent maximum capability test		61 - 73%	8 - 33%	0 - 39%	100%
PJM	Equal to UCAP		42 - 96%	15%	54%	83 - 100%
GB	80%	91 – 95%	91%	6.3%	3.3%	10 - 95%
Ireland	N/A	82 - 91%	80 - 89%	9.1%	12.7%	14 - 68%
WEM	99 - 100%	79 - 100%	N/A	7 - 28%	10 -15%	25%-100%

Note:

CAISO reflects the monthly range specified across delivery year 2022.

PJM numbers reported for these classes: Hydro Intermittent and Hydro with Non-Pumped Storage, Onshore Wind, Solar Tracking Panel, 4-hr to 10-hr Storage for delivery year 2023/2024. UCAP is Unforced Capacity which is adjusted for the forced outage rate and ambient conditions.

GB reported for CCGT / OCGT, Onshore wind, Storage 0.5hr to 5.5+ hr and Solar PV for delivery year 2025/26.

Ireland reported for Gas Turbine, Hydro, Wind, Solar, Other Storage (i.e. not pumped hydro) 0.5hr to 6+ hr for delivery year 2025/26. Ranges depend on initial capacity.

WEM de-rating assessed annually in accordance with specified methodologies.

Questions for stakeholders

- Q5 The de-rating factors produced by different at-risk period definitions and modelling methodologies can show large ranges particularly for non-traditional technologies. How should this and potential year to year variability in de-rating factors be addressed?
- Q6 What approaches should be used to de-rate different technologies? Should different approaches apply to different technologies?
- Q7 What is the right balance between transparency/simplicity and accuracy?
- Q8 Should de-rating factors be determined at a technology class/region level or at a station level?

5.7. Forecast Capacity Requirement

5.7.1. Role of the NEM Reliability Standard

A capacity requirement in a NEM region would need to reflect the NEM reliability standard (or currently the interim reliability measure) which articulates the maximum amount of USE that is acceptable in a region over a financial year.

Therefore, the starting point for determining the capacity requirement is the ESOO USE forecast for the region in the relevant year. The ESOO models all existing supply and new resources that have reached the required “committed” stage of development. It also takes account of intra-regional transmission constraints and interconnector ratings and calculates the amount of USE under a range of weather and forced outage scenarios for forecast demand at the 10 per cent and 50 per cent probability of exceedance.

This USE outcome will either be above or below the reliability standard.

If the USE is above the standard there is a **reliability gap** and AEMO has an existing process under the RRO to quantify the size of the gap. This method adds incremental capacity that is assumed to be 100 per cent available until the size of the residual USE is reduced to the level of the standard. The amount that is added sets the reliability gap.

If there is no reliability gap this means there is surplus capacity and in principle the opposite approach can be used to determine the **reliability surplus**. This would require AEMO to develop a new process that combines USE periods with periods of low reserves. Then 100 per cent available capacity could be removed until the low reserve periods become USE periods and the size of the USE meets the standard.

5.7.2. Setting the Target Requirement

Having determined a reliability gap or reliability surplus there is then the question of what this should be added to in setting the capacity requirement to meet the standard. This is not straight-forward given the stochastic nature of ESOO modelling means that it cannot be easily converted to a single, deterministic outcome.

However, if all existing capacity participates in the mechanism the sum of their de-rated capacity will form the supply curve for capacity. To ensure consistency and avoid creating mismatches which might impact price outcomes the same de-rated capacity should also be used on the demand side in setting the capacity requirement.

Given that not all capacity may participate in the mechanism (for instance, a winner of a long term contract will not need to participate in subsequent auctions) a further adjustment is required to set the Target Capacity.

Target Capacity = De-rated Capacity of *Participating* Existing Providers +/- Reliability Gap/surplus

If the above approach to setting the capacity target is adopted, it will be very important that the ESOO modelling reflects all existing providers and that the list of participating providers and their de-rated capacities is accurately reflected in setting the target capacity for the auction. Hence, whilst the capacity requirement would be known once the ESOO results are available, the target capacity will not be locked in until it is clear who is participating. For instance, in Ireland the list of participating providers is only known after their qualification has been finalised which is very close to the auction date.

Questions for stakeholders

- Q9 Do you agree with the approach to setting the forecast capacity requirement and the target capacity in a region?
- Q10 How should the target capacity be determined where there are gaps in more than one region?

6. Procuring capacity and auction design

Summary

A fundamental design choice is who would be responsible for procuring the capacity to meet the capacity requirement identified in the forecast. The ESB considered centralised, decentralised and hybrid options.

A centralised approach would see a central body (AEMO) procure capacity through a competitive auction. A decentralised approach would see retailers directly engaging with capacity providers to secure the rights to capacity to meet their identified share of demand. A hybrid approach would combine the two; AEMO would run auctions to procure capacity centrally, but retailers may opt to directly procure resources to cover some or all of their share of the capacity requirement.

The ESB proposes procurement be centralised, using competitive auctions. However, the ESB will consider hybrid approaches further in detailed design. Key reasons include:

- Centralised procurement of capacity provides a more direct route to ensuring adequate resources are procured.
- Procurement by AEMO can reduce capacity providers' counterparty risk, regulatory burden and transaction costs, notably for smaller retailers.
- Competitive auctions can deliver cost benefits (which could occur in either centralised or decentralised models), such as allowing for transparent price discovery. However, decentralised procurement may also provide cost benefits, as retailers would have an incentive to seek out the lowest cost options and pursue more innovative procurement solutions. The ESB proposes further exploring the potential role of retailers in a centralised approach.

Issues for detailed design include:

- the terms of support on offer to capacity providers through auctions, including long-term capacity contracts for new capacity
- a role for retailer-led procurement in a centralised model
- auction eligibility and obligations on auction participants
- auction design, including a demand curve.

6.1. Centralised versus decentralised capacity procurement

In the December Initiation Paper, the ESB outlined two physical capacity mechanism options, which can be grouped generally as being based on:

- decentralised procurement where retailers are incentivised (or required) to procure capacity, which drives investment in the required resources
- centralised procurement where a central body determines the capacity requirement and has responsibility for procuring the necessary resources to meet the reliability requirements. This option also has the flexibility for some retailer participation, referred to as a hybrid arrangement in this paper.

The ESB proposes that the preferred capacity mechanism design will be underpinned by centralised procurement processes, with competitive sealed-bid auctions to procure capacity ahead of a delivery year. The ESB has considered various capacity mechanism designs and the views expressed by stakeholders in coming to this decision.

The ESB notes that a centralised capacity mechanism will provide a more reliable forward-looking information on capacity adequacy. This, in turn, will better meet the objective of

increasing government and community confidence that the market will deliver resource adequacy and reduce the need for market interventions.

A central capacity buyer would represent a lower counterparty risk that may have cost savings relative to a decentralised mechanism. However, these should not be overstated since retailers in a decentralised system would be highly motivated to contain costs.

Further, transaction costs are likely to be lower through a centralised procurement process, particularly for smaller market participants, relative to the costs of establishing a certificate trading platform or requiring retailers to contract bilaterally.

While the ESB has decided upon a centralised mechanism, it will also explore the potential role of retailers in the procurement process.

6.2. Eligibility, auction design and emissions reduction

All Australian jurisdictions have adopted the goal of achieving net zero carbon emissions by 2050 if not sooner. Jurisdictions vary with respect to the interim targets and supporting measures designed to achieve this goal. This reflects that the current emissions intensity of electricity supply in the NEM regions is significantly varied.

A key factor that would influence issues of eligibility and auction design will be the operationalisation of the Ministerial principle that the mechanism should ‘focus on affordability, reliability, security *and continued emissions reduction of electricity supply.*’

To this point, the ESB seeks guidance from Energy Ministers on sectoral emissions reduction in the context of net zero and the operationalisation of such guidance in the capacity market design.

The existing NEM framework does not provide guidance to draw upon on this matter as it currently does not include emissions abatement in the objective, nor a sector specific carbon emissions target or abatement trajectory given the economy-wide emissions abatement. There has, however, been consideration of achieving net zero which could be drawn upon, for example in the Draft 2022 Integrated System Plan. A strong consensus of stakeholder representatives has been that the Step Change scenario, which sees a consistently fast-paced transition from fossil fuel to renewable energy in the NEM, is the most likely.

The ESB also notes that there may be future work to draw upon with Energy Ministers recently agreeing the time is right to work together on a new agreement to set the vision for Australia’s energy sector transition to net zero. To this end, Energy Senior Officials have been tasked to work together intensively ahead of the Ministerial meeting in July to consider how a new agreement could reframe and reset existing priorities, frameworks and governance to ensure the sector can chart the course out of the current challenges, and set the sector up for a stable transformation towards decarbonisation.

Guidance on this emissions reduction principle will help inform design matters including eligibility and auction design. Any emissions reduction guidance and operationalisation in the capacity mechanism will not alter, or limit, the principle that jurisdictions must be able to determine which technologies are eligible for participation in a capacity mechanism in their region.

6.3. Long-term investment support

The core procurement auction in the preferred mechanism will allocate capacity certificates for one delivery year at a time. To ensure investment for capacity adequacy, the ESB considers that the preferred capacity mechanism should include longer-term support for new capacity entering the market for the first time. When offering such longer-term support, the ESB proposes that criteria be developed to ensure that the resources procured will be consistent with the NEM's transition to net zero emissions.

In reaching this decision, the ESB considered that longer-term investment support is necessary to support the financing of new capacity investment, lowering the cost of investor capital, with those cost savings likely passing to end consumers. The ESB also expects that such support would increase the number of market participants who could finance new investments.

However, the ESB recognises that long term investment support represents a risk transfer from capacity providers to customers and that such longer-term capacity contracts could become 'out of the money' over time.

Several capacity mechanisms in other jurisdictions provide longer-term support for new capacity investment:

- the GB capacity market offers contracts of up to 15 years for new facilities, and three-year contracts for a refurbished plant, with costs that exceed prescribed thresholds
- the Irish market offers contracts of up to 10 years for qualifying plant
- in the WEM's Reserve Capacity Mechanism, new capacity providers may nominate to receive a fixed price for five years.

Section 6.5 outlines how the ESB will consider longer-term investment support for detailed design.

6.4. Stakeholder responses to the initiation paper

Stakeholder feedback about capacity procurement and trading focused on choosing between a centralised or decentralised mechanism and whether the design should include long-term investment support.

Of the 19 stakeholders that expressed a preference between centralised or decentralised approaches, approximately two-thirds indicated support for either a centralised or hybrid mechanism. Views expressed by these stakeholders included that:

- a centralised mechanism was likely to provide policymakers with greater confidence in resource adequacy
- a centralised mechanism was more likely to provide clear investment signals and encourage investment
- a hybrid mechanism, with a role for both AEMO and retailers, could balance the greater regulatory oversight of capacity adequacy with the benefits of procurement and trading flexibility for retailers and could readily accommodate existing long-term contracts
- centralised mechanisms provide greater protection against the exercise of market power while allowing simpler compliance arrangements for retailers.

Shell and Origin Energy specifically noted that long-term investment support is needed for new capacity. Origin Energy suggested that seven-year contracts be made available, and Shell suggested that capacity auctions cover multiple years.

The ESB's preferred mechanism aligns with these views: a centralised mechanism that incorporates longer-term investment support for new capacity.

