ENERGY SECURITY BOARD

Post-2025 Market Design
Final advice to Energy Ministers
Part B

27 July 2021

Dr Kerry Schott AO

Independent Chair

Energy Security Board

David Swift

Independent Deputy Chair

Energy Security Board

Clare Savage

Chair

Australian Energy Regulator

Anna Collyer

Chair

Australian Energy Market Commission

Daniel Westerman

Chief Executive Officer

Australian Energy Market Operator

Table of contents

List of Figures

List of Tables

Abbreviations

ACCC	Australian Competition and Consumer Commission
ACL	Australian Consumer Law
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
API	Application Programming Interface
CMM	Congestion Management Model
C&I	commercial and industrial
CoAG	Council of Australian Governments
DEIP	Distributed Energy Integration Program
DER	distributed energy resources
DNSP	Distribution Network Service Provider
ECA	Energy Consumers Australia
ENA	Energy Networks Australia
ESB	Energy Security Board
ESS	Essential System Services
ESOO	Electricity Statement of Opportunities
FCAS	frequency control ancillary services
FFR	fast frequency response
GW	Gigawatt
IBR	inverter based resources
ISP	Integrated System Plan
LMP	Locational Marginal Pricing
MT PASA	Medium Term Projected Assessment of System Adequacy
MW	Megawatt
NECF	National Energy Customer Framework
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NSP	Network Service Provider
PFR	Primary frequency response
PRRO	Physical Retailer Reliability Obligation
PV	Photovoltaic
RAMs	Resource Adequacy Mechanisms
RERT	Reliability and Emergency Reserve Trader
REZ	Renewable Energy Zone
RRO	Retailer Reliability Obligation
ST PASA	Short Term Projected Assessment of System Adequacy
SSM	System Services Mechanism
TNSP	Transmission Network Service Provider
UCS	Unit Commitment for Security
VPP	Virtual Power Plant
VRE	Variable renewable energy
WDRM	Wholesale demand response mechanism

Executive Summary

Note: This Executive Summary is a copy of the Part A document.

It is difficult to overstate the scale and pace of change across Australia's electricity sector as, both large and small scale, renewable generation enters the system rapidly and in volume. This relatively low-cost power has caused wholesale prices to fall and emissions to reduce.

The energy transition has created a number of challenges and opportunities that need to be addressed in order to deliver affordable, reliable and low emissions energy services to customers into the future. These include the need for:

- **Resource adequacy mechanisms**: to provide the right incentives to drive investment in an efficient mix of resources (that is variable renewables, storage, and flexible and firm generation) to minimise costs and maintain reliability;
- **Essential system services and ahead scheduling**: to ensure that the essential services required (frequency, control, operating reserves, inertia and system strength) are available to maintain system security;
- **Integration of distributed energy resources and flexible demand**: to deliver benefits to customers through the integration of rooftop solar, battery storage, smart appliances, electric vehicles, and other distributed energy resources into the system in an efficient way; and
- **Transmission and access**: to ensure timely transmission investment, better use of capacity on the network to lower costs for consumers and reduce uncertainty for investors by making future patterns of congestion more predictable.

The Energy Security Board (ESB) was tasked by the former Council of Australian Governments Energy Council (COAG EC), to develop advice on reforms to the National Electricity Market (NEM) to meet the needs of the transition up to and beyond 2025. This paper sets out an integrated framework to reform the NEM, with policy directions across four reform pathways. These pathways sequence a series of reforms necessary to promote a secure, reliable, and efficient energy transition while maintaining affordability for customers. The proposed pathways build on the Options paper published in April 2021.

Pathway for reforms

The reform pathways are set out to reflect the urgency of the situation and fall into three categories: immediate reforms to be done now, initial reforms to be developed and implemented in the near term, and longer-term reforms which should be progressed over time and depend on developments in the industry including technological change.

Together, these pathways deliver appropriate reforms over time. With ongoing oversight, these pathways can be adjusted to address emerging needs, their interdependencies, and uncertainties during the transition. Monitoring progress is especially essential so that as experience grows, and learning occurs adaptations can happen in the new system and changed market conditions.

Resource adequacy mechanisms and ageing thermal retirement

The ESB considers the existing market, and its related arrangements, are unlikely to be sufficient to ensure the commercial provision of the right mix of resources required as the market transitions towards a higher penetration of variable renewables. This is due to a range of uncertainties currently facing investors in the market. These include technological and demand uncertainty through to uncertainty over the timing of the closure of ageing thermal generation plant. Government interventions to drive investment in new generation and those to manage the closure of existing plant also significantly impact the investment environment. These interventions can create investment uncertainty and dampen spot and wholesale market prices, impacting long term investment signals for the right mix of resources necessary to support the energy transition.

To ensure investment in an efficient mix of variable and firm/flexible capacity that meets reliability at lowest cost, the ESB has proposed several reforms across the workstreams. More specifically, the ESB propose that detailed design work is undertaken on a capacity mechanism to complement existing arrangements. The introduction of such a mechanism is intended to increase government and community confidence that resource adequacy will be delivered by the market reducing the need for interventions. The ESB notes that the current risk appetite for reliability by investors appears to be higher than that of governments.

1. Immediate reforms

The ESB proposes to make provision in the market arrangements for a NEM wide jurisdictional strategic reserve. This will be developed as a nationally consistent mechanism, to provide the option for a jurisdiction to procure any required reserves beyond the national market reliability standard if they consider this necessary.

The ESB recommends mechanisms to deliver enhanced transparency of future generator availability. This will support the orderly exit of thermal plants as they retire from the system, with improved information to market participants, jurisdictions, and other policy makers.

To guide the development of any future jurisdictional schemes, the ESB proposes a set of principles to ensure a common approach is taken consistent with current market signals for investment. Jurisdictions are encouraged to use currently available information on market needs and seek additional information from the market bodies as necessary when considering jurisdictional schemes.

The ESB also propose that a Ministerial lever for the jurisdictions is introduced to trigger the current Retailer Reliability Obligation (RRO), as is currently in place in South Australia. Introduction of this measure will support a consistent national framework but give jurisdictions the ability to strengthen the RRO if they wish while further detailed design work is undertaken on a capacity mechanism.

2. Initial reforms

The ESB recommend the detailed design for a capacity mechanism that 'unbundles' the value for capacity from energy be developed over the next 12-18 months. In recognition of significant stakeholder concerns over the significance of such a change to current market design, the ESB will work with stakeholders and jurisdictions to develop the detailed design of a capacity mechanism for Ministers' agreement in mid 2023. There are a number of policy choices in the design of a capacity mechanism which need to be carefully considered to ensure the recommended design is both effective and efficient, including the complexity of the design, its potential impact on retail competition (including small retailers), commercial and industrial customers, transaction costs and overall affordability.

The ESB intends that its straw proposal for a decentralised capacity mechanism, where the volume of required capacity is determined by liable entities (market participants), should be the starting point for the detailed design work.

3. Long term reform

Following the implementation of the ESB's Post-2025 reforms, continued monitoring of reliability and overall costs to consumers is necessary. It is important to recognize that operating and regulating a system with significant penetration of variable renewables (both small and large scale) is a new experience globally. Review and monitoring are essential so adaptation can occur as experience grows and learning occurs. While this is happening now the increasing penetration of renewables makes the 'monitor and adapt' approach even more important.

Essential System Services and Scheduling and Ahead Markets

The growing role of renewable generation in the power system increases the need for services to be properly valued to maintain the security of the system. This is exacerbated by the retirement over time of ageing thermal generators who currently provide many of these services 'bundled' together with their delivery of energy and reserves. The ESB considers that we need to specify and value those essential system services and efficiently procure them, including procurement from non-traditional and new sources such as Distributed Energy Resources (DER). The approach proposed is to use co-optimised market-based procurement where possible and, where not possible or appropriate, structured procurement approaches.

The arrangements need to not only ensure that the range of essential system services are available, but also that they are effectively used in a more complex operating environment. Tools are needed to ensure AEMO can efficiently procure, schedule, and call upon these resources when needed, reducing the cost of AEMO market interventions, and improving overall affordability. The ESB is working closely with the AEMC on rule changes in progress that are developing these arrangements.

1. Immediate reforms

Reforms are underway to refine frequency control arrangements, addressing the need for enhanced arrangements for primary frequency control and a new market for fast frequency response.

2. Initial reforms

The ESB proposes to progress the development of a Unit Commitment for Security (UCS) mechanism to schedule resources providing services under structured procurement arrangements (services without real-time markets). The UCS operates as a tool to support efficient scheduling of system services. Over and above a UCS-only option, a system security mechanism (SSM), as a short-term procurement option, could provide an adaptable operational tool to complement planning-based solutions, including for system strength, and provide the system configuration needed to maintain security. Further work is needed to explore the design of an SSM together with stakeholders and this will be progressed by the ESB and market bodies through AEMC rule change processes which are underway.

The potential for a new operating reserve product will continue to be progressed by the ESB and market bodies (with AEMC rule change requests underway addressing operating reserves services). The current provision of reserves in operational timeframes is implicitly valued through the energy spot market. New products and services may be required to manage growing forecast uncertainty and variability in net demand over timescales ranging from minutes to hours. A new reserve service market could provide an explicit value for flexible capacity to be available to meet these net demand ramps. This could be considered as a potential complement to the suite of resource adequacy reforms, rather than as a mechanism to deliver the necessary long term investment signals.

3. Long term reform

The ESB has identified a spot market approach for valuing and procuring inertia as a long-term priority. In the first instance inertia provision is relying on the current arrangements for Transmission Network Service Providers (TNSPs) to procure minimum levels of inertia along with the potential to use a SSM to procure additional inertia when required. This is an area of interest for stakeholders, and the ESB notes that while current measures ensure system security is maintained, there could be advantages to progressing to a spot market to co-optimise the supply of inertia with frequency control services, operating reserves and energy. This work will be progressed with the ESB and market bodies.

In the medium to longer term, the operational challenges of managing the power system with very high levels of renewables will become clearer, and new technologies will arise to supply the necessary services. These operational and technological advances require monitoring and may require further refinement to the spot market and structured procured arrangements. The ESB and market bodies will continue to monitor and provide advice about market conditions and the need for further unbundling of essential system services or an integrated ahead market.

Integration of Distributed Energy Resources and Flexible Demand

The ESB is focussed on driving value for all customers from integrating DER as an important and integral part of the overall power system. There is significant potential for customers to benefit from using their DER resources. They could provide demand flexibility, enter the wholesale energy and service markets, and provide network services to improve the return on their investment. This changing behaviour benefits all consumers by potentially lowering the costs of operating the electricity system.

To support these outcomes, the ESB has set directions for how roles of the various parties in the energy system – customers, retailers or aggregators, distribution networks, and AEMO — need to evolve from their current responsibilities. These reform directions have been built into a DER Implementation Plan, which sequences a program to be worked through together with stakeholders and customer advocates over the next three years to deliver technical, regulatory and market reform to integrate DER. To ensure insights about the experience and expectations of customers continue to inform the program, a collaborative Maturity Plan approach is developed to identify priority customer issues for reform.

1. Immediate reforms

A package of immediate reforms is underway, including expanding the responsibilities of distributors to hosting distributed generation and storage, supporting flexible demand, and introducing technical standards for DER that will smooth the customer experience and assist to ensure the security of the power system. New arrangements to provide for larger customers to participate in the wholesale energy market and gain benefits from managing their demand come into force in October 2021.

The rapid uptake in rooftop PV is creating challenges in maintaining system security associated with low system load. The ESB proposes levers are put in place across jurisdictions to ensure emergency backstop measures are available as system conditions continue to rapidly change. It is important that these measures remain genuine and rarely used 'backstops', and priority must be given to progressing to more enduring arrangements. These arrangements include enhanced market information by AEMO and the development of 'turn up' services that encourage flexible demand to shift to less critical times of the day.

As new retail offers start to become available to customers, foundations need to be in place to ensure customers can easily and safely make choices and switch between DER / non-DER service providers. A key enabler to the success of DER integration is to ensure that consumer trust is developed in new services and products The ESB has therefore put in place a new risk assessment tool that enables market bodies to test on an iterative and ongoing basis whether the customer protections in place remain fit for purpose.

2. Initial reforms

Initial reforms through the DER Implementation Plan focus on rewarding customers for their flexible demand and increasing value to the system from flexible resources. Customers should benefit from building flexibility into their energy use with potential revenue where this flexibility can be offered (through a retailer or aggregator) to the wholesale market.

To provide these opportunities to customers, changes are needed to make it easier for innovative new retailers and service providers to enter the market, enabling customers to benefit from greater choice and competition. This does not mean small customers will have to do more in the market. Customers will continue to interface with retailers and aggregators, but retailers and aggregators will have new opportunities to engage in the market and offer different choices to customers. Where customers wish to engage more than one service provider (e.g., for their standard energy use to be managed separately to supplies for their electric vehicle), arrangements should support this.

3. Long term reform

The DER Implementation Plan sets out an adaptive approach, enabling continued engagement with industry, customer advocates and interested parties to collaborate on design of future reforms. The pace of change underway means that new risks and opportunities will continue to emerge (e.g., the forecast uptake of electric vehicles and smart home technology). The Maturity Plan will support this by bringing together a diverse mix of stakeholder views to focus on priority customer issues.

Transmission and access

Investment in, and access to, an enhanced national transmission system is key to a successful transition. The ESB has developed a range of measures to ensure that much needed transmission investment is delivered in a timely and efficient manner. These measures include a solution that ensures that new generation and storage facilities are located in optimal parts of the network, including Renewable Energy Zones (REZs) delivered through the Integrated System Plan (ISP), to help deliver the energy transition at least cost. It is also important to ensure that these investments, once made, are used in an efficient manner.

The management of congestion in operational timeframes is expected to become increasingly critical in the future as the role of Variable Renewable Energy (VRE) increases and power system flows become more variable in accordance with their fuel sources (the sun and the weather). The ESB has developed reform proposals designed to support an efficient level and management of congestion in future.

1. Immediate reforms

AEMO has prepared and regularly updates the ISP. The ISP describes a least cost pathway for the development of the power system, taking into account demand-side, supply-side and network costs. The Group 1 projects identified in AEMO's 2018 ISP are now committed projects and are underway.

The ESB's actionable ISP changes help to implement the priority network investments identified in the ISP and deliver additional network capacity where needed. Further changes have been recommended to provide an interim framework for REZ. REZ schemes can promote efficient location decisions by making it more attractive for generators to invest in certain parts of the network where resources are plentiful, and the grid has capacity.

2. Initial reforms

Challenges are emerging in getting the new transmission projects built, and the costs of investing too late can be substantial. The current regulatory test may not capture wider economic benefits that could be captured in a broader cost-benefit test for actionable ISP projects and additional funding options such as contestability may also need to be considered to deliver these projects at least-cost. The AEMC is undertaking a transmission investment review to consider these issues. The ESB has provided advice to Energy Ministers on transmission cost allocation and governments are currently conducting further analysis and considering next steps. Given the scale of transmission build necessary for the future, the ESB considers there is a need to resolve an appropriate fair cost allocation methodology for transmission.