However, the ESB also received feedback that the ESB should pursue a more decentralised approach, on the basis that retailers are best placed to manage their risks and have incentives to forecast and procure their capacity requirements accurately. These stakeholders argued that a decentralised approach was more likely to complement the existing market design and retailers would be incentivised to seek out the lowest cost capacity options. The ESB notes these concerns and will consider the roles of retailers in the

procurement of capacity to take advantage of potential efficiencies. This is discussed further in section 6.5.1 below.

6.4.1. Market power mitigation

Ten submissions provided comments in relation to market power, which is relevant to the design of procurement arrangements, with mixed views on the nature of high market concentration in the NEM:

- some considered it an issue particularly for vertically integrated participants, but noted it may be ameliorated with a centralised design choice
- some did not consider it an issue and noted the NEM's competitive circumstances were improving
- some suggested that market power mitigation should not be progressed as a priority area for the project, only requiring consideration once the high-level design is settled.

The ESB is generally aligned with stakeholder views that market power mitigation is an important issue for detailed design, particularly for auction arrangements.

Stakeholders also provided feedback on how to resolve issues relating to market power in the capacity mechanism design, but considered these should be weighed against the likely additional costs:

- suggestions included the use of offer caps above certain volume thresholds, or allowing only new generation to participate to avoid the exercise of market power in respect of legacy large-scale assets
- it was also noted the market liquidity obligation (MLO) has somewhat addressed market power issues in the RRO.

6.5. Focus areas for detailed design

6.5.1. A procurement role for retailers (hybrid approach)

While the preferred capacity mechanism design will have AEMO as the default buyer of capacity, the ESB will consider incorporating hybrid arrangements where market participants have a role in capacity procurement.

Capacity mechanisms in other jurisdictions also employ various hybrid arrangements, combining centralised and decentralised elements. For example, in the WEM, retailers can procure capacity certificates bilaterally from capacity providers, and AEMO settles uncontracted capacity at the reserve capacity price. AEMO then bills retailers for the remainder of its capacity requirement. In California, load serving entities are responsible for procuring capacity but must comply with demand forecasts that are developed by either the CAISO or a combination of the load-serving entity and CAISO.

The inclusion of such arrangements should provide greater flexibility for each retailer to contract with capacity providers under mutually beneficial terms and conditions, which may include multi-year contracting for new capacity. They would allow each retailer to procure its anticipated needs, and to be billed by AEMO for its residual capacity requirement as the default counterparty to the capacity certificate.

The ESB is considering the following methods of retailer participation in the centralised capacity mechanism:

- AEMO would purchase all capacity certificates in the initial auction. Retailers would then be obliged to purchase certificates from AEMO after the capacity auction, ahead of the delivery year, to meet their own projected requirements. This option would provide greater visibility of retailer forecasts of their own demand and would allow some risk of forecasting errors to be transferred to retailers. However, AEMO would still need to

recover the costs of any additional certificates that it had purchased. Also, there would need to be an ability for retailers to purchase additional certificates outside of the centrally-procured pool in the event that retailers' combined forecasts were actually higher than AEMO's.

- Retailers could be allowed to participate in the capacity auction, with retailers participating as buyers alongside AEMO. This may allow retailers to indicate their future capacity requirements, increasing transparency and potentially mitigating market power concerns. However, in order to satisfy the objective of the mechanism to support reliability, AEMO would need to procure capacity to meet the projected demand, irrespective of retailer participation. This option is also likely to increase the administrative costs of the mechanism.

The design of hybrid arrangements must also consider what would happen if a market participant was to default or not meet its prudential requirements. These are issues for detailed design.

Questions for stakeholders

- Q11 Should retailers have a role in a centralised capacity mechanism?
- Q12 If you support retailer involvement in procurement, what are your views on how this could operate?

6.5.2. Auction frequency and timing

The ESB considers that AEMO should procure capacity as an annual product related to a specific delivery year. This is consistent with most capacity markets and mechanisms in other jurisdictions, including the reserve capacity mechanism (RCM) operated by AEMO in the WEM.

Given the role of capacity mechanisms to support investment, the capacity procurement processes typically commence two to four years ahead of delivery to align more closely with investment and project development timeframes for generation plant, with the aim of enabling competition between potential new entrants. The facilitation of new-build capacity is also important from an efficiency perspective, to help mitigate the risk of 'zero/infinity' pricing outcomes.¹⁸

Importantly, there is a trade-off between the provision of forward investment certainty (tending towards earlier procurement) and the accuracy of capacity forecasts (tending to later procurement). A common approach used to manage this trade-off in other jurisdictions is to conduct two or more auctions.

- An initial auction held several years in advance of the delivery year in the capital investment timeframe. It is configured to procure less than the entire forecast capacity requirement. Procuring less than the anticipated need mitigates the risk of consumers bearing the cost of over-procurement if forecasts reduce in subsequent years.
- One or more supplementary or reconfiguration auctions are held closer to the delivery year, with the last such auction configured to procure the entire, updated forecast capacity requirement. These auctions may also allow some secondary trading, such as

¹⁸ The 'zero/infinity' problem refers to the potential for binary pricing outcomes in capacity markets if there is insufficient time for the market to respond: very low (near zero) pricing if the market is over-supplied, and very high pricing if there is a capacity shortage. Source: The Lantau Group, 2014, *Improving Western Australia's Reserve Capacity Market: Steps and thoughts to Date*, presentation accessed from: http://www.lantaugroup.com/files/ppt_wa_mtt.pdf.

enabling participants cleared in the initial auction to trade out of that position if their circumstances have changed. A second auction close to the delivery year may reduce or replace some of the reliance on backstop procurement such as the RERT.

When determining the timing of capacity auctions for the NEM, an additional consideration is the interaction with the generator notice of closure obligations, which currently require 42 months notice ahead of the closure of a scheduled or semi-scheduled generating unit. The AEMC has also received a rule change request looking to lengthen this time to five years. The ESB will consider how the auction timing may interact with the notice of closure requirements in detailed design.

If the initial auction occurred after the notice of closure deadline, the closure notice would encourage the remaining or new participants to fill any shortfall created by the closure, as long as they have sufficient time to respond.

For the timing of an initial auction, an important consideration will be the development time for the technologies that would be expected to enter the NEM in future. A deliberate design choice will need to be made ensure we have the right dispatchable capacity in the NEM, including consideration of the depth of storage. Therefore, the ESB will need to consider how far out to conduct an initial auction ahead of the delivery year (e.g T-3 or T-4, or longer) and if a single supplementary auction one year ahead of the delivery year (T-1) is needed.

Questions for stakeholders

- Q13 Do you agree with holding two auctions for each delivery year and is this timing appropriate? If no, what auction frequency and timing is appropriate and why?
- Q14 How should the timing of the auctions align with the notice of closure obligation?

6.5.3. Auction participation and clearing for capacity providers

The ESB is progressing a capacity mechanism that includes both new and existing capacity. However, the ESB acknowledges that the detailed design of the capacity auctions will require further consideration of the eligibility of (and obligations on) market participants to participate in the capacity auction, any conditions to be placed on their participation, and the clearing process for the auctions.

As a starting point, the ESB proposes the following minimum criteria for participation:

- Capacity providers qualify to participate in the auction by passing a technical assessment performed by AEMO, to confirm the amount of capacity that they are eligible to offer into the capacity auction
- Capacity providers participate in the auction on a unit-by-unit basis, with both new and existing capacity eligible to participate in the capacity mechanism. However, the ESB may consider whether additional auction rules should apply to certain classes of capacity providers.
- The auction clearing process will incorporate network constraints (discussed in section 9).

The detailed design will need to consider how any difference in jurisdictional eligibility requirements might be incorporated into the auction design, and whether capacity that is supported through a jurisdictional scheme should be eligible (or required) to participate in the auction, and the conditions of participation.

Further, and as mentioned earlier, the ESB will consider the method for allocating support to new capacity. There are several areas the ESB will need to consider, including:

- how the different needs of new and existing resources should be taken into account in the auction design process, in a way that avoids over-paying existing capacity
- duration of support to be offered
- form of support, through either a:
 - guarantee of both price and quantity – a contract that allocates capacity certificates and sets prices for a long term
 - guarantee of price only – through a price lock-in option that still requires the capacity provider to reapply for capacity certificates each year and for the facility to be technically reassessed.

Questions for stakeholders

- Q15 What are your views on how existing and new capacity should be treated in the auction process?
- Q16 Are there other considerations the ESB should take into account for the detailed design?
- Q17 Do stakeholders have a view on the optimal duration of certificates or price certainty for new capacity?
- Q18 Do stakeholders have a preference as to whether the investment support scheme provides guarantees of price only, or of both price and quantity?

6.5.4. Auction price settings

The price settings of the capacity mechanism must be considered in detailed design. In particular, this includes:

- the offer price cap and price floor for the capacity auction
- whether and, if so, how new and existing capacity may be subject to different offer price caps or floors
- the nature of the capacity auction and whether multiple price bands and offers may be considered.

The ESB will also consider the implications of the capacity auction on the market price settings in the energy market. This is discussed further in section 7.

Questions for stakeholders

- Q19 Internationally, capacity mechanisms rely on some multiple of the net-cost of new entry (net-CONE) assessment to determine the capacity mechanism market price cap. Is this appropriate or should an alternative approach be used?
- Q20 How should the price settings interact with the energy market price? Over time, when settings are regularly reviewed, should the price settings in the capacity auction and the energy market be jointly determined?

6.5.5. Auction demand curve

In addition to the price settings, the ESB must consider the auction demand curve in detailed design.

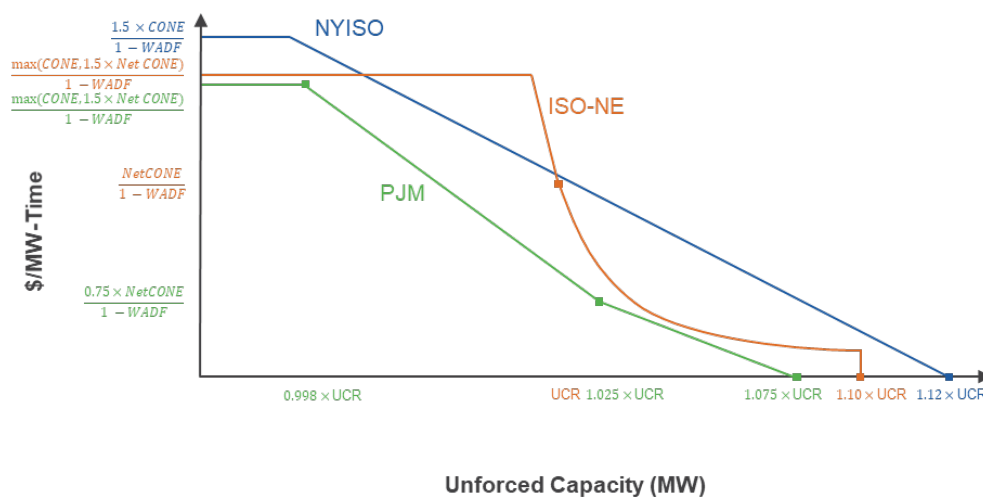
Rather than operate a capacity auction to procure a fixed requirement, other jurisdictions with capacity auctions vary the quantity of the procured capacity subject to the price offers –

procuring slightly more if prices are low and slightly less if prices are high. This is done for two reasons:

1. The reliability standard, and the regional capacity requirements, are set to find the optimal point in the cost-benefit trade-off between the cost of additional capacity and the benefit of avoided unserved energy. However, the optimal point would vary depending on the assumed cost of capacity. A sloped demand curve for capacity reflects that the optimal volume of capacity may be higher when capacity is cheaper and lower when capacity is more expensive, enshrining an economic trade-off between different reliability levels.
2. A sloped demand curve also reduces the volatility of capacity price outcomes, mitigating the risk of 'zero/infinity' pricing outcomes described above.