The ESB considers the planning and implementation of priority REZs is an important step to the efficient connection of generation to the enhanced grid. To support the integration of REZs a congestion management model is proposed. This model complements the Interim REZ framework and addresses the emerging congestion management needs of the system. Together these changes are intended to encourage new generation and storage to locate in REZs, lessen the likelihood that their access to the grid is degraded by the connection of other generators outside the REZ, and also lessen the impact of other REZs. A detailed design needs to be developed enabling comprehensive consultation with stakeholders and interested parties.

Implementing the reforms

The ESB has completed a high-level, indicative evaluation of the likely benefits each reform pathway could be expected to deliver. Understanding that the benefits are an order of magnitude significantly greater than the costs of implementation gives confidence for the case for change even though estimates of both costs and benefits at this stage are illustrative only. The implementation costs should be considered in perspective. There are costs in the electricity sector because of the transition occurring, and whether or not the reforms in this paper occur. What can change is the nature of those costs and how they are managed through the right market design and forward planning for implementation. The preliminary evaluation at this stage shows that the benefits of implementing the reforms - which is in the order of billions of dollars — dwarf the implementation costs that can be expected.

The NEM of 2025 and beyond requires modernisation of critical market systems and business processes and adequately resourced market bodies. There are risks associated with the scale of the energy transition including critical data needs, potential changes to the policy landscape, its governance, the need for an adaptive management approach, interdependencies between the pathways, and costs of implementation. The ESB has sought to address these risks in its recommendations, in the design of both reforms and the pathways themselves and the development of the ESB's Data Strategy.

Outline of this paper

This report about advice on design changes in the National Electricity Market (NEM) is set out in three parts:

- **Part A:** provides an overview of the four reform pathways that comprise the reforms package for the market design changes necessary for the NEM along with ESB's final recommendations to Energy Ministers in relation to them.
- **Part B:** provides a more detailed discussion of each reform pathway, including the ESB's reasoning, analysis and response to stakeholder feedback.
- **Part C:** contains appendices providing technical detail for particular reform options and relevant consultant reports. A summary of the stakeholder feedback to the ESB' April Options paper is available on the ESB's website.[1]

[1] This summary can be found here: https://esb-post2025-market-design.aemc.gov.au/reports-and-documents#submissions

1. The Task and the Approach

1.1. The Task

The Energy Security Board (ESB) was tasked by the former Council of Australian Governments Energy Council (COAG EC), to advise on design changes required in the National Electricity Market (NEM) as it transitions from a fleet of largely coal fired generation to more variable renewable generation[2]. A pathway that sets out reforms and a timetable for their implementation, towards the year 2025 and beyond, is the basis of the ESB advice.

The request by Energy Ministers for this work reflects a general concern about NEM reliability, security, and affordability as the rapid uptake of renewable generation occurs and the existing ageing generation fleet progressively retires. Similar changes are occurring in many electricity markets across the world, but Australia stands out for the rapid pace of its change and for its adoption of distributed (rooftop) solar photovoltaic (PV) systems - the highest in the world.

There are four key drivers of the current transition.

- First, the dramatic and continuing increase in the supply of renewable energy driven by government policy and renewable energy targets. The government schemes incentivise the entry of both large-scale wind and solar generation and small-scale solar PV systems. Community concerns about the impact of fossil fuel generation on carbon emissions, together with the declining financial viability of thermal coal generation, leaves little interest or commercial appetite for future investment in thermal coal generation.
- Second, much of the current thermal generation fleet is ageing and is becoming commercially unviable. Variable renewable generation, with zero fuel costs, puts downward pressure on wholesale energy prices, reducing revenues for much of the existing thermal fleet. Together with the higher operating and maintenance costs of the ageing thermal fleet, there is significant pressure on this less economic generation to exit the market.
- Third, technology costs for renewable and storage resources, both large and small scale, are falling rapidly. These cost reductions, coupled with zero fuel costs and low operational costs, make this new technology highly competitive when compared with the costs of investing in more traditional forms of generation. Battery costs have fallen substantially and continue to drive the uptake of electric vehicles and home storage systems that complement small scale solar PV systems. Digitalisation drives technology advances that will radically change not only how energy is produced, but how it is used by consumers.
- Finally, an increasing number of households and business customers have made investments in DER (such as solar panels, batteries, and smart appliances) and their value is not being fully realised by either their owners or the system as a whole. With the new technology now available, customers can be rewarded for their export of electricity, their ability to manage their load across the day, and for their provision of services to the network. It needs to be easy for customers to switch providers and access choices that meet their needs. Building consumer trust in new energy services through effective co-design and consumer protections will also be a key enabler to increased consumer participation, and the effective integration of DER. If managed well, integration of DER into the system will benefit the owners of the DER resources as well as the system as a whole.

2 https://energyministers.gov.au/publications/post-2025-market-design-national-electricity-market-nem

1.2. The Approach

To address the large task of redesigning the NEM the ESB divided the work into four interrelated reform pathways, a timeline for implementation and consulted widely. The four pathways are:

1. Resource adequacy and ageing thermal generation retirement

The objective of this pathway is to be prepared for the retirement of the thermal fleet and have its replacement generation in place. To enable this outcome, investment is needed that provides an efficient mix of capacity (generation, storage, and demand response); and is timely, so the exit of ageing thermal generation does not cause significant price or reliability shocks to consumers.

2. Essential system services and ahead mechanism

The retirement of thermal generation means the essential system services these generators provide (along with energy) also exit the system. These services include frequency control, inertia, operating reserves, and system strength – and all are essential for the security of the electricity system. The objective of this pathway is to ensure that essential system services are provided. Changes are also needed to AEMO's dispatch mechanisms so that the operator can be assured, ahead of dispatch, that they have the essential services on hand that are required for system stability.

3. Transmission and access

The Integrated Systems Plan (ISP) describes a least cost pathway for new transmission and Renewable Energy Zones to meet the needs of the sizeable investment in variable renewable generation that is occurring. The objective of this workstream is to further facilitate 'actioning the ISP'. A plan about how best to develop Renewable Energy Zones (REZs) is needed, and once the new transmission and REZs are developed congestion on the grid is expected in some places and at sometimes. To manage this congestion a management model is proposed.

4. Integrating Distributed Energy Resources (DER) and flexible demand

The objective of this pathway is to integrate DER into the NEM and introduce flexible demand to a market that has always been dominated by supply. The DER Implementation Plan, the centre piece of this pathway, maps out the investment, reforms, and actions necessary to integrate DER. Digitisation can untap the potential of these smaller assets and add great value to all consumers.

Each of these four pathways is set out on a timeline to reflect the urgency of the situation. There are three time 'zones': immediate reforms to do now, initial reforms to develop and implement in the near term, and next reforms which are longer term and depend on developments in the industry including technical changes. As a package these four timely and interrelated reform pathways deliver the necessary changes in the NEM in the period to 2025 and beyond.

This paper, prepared by the ESB, represents the joint and collaborative efforts of the energy market bodies: the Australian Energy Market Commission (AEMC), Australian Energy Market Operator (AEMO) and the Australian Energy Regulator (AER). The ESB has also worked closely with a broad range of industry stakeholders, consumer bodies, academics, government bodies and interested parties over the two-year reform program:

- Over the two-year program, the ESB has carried out approximately 150 work group meetings and briefings (as well as those run by / together with AEMC processes)
- These include the regularly convened Technical Working Group and Advisory Group meetings (comprised of a broad range of stakeholders with relevant expertise from more than 30 organisations), as well as deep dive workshops, integrating DER design sprints, CEO Roundtables, and reference groups.
- In late 2019, ESB ran an International Symposium to bring together academics and speakers from a number of energy markets to engage in discussions on critical issues facing the NEM.

- For the Post-2025 market reform program, ESB has published an Issues Paper (September 2019), Directions Paper (April 2020), Consultation Paper (September 2020), Directions Paper (January 2021), Options Paper (April 2021) and now Final Advice (July 2021). We have received substantive stakeholder feedback to each of these processes, with over 100 submissions received to each of the consultation processes carried out.

- These processes have been complemented by adjacent processes carried out in relation to specific reform elements, and in collaboration with our market body colleagues (AEMO, AEMC, AER). Considerable stakeholder interest and feedback has been received via these processes which has also greatly contributed to thinking in the Post 2025 program.
- ESB has commissioned and published consultancy reports to provide advice and input into the issues being considered across various workstreams. Details of these reports can also be found on the ESB website.

Stakeholders have committed significant time and resources to provide considered and thoughtful input into the Post-2025 reform process. The ESB values this engagement and sincerely thanks all stakeholders for their participation in this process.

2. Resource Adequacy and Ageing Thermal Generator Retirement

2.1. Key points

- The objective of this pathway is to facilitate the timely entry of new generation, storage and firming capacity and the orderly retirement of ageing thermal generation, to deliver reliability and price outcomes that meet jurisdictional and community expectations.
- Emerging challenges indicate a need to reconsider the resource adequacy arrangements for the NEM. There is a profound change in the generation mix as significant entry of variable renewable capacity occurs. The 2020 ISP envisages that half the NEM's coal fleet retires by 2030. As more economic Variable Renewable Energy (VRE) and storage comes into the market, more pressure is exerted on existing thermal generators as their financial viability is challenged.
- Jurisdictional schemes are introducing additional uncertainty. While they may provide longer-term certainty for individual projects, policy priorities of these schemes are often broader than reliability and reflect a limited willingness to tolerate periods of high scarcity pricing. The operation of these schemes can dampen the spot and contract prices necessary to drive investment under current market arrangements. The schemes may also be regionally focused without considering NEM wide impacts and may drive increased risks of unexpected or early closures of plant including in neighbouring regions. This may then necessitate further government interventions to keep thermal plant open for longer.

  There are further uncertainties giving rise to additional investment risk, including:

  - Rapidly changing technology costs for variable renewable and storage resources,
  - Potential changes by generators to the timing of large thermal exits,
  - Persistent demand risk, which poses challenges for hedging,
  - Expectations of spot prices being low on average but exhibiting periods of extreme volatility,
  - A lack in confidence that the periods of high prices necessary for investment will be tolerated and a belief that government intervention is likely to dampen the price effect.
- Existing arrangements may be sufficient in the short term particularly given the recommendations made in the other three reform pathways. However, the ESB is concerned whether commercial incentives for existing plant in the market are sufficient, and if investors in replacement technologies are confident enough in future revenue streams to invest to meet needs over the medium and long term.
- The problem to address is one of risk allocation. Without the ability to lock in longer-term revenue streams, participants need sufficient incentive and confidence to invest in capacity in an environment of extreme uncertainty. Jurisdictions need reassurance that participants are going to meet the needs of the system. Without this assurance, jurisdictions will continue to intervene in the market in order to ensure supply meets reliability with capacity-equivalent arrangements, increasing investment risk in the process.
- The enduring solution is to explicitly value capacity through a new capacity mechanism. The complementary revenue stream from such a mechanism could provide a 'investable' and enduring long-term signal that may more directly target the needed capacity for timely entry and orderly exit. In doing so it will reduce the current and future investment uncertainty faced by investors.

- A new mechanism that aligns the risk decisions faced by the participants with the expectations of the jurisdictions should ensure investment in an efficient mix of variable and firm/flexible capacity that meets reliability expectations at lowest cost. Government and community confidence about resource adequacy should reduce the need for government interventions.
- The significance of this change to market design means there is a need to consult on the development of the detailed design for the mechanism over the next 12-18 months. The market will then need sufficient notice before it can be implemented.
- However, there are improvements to be made in the short term**,** prior to the implementation of a capacity mechanism, to support efficient risk allocation and to provide jurisdictions greater confidence that reliability will be maintained in a way that preserves market signals.
- The ESB is recommending a number of *immediate reforms* to support immediate resource adequacy including:
    - proposed principles for a common approach for all jurisdictional investment schemes to support consistency, efficiency, transparency and competitive outcomes that is consistent with current market signals for investment.
    - enhancements to existing generator exit mechanisms to increase information disclosure for generators that are taken out of service for an extended period and so provide greater transparency of generator availability.
    - a new, opt-in, jurisdictional strategic reserve, allowing jurisdictions to procure any required reserves beyond the market reliability standard that individual jurisdictions consider necessary for their region.
    - extension of the existing South Australian ministerial 3 year ahead trigger for the Retail Reliability Obligation NEM-wide, so it is available to all jurisdictions to trigger in their regions if they wish. This would give Ministers the ability to strengthen the Retailer Reliability Obligation while further detailed design work is undertaken on a capacity mechanism.
- The ESB is recommending an initial reform to support resource adequacy, specifically a capacity mechanism for the NEM in the medium term to ensure the competitive provision of a sufficient volume of the right mix of resources as the market transitions towards net zero emissions.
- The ESB has considered capacity mechanisms and proposes the initial development of a physical retailer reliability obligation (RRO). The related straw proposal is a decentralized capacity mechanism in that the volume of required capacity is determined by liable entities who would be required to hold a certificate position to cover their actual demand. Whether it would be preferable to centrally determine the volume of required capacity will be considered in the detailed design process.
- In the straw proposal for the PRRO:
    - certificates would be allocated to physical resources, based on their expected ability to be available during 'at risk' reliability periods. As a new tradeable product, its complementary revenue stream could provide a 'investable' and enduring signal that may more directly target the needed capacity for timely entry and orderly exit. The price of certificates would value a prospective reliability shortfall. The forward value of certificates would reflect any perceived risks of scarcity (high prices) for capacity, with the length of the auctions for these products affecting this.
    - certificates would value both existing fleet and new investment in assets that are best placed and most cost-effective in responding to shortfall periods.

- requiring liable entities to hold sufficient physical certificates to meet demand during a predefined period provides a ‘line of sight” between demand and physical supply, providing transparency and confidence that demand will be met. Participants would continue to manage their financial risk in the spot market through financial contracts, making the straw proposal an 'adjunct' to the current market.
    - arrangements could also be put in place to facilitate integration of jurisdictional schemes with a PRRO.
- While a PRRO straw proposal has been developed, there are a range of design settings that need to be selected, including but not limited to certification, assessment frequency, certificate duration, locational restrictions, time of compliance assessment, trading arrangements, market liquidity obligations and penalties. Whether it would be preferable to centrally determine the volume of required capacity, rather than have it determined as is currently the case in the market and under the straw proposal, should also be considered. There will be extensive consultation on these settings, and they are to be determined during the detail design phase.
- Targets for jurisdictional schemes could also be integrated in a new capacity mechanism. There are a range of options for a NEM-wide, common approach to jurisdiction investment schemes to work alongside the new capacity mechanism which will be considered as part of the detailed design.
- An alternative to creating a physical RRO based on capacity certificates is to alter the definition of qualifying contracts in the existing RRO in a way that increases the likelihood of a physical linkage. Altering, or limiting the nature of contracts that are considered as ‘qualifying contracts’ for the purposes of the current Retailer Reliability Obligation (RRO) could incentivise financial contracting which has a stronger link to achieving a ‘firm’ physical resource outcome. Whether this is preferable is to be examined during the detail design phase.
- The ESB is cognisant of the potential impacts associated with this significant shift in market design. Addressing these risks is a key priority in the detailed design phase in order to safeguard competition in the retail and wholesale market (the impact on small customers and innovation), reduce impacts on commercial and industrial customers, minimize the transaction costs of market participants and maintain affordable outcomes for consumers.

2.2. The issue

The Resource Adequacy Mechanisms and Ageing Thermal Generation workstream seeks to facilitate the timely entry of new generation, storage and firming capacity, and an orderly retirement of ageing thermal generation. The goal is to have the right mix of resources in place in time for plant closures, and for those closures to not cause significant price or reliability shocks to consumers. The ‘right mix of resources’ refers to a sufficient combination of variable, firm and flexible assets that are available for dispatch at any one time, but especially during ‘at risk’ reliability periods, which will change as the market transitions.

The power system is changing and so must the market

A variety of emerging challenges and trends mean that a reconsideration of our resource adequacy arrangements is required. These challenges are:

- **A profound change in the generation mix –** the NEM is rapidly transitioning to a low-emissions generation profile. The 2020 Integrated System Plan (ISP) step change scenario projects that 29 GW of large and small-scale variable renewable capacity will be built by 2030. The same modelling also projects that coal capacity will decrease from over 23 GW to around 12 GW by 2030. On current performance the transition is likely to occur at an even faster rate than the modelled step change scenario.

- **New technologies will displace the existing thermal fleet –** as new, more economically competitive Variable Renewable Energy (VRE) comes into the market, more pressure is exerted on existing thermal generators to retire. As renewable resources are built, the role for traditional thermal generators decline. They either operate at lower capacity factors (producing less of the time) subject to technical constraints or are replaced by storage and/or other types of firming resources that operate at times when renewable resources are low.
- **Jurisdictional schemes are introducing additional uncertainty –** the political hurdle rate (that is willingness to accept gaps in reliability or higher prices) seems to be significantly lower than the private sector hurdle rate with governments investing sooner to manage risk on behalf of customers. Jurisdictional investment schemes can support new investment, but the long-term certainty they provide is not easily replicated through market mechanisms. The policy priorities of these schemes however are often broader than reliability and reflect limited willingness to tolerate periods of the very high scarcity pricing that is necessary to drive investment under current market arrangements.

  Consequently, these schemes may dampen the investment signals of spot and contract markets. Further, schemes with objectives broader than addressing reliability can create risks for commercial investment, and related resource adequacy, if they are not well integrated into existing market arrangements. In addition, these schemes are generally regionally focussed, and there is a risk that they may not take into account NEM wide impacts on resource adequacy and reliability. For example, there may be impacts on the timing of closure of ageing thermal generation in other NEM regions. These impacts may in turn encourage government interventions to keep thermal plant open for longer.
- **Uncertainty is giving rise to investment risk –** the level of uncertainty brought about by the transition of the power system is significant, and this gives rise to concerns that the market no longer adequately signals the need for timely entry of the right mix of resources. Added to the impact of jurisdictional schemes are the following factors that drive uncertainty:
  1. Rapidly decreasing technology costs for renewable and storage resources.
  2. Potential changes to the timing of large thermal generation exits.
  3. Persistent demand risk, which poses challenges for hedging.
  4. Expectations of spot prices being low on average but exhibiting periods of extreme volatility.
  5. A lack of confidence that government will tolerate the periods of high prices necessary for investment without increased intervention, including decisions to keep ageing thermal plant open for longer.

In combination, these factors tend to undermine investment confidence, and lead participants to delay or defer investment decisions.

Existing arrangements may be sufficient for a time

In consultations and submissions to the ESB, many market participants have supported the current arrangements. They argue there is no impending threat to reliability and that the current energy only market design is sufficient to elicit the future investment in capacity.

The ESB agrees, in part, with these views.

Over the medium, forecasts of resource adequacy suggest that the reliability standard will be met. Moreover, the existing Reliability and Emergency Reserve Trader (RERT) mechanisms, including the Interim Reliability Reserve, can manage near-term challenges that may emerge. Jurisdictional interventions have also brought new capacity into the market and have supported a clearer timing for exits.

However, the ESB remains concerned around the sustainability of these current arrangements, and whether they are fit-for-purpose on an enduring basis. There is doubt that in the current environment commercial incentives for existing plant in the market will be sufficient, and if investors in replacement technologies will be confident enough in their expected revenue streams to invest over the longer term. Participants who may have an incentive to manage short-term exposure risk, do not have sufficient incentive to manage long-term capacity risk, recognising that different participants have different risk approaches. This leads to a disconnect between the risks faced by the market and those borne by consumers. Consumers are left bearing the risk of a failure to invest over the long term.

But the medium to long-term solution will require an explicit value for capacity

The NEM needs a new mechanism that can harness the power of commercial investment to meet capacity requirements. The problem to address is one of risk allocation: without the ability to lock in long-term revenue streams, participants need sufficient incentives and confidence to invest in an environment of extreme uncertainty. Jurisdictions also need reassurance that participants will meet the needs of the system. Jurisdictions have a lower tolerance for high prices and reliability risk and therefore a lower hurdle rate for investment. As such, without this reassurance, jurisdictions will continue to intervene in the market in order to ensure sufficient supply to deliver reliability (and affordability), increasing investment risk in the process.

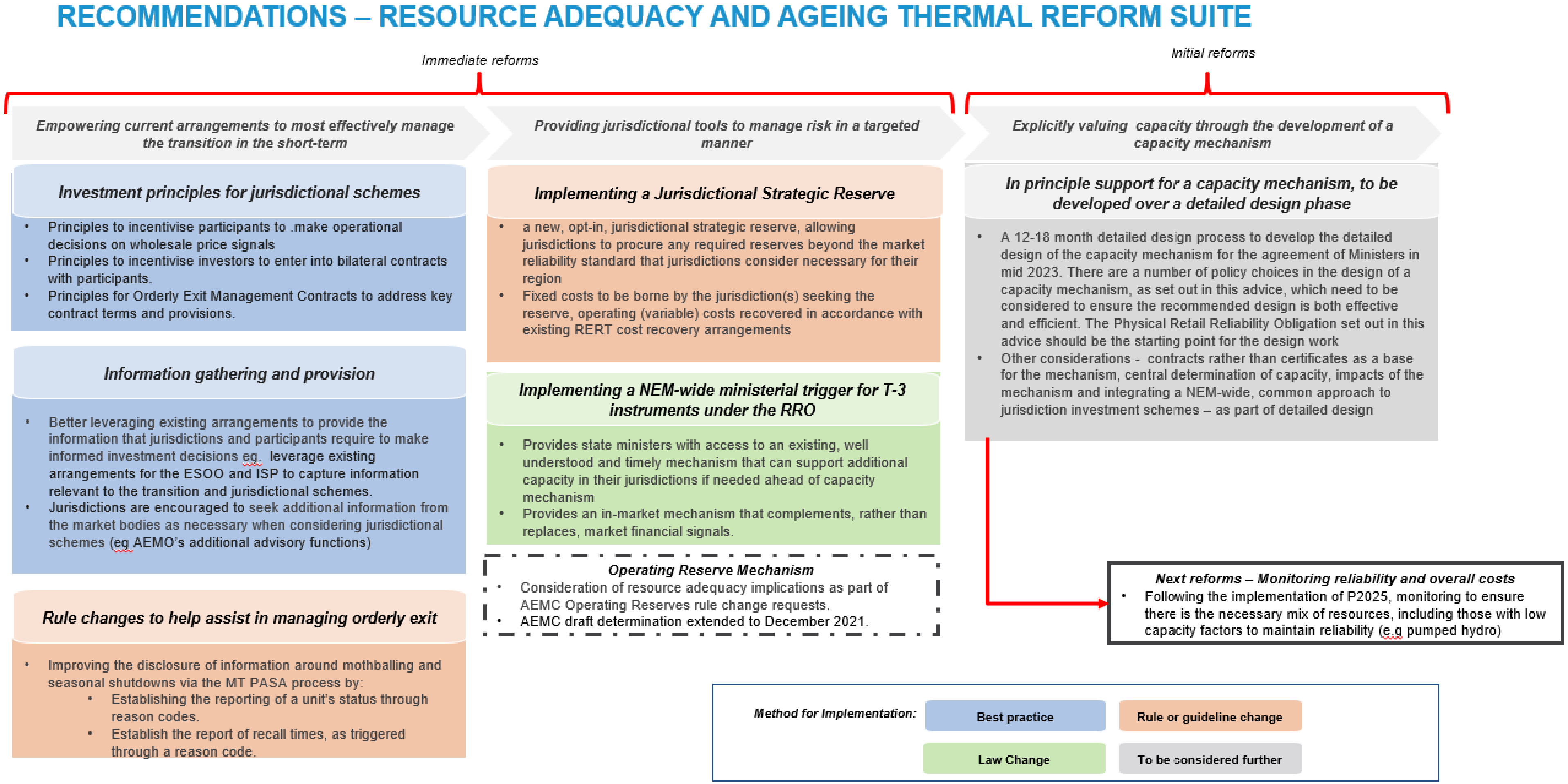
This could lead to significant discounting of the investment signals in an energy only market that would otherwise be more effective in a different, less challenging external environment. This comes as the NEM anticipates a need to replace a significant volume of exiting fleet over the medium term.

The solution is to *align* the risk decisions faced by the participants with the expectations of the jurisdictions. Governments can thereby be reassured that the market will deliver timely entry and orderly exit in a manner that is consistent with the expectations of consumers.

The ESB considers this can be achieved by unbundling the signal for capacity from the implicit capacity signals within the energy price. This can be done through a form of capacity mechanism that complements the existing market, which will strengthen the overall case for capacity investment in the process. The implementation of this reform involves the following components and staging:

1. In the short term, we need market arrangements that continue to encourage the behaviours that can support efficient allocation of risk between participants, jurisdictions, and consumers. At the same time, we need to create tools that provide jurisdictions sufficient confidence that reliability can be maintained in a way that preserves market signals. The proposed immediate reforms address these needs.
2. In the medium term, we must prepare for the challenges beyond 2025. Having laid the foundations through the immediate reforms, the market is ready for a capacity mechanism to provide the enduring solution to deliver timely entry and orderly exit and can be resilient to the changing circumstances of the transition.

Figure 1 Resource Adequacy and Ageing Thermal Reform Suite



2.3. The reform package: Immediate reforms

It takes time to develop and implement a new capacity mechanism. The ESB has considered how to meet the need for flexible and firm capacity prior to 2025, when a new capacity mechanism could be in place. The proposed immediate reforms facilitate increased information for market participants, support the efficient operation of spot and contract markets and provide insurance tools to give jurisdictions confidence that reliability gaps arising in the short term can be addressed

The ESB considers these reforms – all implementable in the short-term – to be important foundations to:

- optimise investment decision-making by market participants and by jurisdictions.
- equip the market to manage capacity adequacy in a way that is both targeted and least distortionary to current incentive structures. This allows signals in spot and contract markets to effectively support timely entry and orderly exit outcomes in the short term.
- provide jurisdictions with tools that can provide 'insurance' that reliability is met, as well as increasing reliability outcomes, in a non-distortionary manner should they so wish.

Options for immediate reforms and measures were set out in the April Options paper. The ESB has considered the extensive feedback in relation to each of these reforms. The ESB is mindful that two additional reforms – the establishment of a Jurisdictional Strategic Reserve (JSR) and a possible Ministerial trigger for the RRO – were not included in the April Options paper. The proposed JSR would be triggered by request of a jurisdiction and would implement 'out of market' reserve capacity sufficient to meet that jurisdiction's requirements beyond the market wide reliability standard. The ESB proposes to implement the JSR through a rule change process, allowing consultation with stakeholders on its final design. An overview of the proposed reform is set out in section 2.3.4. Should jurisdictions consider the need for a possible Ministerial trigger for the RRO (discussed in section 2.3.5), implementing such a trigger also includes consultation prior to its implementation.

2.3.1. Adopting investment principles for jurisdictional schemes

Following stakeholder feedback, the ESB recommends the following principles be adopted by jurisdictions to guide a common approach for all jurisdictional investment schemes. A (voluntary) common approach to coordinating jurisdictional investment schemes will be considered further in the development of the capacity mechanism (see section 2.5.3). Subject to that design process, these principles may only be needed on an interim basis.

The principles are:

1. Participants that are party to jurisdictional contracts should be incentivised to make operational decisions based on wholesale price signals (inclusive of ancillary services).
2. Jurisdictional schemes should incentivise investors to enter bilateral contracts with market participants rather than rely on an underwriting contract with a jurisdiction. This minimises the level of Government support required, the risk that is borne by consumers or governments on their behalf and maximises liquidity in the contract market.
3. Consideration should be given to maximising the transparency around government investment. Where possible, jurisdictions should share with the market information about:
    a) the volume, technology type, location, and timing of entry and/or exit of generation supported by jurisdictional schemes, as soon as is practical to do so.

b) subject to confidentiality constraints, the nature of any arrangements reached in an Orderly Exit Management Contract that are relevant to the exiting generator's behaviour in the market.

4. If jurisdictions are considering an Orderly Exit Management Contract in relation to a retiring generator:

   a) recovery of the costs of these arrangements should be funded by state governments, rather than the market, and should be kept separate to cost recovery arrangements in place for the RERT.

   b) the contract itself should include obligations on generators to:

      i. bid into the market and make the specified capacity / services available at the required times.

      ii. ensure sufficient fuel is available and maintenance undertaken to meet output requirements until the end of the agreed term.

The principles seek to maintain alignment between both the physical needs of the electricity system and the financial interests of generating resources that are party to long duration underwriting agreement. By dovetailing government schemes in this manner with existing market arrangements, they support, and lessen the distortion of, efficient dispatch and investment market signals. Jurisdictional schemes that incentivise the investor to enter a bilateral contract with a market participant minimise the level of government support required and enhance liquidity and competition in the contract market, while minimising the risk that is borne by consumers or governments on their behalf.

There is strong support from stakeholders for consistency and coordination across jurisdictions and for the financial principles for jurisdictional investment. Those stakeholders who commented on this reform supported increased provision of information from jurisdictions to allow market participants to better anticipate and respond to market signals. Greater transparency around jurisdictional investment schemes – subject to commercial and cabinet in confidence arrangements – improves market participants' ability to assess the viability of their own new and existing projects.

There are enduring impacts on the market of uncertainty that comes from ambiguous announcements, confidential schemes, or arrangements that do not integrate well with current financial contract structures. These include a lack of coordination as well as impacts on market-led investment, risking sub-optimal affordability and reliability outcomes for consumers.

The investment principles are considered an important foundation of NEM best practice. If adopted by jurisdictions when considering government investment, the efficacy of existing arrangements, as well as enabling a new capacity mechanism to function more effectively, minimising total costs and risks for participants and jurisdictions, is improved.

2.3.2. Information gathering and provision

Following stakeholder feedback, the ESB considers that the intent of the information gathering, and provision reforms consulted on in the April Options paper can be achieved by the existing information arrangements.

The case for proactive information gathering and provision

Given the risks facing investors, broader government policy objectives and the speed of the transition, government intervention for new generation resources has been understandable. The ESB recognises that, over the course of the transition, jurisdictions are likely to benefit from the targeted provision of information from market bodies that:

- assess potential market impacts of government policies
- set out potential market responses, including capacity that is prospective or being planned but may not yet have received regulatory approvals or a final investment decision, and
- highlight least cost capacity options.

Consistent with its overall approach, the ESB's preference is to use market frameworks to incentivise investment. To the extent that governments provide incentives for investment, this should be coordinated with transmission, firming and storage needs, REZ implementation and other current or prospective market developments.