Demand curves vary significantly between markets, even between the three main markets of the north-eastern United States. Figure 15 below compares the demand curves for the PJM, ISO-NE and New York ISO (NYISO) markets as at 2018.

Figure 15 - Comparison of capacity auction demand curves



Note: CONE = cost of new entry; net CONE = Cost of new entry less expected revenue from energy and ancillary services markets; WADF = weighted average de-rate factors (translation between installed capacity and de-rated or unforced capacity); UCR = unforced capacity requirement.

Source: Byers, Levin and Botterud 2018, Capacity market design and renewable energy: Performance incentives, qualifying capacity, and demand curves.

The concave shape of the demand curves for PJM and ISO-NE is chosen as it more closely reflects the economic value of capacity. The demand curves in Figure 15 are for the whole-of-market capacity requirement. Jurisdictions may determine alternative demand curves that may apply for a constrained region within the market (these tend to be flatter in shape due to the greater risk of price volatility in a smaller sub-market).

The ESB will consider whether the auctions in the preferred capacity mechanism design will include sloped demand curves. Given that the auction curve is designed to reflect the trade-off between reliability and cost, and will be calibrated to the reliability standard, the ESB will need to consider who will be responsible for periodically defining the shape and anchor points for the demand curve.

The detailed design of these curves will include the following considerations:

- the demand curve shapes and anchor points, which may be different for each region
- the frequency at which the demand curves are reviewed and recalibrated

- whether the reference price will be the same for all regions
- the frequency at which the reference price should be recalculated
- which organisation should be responsible for calculating the reference price.

Questions for stakeholders

- Q21 Are there other considerations the ESB should take into account when determining demand curves in the detailed design?

6.5.6. Mitigating market power concerns with auction settings

The ESB will consider market power mitigation measures in detailed design. Currently, the ownership and control of capacity in the NEM is highly concentrated to a few market participants. While this is likely to change over time, risk remains that participants may have a sustained, rather than transient, ability to exercise market power to influence prices in highly concentrated markets.

Other capacity mechanisms have used market power mitigation measures that impact large market participants' ability to physically or economically withhold capacity.

- Mandatory participation of a certain proportion of de-rated capacity to address physical withholding risks – the MLO in the current RRO is a form of mandatory participation.
- Additional price settings to address economic withholding risks – in the GB capacity mechanism, existing capacity is not able to set prices in the capacity auction and has a lower price cap.

The fact that these are levers used internationally does not mean they will be needed in the NEM. In detailed design, the ESB will consider market concentration thresholds that may warrant market power mitigation measures.

The ESB will also consider whether market power mitigation measures are required if a hybrid procurement approach is taken in detailed design.

Questions for stakeholders

- Q22 While the RRO requires mandatory participation for the largest three participants in a region, the ESB considers a methodology for determining market power should be applied to account for changing market concentration over time. Are there specific market concentration thresholds of concern?
- Q23 Should market power mitigation measures be applied to capacity providers with large market shares in supply-side regardless of their market share in retail?

6.5.7. Payments and settlement

Consistent with the preference for a centralised procurement model, the ESB will consider how payments and settlement may also be incorporated. The ESB would prefer as much as possible to incorporate the settlement of capacity certificates by AEMO and integrate this with existing settlement processes.

However, the ESB notes this must be considered in the context of other elements of the design such as the treatment of interregional trade and the design of the performance obligation.

Questions for stakeholders

- Q24 Do stakeholders support the proposal to integrate capacity mechanism settlement with the existing NEM settlement process? If not, what alternative process would better meet the design objectives?

7. What are the obligations on capacity providers?

Summary

Capacity mechanisms can involve a change to the sources of revenue and incentives for capacity providers to perform when needed. As the ESB is proposing a mechanism with centralised forecasting and procurement, there will need to be an obligation on successful capacity providers to ensure that they deliver the benefits in the market they have been contracted to deliver. The ESB is considering three conceptual models for a performance obligation, based on:

- expected availability during time-based performance windows as determined by AEMO
- de-rated physical capacity exposure to spot prices above a certain threshold that may be triggered at any time (such as Reliability Options)
- availability year-round, with additional requirements to be available during actual lack of reserve events that may be triggered at any time.

The ESB has focused on the third option in this paper for consultation. The key reasons why the ESB intends to consult on this approach are that it:

- is most likely to work with the existing energy market and have the smallest impact on other markets or contracts used to manage risk
- best meets governments and consumers expectations of reliability, as the obligation will encourage capacity providers to be available whenever a system stress event occurs, regardless of whether it is in an expected peak time or corresponds to high prices.

Issues for further detailed design and consultation include:

- how incentives should be structured to ensure capacity providers are incentivised to turn up during times of system stress
- definition of availability during the year
- methodologies for defining system stress events
- interaction between the performance obligation, capacity payments and existing market design.

The performance obligation and compliance scheme must work with and support other design elements. As outlined, the ESB has endorsed centralised forecasting and procurement for the high-level design. As a result, the compliance models for consultation relate to obligations on the capacity provider (such as generators, batteries and demand response).

This section refers to performance obligations in the operational timeframe for capacity providers, that is, what a capacity provider must do on the day. The ESB had regard to the following principles to develop the performance obligation and compliance design:

- Stakeholder responses to the initiation paper – strong real-time market incentives should be retained; instances outside the asset owner's control should not result in penalties, and a view from some that penalties larger than the clawback of the capacity payment should be considered.
- Other principles for performance obligation – linked to measurable outcomes known to capacity providers in advance and have control over and should not include unhedgeable risks.

Introducing a capacity mechanism will involve a fundamental change to the electricity market design. The ESB acknowledges that this may significantly impact the incentives that drive market decisions and the scale of market monitoring and compliance required to facilitate a culture of performance and compliance. Therefore, in designing a compliance regime, the ESB would prefer as much as possible for a regime that is simple and clear, and involves:

- incentives that are automatic and self-enforcing
- a clear definition of performance that is capable of simple, objective determination, rather than relying on complex or arguable judgements
- a direct, formulaic link between performance and payments, as well as for non-performance and the withholding of payments
- works with the existing market design whose incentives and risks are well understood by market participants.

Such a regime should help reduce the overall regulatory burden (on capacity providers, retailers, AEMO and the AER) and create strong incentives for compliant behaviour. The ESB may consider additional penalties for special cases but these should not be relied upon as the primary driver for operational performance.

The ESB is also considering other compliance obligations in the capacity mechanism but will explore these in detailed design:

- the role of retailers in procurement (hybrid model described in section 6.5)
- requirements for new entrant capacity in building the asset or to participate in the auction.

7.1. Performance obligations considered by the ESB

A performance obligation refers to what a capacity provider, awarded with a capacity certificate, must do to receive payment for its certificate and/or be considered compliant.

The ESB considered three performance obligation models for capacity providers in a centralised procurement and forecasting model. These are:

1. **Option 1** – performance obligations based on a capacity provider's expected availability during time-based performance windows as determined by AEMO
2. **Option 2** – performance obligations based on a capacity provider's exposure to spot prices above a certain threshold that can be triggered at any time (such as reliability options)
3. **Option 3** – performance obligations based on a capacity provider's availability throughout the year plus additional obligations/incentives during actual lack of reserve events, which can be triggered at any time.

The ESB proposes to take forward the third option for consultation and stakeholder feedback. While all capacity mechanisms are likely to impact on market incentives, the ESB considers using actual availability during periods of system stress was a mechanism worth exploring in the NEM context. A high-level description of these models and the strengths and weaknesses considered by the ESB are explained below.

7.1.1. Performance obligation based on expected availability during time-based performance windows as determined by AEMO

Description of option 1

What must capacity providers do to receive payment – capacity providers must have an expected availability to deliver during the time-based performance windows determined by AEMO (for example, in summer between 4 pm and 9 pm). Expected availability means that, at the time of assessment (say, one week in advance), the capacity provider must be ready to perform on the relevant day. This could include being Project Assessment of System

Adequacy (PASA) available (with short-term PASA (ST PASA) requiring fuel availability for dispatch within 24 hours' notice) or bid availability for the relevant day using offers that were used during this one week. The closing offer is irrelevant because of this ex-ante assessment.

What's the assessment – ex-ante (prior to the relevant day). If a capacity provider is available in ST PASA it would qualify for payment. In this model, it does not matter if a capacity provider experiences an unplanned outage or cannot dispatch on the day. There is no post-event assessment for capacity payments.

When does the obligation apply – only during time-based performance windows determined by AEMO, regardless of whether or not there is a period of system stress or high prices.

International examples – this model is most similar to the Californian capacity mechanism.

Assessment of option 1

On balance, the ESB Board did not endorse this option for further detailed design as it does not reward actual contribution to reliability events at other times of the year and is highly dependent on the correct selection of appropriate time-based window(s).

Strengths	Weaknesses
- Targets the time periods when AEMO expected the system need to be greatest - Expected performance minimises the likelihood that capacity providers be considered non-compliant for issues outside their control - Clarity on when obligations would apply and provides certainty for outage planning	- Does not directly account for and reward performance in unplanned system stress outside of pre-specified time windows - Does not require actual contribution to reliability - Capacity providers may be paid regardless of their contribution to reliability events - Requires ex-ante compliance assessments that have a high regulatory burden

7.1.2. *Performance obligation based on exposure to spot prices above a certain threshold that may be triggered at any time.*

Description of option 2

What must capacity providers do to receive payment – capacity providers are awarded a capacity certificate and receive the capacity payment at the beginning of the delivery year. Capacity providers are required to pay difference payments in instances where the spot price exceeds a strike price. If a capacity provider is dispatched, it uses its spot revenue to pay the difference payments. However, if it is not dispatched, it must pay difference payments without spot revenue. Therefore, this is an automatic and self-executing scheme that gives capacity providers a strong incentive to dispatch during periods of high prices.

What is the assessment – no assessment is needed aside from the requirements for participating in the capacity auction.

When does the obligation apply – capacity providers must make difference payments whenever the spot price exceeds a certain threshold, this could occur at any time in the delivery year.

International examples – most similar to the Irish and Italian markets that use reliability options.

Assessment of option 2

On balance, the ESB Board did not endorse this option for consultation as the impacts on the contract market may be significant and this model has been used internationally in

jurisdictions without a sophisticated contract market. Further, it is most likely to be effective through mandatory participation. This may make it difficult for the capacity mechanism to accommodate a mix of eligible and ineligible resources to align with jurisdictional principles.

Strengths	Weaknesses
• High spot price exposure creates a strong incentive to generate at key times • Recognises capacity providers best placed to plan maintenance to minimise difference payments throughout the delivery year • Rewards for actual contribution to reliability events with firm dispatch • Strongest incentive scheme with real costs for non-performance larger than the size of the capacity payment • Automatic difference payments remove the need for a compliance assessment. This option has the lowest burden for the AER to monitor and enforce the obligation.	• Unknown magnitude of impact on risk management and contracts market (likely replace cap contract market) • Likely requires a high proportion of participation and accurate demand forecasting for procurement to be effective • Without firm transmission access rights capacity providers may have adverse bidding incentives or not be dispatched for reasons outside their control • Replaces retailer management of high price risks with centralised procurement of hedges • Reliability options have only been used in markets without a highly liquid market to manage risk. This is the largest risk of this model to the NEM that has a well established market for managing risk

7.1.3. Performance obligation based on availability during actual lack of reserve events that may be triggered at any time.