Publication of information about market needs and developments in the public domain is likely to help jurisdictions 'look over the border' to coordinate and implement proposed investment schemes that reflects the resource adequacy needs of the market, as well as their region. It also provides market participants with improved clarity and greater certainty in assessing the viability of proposed projects.

Stakeholders held mixed views on the need for improvements to the information provided to jurisdictions. While acknowledging the benefits of well-informed government policy and investment decisions, there was a general view that the information already made publicly available via the Electricity Statement of Opportunities (ESOO) and ISP was sufficient.

The ESB considers if existing arrangements are better leveraged, they can provide the information that jurisdictions and participants require to make informed investment decisions.

Through the publication of the ESOO, AEMO currently provides technical and market data that informs the decision-making processes of market participants, new investors, and jurisdictional bodies regarding potential reliability gaps over a 10-year outlook. The ISP complements this information by providing a comprehensive least cost expansion plan for resource development required to maintain reliability outcomes across a 20-year outlook. This development includes energy producing resources, firming and storage resources, and the transmission infrastructure required to support and share new and existing resources. The ISP looks across a broad range of scenarios of possible futures and considers all currently known and projected technologies for this resource and transmission development.

In preparing the ISP, AEMO includes all policies meeting the 'public policy criteria'[3] that impact generation development, including the currently legislated NSW Electricity Roadmap and Queensland Renewable Energy Target (QRET).[4] The ISP captures the risk of earlier, economic retirement of coal-fired generation that may result from such policies and/or to meet decarbonisation levels associated with the scenarios modelled as part of the ISP.

Additional information on the mix of resources needed for reliability and security, in light of jurisdictional policies, could be provided through the modelling of additional scenarios or 'sensitivities' in the ESOO. Under current guidelines and methodologies[5] for the development of the ESOO, it is open to AEMO to include in the ESOO scenarios or sensitivities that consider 'anticipated' projects and/or generation development pathways under jurisdictional schemes, such as those anticipated by the NSW Electricity Roadmap.

---

[3] NER 5.22.3(b)

[4] The ESB note various demand management, electrification and other drivers such as 'net zero by 2050' are also incorporated in the ISP scenarios modelled and reported on.

[5] AEMO consults on the guidelines and methodologies that guide the development of the ISP and ESOO at least every four (4) years with a range of external stakeholders including jurisdictions. This provides an opportunity for all stakeholders, including jurisdictions to ensure the methodologies, scenarios and sensitivities continue to meet the wider objectives of the market.

Finally, should jurisdictions require additional information when designing investment schemes or making investment decisions, it is open to jurisdictions to use the existing advisory functions that can be provided by AEMO.

Under the National Electricity Law (NEL) AEMO has additional advisory functions that can be provided at the request of the Minister of a jurisdiction. South Australia has been using this function for several years to help adjust to the emerging power system conditions associated with their high penetration of variable renewable energy resources. This has culminated in the preparation and publication of various independent reports by AEMO specific to South Australia's needs.

This AEMO function allows for the provision of targeted information to governments to inform their decision-making about new policy or investment scheme design. Where appropriate, jurisdictions are encouraged to make such information readily available and accessible to other jurisdictions and the market. This better enables the resource-sharing benefits of an interconnected market and reduces the possibility that jurisdictions and market participants face adverse risk or liability later on from uneconomic investments.

Given the scope of the above arrangements in being able to deliver more information when it is needed, no specific reforms are proposed.

2.3.3. Managing orderly exit

Following stakeholder feedback, the ESB recommends changes to obligations on generators when submitting their availabilities to generate to AEMO for inclusion in AEMO's Medium-Term Projected Assessment of System Adequacy (MT PASA). These changes will provide greater transparency around when generators are available to supply, and the lead time required for recall from an outage.

What is the MT PASA?

The Projected Assessment of System Adequacy or PASA is AEMO's principal method of forecasting the adequacy of the power system to stay within the reliability standard. The National Electricity Rules require AEMO to prepare PASA in two-time frames:

- Short Term PASA (ST PASA) covers 6 trading days from end of the trading day covered by most recent pre-dispatch schedule with a half hourly resolution; and
- Medium Term PASA (MT PASA) covers 36 months from the Sunday after the day of publication with a daily resolution.

MT PASA assesses the adequacy of expected electricity supply to meet demand across the two-year horizon through regular assessment of any projected failure to meet the reliability standard. This assists Registered Participants and other stakeholders making decisions about supply, demand, and transmission network outages over that period.

Each week participants must submit forecasts of availability to AEMO for the next 36 months, commencing from the first Sunday after the latest MT PASA run. These forecasts form the basis of the MT PASA report that will be produced the following week.

Source:https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/projected-assessment-of-system-adequacy

Making the following changes to the MT PASA process increases information around mothballing and seasonal shutdowns:

- Establishing the reporting of a unit's status through reason codes via MT PASA in accordance with IEEE Std 762-2006, tailored to a domestic context, or equivalent; and
- Establishing the reporting of recall times via MT PASA when triggered through a reason code.

IEEE Std 762-2006 is an internationally recognised standard that "provides standard definitions for use in reporting electric generating unit reliability, availability, and productivity".[6]

The ESB does not recommend implementing the other changes that were considered in the April Options paper. For reference these were:

- Further amendments to the information provision requirements established via AEMO's Generator Information Survey (GIS), given its focus on longer term reliability and manual collection,
- Explicit reference to mothballing within the AER's notice of closure exemption guidelines, given the information captured through the proposed changes to MT PASA may be used by the AER as part of its existing monitoring functions and inform its assessment of compliance under the current notice of closure arrangements, or
- The establishment of an integrated process to manage early exit.

Increased information provision around mothballing and seasonal shutdowns to support notice of closure requirements

Stakeholders are generally supportive of the concept of increased information provision in relation to orderly exit. However, many submissions noted that additional provisions targeting mothballing and/or seasonal shutdowns could easily become onerous and a barrier to efficient operational decisions by diminishing the flexibility of participants to operate their plant in response to prevailing market dynamics. Further, stakeholders consider the existing notice of closure exemption arrangements to be sufficient to manage early exits and largely opposed broadening the current exemption from notice process to include mothballing.

The ESB acknowledges the concerns of stakeholders and considers that changes to the notice of closure requirements should:

1. ensure any changes are sufficiently flexible to adapt to a changing environment,
2. establish where possible simple, automated, and transparent means of collecting and reporting participant information, and
3. avoid undue regulatory burden on participants, market bodies and jurisdictions.

The ESB considers that the changes proposed satisfy the above criteria and the potential benefits are likely to outweigh the additional costs and regulatory burden associated with amending AEMO and participant systems and processes. These trade-offs are explored further in Table 1.

Table 1 Recommended reform options – High Level Benefits and Costs.

Recommendation	***Establish the reporting of a unit's status through reason codes via MT PASA***	***Establish the reporting of recall times via MT PASA when triggered through reason code***
Benefits	• Implemented with minimal changes to NER • Simple, automated, and transparent means of collecting and reporting participant information	• Implemented with minimal changes to NER • Anticipated low implementation and ongoing costs for AEMO/participants • Provides more granular information to all stakeholders

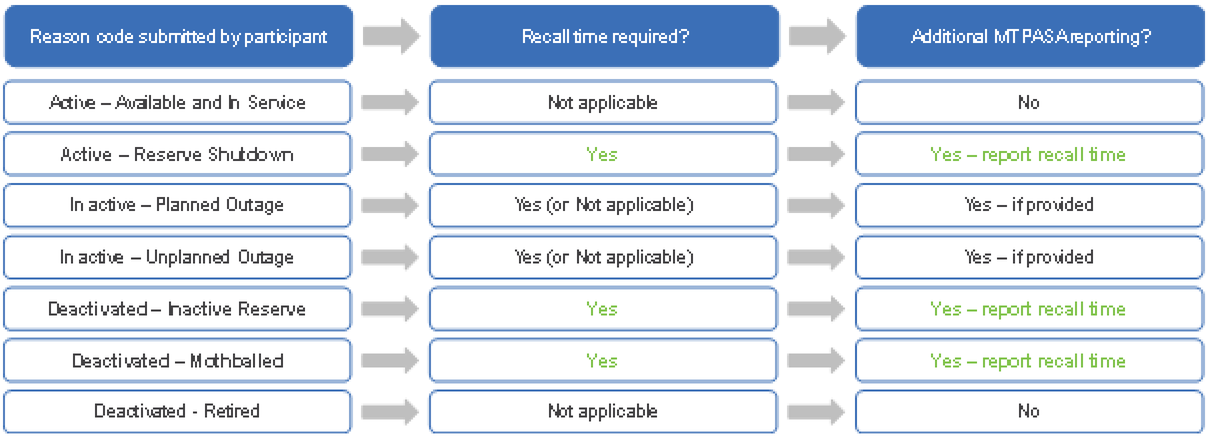
[6] https://standards.ieee.org/standard/762-2006.html

Recommendation	***Establish the reporting of a unit's status through reason codes via MT PASA***	***Establish the reporting of recall times via MT PASA when triggered through reason code***
	• Clear compliance obligations for participants to update immediately once decisions to change unit availability are made • International precedent for use of IEEE Std 762-2006, tailored to a domestic context[7] • Improve information to support the AER's monitoring functions and compliance assessment	including how existing participants availability may change if units are recalled • Avoids automated publishing of additional reliability runs, however provides for greater flexibility in modelling sensitivity analysis of real-world outcomes • Allows for submission of a range of recall times, capturing a variety of operational cases
Costs	• Requires clear definitions of individual reason codes • Requires scheduled generators to submit reason codes • Additional reporting by AEMO resources (if not automated) • Updates required to AEMO procedures and guidelines • Anticipated low/medium implementation and ongoing costs for AEMO/participants	• As adjacent

This information may be leveraged by other market bodies, including the AER. Specifically, this information may be used by the AER as part of its existing monitoring functions and could inform its assessment of compliance under the current notice of closure arrangements. This ability, together with:

[7] The figure below highlights how reason codes and recall times may be incorporated in practice leveraging at a high level those codes written into IEEE Std 762-2006. A range of recall times (e.g., days or months) may be accommodated in practice providing participants with sufficient flexibility to reflect their individual operational cases.

Figure: Reason code and recall time example



- stakeholders' opposition to including mothballing into AER's notice of closure exemption guideline
- difficulties in defining mothballing in a manner that reflects the potential spectrum of alternative arrangements, and
- uncertainty around compliance outcomes and potential cost impacts for all stakeholders

are the reasons why the ESB did not consider expanding the notice of closure exemption requirements to include mothballed plant.

The inclusion of recall times is a change from the option presented in the April Options paper which canvassed additional MT PASA modelling runs with alternative prescribed recall times (e.g., 7 days, 1 month). In light of feedback, the ESB has not recommended mandatory additional MT PASA modelling on a business as usual basis given the associated AEMO resourcing requirements and unclear benefits to the market. Additionally, setting prescribed recall times for such modelling may misrepresent the variety of operating conditions generators may select in the future, and may therefore not provide any insight into potential generator response to any reliability concerns.

Finally, no amendments to AEMO's existing Generator Information Survey (GIS) are proposed. Information gathered through the GIS is for the purposes of long-term reliability studies and does not provide the near-term granularity that can provided by the MT PASA. Further, the GIS process is manual in nature. It requires considerable AEMO and participant resources and interaction to ensure its accuracy and timeliness. Given AEMO has the ability to ask generators for additional information it reasonably requires in order to complete ESOO modelling, it is unnecessary to increase the regulatory burden on generators by amending the GIS.

Box 1 Torrens unit 4 – Looking into an example of mothballing

On 7th July AGL announced that from October 2021 it would be mothballing a unit (B1) at its Torrens Island Power Station[8] with a return to service period of 6 months. This is now represented in MT PASA as 0 MW available for unit B1 over the entire three-year outlook. AGL has indicated no change to the expected closure year for this unit which remains 2035.

The impact sought from the proposed changes to MT PASA focus on improving transparency and certainty to support improved reliability outcomes. The measures would seek to gain more visibility over when capable fleet – although mothballed – can be returned to service if the NEM were to encounter unexpected reliability shortfalls. Considerations of the cost of returning the unit to service can be made thereafter. The rule changes would also seek to provide improved certainty to potential entering fleet. Ambiguity as to whether a mothballed unit is out of service with the intention to return, or out of service with an intention to retire outside of significant reliability shortfalls, may prove to be important information in determining the outcome of a business case.

Under the proposed changes to MT PASA more information would be available to participants than at present about the nature of this outage. Specifically, AGL would be required to define the nature of the outage i.e., "mothballed" and the return to service period i.e., 6 months.

These details provided in MT PASA – bound by best endeavours in terms of its veracity – combined with other information about the generator's technology type, changes in the market and other insights drawn from public domain, may help an investor better assess the market need and profitability of a new generation investment.

Integrated process for managing early exit

The April Options paper also proposed an integrated process for managing early exits. Under this new process, additional information would be collated to allow a complete System and Market Impact Assessment, alongside the AER's exemption from closure decision. A System and Market Impact

8 https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2021/july/agl-to-mothball-one-unit-at-torrens-b-in-south-australia

Assessment would consider the operational risks and challenges to reliability and security that may arise from an earlier closure of one of a designated set of coal and gas fired generators, its likely impact on wholesale prices, and the continuing operational viability of the plant in question.

A small number of stakeholders offered broad support for the new, additional process. Of those offering support there is common agreement that this could integrate well with existing processes. However, a substantial number of participants did not support an integrated process. Stakeholders are concerned about the potential for such a process to end in an agreement with exiting plant for an Orderly Exit Management Contract. Even as a last resort option, stakeholders considered this could further undermine the role of the market.

On balance, taking into account feedback received, the ESB considers that the benefit of implementing a new prescriptive exit process is incremental at best. A more prescriptive, integrated process does have the potential to deliver benefits including:

- ensuring market participants are well informed in knowing what to expect if early exits were to emerge
- defining what information is to be gathered and shared when a retirement is announced
- helping to avoid the need for future ad-hoc formation of governmental task forces
- providing public reporting of the critical system and market risks, and
- providing greater transparency in future decision-making processes including for example where an OEMC is under consideration as a last resort option.

However, it is not without considerable costs and additional regulatory burden. For example:

- who should be responsible for completion or coordination of an assessment
- who should pay for an assessment to be completed
- what additional participant information requirements may be prescribed under the Rules
- who should be burdened with such compliance obligations (e.g. a definition or list of designated generators to be assessed), and
- how would "protected information" would be shared among market bodies and jurisdictions.

The ESB therefore no longer recommends this reform. The policy objectives associated with an integrated process can be met through a combination of existing processes, without the need for additional rule changes. For example, a jurisdiction may request relevant information from a participant, market body or, in specific instances, a third-party consultant.

AEMO also has existing obligations to reassess reliability reported under the ESOO following a material change in inputs or assumptions. Similarly, components of the proposed integrated process may be gathered through the AER's notice of closure exemption process. While the AER would not ordinarily publicly disclose any supporting information it received as part of an exemption application, it does have existing powers to share such information with certain government agencies and persons, including its related market bodies AEMO and AEMC.

Prior to the disclosure of confidential information, the AER would typically seek to notify and consult with the participant who had previously provided the information. In publishing its final decision, where possible, the AER would look to provide non-confidential reasons and analysis supporting its decision.

While a new integrated process is not recommended, the ESB strongly recommends that all jurisdictions engage early and regularly with participants and market bodies to understand any risks to reliability and available options, as well the spectrum of system and market impacts associated with any investment or contracting decisions.

The ESB also recommends that any viability, market impact or other assessments completed when considering the impact of a generator's retirement, be made transparent to the market to the extent practical. Understanding the assessed risk of early exits assists the market in making better decisions about how to address the implications of generator exits.

2.3.4. Implementing a Jurisdictional Strategic Reserve (JSR)

As we move to a new capacity mechanism in the medium term, a JSR may provide those jurisdictions who are concerned about increasing risk of unforeseen reliability events (for example, the early exit of generators within the notice of closure period) with an additional backstop. A JSR would facilitate the procurement of any required reserves additional beyond the market reliability standard that jurisdictions consider necessary, in a manner which is targeted and least distortionary to current market arrangements.

The jurisdiction would be responsible for determining the level of reserve that it considers appropriate and for requesting the reserve be established. The JSR would then become part of AEMO's RERT portfolio and would be activated by AEMO as needed. Fixed costs of the reserve would be recovered from the jurisdiction requesting them, while any operating costs would be recovered in a manner consistent with the existing cost recovery arrangement for the current RERT. As an out of market reserve, it also has no impact on spot prices, which are settled as if the JSR didn't exist.

The proposed design for the JSR and key considerations in determining some of the design choices are outlined below.

Choice of reserve level

The market settings are at levels which aim to deliver the resources needed to meet the market wide reliability standard. Where the market is not delivering sufficient capacity, AEMO would procure RERT. The proposed JSR allows jurisdictions that consider additional reserves are necessary to decide the level of reserves that are appropriate for its circumstances. In doing so, each jurisdiction makes its own trade-off between the risk of load shedding and the cost of procuring additional reserves, above those needed to meet the market wide reliability standard. The risk of load shedding will be provided through the information that is currently made available by AEMO in the ESOO and ISP, as well as other information made available by the AER through the notice of closure process (see above in section 2.3.3)

The current reliability standard of 0.002% unserved energy (USE) is under review by the Reliability Panel. There is also an interim reliability measure of 0.0006% USE which applies to triggering of the RRO and the procurement of RERT. Its continuation is subject to review by the AEMC by 1 July 2023[9]. Increasingly jurisdictions have their own specific criteria that they apply to trigger a reliability related action. For example, in South Australia, the Minister forms a view as to whether to trigger a T-3 RRO instrument, whereas in NSW the Minister considers his response in light of a breach of the NSW Energy Security Target.

The ESB recommends that the market settings and RERT be focussed on achieving the NEM reliability standard – 0.002% USE or its replacement. A jurisdiction can use the JSR mechanisms to ensure additional reserves it deems warranted. Allowing jurisdictions to determine a reserve level that meets any additional criteria allows those states that do not have reliability concerns the flexibility to choose whether to participate in or fund the additional reserves a JSR could provide.

9 NER 11.128.12(c)

Costs of a JSR

The ESB proposes that the fixed purchase and establishment costs of the strategic reserves be met by the jurisdictions seeking the reserves. It will be for a jurisdiction to balance the costs of these additional reserves with the risks that a jurisdiction seeks to address given its circumstances. Variable costs, that is the cost of using the resources over and above the setup costs, would continue to be recovered through current RERT arrangements.[10]

Procuring strategic reserves in one jurisdiction could have benefits for neighbouring jurisdictions given the NEM's interconnected power system. Given that the decision to enter a JSR is made by a jurisdiction in relation to its own circumstances, the starting position when considering sharing of costs is that the fixed cost of the JSR should be borne by the jurisdiction seeking the additional reserve. If there are benefits to a neighbouring jurisdiction from the JSR then it would make sense for the two states to reach an agreement to share costs.[11] Variable costs can be dealt with under the existing RERT arrangements, which assigns them to the benefitting regions.

The cost recovery arrangements provide protection for electricity consumers in each region from unnecessary over-procurement of reserves, and from contributing to the cost of reserves established in other regions. The actual dispatch of reserves depends on whether any reliability events occur and so electricity consumers are only asked to cover the variable cost of actually using the JSR in the region it was activated, unless jurisdictions recover fixed JSR costs from consumers through a separate mechanism.

Dispatch of the Jurisdictional Strategic Reserve

Once established, the JSR could form all or part of AEMO's portfolio of RERT resources and would be dispatched in accordance with AEMO's Procedure for the Exercise of the RERT.[12] AEMO optimises reserves on the day to activate whatever reserve contracts it has already procured in a manner to minimise costs. Intervention pricing would generally apply during the use of such reserves, as is the case now when reserves are used under the RERT, restoring the whole price signal.

Out of market provisions

The proposed JSR will be an out of market mechanism compatible with the RERT so it acts to provide an enhanced backstop for jurisdictions. Some jurisdictions already have the ability to increase the volume of resources in the market. For example, NSW could use a breach of the Energy Security Target to trigger underwriting of a new on-market firming resource.

Under the current RERT rules AEMO must not contract resources (a scheduled generator or scheduled demand response) where the resource has participated in the market within the last 12 months. Whether this restriction needs to change to meet the objective of a JSR needs to be considered further in the detailed design of the mechanism, particularly in light of the principles proposed above for Orderly Exit Management Contracts.

10 This proposed cost model replicates the approach that was used for the SAPN diesel generators and the ARENA RERT contracts. In both instances the fixed costs (availability) establishing reserve were paid for outside of the market and the variable costs (pre-activation and activation) were recovered through the normal RERT cost recovery framework.

11 A protocol for the use of the JSR to avoid interstate load shedding could also be agreed.

12 AEMO. Procedure for the Exercise of Reliability and Emergency Reserve Trader RERT. Available here <https://www.aemo.com.au/-/media/Files/Electricity/NEM/Emergency_Management/RERT/Procedure_for_the_Exercise_of_Reliability_and_Emergency_Reserve_Trader_RERT.pdf>

RERT reporting provisions

There are extensive reporting requirements associated with RERT to provide transparency about AEMO's contracting and dispatch decisions for the use of reserves. These provisions need to be considered with a view to understanding which ones remain appropriate for a JSR where the state rather than AEMO is making the decision to procure.

Interactions with the RRO

As an out of market reserve the proposed JSR would not be relevant to considering the reliability gaps in AEMO's reliability forecast contained within the ESOO. Therefore, if a reliability gap is forecast in a year's time, then (under the current RRO), retailers and market customers are still required to demonstrate compliance with the RRO, that is ensure sufficient qualifying contracts to meet their scaled demand.

2.3.5. A Ministerial trigger for T-3 RRO instruments

Until a new capacity mechanism is in place, the ESB considers a jurisdictional lever to trigger the RRO to be an appropriate tool for jurisdictions to manage reliability gaps, where a jurisdiction considers additional confidence (over and above the other immediate measures) is needed. The ESB recommends this be implemented nationally to allow Ministers to use a lever if they so wish. If this reform is not agreed, it is open for jurisdictions to implement a lever in their own jurisdictions.

Box 2 The current RRO

The current RRO scheme started on 1 July 2019. The RRO scheme supports reliability by requiring retailers and large energy users to enter contracts (or own generation capacity) to match their electricity demand in periods when AEMO forecasts a reliability gap between generation and peak demand. If a material gap is determined 3 years out then AEMO will ask the AER to formally trigger the RRO.

Once the RRO is triggered, electricity retailers and large energy users (liable entities) are on notice to secure contracts for sufficient generation to cover their expected demand for grid-supplied electricity, based on a one-in-two-year peak demand forecast.

If a forecast gap persists one year out then liable entities must submit their contract position to the AER. AEMO may also procure emergency reserves through the RERT mechanism to address any remaining supply gap. If actual peak demand exceeds the forecast, the AER must assess liable entities' contract positions against their share of system load (scaled to P50 demand). Entities without adequate contracts will be required to contribute to the cost of AEMO procuring emergency reserves.

At present, only the South Australian Minister has the ability to trigger the RRO at T-3 in the event it does not trigger automatically.[13] The Minister triggered the RRO in South Australia for periods in the

13 At its 26 October 2018 COAG Energy Council meeting, Ministers agreed that the Energy Security Board (ESB) would progress development of draft National Electricity Law (NEL) amendments that would give effect to a Retailer Reliability Obligation (RRO), including undertaking any further necessary stakeholder engagement. Ministers noted the need for final design of the RRO to ensure South Australia can manage its reliability concerns through the transition to the new mechanism. The ESB consequently consulted on the draft of the National Electricity (South Australia) (Retailer Reliability Obligation) Amendment Bill 2018 (Reliability Draft Bill). Consultation on the Reliability Draft Bill ended on 22 November 2018. The COAG Energy Council agreed on 20 June 2019 to amendments which empower South Australia's Energy Minister to trigger the RRO in South Australia.
https://www.energymining.sa.gov.au/__data/assets/pdf_file/0019/336007/181129_SA_RRO_Amendment_Bill_Consultation_Paper.pdf
https://energyministers.gov.au/sites/prod.energycouncil/files/publications/documents/RRO%20Bulletin%20-%2020190701.pdf

first quarters of 2022, 2023 and 2024. The 2022 RRO period was subsequently revoked, as AEMO did not identify an enduring reliability gap one year ahead.[14]

Until a new capacity mechanism is in place, it is important that jurisdictions have confidence that reliability concerns will be met within their regions.

The benefits of a jurisdictional RRO trigger, include access to an existing mechanism that:

- can be implemented relatively quickly, with low costs, to support additional capacity in a relevant jurisdiction. This could obviate the need for government investment in that additional capacity.
- is well understood by market participants.
- complements, rather than replaces, market financial signals and so is not distortionary.

Removal of the T-3 trigger

In the April Options paper, the ESB proposed an option of modifying the current RRO by removing the T-3 trigger and maintaining the use of financial contracts. This option sought to improve the current RRO's focus on encouraging retailers and large load to contract earlier, and provide stronger investment signals, while concurrently looking to simplify some of the RRO's complexities.

Some stakeholder submissions to the April Options paper commented on this option. There were mixed views on whether removing the T-3 trigger would increase contracting and strengthen investment signals, with those opposed to the change noting retailers may be more likely to offset additional hedging risk through short-term products.

Given the ESB's concerns around the sustainability of the current arrangements, the ESB chose to focus on a more physical RRO as an enduring solution. However, given its use in South Australia, and speed with which a Ministerial trigger could be implemented, the introduction of a Ministerial trigger may provide additional confidence for those jurisdictions that reliability in the short term will be met.

2.3.6. Operating reserves

Stakeholder feedback to the April Options paper suggested there was a need to consider an operating reserve as an alternative to modifying the RRO.

Careful consideration of the benefits and the costs and risks of explicitly unbundling operating reserves to create a new service, including its resource adequacy implications, is ongoing. The ESB notes these issues are being considered as part of the AEMC's reserve services rule changes and it is appropriate for these matters to be resolved within that forum. Further discussion of this reform is set out in section 3.3.4.

2.4. Initial reforms

The ESB recommends that Ministers agree in principle to adopt a capacity mechanism for implementation over the medium term. Over the next 12 – 18 months,[15] the ESB is proposing to develop the detailed design for a mechanism to explicitly value (or unbundle) capacity from the implicit capacity signals within the energy price. The straw proposal for the Physical Retail Reliability Obligation (Physical RRO) is proposed as a starting point. The features of a straw proposal are

14 AER, State of the Energy Market 2021, p.40.

15 The ESB notes that international experience suggests that development of an appropriately designed capacity mechanism can be an involved process. The UK developed a central capacity market over five years and introduced it in 2014 as part of a wider programme of reform to decarbonise the UK's electricity supply while maintaining reliability and affordability. The French capacity mechanism was implemented in 2017, with development beginning in 2010 and detailed rule design from 2014.

discussed below and set out in detail in Part C. The straw proposal intended to meet the objective of long-term investment signals for the right mix of resources, such as variable, flexible/firm capacity across the generation fleet. Features of such a mechanism, and choices for its settings can be combined to deliver various outcomes. The detailed design process will also consider whether alternative approaches, or adaptations to the Physical Retail Reliability Obligation, are preferable. These are discussed below.

Importantly, the detailed design process provides the opportunity for comprehensive consultation on the choices to be made for a mechanism – noting there are trade-offs between confidence in the capacity mechanism and in the associated implementation costs – and how to address the impacts of what is a very significant shift in market design.

2.4.1. The resource adequacy problem

Over the course of the Post 2025 project, the ESB considered a spectrum of options to manage timely entry and orderly exit in different ways. A subset of these options explored approaches based on existing arrangements, including various modifications to the RRO considered in the April paper. These included an enduring Physical RRO, which proposed a model to change the definition of qualifying contracts to newly created physical certificates.

Stakeholder feedback on the options was extensive, particularly in relation to the Physical RRO. There are mixed views on the nature and definition of resource adequacy problems and the need to address them with new or enhanced mechanisms. Some stakeholders considered there to be no material resource adequacy problem, or that existing market arrangements are sufficient to manage timely entry and orderly exit. Others noted the problem remained undefined, which made it difficult to effectively assess the trade-offs involved in new mechanisms. There are views that resource adequacy problems are emerging and that the continued departure from using the NEM spot price as a fundamental driver for new investment may necessitate more substantial changes from the existing architecture of the NEM, including additional markets that value attributes other than energy. With those stakeholders who considered there may be a case for change, there was limited consensus on the reforms proposed by the ESB. Concerns are raised that there is inadequate time to consider the options, and that the options are not sufficiently developed to allow for substantive consultation.

The ESB took note of stakeholder feedback – particularly in developing immediate reforms – but remain concerned that submissions that advocated for reform options that closely reflected current arrangements did not sufficiently engage with the scale of the transformation ahead, or whether sufficient investment in the right mix of resources would be delivered without reform. In considering the need for a capacity mechanism, the ESB placed less emphasis on whether there is a reliability problem now and considered what is needed to drive future investment, given the trends that are observable now and their ongoing impacts.

Market dynamics are changing rapidly. Technology costs for renewable and storage resources continue their sharp decline, while persistent demand risks pose challenges for hedging. Potential changes by generators to the timing of large thermal exits will impact the timeliness of replacement capacity and potentially affect reliability and price. A future high-VRE power system with low-to-no fuel costs diminishes the value for capacity implicit in current spot and contract prices, which are currently low on *average*. Power Purchase Agreements – which predominantly underwrite VRE – may not be in such plentiful supply. Lower prices drive out existing older thermal generation earlier thereby increasing spot prices without timely replacement. Higher spot prices however are needed under the current frameworks to encourage investment in replacement capacity.

Because of this, periods of extreme price volatility, which could mitigate the dampening effect of low average prices, could be 'discounted' by investors in calculating revenue streams, because of concerns that they will not be tolerated by jurisdictions or that such revenue from high prices is too infrequent or uncertain to rely on. Without adequately valuing capacity, it is unclear if price signals in the current market are enough for the investment in flexible capacity needed to support a high level of VRE penetration.