Description of option 3

What must capacity providers do to receive payment – the capacity payment can be awarded in two parts for availability throughout the delivery year and for being bid available during periods of system stress. Where a capacity provider is available it receives the initial part of the capacity payment. Where a capacity provider bids available during periods of system stress such as an actual LOR2 or LOR3 it would receive the final part of the payment. The balance between the two payments will shape the additional incentives and rewards provided under this model. This relative weighting is described in section 7.3.

What is the assessment – For the initial payment availability is assessed across the capacity payment period at regular intervals. By virtue of the fact the capacity provider is available it will receive a payment. For the final payment, following an actual system stress event, the capacity provider's actual bid availability is measured. If the capacity provider's bid availability meets its de-rated capacity, it receives the final part of the capacity payment.

When does the obligation apply – At all times for the initial payment. For the final payment capacity providers must be bid available during actual LOR2 or LOR3 events, whether or not they are forecast in advance, at any time in the delivery year.

International examples – most similar to the GB capacity mechanism with some significant departures. The GB mechanism requires firm dispatch in system stress events with four hours notice – effectively like an option for the market operator to issue directions in times of system stress.

Assessment of option 3

The ESB proposes this option for consultation and further development as it was most likely to work with the existing energy market.

The ESB considers an availability requirement is more likely to work with current market incentives, especially in circumstances where system stress events do not require all procured capacity to be dispatched (such as LOR2).

Strengths	Weaknesses
- Minimal disruption to existing spot incentives and additional incentives from bidding availability create a strong driver to generate at key times - Leverages spot incentives with an added driver to bid available into the market at times of stress - While likely significant, should have the smallest impact on contract market operation of the options considered	- Without firm transmission access rights, capacity providers may not be able to be dispatched for reasons outside their control - Requires a compliance assessment for capacity providers to qualify for payment. Regulatory burden is higher in a two-part payment model

Questions for stakeholders

- Q1 Do you have preliminary views on compliance obligations for capacity providers?
- Q2 Do you have views on compliance obligations for new entrant capacity in advance of the delivery year?
- Q3 Do you support the ESB's proposed performance model for consultation? If no, what other proposed model would be better and why?

7.2. Stakeholder responses to the initiation paper

Some stakeholders provided responses on compliance and penalties. The ESB considered these perspectives in developing the high-level compliance regime and performance obligation for consultation.

Eleven submissions commented on this area with the majority of submissions preferring automatic incentives over penalties for capacity provider performance obligations. Around half of these highlighted the importance of real-time wholesale market links with some explicitly supporting reliability options.

Stakeholders also raised some capacity provider obligation issues to be considered:

- rigorous ex-ante assessment plus real time incentives
- only focus on expected (not actual) performance
- instances outside the asset owner's control should not result in penalties
- real time non-delivery requirement rather than just an ex-ante assessment
- robust penalties for non-delivery larger than the clawback of the capacity payment
- raised the question of how unforeseen shortfalls should be dealt with.

Some of the issues raised conflicted with one another on the expectations on capacity providers and the ESB has sought to navigate all perspectives raised carefully.

7.3. Key compliance issues for detailed design

The ESB is considering option 3 and seeking stakeholder views on this to inform detailed design. This section describes some issues the ESB is considering and preliminary views. The ESB welcomes stakeholder perspectives for a performance obligation that drives operational incentives and supports a culture of compliance for all capacity to work in the current energy market.

7.3.1. Designing the performance obligation

Capacity providers availability, and subsequent bidding, should directly impact its eligibility to participate in the capacity mechanism and receipt of capacity payments.

- **Being available** – if a capacity provider is expected to be on long term outage or mothballed in the period for which capacity is being procured, it should not be permitted to participate in the auction process. If a capacity provider is awarded a capacity certificate, and its availability is low during the delivery year, it should receive a reduced payment.
- **Bid availability** – capacity providers have an incentive to be available for dispatch in periods of system stress or will only receive a partial payment in the capacity mechanism if they are not. That is, not bidding available or being on any form of outage (planned or unplanned) would result in a capacity provider not receiving the portion of payment that rewards response to system stress events.
- **Periods of reliability or system stress** – the ESB is considering minimum reserves below a certain threshold and may be during actual LOR 2 or LOR 3. The ESB's initial view is that this should include all instances of actual LOR2 and LOR3 reliability events, regardless of whether or not they were forecast in advance. Therefore, each event forms a part contribution to the annual capacity payment value encouraging capacity providers to make outage and operational decisions to maximise availability during periods where they may expect system stress.

Several trade-offs were considered for the performance obligation for capacity providers:

- **Burden of the obligation** – ranging from being available in MT PASA (i.e. not mothballing), ST PASA availability, bid availability or dispatch.
- **Lead time for preparedness** – ranging from all actual events that may be unforecast, only forecast events, or defined time windows known at the time of the capacity auction.

The ESB considers capacity providers should be incentivised to take steps to make assets available on a best endeavours basis to meet system stress events. This means rewards should be tied to taking all reasonable steps to maintain the asset to perform when its needed.

Nonetheless, additional value should be made available to capacity providers that “turn up” at times of system stress. In this way, the capacity payments could act as a reward for achieving expected average availability and for meeting specific availability.

The ESB's proposal considers that bid availability better complements a system stress trigger as capacity providers' availability contributes to the minimum reserve margin and the trigger of LORs. Capacity providers have control over their bid availability and the contribution of that to either increasing the minimum reserve margin (if bid available) or lowering it and triggering a LOR event (if not bid available). Firm dispatch does not directly relate to an actual LOR. Therefore, a requirement for firm dispatch in response to LORs may result in adverse bidding incentives and result in capacity provider's seeking uneconomic dispatch to ensure they receive the capacity payment.

Questions for stakeholders

- Q25 Are there any issues with using LOR2 and LOR3 as the trigger for capacity payments? If yes, please explain the issues and any alternative triggers.
- Q26 How would an appropriate methodology year-round availability be determined?

7.3.2. Capacity payment

In the context of option 3, the ESB is considering payments based on both availability during the delivery year (that is, not mothballing or being out for maintenance for a significant part of the year) and bid-availability during times of reliability system stress. A capacity provider will receive payment if it performs, and risks not receiving the capacity payment if it underperforms relatively to clearly defined expectations.

The drivers of performance include both the opportunity cost of lost capacity revenue and the opportunity of high spot prices. A critical part of the detailed design will be determining what a 'high' spot price would look like. That is, what settings would need to be in place to drive performance while ensuring capacity providers do not receive revenues for services that have not been provided.

The ESB is considering the eligibility for the capacity payment could be partly based on availability throughout the year and partly for contributing to system stress events. The greater the portion of the first part of the payment, the more revenue certainty it gives to capacity providers. On the other hand, the greater the portion of the second part of the payment, the less likely consumers are to pay for underperforming capacity providers who do not contribute to reliability. The ESB has not formed a view on what this relative weighting should be and is interested in stakeholder views.

How the response to events is rewarded in practice is a little more complex. A capacity provider's incentive to respond to events and receive the second part of the payment is highly dependent on the event/s chosen and their relative weighting, and the number of events in a delivery year.

- **Event/s chosen** – the ESB is considering LOR2 and LOR3 performance thresholds and consider it be more reasonable to reward LOR3's with a higher value than LOR2. This may be achieved by considering response to LOR3 events is 50 per cent more valuable than responding to LOR2 events.
- **Number of events in a delivery year** – the ESB is considering distributing the second part of the capacity payment across all events in a delivery year. If there are very few events, the contribution to events will have a larger capacity payment, if there are many events then the contribution to each event will be smaller. If there are no events, this will then be paid to the capacity provider in a lump-sum. The ESB may consider certificates that cover the delivery year or quarterly but notes there is additional regulatory burden associated with quarterly periods.

The ESB anticipates that payments will be made throughout the year with a true-up at the end of the delivery year based on the actual number of events and payment for each. AEMO may anticipate the number of LOR2 and LOR3 events that are likely to occur in a delivery year, and then allocate a relative weighting of responding to each event. The ESB is considering whether an upper threshold of events may be appropriate.

However, if there are no events in a delivery year, a self-assessment by each capacity provider will be used to assess eligibility for payment.

The ESB may also consider rewarding capacity providers only for responding to system stress events. While this would be a relatively simple approach, it would effectively serve as a price adder like the Texas market and may increase the risk of revenues to events that are likely already valuable.

Questions for stakeholders

- Q27 Do you support the ESB considering capacity payments based on availability throughout the year and during periods of system stress?
- Q28 If you support payments based on two factors, what is the preferred distribution of the first and second payment? Should more or less weight be given to responding to events?
- Q29 To support revenue smoothing, should the ESB consider grouping events within the delivery year? If yes, what frequency (such as quarterly or monthly) is appropriate?
- Q30 Should an upper threshold of performance events in a delivery year be considered? If yes, what is an appropriate threshold?

7.3.3. Costs of underperformance to the capacity provider

A capacity provider may underperform in the capacity mechanism relative to its de-rated capacity if it is not bid-available during actual reliability system stress events. There are several implications of underperformance:

- not receiving capacity payments
- lack of contribution incorporated into capacity de-rating for future delivery years.

The ESB does not propose non-performance in and of itself to result in a potential enforcement action (that is, the forfeiture of capacity payment is the consequence, not a court-ordered penalty).

7.3.4. Compliance assessment should be minimal but leverage existing obligations

An effective incentive scheme should be automatic and self-enforcing. The ESB focused on conditions to qualify for capacity payments in designing an incentive scheme. That is, non-performance will result in the loss of capacity revenue but not directly result in the subsequent risk of the AER pursuing civil penalties on this basis.

However, the proposed performance obligation is not entirely automatic. To effectively work with the existing market, a small post-event assessment is required for capacity providers to qualify for payment. If payment is based on availability throughout the delivery year and contribution to events, two checks are needed for a capacity provider to qualify for payment:

- **Being available** – should include a check of availability (as defined in the regime, which is an issue requiring further consultation) for the delivery year. Availability requirements, linked to de-rating factors, need to allow for maintenance planning. Following this assessment, the capacity provider will be eligible to receive this part of the capacity payment through standard settlement processes. This step is not needed if a single-payment approach is preferred.
- **Bid availability in response to actual events** – after a reliability system stress event occurs, a capacity provider's actual bid availability during the event is assessed. If the capacity provider is bid-available, it will receive the second part of its capacity payment. If the capacity provider is not bid-available, it will not receive the second part of its capacity payment.

While the additional capacity payment assessment is likely to be small, the information capacity providers must provide will fall under the AER's existing compliance monitoring arrangements in the spot market. This includes but is not limited to:

- the provision of accurate and timely information in the form of bids and offers
- offers, bids and rebids must not be false or misleading.

Civil penalties for breaches of the NEL carry maximum penalties for corporations of \$10 million.¹⁹

The ESB considered an availability performance obligation balanced the burden of the obligation. However, availability has some significant enforceability weaknesses as it may be difficult to verify the accuracy of the information. In the capacity mechanism, some instances may occur where a capacity provider is bid-available in response to a LOR2 event but is not called upon for dispatch. The ESB considers self-reporting in these instances may be effective in increasing transparency and foster a culture of compliance with the mechanism. The AER took this approach in response to contingency FCAS compliance issues.

Questions for stakeholders

- Q31 Are there any other interactions with the existing energy only market that the ESB should consider when designing the capacity mechanism performance obligation?
- Q32 Are there any other compliance issues the ESB should be mindful of in detailed design?

7.3.5. Primary bid-availability and dispatch incentive

The ESB's proposed performance obligation seeks to leverage existing market incentives. As such, there are two main incentives for performance: the spot price in the energy market and collecting additional payment for bid availability in periods of system stress. The price settings and importance of the market price cap are described later in this section.

7.4. Other compliance issues for detailed design

In addition to the design features explained above, the detailed design of the performance obligation will also consider the implications of the design on:

- other market reforms being considered by governments, ESB and the AEMC
- markets for managing risk such as the contracts market.

Questions for stakeholders

- Q33 Are there any other implications the ESB should consider in detailed design?

7.5. Impact of performance obligation on other design decisions

7.5.1. Interaction between the capacity certification and performance obligation

There is an interaction between how capacity is de-rated for the purpose of awarding capacity certificates and how capacity performs during actual performance events. For example, if the time periods (and associated seasonal and weather conditions) against which capacity is de-rated (the 'at-risk periods' discussed in section 5.3) are substantially different from the actual compliance events (e.g. LOR events discussed in this section), then capacity may have been over-or under-awarded capacity certificates relative to its actual performance.

As noted in section 5.3, alignment between the at-risk periods for the purpose of de-rating and the compliance events is desirable. However, there may be other reasons to adopt a more simplified approach to defining at-risk periods, including transparency and replicability of the de-rating methodology for stakeholders.

¹⁹ Civil penalties for breaches of the National Energy Laws increased from 29 January 2021. Maximum amounts will be indexed every three years to ensure their deterrent value is maintained.

The ESB recognises the form the performance obligation takes has implications for how ‘at-risk periods’ are defined and the de-rating methodology. The ESB is seeking stakeholder views on this interaction.

Questions for stakeholders

- Q34 What is the appropriate combination of performance obligation and capacity de-rating methodologies?
- Q35 Should de-rating be based on pre-defined time periods or a forecast of when the anticipated trigger periods are expected to occur?
- Q36 Given VRE is likely to be particularly affected by any mismatch in the forecast and actual conditions during performance events, should special consideration be given to VRE’s compliance with the performance obligation?

7.5.2. Market settings in the spot market and the capacity mechanism

The ESB will consider the criteria and level for the market settings in both the capacity mechanism and spot market. Under the current market framework, the market settings are set to provide financial incentives for investment and operational decision-making that are sufficient to achieve the reliability standard. It also plays an important role in providing contracting incentives for assets and price signals for storage and demand response.

Depending on the design, a capacity mechanism could deliver a varying proportion of capacity providers’ required annual revenues to enter and remain in the market, as it unbundles capacity and energy revenue. Ensuring a sensible mix of payments and incentives for capacity and for generation is a key issue when considering introducing a capacity mechanism. This will be an important issue for ongoing consultation and analysis.

The ESB will need to determine if the MPC should be lower than it would be in the absence of a capacity mechanism. In considering this issue, the ESB will focus on issues including incentives for real-time generation through the wholesale market; impacts on resources that are ineligible to participate in the capacity mechanism (or which contribute significant energy but less capacity) and whole system costs. The ESB will carry out a detailed assessment of this issue as part of the detailed design, including quantitative analysis.

Questions for stakeholders

- Q37 Do you think the MPC should be reduced if a capacity mechanism is introduced, and if so, by how much? What key issues should the ESB take into account when considering this issue?

7.5.3. Interaction between network constraints and performance obligation

Capacity providers do not have firm access to the network. As a result, market participants may be unable to be dispatched and therefore unable to bid available if there’s network outages out of their control.

The ESB’s congestion management model seeks to resolve this and the inter-state trading section explores how interconnectors may be considered in the capacity mechanism. However, without network access, firm dispatch (or even bid availability) obligations may create adverse bidding incentives or result in capacity providers being non-compliant for reasons outside their control or to undermine the bid-dispatch model as capacity providers may submit offers they are unable to honour.

8. How will costs be allocated?

Summary

Under a centralised procurement approach, there needs to be a way for the central body to allocate costs of the capacity mechanism to consumers. Cost allocation can be achieved via retailers or network service providers (NSPs).

The ESB proposes that AEMO could recover costs of capacity via retailers using actual demand (ex-post) during periods where the capacity performance obligation applies. Key reasons include:

- Recovering costs from retailers can be incorporated into the settlements and prudential requirements and reduce the likelihood of cashflow issues for AEMO.
- Recovering costs from retailers using actual demand incentivises retailers to use demand response to reduce their load in critical periods.
- Without significant benefit, non-competitive participants that are subject to revenue determinations (i.e. NSPs) should not be involved in competitive elements of the market.

Issues for detailed design include the formula by which costs will be allocated to retailers

8.1. Cost recovery through retailers versus NSPs

Under a centralised procurement and forecasting approach, AEMO would determine the total quantity of certificates required in a region to meet reliability requirements. This will establish a contract between AEMO and the capacity provider, and AEMO will make payments to capacity providers under these contracts. An additional step is needed to facilitate the cost allocation from AEMO to consumers.

The ESB has considered two options for cost allocation in a centralised capacity mechanism – either through retailers or NSPs. The ESB proposes costs be recovered through retailers.

The ESB's preference is for AEMO to recover the costs of procuring capacity through market customers (retailers and other large users) through the NEM settlement process. This approach is simpler, well understood in the NEM and will allow retailers to manage their costs by actively managing their customers' demand.

8.1.1. Recovering costs through retailers

Cost allocation through retailers using actual demand could be configured to allow for a simple per MWh approach using AEMO settlements. This approach would align with the current operation of the energy market and ensure that costs are allocated in a timely way to customers during the relevant period. It also allows for subsequent meter data revisions to be incorporated.

As part of the detailed design, the ESB will consider ways to incentivise retailers or large customers to minimise their demand in real-time. Further, the design could consider an approach where retailers can manage some or all their liability and could lead to a more efficient outcome than an apportionment approach.

8.1.2. Recovering costs through NSPs

Alternatively, costs in a centralised approach could be allocated through distribution and transmission network charges. Similarly, this could be a relatively simple approach, and NSPs are familiar with cost pass-through schemes. However, this approach has significant disadvantages that make the approach complex, including:

- regulatory burden associated with giving regulated market participants additional roles, which will be considered in its revenue determinations
- additional complexity associated with NSPs incorporating costs into annual tariff proposals based on estimates with subsequent annual true-ups using actual outcomes
- funding and cashflow issues for AEMO, where it will need to pay capacity providers and then subsequently recover the costs from NSP businesses
- no incentives to reduce demand at critical times.

8.2. Summary of stakeholder feedback

Stakeholder feedback to the Initiation Paper on this issue was limited as the ESB did not expressly outline cost recovery in a centralised mechanism. However, in subsequent discussions with the Advisory Group, there has been significant support for costs to be recovered via retailers and other direct market customers rather than through NSPs.

8.3. Implications for detailed design

The ESB will consider the way costs will be calculated and allocated in detailed design.

The formula by which costs are allocated to retailers needs to ensure that:

- retailers can predict the costs that will be passed onto them, in timeframes that allow them to incorporate them into tariffs
- ideally, incentives are created for retailers to seek to minimise peak demand.

Internationally, the Great Britain scheme recovers costs against retailers based on their contribution to peak consumption in the system (measured in megawatt hours) through a monthly charge. In the WEM, retailers are allocated their share of capacity costs by AEMO ex post, according to their contribution to system peak conditions in the previous delivery year.

Question for Stakeholders

Q38 Do you agree that costs should be passed on via retailers, rather than NSPs?

Q39 What do you consider to be the most appropriate mechanism to allocate costs to retailers?

9. How is transmission capacity reflected in the capacity mechanism design?

Summary

The transmission network impacts the ability of capacity providers in one part of the grid to meet demand in another location. The ESB is separately considering how inter- and intra-regional transmission capacity could be reflected in the capacity mechanism design.

This consultation paper focusses primarily on the proposed treatment of inter-regional transmission capacity. This is because the approach to intra-regional constraints will need to be aligned with the congestion management mechanism, for which a variety of design options are still being considered.

The ESB considers that the capacity mechanism should recognise inter-regional resources when determining how much capacity, and which capacity providers, will be procured to meet demand within a region. This promotes efficient sharing of resources between regions, which will be important in a system increasingly dominated by VRE.

The ESB proposes two broad approaches to recognise inter-regional capacity. These are:

- Only capacity located within a region would be allowed to be procured to meet that region's capacity requirements. However, capacity requirements for each would be adjusted to reflect expected interconnector flows during periods of system stress (i.e., inter-regional resources would be recognised, but not procured). This would be by far the simplest approach.
- Capacity providers located in one region would be eligible to sell capacity to meet reliability in another region (i.e., eligible for procurement). This adds considerable complexity, but would more appropriately reward resources in one jurisdiction that provide capacity support to a neighbouring region. The ESB would prefer this option, subject to ensuring a workable and cost-effective way of incorporating these resources can be identified.

These options will be considered further in detailed design, including sub-options on how to enable capacity providers to sell capacity between regions.

The transmission network impacts the ability of capacity providers in one part of the grid to meet demand in another location. Therefore, the capacity mechanism design needs to account for transmission constraints when determining which capacity resources can be procured to support reliability during system stress events, to ensure both reliability of supply and efficient investment in capacity. If transmission system capacity is not appropriately reflected in the design, the capacity mechanism may either:

- Underestimate the available capacity to meet demand in a given location. If each region is considered a separate market, then the amount of capacity potentially available from neighbouring regions is ignored. This means that more local capacity would need to be procured, leading to higher costs for consumers. Further, capacity providers would be unable to be appropriately remunerated, despite the presence of spare generation and transmission capacity.
- Overestimate the available transmission transfer capacity during scarcity periods, leading to a greater risk of a reliability shortfall.

9.1.1. The ESB is separately considering intra- and inter-regional transmission capacity

Given the regional design of the NEM, the ESB is separately considering how inter- and intra-regional constraints could be reflected in the capacity mechanism design. Inter-regional constraints occur between NEM regions, while intra-regional constraints refer to transmission system congestion within a region. While the capacity mechanism does not need to account for inter- and intra-regional constraints in precisely the same way, the approaches need to work effectively together.

This consultation paper focusses on the treatment of inter-regional transmission constraints. This is because the approach to reflecting intra-regional constraints in the capacity mechanism will need to be informed by and aligned with the work being undertaken in the transmission access reform workstream. As multiple design options for transmission access reform are still being worked through, this consultation paper does not consider design options for the treatment of intra-regional transmission constraints. The ESB will consider these issues concurrently when considering its detailed design proposal.

9.1.2. Interactions with other design decisions

Other capacity mechanism design decisions impact how transmission network capacity should be accounted for. These include: the approach to de-rating capacity resources and the definition of at-risk periods; the capacity procurement model (centralised or hybrid); the auction design; and compliance obligation and incentive arrangements.

The ESB considers that the treatment of transmission constraints is secondary to these decisions. In other words, while the treatment of constraints in the capacity mechanism will need to be made compatible with these broader design decisions, it will not drive those decisions. Therefore, the design options discussed here may change as other aspects of the design evolve.