Meanwhile, jurisdictions naturally feel compelled to step in to manage longer-term risk if they feel it isn't being managed elsewhere in the market by implementing their own reliability measures, announcing ambitious renewable energy targets along with mechanisms to underwrite existing or new firm capacity. The political hurdle rate (that is, the willingness to accept gaps in reliability or higher prices) seems to be significantly lower than the private sector hurdle rate with governments investing sooner to manage risk on behalf of customers. This speaks to their limited confidence in the market to deliver the investment required without some form of government intervention.

These dynamics mean there is a choice to be made as to where the signal to invest in the NEM for the future should come from and who should bear the risk of ensuring resource adequacy.

The above trends, together with a one-to-three-year focus by market participants on customer contracting behaviour, incentivises participants to manage their risk over the short rather than longer-term. It suggests an insufficient market incentive to manage long-term capacity risk. This leads to a disconnect between the risks faced by the market and those faced by governments on behalf of consumers. Consumers are therefore left bearing the risk of resource inadequacy due to a failure by the market to invest for the long term.

The problem to address is one of *risk allocation.* Without the ability to lock in longer-term revenue streams, participants need sufficient incentive and confidence to invest in an environment of extreme uncertainty. Jurisdictions need reassurance that participants are going to meet the needs of the system. Without this assurance, jurisdictions will continue to intervene in the market in order to ensure supply meets reliability with capacity-equivalent arrangements, increasing investment risk in the process.

The ESB considers there needs to be *alignment* between the risk decisions faced by the participants and the risk expectations of the jurisdictions. Governments can therefore be reassured that the market delivers timely entry and orderly exit, in a manner that is consistent with the expectations of consumers

To encourage investors to take long-term capacity risk, market arrangements that unbundle the signal for capacity from the energy price are needed to support the quantum of build required over the next decade. Valuing capacity explicitly complements existing spot and contract market revenue streams, and in doing so may fill what the above trends would suggest is 'missing' from our current market design.

2.5. The case for explicitly valuing capacity

A mechanism to explicitly value capacity for the competitive provision of the right mix of resources is a significant change to present NEM design. There are a number of challenges arising from the above trends that suggest this change is necessary.

First, the NEM does value capacity at present, but the ESB considers that its 'energy only' market design may no longer be sufficient to encourage the new investment in the right mix of resources that is needed in future for reliability in the system. This is because a generation fleet with a high proportion of variable renewable generation changes the underlying dynamics in an 'energy only' market. Unlike thermal and hydroelectric plant, their output is weather dependant and variable. Typically, their fuel costs and related marginal costs are very low. Within the "merit order" at dispatch - if weather allows it - they displace higher cost firm generation. This includes higher fuel cost thermal plants whose profits decline and whose financial viability becomes tenuous. As a result, prices on average are lower.

The basic problem is that the NEM requires firm and flexible resources to back up the weather dependent low-cost wind and solar fleet. And while this need may not be evident in all seasons at present, the future need is clearly growing. Over the next two decades 26-50 gigawatts (GW) of new large scale variable renewable energy and 13 – 24 GW of distributed PV – in addition to existing and committed projects – are forecast to come online. This means there is a need for 6-19 GW of new utility scale, flexible and firm resources, as up to 63% of the current coal and gas fleet in the NEM retires by 2040.

To ensure the high levels of reliability we expect, that need must be met under a range of relatively extreme situations. An energy only market relies on prices being high enough to incentivise investment in some resources which may only be called on rarely. In the future, the ability to recover the fixed costs of capital of investment through market revenue - regardless of its technology type - will be challenged as the volume of VRE plant with little to no running costs increase.[16] Average prices will be low, high price periods may be frequent, but will be unpredictable, or occur irregularly. While the value of energy is effectively signalled and compensated under these conditions, high price periods are the market's only way to signal the value of capacity. Limited government tolerance for, and the possibility of government intervention to reduce these high prices challenges an energy only market to generate the right signals necessary for long term capacity.

Box 3 How resource adequacy is currently managed in the NEM: price signals to deliver the quantity of capacity

The reliability standard currently defines the level of reliability which balances the cost of achieving that standard with consumers' willingness to pay for avoiding being without power - representing the trade-off between the dual objectives of reliability and affordability.

The reliability standard is accompanied by regulated price settings. One of these regulated price settings is the Market Price Cap (MPC). It aims to provide an upper price limit high enough to drive the necessary investment while protecting market participants and customers from extreme prices. These settings are reviewed every four years by the Reliability Panel.

The level of - and how often prices are expected to reach - the MPC affects the attractiveness of investing in the NEM. Using the MPC and other settings is an indirect approach to achieving the required reliability standard. Absent perfect foresight, the selected MPC may not drive the level of investment needed to retain all the resources required to meet the reliability standard exactly

Under the current market arrangements, the NEM has a high MPC in comparison to other international markets given it is an energy-only market. The MPC is set at a level needed to recover the costs of investment in the resources needed to meet the reliability standard. The impact of a higher MPC is twofold:

- It creates price risk in the market. This incentivises generators and retailers to provide generation and contract with each other to a greater degree to reduce the greater potential price volatility. The amount of capacity that is contracted is decided by the retailer, based on what they think will be the demand for energy from their customers. Generators that have sold those contracts to retailers then make sure that their plant is available to the contracted amount when high prices occur.
- It is the combination of price risk and the contracting incentives derived from this risk that drives investment in the NEM. These long-term investment decisions include decisions to invest in new

[16] This is expected to occur until discretionary loads, such as the production of hydrogen and charging of storage resources, become more economically viable increasing overall demand and placing upward pressure on prices.

capacity, to provide demand-side solutions and to retire capacity, determining the quantity of how much capacity is invested in the NEM, aside from government-led investment.

Second, within the present market design, the investment case for a participant to build a new source of firm generation supply is not compelling. The uncertainty of the future investing environment adds significant risks which the exiting architecture of the market may no longer be equipped to address for the long term. It is difficult (if not impossible) to forecast when the high price events in the NEM will occur and how long they will last. The difficulty is acute for new thermal and hydro plant where a typically large capital cost must be recovered over a long lifetime. For renewables, PPAs (or a large existing customer base for vertically integrated gentailers) is the main way that new build is underwritten. This may change in future if these parties cannot get a PPA to form the basis for its investment based on a low average and volatile pool price, alongside high uncertainty in demand.

At least three matters add to this future investment uncertainty:

1. The first is the future change in technology and costs. The costs of variable renewable technology and batteries are changing, creating new considerations for what will be the most economically viable technology for generation in the longer term. Battery technology is a good example. The capital costs of battery technology has been falling significantly. While existing plant equipped to provide similar services may become uncompetitive against new battery entrants, new entrants however may decide to delay their investment until their initial capital cost declines further. This technology has the advantage of relatively low cost and relatively short asset life but the service they can commercially offer as firm and flexible plant is time limited (to about 4 hours) at present, and not yet completely substitutable with existing capacity assets.

2. Second, demand risk in the market is changing rapidly. As we move forward DER and demand response will have a key role in maintaining reliability and minimising both system and consumer costs. Both can provide flexible energy sources to shift and flatten load and provide alternative ways of meeting peak demand. Demand profiles are changing as residential customers support the growth in solar PV and battery installation, along with engaging with smart appliances and other DER. More active DER, and the integration of flexible demand allows consumers, or third-party aggregators on their behalf to become more active in the wholesale market, leading to increasingly altered demand outcomes and impacting the 'at risk' reliability periods that capacity in the whole market need to address.

   In the commercial and industrial sector, a similar trend is occurring. Large users are examining ways to modify their production processes to become more flexible as they strive to produce 'green' steel, aluminium and even 'green' cement. Energy intensive commercial and industrial demand has also been falling, and there is uncertainty over future energy intensive industries, also making it difficult for generation investors to undertake long term investments that would have otherwise underpinned commercial and industrial electricity demand. In addition, many of these large commercial and industrial customers – and an increasing number of retailers for residential customers – do not contract forward but instead lower their costs by managing their price risk in the real time market.

   At a broader level it is also argued that demand may increase substantially after years of decline with the entry of EVs, larger demand from energy intensive data centres, from hydrogen electrolysis production and increasing electrification in other sectors as they seek to decarbonise.

   Integration of these new sources of supply into the market is underway. In the meantime, the changing nature of demand risk in the market creates uncertainty for investment in generation plant, particularly in how to hedge this risk as an increasing number of customers manage their load.

3. Finally, the risks of investing is exacerbated by government intervention. In recent years the industry has experienced government policy that encourages new renewable generation in order to meet various emissions reductions targets as well as other objectives. At the same time governments have also intervened to ensure supply is available by effectively subsidising capital expenditure in firm generation or directly contracting to have plant built. Such interventions in the market do not encourage independent private sector entrants or upgrades and maintenance to existing firm generation plant. The uncoordinated nature of these interventions also dampens price volatility in the market and lessens the high price events needed to encourage investment in the right mix of resources. There is a risk that more participants take an uncovered risk on the spot market as governments continue to intervene in a way that reduces prices.

This investment uncertainty and the increasing volatility of high price events suggest that under the current market design, investors will discount the contribution of these events to revenue streams in their business case analysis for new firm and flexible resources. The revenue potentially earned during high price events in the NEM would need to increase significantly to facilitate investment to deliver the reliability standard. Increasing the MPC could provide a solution to the issues identified. Quantitative analysis conducted by the ESB has assessed the level to which the market price cap must be lifted to achieve the same level of reliability, under the assumption that participants are discounting spot prices above $300 per MWh. This analysis suggests that if this discounting by investors amounts to 50-75% of prospective over cap revenue streams, the MPC may need to increase to between $35,000 to $60,000 to support resources expecting 5.5 hours of revenue at price cap (from its current level of approximately $15,000).

Adjusting the current market signal for capacity, the MPC, could (at least in theory) provide a solution to the issues identified above. However, governments (and indeed consumers) have shown little tolerance or enthusiasm for periods of such high prices that an adjusted MPC could provide. Neither is there confidence in market participants' willingness to act. However, by explicitly valuing capacity, the volume of capacity needed to meet reliability can be targeted more directly with market signals. The certainty of revenue for capacity from a more 'targeted' signal better addresses the current and future investment uncertainty. As this uncertainty subsides with a new market design, government and community confidence about resource adequacy can be expected to increase, reducing the need for interventions.

International electricity markets are facing similar issues to those in the NEM. It is notable that most international markets have some method of valuing capacity directly, often working as an 'adjunct' to other market mechanisms. An overview of international developments in included in Part C.

2.5.1. A new capacity mechanism

A future NEM needs to achieve a more 'investable' and verifiable signal that more directly targets the needed capacity for timely entry and orderly exit. Through a regulatory framework for an additional tradeable product such as a certificate scheme, the capacity needs of the NEM can be incentivised additionally, but complementary, to an energy only market that may no longer be best equipped to signal for capacity solely through an energy price.

Any capacity mechanism needs to support investment signals in the mix of technologies and capacities that are needed to provide reliability, namely those that are flexible and responsive to support very high penetrations of variable fleet. It needs to support existing assets to be reliable until they are expected to exit – particularly those existing assets which are both critical and cost-effective in supporting increasing levels of VRE penetration. Further, the mechanism must be effective in impacting the timing of outcomes. Sufficient capacity must be in place in time for anticipated plant closures, in order to meet the expectations of jurisdictions but also to not cause significant price or reliability costs to consumers.

In considering a capacity mechanism, a key objective was that it complements the existing market, in an environment where the efficacy of spot and contract prices are at risk of being dampened or discounted. It should bolster, not distract from, the market settings. A straw proposal - a Physical Retailer Reliability Obligations - was developed in this context.

The key feature of the proposed PRRO is to change the nature of qualifying contracts under the current RRO to a separate tradeable certificate (detailed in Box 4 below). The intent is to support timely entry and orderly exit by defining the tradeable certificates in terms of their ability to be available during 'at risk' reliability periods. Participants would continue to manage their financial risk in the spot market through financial contracts. Market customers would need to hold enough certificates to cover their determined liability when positions were assessed.

Box 4 Recap - The Physical Retailer Reliability Obligation

The PRRO is a straw proposal for a capacity mechanism achieved through physical certificates and leverages existing market arrangements to work as an adjunct to them. It borrows features from other decentralised capacity markets, such as the French Capacity Mechanism, and applies them as they are practical in a NEM context. Its key design features are described below:

- Change the nature of the current obligation so that liable entities (retailers and large customers and other customers who opt in) are required to hold sufficient qualifying capacity certificates rather than sufficient qualifying financial contracts to cover their share of actual peak electricity demand. Liable entities would hold certificates for RRO-compliance purposes. However, they will remain incentivised to purchase financial contracts to continue to manage price risk in the spot market.
- It would operate as an ongoing obligation, without either the T-3 or T-1 Reliability Triggers that exist in the current RRO design. Under a certificate scheme, these two time points remain important for the purpose of certifying resources [T-3], or for the purpose of AEMO procuring out-of-market resources in the event of a reliability shortfall [T-1].
- Physical resources to support certificates would be assessed and certified by AEMO in advance.
- Liable entities would not be required to submit their certificate positions in advance of a potential shortfall. Instead, reporting on certificate positions would become an ex-post obligation at T, not T-1, contingent on the triggering of a compliance assessment.
- Compliance assessment and enforcement would be dependent on a reliability shortfall having occurred, namely RERT activation or dispatch, or unserved energy. This shortfall would need to occur during a predefined period of time and demand level that would align with the certification assessment time period.
- The volume of required capacity is determined by liable entities, leaving the risks for forecasting with these entities, who are best placed to forecast their demand requirements. Liable entities would be required to hold a certificate position to cover their actual demand. Requiring retailers to cover their full load, as opposed to a share of P50, or P10 levels, creates a decentralised market demand for certificates. Market customers would decide how risk averse they want to be in avoiding compliance penalties if assessment periods are

triggered, in turn creating a demand that reflects risk sensitivities of different load business models.

- The forward value of certificates would reflect any perceived risks of scarcity (high prices). Certificates would be expected to have minimal value where energy market price settings are adequate to drive the investment needed.

The April Options paper considered a range of design settings for how the tradeable certificate could be defined, certified, allocated, traded, and assessed for compliance, among other criteria. Within these criteria, there are different design choices on where to 'set the dial,' which alter the outcome of the mechanism. There are choices that decentralise risk and signal a value for certificates that closer reflect the needs of the system in real-time. This can ensure the signal for capacity closely matches the market price settings but may provide less long-term certainty for investors.

Conversely, there are design choices that use a more centralised forecasting approach that anticipates or insures for the needs of the system in advance. However, having a long gap between the real-time and when procurement decisions are made runs the risk of the mechanism not accurately reflecting the needs of the system, leading to over or under supply with greater risk borne by consumers as opposed to market participants. The objective of the PRRO straw proposal should be for its obligations and its value to be reflective of, and reactive to, the needs of the power system at points in time where reliability may be at risk.

The criteria and settings for this tradeable certificate should remain consistent and certain for periods of time so that market participants can have confidence in its value and its ability to effectively support revenue streams. The criteria and settings should also be adjustable to an extent so that policy-makers – over the course of review cycles – can leverage the certificate framework to facilitate timely entry and orderly exit at the most efficient cost to consumers.