9.1.3. Summary of relevant stakeholder feedback, and how this informed the Board's decision

In the initiation paper, the ESB noted two broad options for incorporating transmission constraints into the capacity mechanism design:

- A 'de-rating' approach, which involves AEMO de-rating generation and/or interconnector capacity on a prorated basis to reflect the transmission constraints which are likely to bind during system stress events for the forecast timeframe into the future.
- A 'locational pricing' approach under a reliability options model, whereby exposure to reliability option difference payments would incentivise capacity providers to account for transmission constraints when determining how much capacity to sell.

Since the initiation paper the ESB has decided not to pursue a reliability options model. Therefore, the ESB is no longer considering a locational pricing approach for incorporating transmission constraints into the capacity mechanism. Some stakeholders highlighted their preference for using a de-rating approach.²⁰ This is discussed with regards to the treatment of inter-regional transmission constraints below and will be examined as part of detailed design.

²⁰ Snowy Hydro, Origin,

Stakeholders highlighted the need to consider work on the congestion management mechanism and the overlap with transmission constraint considerations under the capacity mechanism design.²¹ These issues will be kept in mind as the detailed design progresses.

Stakeholders outlined the need to consider the firmness of access and the use of inter-regional settlement residues.²² These issues are discussed below and will be further explored as part of detailed design.

Stakeholders noted the role of market network service providers (MNSPs) and the potential role for new network investment as a participant in the capacity mechanism.²³ The potential for MNSPs to participate is explored below and will be further considered as part of detailed design. The scope for participation by new network investment will depend on the approach to the treatment of regulated and market interconnectors in the capacity mechanism, and will be considered further as the detailed design progresses.

9.2. Issues that will be the focus of detailed design

There are two high-level questions which need to be addressed in relation to how inter-regional transmission constraints are accounted for in the capacity mechanism design:

- Should inter-regional capacity be explicitly procured and remunerated through the capacity mechanism?
- If yes:
 - How should inter-regional capacity be procured?
 - Should interconnectors participate in the procurement of inter-regional capacity?

These issues are considered in the following sections.

9.3. How should resources in one region that contribute capacity to a neighbouring region be treated?

The ESB has identified two high-level options to address this question:

- **Option 1 – recognise inter-regional transfers in the capacity requirement:** In this option, only capacity located within a region can be procured to meet the capacity requirements of that region. However, expected interconnector flows during periods of system stress would inform each region's capacity requirement.
- **Option 2 – explicit procurement of inter-regional resources:** Allow explicit procurement of inter-regional capacity. Capacity providers located in one region would be eligible to sell capacity to meet reliability in another region. These capacity providers would receive an inter-regional capacity contract, with compliance obligations tied to the region they are supplying.

The ESB supports Option 2 in principle, but notes that it adds considerable complexity to the overall design. In particular, if Option 2 is preferred, decisions will then need to be made on how inter-regional participation will be managed, and which entities are allowed to participate. Therefore, further consultation and analysis is required to ensure a workable and cost-effective method can be identified before Option 1 can be ruled out.

²¹ Shell, EUAA, AEC,

²² AEC,

²³ CS Energy, AEC

The options, and their relative merits, are discussed in more detail below.

9.3.1. Option 1 – Recognise inter-regional transfers in the capacity requirement

The reliability gap is based on the ESOO, which accounts for interconnector flows in and out of a region in determining the reliability gap or surplus. In other words, the expected overall direction of interconnector flows is already factored into the amount of capacity that is required for the region to meet the reliability standard.

Under Option 1, AEMO would procure the target capacity for a region from participating capacity resources that are located within that region.

9.3.2. Option 2 – Explicit procurement of inter-regional resources

This option involves explicit procurement of inter-regional capacity. Under this approach, capacity providers located in a neighbouring region would explicitly participate in the capacity mechanism. Resources that are procured to support reliability in a neighbouring region would receive an inter-regional capacity contract, with compliance obligations tied to the region they are supplying.²⁴

The way that an inter-regional capacity contract works depends on the broader capacity mechanism compliance regime. The ESB is proposing that compliance will be based on availability throughout the year (according to de-rated capacity) plus availability during a LOR2 or LOR3 event. The following discussion of inter-regional capacity procurement is based on this compliance model. If a different compliance framework was proposed, such as a reliability option model, there would be different implications for inter-regional capacity procurement.

9.3.3. Assessment of the options

Under Option 1, only capacity resources that are located in a region can be procured to meet that region's capacity requirement. If the capacity of existing resources in that region is not sufficient to meet demand (after account for imports and exports), new capacity resources may need to be procured. However, it may not always be efficient for new capacity to be located in the region where there is a reliability gap. Further, new capacity resources may be able to support reliability in multiple regions. By allowing inter-regional resources to participate directly, Option 2 may better promote new capacity resources being sited in the best location.

Under Option 1, capacity resources may hold a contract that is tied to the region that they are located in, even though their capacity may be exported to a neighbouring region. This creates two issues that would need to be addressed if Option 1 were selected:

- Firstly, under Option 1 there would be no explicit obligation for capacity providers to offer capacity when required by a neighbouring region. Consequently, obligations for these resources may not be aligned with the reliability requirements of the region that they have been (implicitly) procured to support. In contrast, under Option 2, if a resource is procured to support reliability in a neighbouring region, it will hold a capacity contract that is linked to the requirements of that region (e.g., compliance would be assessed based on availability during LOR2/LOR3 events declared in that region).

²⁴ There are several sub-options for how inter-regional capacity is procured and which entities (capacity providers, MNSPS, and/or regulated interconnectors) should participate. These options are discussed in Sections [1.4] and [1.5].

- Secondly, Option 1 would effectively increase the capacity requirement of an exporting region, although exports benefit a neighbouring region. Therefore, a mechanism to allocate the cost of these resources to that neighbouring region may need to be considered.

A further difference is that Option 2 requires AEMO to form a view to de-rate the interconnector flows during periods of system stress. Interconnector flows are a product of interconnector capacity, but also the availability and dispatch of capacity resources. Therefore, projections of interconnector flows may be volatile and this has been an issue in the GB mechanism. Under Option 2, AEMO is still required to estimate interconnector capacity at times of system stress, which may be a complex task. However, capacity resources on either side of the interconnector commit themselves to being available when required. This may reduce forecasting uncertainty around the availability of inter-regional resources, relative to Option 1.

A potential advantage of Option 1, relative to some versions of Option 2, is reduced operational complexity for capacity mechanism participants. In some of the Option 2 variants discussed below, participants may be required to account for inter-regional transmission constraints themselves by, for example, securing a transfer right that demonstrates their eligibility to provide inter-regional capacity.

In summary, the ESB supports Option 2 in principle, as it results in appropriate remuneration and obligations for capacity resources that support reliability outside their own region. However, the ESB also notes that this adds considerable complexity to the overall design.

Questions for stakeholders

- Q40 Do you think that Option 1 or Option 2 better meets the assessment criteria?
- Q41 Are there any other factors that the ESB should consider when assessing the relative merits of the options?

9.4. How should inter-regional capacity be procured?

If Option 2 is adopted, meaning a decision is made that inter-regional capacity should be explicitly procured, decisions will then need to be made on how the participation of interstate capacity resources will be managed. Specifically, the capacity mechanism design would need to ensure that interstate capacity sales are consistent with the inter-regional transmission capacity that is expected to be available at times of system stress.

The ESB has identified two potential options for ensuring that interstate capacity sales do not exceed expected inter-regional transmission capacity:

- **Option 2(a) - transfer rights:** Under this option, the maximum volume of interstate capacity sales is restricted *before* capacity is procured. To be eligible to sell inter-regional capacity, capacity providers must acquire an inter-regional transfer right (Box 5 below) between their region and the region they are supplying capacity to. Capacity providers would only be able to sell interstate capacity up to the MW volume of the transfer right that they hold. The total volume of transfer rights available to capacity providers would be limited to the de-rated inter-regional transmission capacity that is expected to be available between the regions at times of system stress.
- **Option 2(b) - transfer limits:** This option assumes that capacity is being procured through a centralised auction operated by AEMO. Under this method, interstate capacity sales are restricted by the de-rated interconnector limits *through the auction algorithm*. Capacity providers would submit bids to AEMO without needing to hold a transfer right or specifically nominate which region they are offering capacity to. AEMO would then

purchase the lowest cost combination of capacity bids to meet the capacity requirement in each region, subject to the constraint that interstate capacity sales cannot exceed predefined inter-regional transfer limits. This means that the award of inter-regional capacity contracts would depend only on bid prices and not on which entities hold transfer rights.

Box 5 Transfer rights

In the context of the capacity mechanism, a requirement to hold a transfer right limits how many inter-regional capacity contracts can be sold. The purpose of a transfer right is therefore to allocate expected interconnector capacity between participants, ensuring that any inter-regional capacity procured is consistent with the physical transmission system.

In the NEM currently, a form of inter-regional transfer right is available through the settlement residue auction (SRA) process. Through the SRA, eligible parties are able to purchase the right to receive a portion of the inter-regional settlements residue that accrues through the operation of the spot market. The rights that parties can purchase are referred to as settlement residue distribution units (SRD units). Under the current RRO, liable entities can use inter-regional contracts to meet their obligations by pairing these contracts SRD units.²⁵

In principle, SRD units could be used to limit interstate capacity sales. However, SRD units may not be appropriate for this purpose:

- The capacity mechanism does not require transfer rights that provide a financial link to spot market prices. This is because the proposed capacity mechanism compliance arrangements relate to availability, not physical dispatch.²⁶ Indeed, NEM participants may use SRD units to support their energy market transactions, it may be best that they are reserved for this purpose rather than being linked to the capacity mechanism.
- The current schedule for auctioning SRD units may not correspond to when capacity providers would need to acquire transfer rights to participate in the capacity mechanism.
- SRD units do not have a fixed MW volume. In principle, an equivalent MW volume could be determined based on anticipated interconnector flows at the time the capacity obligation is likely to be binding.²⁷ This may be overly complex in the context of the capacity mechanism design.

Therefore, the ESB anticipates that if transfer rights were used to manage interstate capacity sales, SRD units would not be suitable, and a specific form of transfer right would need to be created for the capacity mechanism.

The ESB considers that the appropriateness of transfer rights or transfer limits depends substantially on other capacity mechanism design choices. In particular, the decision will be affected by design choices in relation to:

- the procurement mechanism (i.e., centralised or hybrid)

²⁵ Further details are set out in the AER's RRO Interim Contracts and Firmness Guidelines.

²⁶ This statement assumes that a reliability options model is not adopted. If reliability options were the proposed compliance mechanism, capacity market participants might require a form of financial access to inter-regional prices to ensure that they could manage their exposure to reliability option difference payments.

²⁷ This approach is similar to the treatment of inter-regional contracts under the current RRO, as set out in the AER's Interim Contracts and Firmness Guidelines.

- the centralised auction design (i.e., NEM-wide or individual regions)
- definition of at-risk periods (i.e., NEM-wide or region-specific).

For example, under a centralised capacity mechanism where capacity requirements for all regions are cleared simultaneously, interstate transfer limits could be reflected as a constraint in the auction run by AEMO. Under a hybrid model however, retailers would be responsible for procuring some portion of their region's capacity requirement. This means that capacity purchases would be happening at different times, rather than taking place through a single centralised auction. In these circumstances, a transfer rights approach may be needed to ensure that in aggregate retailer purchases of interstate capacity do not exceed expected interconnector capacity.

Accordingly, the ESB has not yet formed a view on whether a transfer rights or transfer limits approach is the preferred mechanism to ensure that interstate capacity sales are aligned with interconnector capacity. The ESB will consider this issue further as the detailed design develops.

Questions for stakeholders

- Q42 Are there other ways to ensure that procurement of interstate capacity resources does not exceed inter-regional transmission limits, in addition to the two approaches outlined above?

9.5. Participation by interconnectors

The preceding sub-sections assume that interconnectors are passive participants. Inter-regional capacity resources were assumed to be responsible for submitting capacity offers to AEMO, with no explicit participation of interconnectors. There are two alternatives to this model. These include:

- **Option A:** Allowing all interconnectors (regulated and market), rather than capacity resources, to submit inter-regional capacity bids.
- **Option B:** Allowing only market interconnectors, rather than capacity resources, to submit inter-regional capacity bids.

In relation to Option A, the ESB considers that there is limited value in pursuing a model where regulated interconnectors are allowed to submit inter-regional capacity bids. Existing regulated interconnectors represent a sunk investment cost that is paid for by consumers through regulated transmission charges, and regulatory incentives apply to incentivise availability. New regulated interconnectors are currently developed through a separate planning and approval process. Further, the economic case for a new regulated interconnector may be linked to a range of factors other than meeting regional capacity requirements at the lowest cost. Therefore, linking the transmission planning and development process to the capacity mechanism may be complex and may not be necessary to promote timely investment in new transmission capacity.

However, the above issues do not apply to market interconnectors. These assets are not developed or funded through a regulatory process. Further, market interconnectors can control flows across their assets and are able to contract with capacity providers in the exporting region to provide capacity when it is needed. This suggests that market interconnectors could potentially participate in the capacity mechanism.

Participation of market interconnectors is contemplated under Option B. Under this model, where a market interconnector connects two regions, they would be the entity eligible to sell inter-regional capacity. Capacity resources (i.e., generation, demand response, storage) would not be eligible to sell inter-regional capacity. The market interconnector would:

- receive the capacity price for the region they are supplying capacity to.
- be responsible for delivery and face any penalties under the capacity mechanism for not meeting its obligations.

Participation of market interconnectors could in principle be combined with either the transfer rights or transfer limits options discussed in section 9.3. The table below outlines how this might operate in practice.

Table 9.1: Participation of MNSPs under a transfer rights or transfer limits model

Transfer rights	Transfer limits
The MNSP would need to demonstrate that it held contracts with interstate capacity resources that require them to make capacity available for export at times of system stress (conceptually, this might be thought of as a 'generation right' rather than a transfer right).	Under this approach, the maximum capacity the MNSP could bid would be subject to accreditation by AEMO, reflecting AEMO's view of interstate capacity resources that would be available at times of system stress.

The ESB considers that it is possible that where an MNSP exists between two regions, it could be the entity that is eligible to bid inter-regional capacity. The ESB seeks stakeholder views on the feasibility of this approach and whether it is preferable to allowing capacity resources to sell inter-regional capacity directly.

Questions for stakeholders

- Q43 Do you think that where a market interconnector exists between two regions, it should be the entity that is eligible to submit inter-regional capacity bids?
- Q44 Do you think that proposed new market interconnectors should be able to participate in the capacity mechanism?

10. Assessment of high-level design

10.1. Performance against assessment criteria

In its December 2021 Initiation Paper, the ESB set out the criteria it would use to assess capacity mechanism options. These were based on the design principles agreed by Energy Ministers in September 2021.

The proposed capacity mechanism design outlined in this paper is assessed against these criteria, below. The ESB's view is that its proposed high-level design strikes the right balance between these objectives.

In addition, the ESB has considered the compatibility of its proposed design with the principles agreed to by Energy Ministers in September 2021.

10.2. Achieving Optimal Reliability

A mechanism should achieve the level of reliability that consumers and governments value. The ESB proposes that the default target level of reliability within a mechanism be set as the reliability standard. The standard currently under review and is informed by the value customers place on a reliability supply of power, known as the VCR. The ESB's view is that all of the designs it considered would be capable of delivering reliability to a desired standard.

However, the ESB's view is that a centralised model will provide governments with more confidence and transparency that the mechanism will deliver to the standard. In addition, it is possible that jurisdictions may have different risk appetites, and could place a higher (or lower) value on reliability within their jurisdiction. If so, a centralised mechanism would enable the jurisdiction to work with AEMO to calibrate its target level of capacity to meet its expectations.

How a centralised mechanism performs in achieving optimal reliability depends on the quality of AEMO's capacity forecasting and procurement, and the incentives on capacity providers to perform. The first part of this will depend on the forecasting and procurement methods that will be developed in detailed design and will be considered further during that process. On performance incentives, the ESB considers that its proposed model performs strongly on this criterion, as capacity providers will have an incentive to deliver at all critical periods, regardless of when they occur during the year, and regardless of whether they are correlated with high price events. The ESB's view is that a mechanism that does not do this – such as by only placing an obligation at pre-defined peak periods – would not meet consumers' and governments' expectations of reliability.

10.3. Appropriate Allocation of Risk

The chief risks which the mechanism must balance are the costs of capacity, and the cost of unserved energy. Ultimately, it is consumers who experience the costs and disruption of load-shedding as well as the costs of capacity. The mechanism design determines which entity will manage these risks on behalf of consumers.

On the costs of capacity, centralised models are likely to be weaker than decentralised models. This is because the responsibility for forecasting and procuring the right level of capacity sits with AEMO, which does not bear the costs of either load shedding or over-paying. In contrast, decentralised models create an incentive for retailers to seek out the lowest costs for capacity to avoid either having to pass higher costs through to their customers than their competitors, or absorbing these costs. Similarly, retailers would have an incentive to seek out enough capacity to meet their customers' demand to avoid having to pay a penalty.

However, procurement by AEMO – with overall responsibility for system reliability – may be an appropriate point to manage the risk of unserved energy on behalf of consumers. It has the tools and viewpoint to consider reliability across the whole system, and would suffer reputationally if its forecasting or procurement led to load shedding. The concern raised by several stakeholders is that AEMO is likely to be conservative and procure more capacity than required. In this case it will be consumers that will bear the costs of being “over-insured”. However, there are design choices available that can mitigate the risk of over procurement, which the ESB is considering. These include:

- building in safeguards to AEMO’s forecasting process, for example, including an independent review
- employment of a competitive, annual auction – this will reduce this risk by exposing capacity suppliers to competition
- consideration of hybrid approaches to forecasting and procurement, to see if it is possible to retain some of the potential benefits of retailer forecasting
- passing costs through retailers rather than networks - this preserves some incentive on retailers to take steps to manage their share of capacity costs (such as by lowering their demand through demand response)

Ultimately, the ESB considers that, while market participants may be better placed to manage some of the risks, having AEMO responsible for both forecasting and procuring capacity will provide more certainty to consumers and governments that reliability gaps will be addressed.

The costs of load shedding can be substantial and result in large costs across the system and for the specific users that experience it. To address this, an intention of the ESB’s proposed high-level design is to transfer some of the risk of unserved energy onto the parties that can address the problem – capacity providers. It does this by placing a performance obligation on successful capacity providers so that they turn up at times of system stress, i.e. perform the service they have been paid for, or risk losing this payment. The performance obligation would apply whenever a system stress event occurs, meaning capacity providers would be under an obligation to turn up when needed.

10.4. Technology Neutrality

The proposed capacity mechanism design will be technology-neutral. The ESB intends that all capacity types (e.g. thermal, renewable, storage, demand response), as well as both new and existing capacity will be eligible to participate in the mechanism, and compete on their merits in auctions for capacity payments (noting that individual jurisdictions may wish to choose which technologies may participate within their jurisdiction, which is addressed separately below).

By employing a de-rating methodology for each technology type, all technology types will be able to compete on their merit in providing the desired level of capacity during reliability system stress periods.

10.5. Minimise Regulatory Burden

The ESB’s view is that a key feature of its proposed high-level design is that it minimises the regulatory burden on market participants compared to other models. By featuring centralised forecasting and procurement by AEMO it will reduce the compliance cost for market participants versus a decentralised model. This would be particularly useful for smaller retailers, because meeting requirements under decentralised approaches such as bilateral contracting with capacity providers or engaging in capacity exchange platforms could be particularly onerous. However, in exploring hybrid models, the ESB will consider whether

there is a role for market participants to take on this responsibility if it could lead to lower-cost outcomes for consumers.

Capacity providers (including generators, storage and demand-side response providers) are expected to incur the highest administrative costs by participating in the scheme. However, these transactional costs should be more than offset by additional revenue certainty realised by the capacity mechanism. Similarly, expressing the performance obligation as an incentive should also have a lower regulatory burden on capacity providers than if it was a penalty. The administrative costs for the AER should also be reduced, as it will only have to measure compliance when an obligation event occurs.

The proposed capacity mechanism design would replace the existing RRO. It will eliminate the administrative costs imposed on retailers and capacity providers (such as from submitting their contracts to demonstrate compliance or via the MLO) by that scheme.

10.6. Emissions Reduction

All Australian jurisdictions have adopted the goal of achieving net zero carbon emissions by 2050 if not sooner. Jurisdictions vary however with respect to the interim targets and supporting measures designed to achieve this goal. Ministers requested in the principles that the capacity mechanism focus on the continued emissions reduction of electricity supply, which the ESB have reflected in this assessment criterion.

As raised in Section 6.2, the ESB seeks guidance from Energy Ministers on sectoral emissions reduction in the context of net zero and the operationalisation of such guidance in the capacity market design. Guidance on this emissions reduction principle will help inform design matters including eligibility and auction design. Any emissions reduction guidance and operationalisation in the capacity mechanism will not alter, or limit, the principle that jurisdictions must be able to determine which technologies are eligible for participation in a capacity mechanism in their region.

10.7. Consideration of Ministers' principles

The ESB developed the assessment criteria above to reflect many of the principles Energy Ministers set for the capacity mechanism. However, other design principles will require careful investigation to ensure that the capacity mechanism satisfies them while meeting the objective of ensuring investment in an efficient mix of variable and firm capacity that meets reliability at the lowest cost. The ESB has considered how its proposed high-level design addressed these criteria, below.

To ensure adequate investment for capacity adequacy, the ESB considers that the preferred capacity mechanism should include longer-term support for new capacity entering the market for the first time. When offering such longer-term support, the ESB proposes that criteria be developed to ensure that the resources procured will be consistent with the NEM's transition to net zero emissions.

7. Ensure sharing of resources across the NEM by supporting inter-regional contracting

As noted in section 9, directly rewarding resources that contribute to inter-regional capacity is supported in-principle by the ESB. The mechanism will allow for capacity in one region to contribute to the capacity requirements of another region. This will ensure the efficient sharing of resources in the NEM. The ESB will consider options to enable this in the mechanism during detailed design, to ensure a workable and cost-effective approach can be designed.

8. provide greater certainty around closure dates of exiting generation

9. mitigate reliability risks presented by unexpected closures of existing capacity

10. encourage the timely replacement of existing capacity through driving commitments to new investment within reasonable notice periods of closure of existing capacity

The mechanism could support these principles by providing:

- clear signals to the market about an existing capacity provider's planned availability in the market, by its participation in capacity auctions
- a direct route to procure replacement capacity before existing capacity retires
- a revenue stream to incumbent capacity providers to fund maintenance activities, to support availability (up to contracted levels).