The ESB also acknowledges that the nature of the mechanism and particularly decisions about what *goes into* the certificates – to best support the power system over the course of transition – requires consultation. While the ESB has considered a range of models to either unbundle or explicitly value capacity over the course of the project, it is likely that a hybrid design that borrows from each may deliver the best outcomes. In leveraging centralised settings for some criteria and decentralised settings for others, a certificate scheme could complement the spot market in signalling for investment when it is needed, facilitating least-cost entry over efficient time horizons, and lessening price volatility that would otherwise be discounted.

Targets for jurisdictional schemes could also be integrated in a new capacity mechanism. For example, in the context of a certificate scheme, this could be done through a centrally administered scheme that guarantees, in the case of the straw proposal, a minimum certificate price for new entrants based on pre-determined triggers in each jurisdiction.[17] This could involve AEMO running an annual process that would provide a minimum price on certificates for new projects from year 4 onwards for a period of 5-7 years. This process would be triggered by a pre-determined level of reliability over the period and could be run using a reverse auction which would seek to minimise the level of reliability that was guaranteed (and encouraging the risk allocation to remain with investors).

---

[17] This is not dissimilar to the long-term tender mechanism adopted in France. Under this scheme a guaranteed price is set at the conclusion of each tender. Candidates whose offers are below the guaranteed price are selected and awarded contracts for difference, ensuring they receive steady remuneration equal to the guaranteed price for a period of seven years. If the guaranteed price is above the market price over the course of the period covered by a contract, the selected party will obtain the difference. If it is below the market price, the party will pay the difference into a dedicated fund.

Set out in Part C are the key features of such a certificate mechanism and the nature of design choices available in designing them.

2.5.2. Economic and impact analysis of a new capacity mechanism

Benefits

The ESB has undertaken modelling to consider the likely benefits of the introduction of a new capacity mechanism in the NEM. The modelling analysis undertaken by the ESB shows that, to achieve the acceptable reliability in the face of uncertainty as to when generators will exit, there are potential benefits of a new capacity mechanism of $1.3 billion (NPV), when compared to adjusting the current market signals for capacity by raising the market price cap and increasing price volatility in the energy market. This modelling suggests that, with reform (an appropriately designed capacity mechanism) it will be cheaper to deliver capacity under new market arrangements that reduce the uncertainty for investment in capacity. Without reform to the way that plants enter and exit the system to smooth the transition, there will be costs to consumers. The timely entry of generation to replace gaps in available capacity is also crucial to maintaining reliability,

This is discussed further in Chapter 7.

Impacts of the PRRO straw proposal on the fleet

As discussed above, it is envisaged that the compliance assessment for a certificate scheme would be based on a reliability shortfall occurring. Given the timing of the ESB's focus on implementing a capacity mechanism, the natural providers of certificates are expected to change due to the changing nature of anticipated reliability shortfalls. Beyond 2025 the types of resources that are expected to be best incentivised by a certificate scheme are those resources that are flexible, reliable and economically competitive when operating at low-capacity factors. Peaking gas plants such as Open Cycle Gas Turbines (OCGTs) and hydro units are most likely to be suited to such schemes in the short-term, while longer duration storage will become well suited to covering such shortfalls – and therefore should be facilitated by a certificate scheme – as the technology develops. Higher capacity fleet may continue to be valuable from a reliability perspective for a time, but their eligibility for such a scheme would be determined by the extent to which they can respond flexibly to periods of need targeted by certificates.

However, ultimately all resources that operate at these times should be able to benefit from selling certificates. It will be these resources that provide insurance to the system for periods of low renewable energy output or poor reliability from an ageing thermal fleet. Even fleet with lower expected capacity factors during periods of need – such as wind resources during peak summer intervals – will still benefit from some certificate revenue. As long-term forward outlooks of average prices remain low, this revenue may prove valuable in supporting the business cases of resources that are principally capital intensive, regardless of their technology type. Further, it would seek to incentivise fleet that otherwise have lower-capacity factors or are less firm, to seek technological solution to improve their firmness for periods of need.

The value of a capacity certificate should be derived from being available during periods of anticipated reliability shortfalls. All resource types would be considered eligible for participation and certification How much they are certified for depends on the resource, and the timing and duration of anticipated shortfalls. In this sense, all resources seeking certification would be rewarded for the portion of capacity they are able to provide.

Design choices underpinning a capacity mechanism determine how well power system reliability can be preserved while effectively incentivising the most efficient capacity providers as the generation mix changes. An ideal mechanism will be agile so to capture both the evolving nature of power system reliability risks, while also ensuring the resources that participate most fully in the mechanism are best placed and most cost effective at managing these risks over time. Some of these design choices and the impact are expanded upon in Appendix C.

Before 2025, reliability risks will emerge from familiar conditions. Summer evening peak periods of high demand and low or declining VRE output are likely to incentivise capacity providers from dispatchable thermal fleet. As the reliability of traditional thermal generators decline and their capacity is derated, and as technology costs continue to fall, flexible resources like storage, hydro, and demand response will emerge as prominent suppliers. In the longer term, the irregular risk of VRE droughts in a step change transition scenario incentivise the right mix of resources under a capacity mechanism – at first gas turbines, and later deep storage – to manage tail risk reliability events. Although VRE may initially be discounted for reliability gap periods of this type, an appropriately designed mechanism could bring about allocatively efficient outcomes by incentivising storage co-location to shift capacity value of VRE during high output periods to lower periods.

2.5.3. Further considerations as part of the detailed design process

As part of the detailed design process the ESB recommends consideration should also be given to:

a) whether using existing contracts between registered market participants would be preferable as the basis of the scheme (rather than creating a new certificate),

b) how to best address the impacts of the proposed capacity mechanism on retail competition (including small retailers), commercial and industrial customers, market power concerns, transaction costs for market participants, and affordability, and

c) integrating a NEM-wide, common approach to jurisdiction investment schemes to work alongside the new capacity mechanism.

The detailed design process should also consider whether it would be preferable to centrally determine the volume of required capacity. This matter is discussed further in Part C as part of the design choices and settings for a possible mechanism.

Alternative contract structures rather than creating certificates

An alternative to creating a physical RRO based on a capacity certificate is to alter the definition of qualifying contracts in a way that increases the likelihood of a physical linkage, without having a physical certificate in place. Altering, or limiting the nature of contracts that are considered as 'qualifying contracts' for the purposes of the RRO could incentivise financial contracting which has a stronger link to achieving a 'firm' physical resource outcome (see Box 5 below). This could be done a number of ways, including but not limited revising the firming guidelines for different contracts, or only considering qualifying contracts from certified counterparties.

There are both advantages and disadvantages in taking this approach. Altering the definition of the qualifying contracts could provide more confidence that financial contracts are backed by physical resources. Using a different base for the capacity mechanism (contracts rather than certificates) could minimise the time needed for detailed design of the mechanism and has the advantage of not requiring the establishment of a new certificate scheme. It thereby avoids complexities associated with allocating and auditing of physical certificates, avoids the need to design an extensive and potentially complex penalty regime, and could provide for much faster implementation than a physical certificate scheme. It also provides a strong financial incentive to 'show up' on the day due to the price differential between the market price cap and strike price, which is complementary to the enforcement regime of the RRO.

Box 5 Qualifying contract definition under existing arrangements

The existing RRO requires that – following a T-1 RRO trigger – liable entities submit their contract books to the AER, in line with requirements in the regulations and guidelines. Contract books show the contracts held by the liable entity at T-1 which cover the identified reliability gap period. Liable entities are required to hold sufficient firmness-adjusted contracts (totalling a net contract position, in MW) to cover their share of P50 peak demand during the forecast gap period.

Liable entities must calculate the relative 'firmness' of each of their qualifying contracts in line with the AER's Contracts and Firmness Guidelines. For standard contract types, default methodologies are predefined by the AER. For non-standard qualifying contract types, liable entities develop bespoke contract methodologies in line with AER firmness principles and must have an approved independent auditor sign off on an audit of the methodology. The 'firmness' of qualifying contracts is based on the extent to which the contract reduces a liable entity's exposure to the volatility of the spot price.

In the current Interim Contracts and Firmness Guidelines for the RRO, a number of contract types are identified as 'firm', with a firmness factor of one:

- Standard swaps and futures contracts
- Standard cap contracts with a strike price at or below five percent of the market price cap
- Load following contracts
- Grandfathered contracts (prior to 10 August 2018)
- Market Liquidity Obligation products

The current approach does not look behind the contracts. In the case of a compliance assessment, the AER assesses the liable entity against its financial contracting requirements and does not investigate the counterparties to those financial contracts or the resources underpinning them.

The ESB has conducted preliminary investigations into this alternative. It will be considered further in the detailed design phase as foreshadowed in the ESB's recommendations to Ministers.

Impacts of a proposed capacity mechanism

The ESB is cognisant of the impacts associated with the significant shift in market design that comes with a new capacity mechanism. Minimising these risks will be a key priority in the detailed design phase in order to safeguard competition in the retail and wholesale market and reduce adverse market impacts which will ultimately be borne by consumers. The following outlines an overview of these risks.

Gaming and market power

As was the case with implementing the current Retailer Reliability Obligation, any implementation of a capacity mechanism has a potential to give undue market power to those market participants that have the greatest control over capacity in the market, noting that the participants who have this control will change over the transition. Certificate type schemes in the medium term are more likely to favour vertically integrated gentailers who have easier access to physical certificates via their generation assets. It could be a significant barrier to entry and may lead to retail market exit by smaller, independent retailers. This may compromise retail competition and reduce retail innovation, at a time when technology advances are opening up new business models – the costs of which will ultimately be passed onto consumers. Several stakeholders noted this with reference to the PRRO in response to the April Options paper.

Looking beyond 2025, gaming and market power risks are likely to evolve with the transition. As discussed in previous sections, the types of resources that are likely to benefit from a certificate scheme will be flexible, reliable and need to be financially viable when operating at low-capacity factors. The design of an equivalent Market Liquidity Obligation for a capacity mechanism needs to be intrinsically tied any certification process to ensure that the parties that control any certificates are the ones targeted to provide liquidity.

The detailed design of a certificate scheme or other capacity mechanism will aim to be as open and technology neutral as possible, encouraging supply of capacity from the demand side, battery storage and distributed resources as well as generation. Consideration will also be given to rules which aim to eliminate gaming of the mechanism. Liquidity, competition, and market power concerns in the NEM may ultimately lead the design towards a centralised auction approach, if they cannot be appropriately managed with a Market Liquidity Obligation equivalent and central exchange. This may also include exemptions for small retailers and market customers with annual energy consumption below certain limits and the ability for liable entities to adjust their net contract positions within a region, as with the current RRO design. Consideration of limited ex-post rebalancing periods may also be prudent, to minimise the risks of hoarding of certificates which may lead to market power concerns. This would be balanced against the need to ensure the mechanism does not seek to support inefficient settlements at the expense of incentivising reliability prior to at risk periods.

Further, a certificate scheme would provide an additional lever that complements and interacts with reliability settings. The ESB agrees with the Reliability Panel's view that "the goal of this framework is to optimise reliability and certainty, and to minimise costs of delivering that optimised outcome."

If capacity is in short supply during 'at-risk' reliability periods, then the revenue provided by certificates provide an investable signal for capacity to meet these 'at risk' periods. This supports the timely build of capacity that will prevent costly unserved energy outcomes or price volatility under a more disorderly long-term scenario. Certificate costs may be recovered from consumers by liable entities. A high market price cap and a shortage of capacity – besides the structural constraints on spot prices outlined in previous sections – may drive high wholesale and contract prices, which may also assist in incentivising timely entry. As such, there is a clear interaction between certificate penalty and other settings and the market price cap. The market price cap and certificate settings should therefore be co-optimised as part of the detailed design process to ensure that consumers pay no more than they need to for the required level of reliability.

Ideally all of the reliability levers, including existing settings such as the market price cap, as well as new certificate scheme parameters would be co-optimised, to deliver the optimal level of reliability at lowest possible cost.[18]

Static design risks

Capacity mechanisms in other markets have successfully promoted resource adequacy because the traditional systems were largely static - relying on thermal generation without fuel constraints, capable of generating at any time to meet demand for a few hours during either summer or winter evening peaks. Capacity mechanisms could be designed around clearly defined times when 'at risk' events were most likely to occur, making it reasonably straightforward for both generators selling contracts and retailers/consumers buying them.

However, valuing capacity when it is needed most gets more complicated as the generation mix changes and distributed energy resource and flexible demand are successfully integrated, both of

[18] The Reliability Panel in their submission to the April Options paper noted that the are fundamental interdependencies between the market design initiatives being considered by the ESB in the Post 2025 project and the Panel's work, particularly the upcoming Reliability standards and settings review (RSSR). The Panel will need to understand the scope and impact of possible reforms under the Post 2025 process before they finalise their review.

which have the ability to ease the capacity requirements at the wholesale level. As such, the assumptions traditionally relied upon in capacity mechanism become less certain, including:

- What quantity of new generation capacity can generate at specified times
- What generation available at the time required by the capacity mechanism will also be available at other times
- Whether the evening demand peaks will be the most important reliability issue to address compared with other situations (i.e., long wind/solar droughts).

These challenges necessitate a more dynamic capacity mechanism design. Design choices for which need to be carefully considered in the detailed design phase.

Failure to recognise the value of demand response

Voluntary demand response has potentially significant value in meeting reliability requirements at least cost. To the extent that demand response can be included, this reduces the need to artificially retain incumbent assets and minimise the entry of some new capacity which may only be valuable for limited peak demand events and lie idle at other times.

In the detailed design phase, consideration should be given to the ability of the capacity mechanism to incentivise the participation of demand response to allow for potential efficiency gains. Compliance and incentive structures under a certificate scheme would be created in a manner that is sensitive to characteristics of scheduled, semi-scheduled, non-scheduled and demand response resources. The objective is to have resources with the ability to be deployed when the system needs it, irrespective of technology type.

Unintended consequences

In designing a capacity mechanism, the objective of it must be clear. The objective of the straw proposal was to address both timely entry and of orderly exit. An emphasis on one aspect of this objective over the other could have unintended consequences. For example, without careful design, there is a risk that a capacity mechanism could incentivise older, less flexible, and higher-emission resources to remain online longer than necessary, rather than encouraging new firm capacity to be built. There is also a risk that the new capacity incentivises resources that are needed to support the system on a very low number of days in a year, without also due consideration given to the need for the flexible resources (such as short duration storage) to manage the variability and uncertainty associated with higher penetrations of VRE. However, if design choices are fine-tuned, the capacity mechanisms can potentially incentivise competitive VRE and storage co-location outcomes as reliability forecasts deteriorate with thermal exits. The ESB intends to focus on designing a mechanism which encourage a timely entry and orderly exit in the context of the resource adequacy challenges being faced in the NEM.

Impacts on market participant categories

The impacts of each mechanism on small retailers and commercial and industrial (C&I) customers will require careful consideration, particularly in the case of a certificate scheme. Any scheme needs to be designed in a way that does not present asymmetrical barriers for smaller retailers and C&I customers.

The differing nature of costs and risks for liable entities under a certificate scheme creates new challenges for all market customers but may place increased pressure on new and small retailers if design options are not adequately interrogated. Unsuccessful consideration of emerging business models in the retail market as part of a detailed design phase may risk reducing competition and placing vertical integrated retailers in a position of competitive advantage to the detriment of consumers.