Holding two auctions per reliability year would accommodate both timely replacement of existing generation, as well as dealing with unexpected closures. The first auction (e.g. T-4) could align with the notice of closure period for thermal generators and provide sufficient lead time to bring new capacity. The second auction (e.g. T-1) provides a true-up point to take into account any changes that have occurred since the first auction, such as the unexpected closure of a generator in the intervening years. The ESB will also consider the best forms of support, such as long term contracts, to ensure that required new capacity is investible.

In addition, the ESB has provided advice to Energy Ministers on the design of orderly exit management contracts (OEMCs) to support bilateral arrangements between jurisdictions and exiting generators, consistent with Ministers' agreement on the Post-2025 reforms. To the extent that jurisdictions rule out particular incumbent types from participating in the capacity mechanism, OEMCs provide an alternative way of ensuring a managed transition. The ESB will consider the implications of these on capacity mechanism design, and vice versa.

11a. Jurisdictions must be able to determine, via their regulation, provided for in the National Electricity Law framework, which technologies are eligible for participation in a capacity mechanism in their region.

Ministers agreed that jurisdictions should be able to select which technologies should be eligible to participate in the scheme in their respective jurisdictions. For example, Victoria has a position that Victorian fossil fuel generators should not be eligible to receive revenues from a capacity mechanism.

Capacity zones could be set with reference to existing NEM regions (see section 5), which correspond to state boundaries (except in the case of the ACT, which is part of the NSW region). This would mean that, with the exception of the ACT, separate arrangements could be applied within each jurisdiction through local regulation. Where a jurisdiction makes such a regulation to restrict the eligibility of technologies within their jurisdiction, AEMO would incorporate this into its auction process. How this occurs will be considered in detailed design, as will how this would affect forecasting of the capacity requirement within a region – as ineligible technologies would still contribute to reliability within that jurisdiction. For example, after identifying a quantum of demand for an identified risk period, AEMO could then either:

- net out the anticipated contribution of ineligible capacity providers to meeting that demand, and tender for the remaining gap in capacity
- apply a de-rating that takes account of emissions intensity.

12. recognise relevant state and territory policies and investment schemes to account for bespoke arrangements to retain and replace existing capacity

Of particular relevance to capacity mechanism design are jurisdictional measures which provide long-term, out-of-market funding for new entrant capacity. Examples include:

- the Australian Renewable Energy Authority (ARENA)
- New South Wales Electricity Infrastructure Roadmap
- Victorian Renewable Energy Target (VRET)
- ACT Large Feed-in-Tariff scheme.

This list is not comprehensive, and ESB anticipates that other forms of financial support will emerge in response to recent policy commitments such as Victoria's Offshore Wind policy or South Australia's hydrogen CCGT.

The ESB expects these measures to remain in place after adopting a capacity mechanism and therefore, any capacity mechanism will need to integrate with these jurisdictional initiatives.

Broadly the jurisdictional support measures above fall into two categories:

- provision of up-front capital for new projects²⁸
- output-related payments²⁹.

The proposed capacity mechanism will interact with these two types of support schemes in different ways.

Where a jurisdiction provides up-front funding for a new capacity project, it is unlikely that the same capacity provider will need further support through the capacity mechanism to ensure its entry into the market (such as the long term support the ESB is considering for new capacity). It may therefore be appropriate to exclude capacity that in future (i.e. after the commencement of the capacity mechanism) receives such out of market support from qualifying as "new capacity" for the purposes of the capacity mechanism, as otherwise there is a risk that consumers overpay for this capacity. However, this capacity could still participate in auctions on the same footing as existing capacity (much of which received similar out of market support from governments) and compete for annual capacity payments, given that it would also contribute to reliability. Likewise, capacity that received such out of market support before the commencement of a capacity mechanism would be eligible to participate in the same manner as any other existing capacity.

Where the assistance takes the form of output-related payments, the interaction with the capacity mechanism will depend on the form of the agreement between the jurisdiction and the capacity provider.

Many jurisdictional schemes take the form of either a contracts-for-difference or a top up payment. These include NSW long-term energy service agreements (LTESA), VRET and ACT feed-in-tariffs. In these schemes, the jurisdiction and capacity provider agree a fixed price for the energy the capacity provider produces, with the government providing top up payments to the capacity provider whenever the spot price is below the agreed strike price.

²⁸ This includes grants, provision of project debt finance, underwriting, and government taking an equity position in a project.

²⁹ This includes Power Purchase Agreements (PPAs), Contracts-for-Difference (CfDs), feed-in-tariffs (FITs) and Long-term energy service agreements (LTESAs).

In a contract-for-difference, the capacity provider also has to pay the jurisdiction back any spot market revenue above the strike price. Conceptually, these schemes can work with a capacity mechanism. Jurisdictions could consider capacity revenues alongside spot market revenues when determining strike prices or revenue clawback arrangements for agreements entered into following the introduction of a capacity mechanism. As above, capacity providers that enter into this type of agreement with a jurisdiction after a capacity mechanism is introduced will likely need to be excluded from being eligible to receive new entrant support in the mechanism.

Existing agreements may be more complex, as these have been based on both parties' expectations of spot market prices and volatility. These may change with the introduction of a capacity mechanism, whilst capacity providers may start receiving some of their revenue through capacity payments that are not directly linked to output. The ESB will work with jurisdictions to ensure that a capacity mechanism can be compatible with existing arrangements.

Most of the above schemes were developed to target investment in particular types of capacity, such as renewable energy or specific dispatchable or storage technologies. Some jurisdictions have also developed their own reliability schemes. An example is New South Wales's Energy Security Target, which identifies the amount of firm capacity is needed to address forecast gaps in meeting peak demand. The ESB will consider the interaction between such schemes and a capacity mechanism further in detailed design. While the ESB prefers a nationally consistent approach is taken to reliability across the NEM, there may be opportunities to seek alignment between schemes or to learn lessons from work already completed or underway. The ESB will continue to work closely with jurisdictions such as New South Wales on this.

13. enable jurisdictions to opt out, via the National Electricity Law framework

14. enable jurisdictions to opt in, through triggered thresholds for the mechanism

Additionally, Ministers included in design principles the ability to enable jurisdictions to opt out via the NEL framework and opt in through triggered thresholds for the mechanism.

The mechanism will need to recognise the possibility of a jurisdiction opting out of the capacity mechanism. There are several consequences of such a scenario.

If the market price cap is changed in response to a capacity payment, the NEM would need to accommodate different MPCs in different jurisdictions depending on whether they have or have not adopted a capacity mechanism. However, inconsistent MPCs would be expected to produce both complexity for market participants and perverse incentives. For example, parties in a low MPC state will be incentivised to contract for supply to a higher MPC state, possibly in a counter-direction to their capacity contracting. Consequently, market price settings – particularly the MPC – should remain consistent across the NEM. This is because absent a capacity mechanism, these settings are critical in driving investment and ensuring dispatch at times of need.

Equally, the treatment of interconnectors will need to anticipate the potential absence of a jurisdiction. This may include a jurisdiction not allowing capacity providers or a class of capacity providers participating in the mechanism anywhere in the NEM. Managing such a scenario suggests that interconnectors' anticipated contribution be netted out of the capacity requirements for a given region. More complex approaches – in which individual participants contract interstate and manage interconnector congestion risk themselves – appear to be less robust in the face of potential jurisdictional opt-out, and will need to be considered further in the detailed design of the mechanism.

11. Next steps and implementation

11.1. Next steps

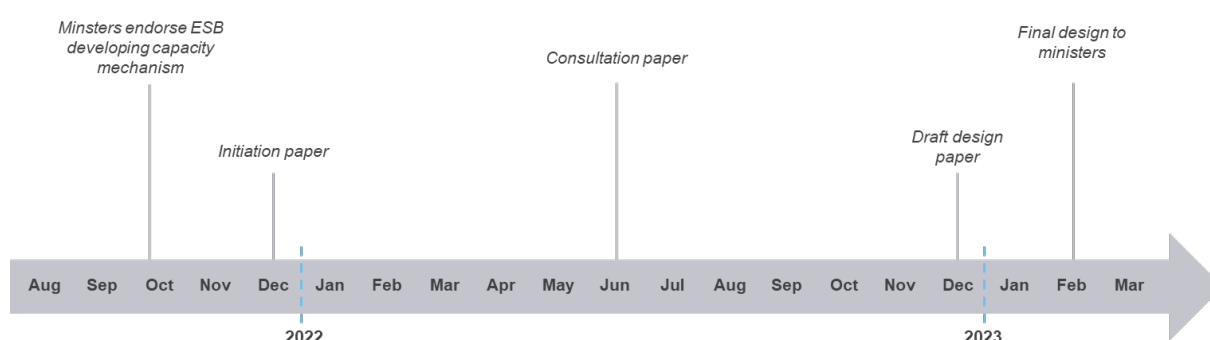
Following the publication of this paper, the ESB will:

- consult on the high-level design and issues in this paper in July 2022
- commence detailed design for the capacity mechanism.

As part of the detailed design, the ESB will consider the design choices and issues in this paper in further detail. Stakeholders' views on the questions in this paper will be a valuable input to inform the ESB as it commences with detailed design. Electricity market modelling will also inform the ESB's preferred capacity mechanism design against a base case, as well as further quantitative analysis to understand the impacts a capacity mechanism could have on the existing energy market.

The ESB will return to Energy Ministers with a draft detailed capacity mechanism design in December 2022, which will be put to stakeholders for further consultation.

Following this, the ESB will present its final detailed capacity mechanism design to Energy Ministers in February 2023, including draft legislation and Rules.



11.2. Implementation

If Energy Ministers agree to implement a capacity mechanism in the NEM, it should be operational by 1 July 2025. AEMO has projected that a reliability gap could emerge in New South Wales from as early as 2025-26, if additional investment does not occur in the intervening years, immediately following the announced withdrawal of Eraring Power Station.³⁰ This highlights the urgency of the task ahead.

At the same time, the ESB recognises that a capacity mechanism is complex and a substantial reform to the NEM. It will require time to develop the processes and systems required to administer it, and for market participants to adjust to the reform.

As set out above, the ESB intends to deliver a final detailed capacity mechanism design to Energy Ministers for agreement by February 2023. The South Australian parliament would pass the required legislative changes following Ministers' agreement to the final bill. This would need to be done in 2023, alongside the rules and procedures needed to implement any mechanism.

³⁰ April 2022 update to 2021 ESOO found [here](#)

The ESB considers this the earliest possible timeline for a capacity mechanism to be legislated. Following this, a number of systems and processes would need to be developed before the scheme could commence, including complex auction and settlement systems. De-rating and prequalification of capacity would also need to occur before the scheme could commence.

As noted earlier, the ESB is considering the length of the timing for the initial auctions. It will not be possible for an initial auction (at say T-3 or T-4) to occur ahead of the projected 2025-26 reliability gap. However, the ESB considers it realistic that a capacity mechanism could commence in the NEM on 1 July 2025, with the first T-1 auction in July 2024 for capacity in the 2025-26 financial year. The 'initial' auction could occur simultaneously for capacity in the later financial years. As a transitional measure, special auctions (e.g. T-3 or T-2) could be run in the intervening years before the first year.

Alternative interim arrangements could also be considered, such as continuing the RRO and using the ministerial trigger (currently under consideration by the ESB) in the short term until the first year with capacity procured through a initial auction if the projected reliability gap remains.

Contact details:
Energy Security Board
Level 15, 60 Castlereagh St
Sydney NSW 2000

E: info@esb.org.au

W: <http://www.energyministers.gov.au/market-bodies/energy-security-board>