The current RRO incorporates specific measures to safeguard competition, and to enhance liquidity and pricing transparency in the retail and wholesale markets. To the extent practical, such safeguards would remain or be modified as needed to reflect the need to safeguard competition and liquidity. Some of these considerations that would need to be reflected on include:

- options for large customers - who are not market customers and meet the requirements to opt-in - to be able to manage the obligation associated with their load, and whether the removal of triggers requires a standing opt-in trigger
- Exemptions for small retailers and market customers with annual energy consumption equal to or below 10 GWh who are not expected to be impacted by arrangements
- The ability for liable entities to adjust their net contract position in a region within a compliance period and grandfathering of contracts that were entered into pre 13 December 1998 will need to be considered further in the context of a certificate scheme.

The considerations of liquidity obligations and transparent trading platforms – outlined in Appendix C – are also key to providing smaller retailers and smaller NEM participants the ability to buy and sell certificates.

Integrating a NEM-wide, common approach to jurisdiction investment schemes

With certificate-based mechanisms, the ESB notes that the most efficient function and triggering of a certificate capacity mechanism relies on the premise that jurisdictions are prepared to allow reliability gaps to be anticipated so that the value of certificates can materialise. Only under circumstances where reliability shortfalls are anticipated over the short-medium term will the demand for certificates be created by liable entities, therefore incentivises commercial investment off the back of this demand. If governments did continue to intervene and support 'firm' supply, this could reduce capacity certificate prices. This would reduce the efficacy of the Physical RRO, diminish the benefits of the mechanism, and continue to incur the costs associated with its implementation.

To mitigate some of these risks, jurisdictions could utilise design elements of a certificate scheme to integrate government investment (as noted above and explored further in part C).

The ESB has explored alternative arrangements which seek to preserve jurisdictional target setting but establish common bodies to better facilitate these targets in an orderly fashion into existing market arrangements. A common investment scheme was discussed in the January Directions Paper, which could be adjusted to support mechanisms based on financial and certificate arrangements. This scheme proposed a more coordinated framework to integrate different jurisdictional objectives and scheme delivery with NEM-wide institutional and governance arrangements. This will be explored further in the detailed design process. A centrally coordinated or integrated approach to government investment could have a number of benefits:

- formalising a role for market body advice to jurisdictions to assist in achieving the optimal level and mix of generation resources nationally, especially given national transmission planning, lowering costs for consumers of potentially unnecessary generation
- providing the market with policy certainty of a uniform scheme to drive investment certainty and minimising participants' cost by only engaging with one scheme
- decreasing transaction costs for jurisdictions in providing underwriting through common contract terms facilitating ease and speed of negotiations; common contract types (increasing liquidity and providing more confidence that the prices in those contracts are competitive.

- pooling liquidity through the use of a central mechanism for underwritten contracts. This provides confidence prices are competitive and coordinate timing of new offers to maximise participation in them.

Importantly a uniform scheme coordinating government investment could minimise the risk that jurisdiction by jurisdiction approaches to government investment fail to take into account the benefits of an interconnected NEM.

2.6. Long term reform

Following the implementation of the ESB's Post-2025 reforms, continued monitoring of reliability and overall costs to consumers is necessary. It is also important to recognize that operating and regulating a system with so much variable renewables (both small and large scale) is a new experience globally. This makes review and monitoring especially essential so adaptation can occur as experience grows and learning occurs. While this is happening now the increasing penetration of renewables makes the approach even more important.

A successful transition would see the right mix of resources incentivised to enter and exit the energy market consistent with reliability expectations and minimising consumer costs. This includes low-capacity factor assets that do not run except when needed during periods of low wind volumes, higher forced outage rates on ageing thermal units or hot and/or cold weather.

In particular, it is necessary to monitor the presence of various types of resources, including long-term storage such as pumped hydro and new innovative fuel types such as hydrogen. Pumped hydro, in particular, with its planning and infrastructure requirements, may require contracting arrangements that go well beyond a market's ability to efficiently deliver. A certificate scheme could be designed to lengthen the investment signal but its decentralised nature means it may make it difficult to provide 10 to 15 year contracts outside of those underwritten by jurisdictions.

Also, the certificate scheme only provides value for the capacity and availability of classes of resources. It is not part of this resource adequacy reform pathway to consider whether large scale storages' ability to provide a broader range of capabilities than just generation (such as to operate in a way that alleviates congestion or provide essential system services). This may require further observation and consideration after the impact of the ESB's Post-2025 reforms are known.

As discussed earlier in this chapter, the criteria and settings for a certificate scheme should also be adjustable to an extent so that policy-makers – over the course of review cycles – can leverage the certificate framework to facilitate timely entry and orderly exit such that long-term signals for investors are promoted but there is flexibility in the amount of certificates minimising inefficient costs for consumers. While the immediate criteria and settings for a certificate scheme are to be determined in a detailed design phase following the conclusion of the Post-2025 work, these may have to be revisited from time to time to ensure the changing needs of the transition are best met, and that the framework established is being leveraged to its full capability to drive good outcomes for consumers.

2.7. Recommendations

1. To support *immediate* resource adequacy in the NEM, the ESB recommends Energy Ministers agree a number of reforms:

  a) instruct the ESB to prepare rule changes for submission to the AEMC to implement:

    i. a NEM wide jurisdictional strategic reserve for the procurement of any required reserves, that individual jurisdictions consider necessary beyond the market reliability standard; and

ii. enhancements to existing generator exit mechanisms to provide greater transparency of generator availability.

b) adopt a set of principles to guide the development of any future jurisdictional schemes to ensure a common approach that is consistent with current market signals for investment. Jurisdictions are encouraged to use currently available information on market needs and seek additional information from the market bodies as necessary when considering jurisdictional schemes.

c) adopt a Ministerial lever to trigger the current Retailer Reliability Obligation as is currently in place in South Australia. This would give Ministers the ability to strengthen the Retailer Reliability Obligation if they wish while further detailed design work is undertaken on a capacity mechanism.

2. To support timely entry and orderly exit of resources in the NEM for 2025 and beyond, the ESB **recommends** Energy Ministers agree to a further *initial reform*:

a) provide in-principle support for a capacity mechanism for the NEM to ensure the competitive provision of the right mix of resources as the market transitions towards net zero emissions. This mechanism will ensure investment in an efficient mix of variable and firm/flexible capacity that meets reliability at lowest cost and increase government and community confidence that resource adequacy will be delivered by the market reducing the need for interventions.

b) In recognition of significant stakeholder concerns, instruct the ESB to work with stakeholders and jurisdictions over the next 12-18 months to develop the detailed design of the capacity mechanism for the agreement of Ministers in mid 2023. There are a number of policy choices in the design of a capacity mechanism, as set out in this advice, which need to be considered to ensure the recommended design is both effective and efficient.

c) a decentralised capacity mechanism (where the volume of required capacity is determined by liable entities, such as the Physical Retailer Reliability Obligation set out in this advice) should be the starting point for the design work. Further consideration should also be given to:

i. whether it would be preferable to centrally determine the volume of required capacity;

ii. whether using existing contracts between registered market participants would be preferable as the basis of the scheme (rather than creating a new certificate);

iii. how to best address the impacts of the proposed capacity mechanism on retail competition (including small retailers), commercial and industrial customers, market power concerns, transaction costs for market participants, and affordability; and

iv. integrating a NEM-wide, common approach to jurisdiction investment schemes to work alongside the new capacity mechanism

3. Essential System Services, Scheduling and Ahead Mechanisms

3.1. Key points

- The NEM currently has over 17GW of wind and solar capacity installed. A further 53GW is proposed for the NEM, which is almost all the current NEM capacity. Coupled with the exit of large ageing thermal synchronous plant, this changing generation mix will press the limits of current system security and operational experience.
- Essential system services were traditionally provided by thermal generation as a by-product with energy and the exit of this thermal generation from the NEM means that these services also exit.
- The ESB identified four essential system services - frequency, operating reserve, inertia and system strength. Current market arrangements do not appropriately value all services that are necessary to maintain essential system capabilities.
- To date, the lack of markets or other means of valuing the system services essential to system security, means AEMO is intervening in the market to procure these essential capabilities. The ESB's Health of the NEM report[19] noted that system security is the most critical issue at present and that AEMO's interventions have increased markedly in recent years.
- New technologies (both demand and supply based) can provide services that meet some of these essential capabilities. This includes large-scale batteries and flexible demand. Large customers, through demand response, may be able to provide services such as ramping products (or operating reserve services) where they are able to build flexibility into their commercial processes.
- Australia is leading the way in operating a system with high levels of inverter-based resources. New technologies are being tested through projects funded by ARENA and trials and demonstration projects. Mechanisms are required in the transitionary period to support continued secure operation of the system while knowledge of operating the power system with these new technologies continues to develop.
- 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. Acting now to incentivise service providers to offer these capabilities to market will realise this value and be delivered at least cost outcomes for consumers.
- Security is critical, and stakeholder feedback suggests that addressing missing system services cannot wait until 2025. A number of security related rule changes implementing the reforms are currently being progressed by the AEMC in close collaboration with the ESB and AEMO.
- The ESB has identified the reform areas below for implementation as soon as practical (immediate reforms), or for near-term implementation following further development (initial reforms):
    - Refining frequency control arrangements and, in particular, addressing the potential need for enhanced arrangements for primary frequency control and a new market for fast frequency response.
    - Developing structured procurement arrangements for system services not suited to spot markets.eg system strength.

[19] http://www.coagenergycouncil.gov.au/publications/2020-health-nem 42

- Proactive procurement of system strength in the investment timeframe, potentially coupled with structured procurement and scheduling in the operational timeframe, will be critical to maintain security and support the transition. Interactions with other system services should also be considered in the investment timeframe to ensure services are delivered as efficiently as possible in the operational timeframe.
- Considering the need to explicitly value operating reserves. The current provision of reserves in operational timeframes is implicitly valued through the energy spot market. New products and services may be required to manage growing forecast uncertainty and variability in net demand over timescales of minutes to hours. A reserve service market could provide an explicit value for flexible capacity to be available to meet these net demand ramps. AEMC rule change requests are underway addressing the issue of explicitly unbundling operating reserves services.

- The ESB has also identified the reforms below for longer-term progression, subject to industry development (next reforms):
  - Further unbundling of system services – Options for further structured procurement and scheduling mechanisms to minimize cost by adopting innovative technologies as they develop and are proven at scale to deliver specific system services.
  - Inertia spot market – As experience in arrangements builds, there may be benefits in market procurement of inertia, through a spot market mechanism. Inertia needs will be met over the short to medium term through TNSP, contracting of resources and structured procurement mechanisms. As we progress to higher penetration of variable renewable resources and battery storage on the system, there is potential to drive efficiencies and lower costs to customers by progressing toward spot market procurement.
  - Integrated ahead market – The ESB considers that an integrated ahead market, which may enable the efficient commitment of resources required to maintain reliability and security could be progressed in the future. This may involve ahead trading of energy and co-optimisation with system services. The case for change will be informed by experience with additional system services, further integration of DER and price-responsive demand-side resources in the wholesale market and increasing use of storage resources.
- Progressing these measures and the broader reform pathway will maintain a secure system with instantaneous variable renewable penetration that is increasing rapidly. It is now over 50% in the NEM and up to 100% in South Australia.
- As technology advances and operational understanding grows, there will be benefit from further ‘unbundling’ the energy provided from the arrangements in place to procure system strength, into the currently defined four essential system services. Beyond this, there may also be benefit in further unbundling some of those four services, to support the transition to the higher penetrations of inverter based renewable generation. Enabling each of these services to be provided independently of energy and one another when new technologies are shown to be able to do so may support efficient outcomes and lower costs for consumers. Regulatory and market arrangements will need to become increasingly adaptive to recognize changing system needs, to address emerging risks and to take advantage of new engineering and technological innovation, to deliver lowest cost solutions for customers.
- ESB will continue to monitor changing market conditions and provide advice on the need for additional future reforms for this pathway, including the need for further unbundling of services or development of spot market arrangements for inertia.

3.2. The issue

The power system must operate with the high levels of wind and solar generation now entering the system, and lower levels of traditional generation, mainly thermal coal generation. As noted elsewhere this change in the generation mix has contributed to a fall in wholesale energy prices through the low marginal operating costs of wind and solar generation. Falling wholesale prices mean operations are increasingly uneconomic for ageing synchronous plant across the NEM, resulting in lower levels of commitment of synchronous generation and early exits of these plants. This means that essential system services (frequency, inertia, operating reserve and system strength) that were traditionally provided as a by-product of energy produced by synchronous spinning generation, are no longer provided in abundance. These essential system services need to be separately valued to encourage alternative sources of supply via market or other procurement mechanisms.

The issue is urgent. Since 2012, 90% of investment in generation in the NEM has been wind and solar. Instantaneous wind and solar penetration in the NEM was 38% in 2018 and 52% last year. In South Australia it reached 100%.[20] The critical importance of essential system services has been noted by the ESB in earlier Health of the NEM reports[21] and the seriousness of the issue is evident in the interventions that AEMO has had to make to secure the power system. In 2016 these interventions totalled 6; last year they totalled 321.

Future operation of the power system requires management of significantly different dynamics. While the physics of the power systems is unchanged the generation mix means supply is more variable; and wind and solar generators are connected through inverters, or power electronics converters. This shift to inverter-based resources is occurring as existing synchronous generation plant are retiring from the system. With this change, the system services that were delivered as a by-product of energy produced by the synchronous thermal plant, can no longer be assumed to be provided in abundance. In addition, the present system is designed around one-way flows and provision of power from a small number of large synchronous generators that are centrally located. There are now new modes of operation with more dispersed non-synchronous generation, a situation never seen before.

Ongoing technical analysis and research is required to ensure that the needs of the power system are provided to support a secure system. This work is underway, with the global power system industry collectively undertaking detailed analysis and research. In Australia, through its Engineering Framework, AEMO will build on work already completed in its Renewable Integration Study, which brings together analysis to understand the expected new dynamics in the NEM.[22] The Engineering Framework seeks to identify and bridge gaps that enable secure operation in those conditions. For example, while Australia is leading the world in experiencing operating conditions of low levels of synchronous generation, to date no gigawatt-scale system has ever operated without some synchronous generation online. This situation can be compared to other power systems, such as in New Zealand or France, where power systems are increasing their proportion of DER and variable renewable energy to meet emissions targets; but both have significant levels of synchronous plant

[20] While the demand in South Australia was 100% met by the amount of wind and solar generation, there were still gas powered generation online in SA at the time providing system support, with this additional generation being exported.

[21] ESB Health of the NEM 2020 report can be found here: https://esb-post2025-market-design.aemc.gov.au/health-of-the-nem

[22] Details on AEMO's Engineering Framework and Renewable Integration Study work can be found here: https://aemo.com.au/en/initiatives/major-programs/engineering-framework

(hydro and nuclear respectively). The progression in the NEM to these new dynamics must be managed prudently, and the reforms recommended here enable this to occur.

The essential services needed are supplied by a variety of resources, in different combinations, technologies and locations. This is facilitated by establishing missing markets or other procurement arrangements for essential services, so these services can be valued separately from energy provision.

Regulatory frameworks will be implemented in the next two to three years that address potential shortfalls in the provision of the identified services. The ESB recommends these frameworks be introduced in advance of the services becoming scarce, particularly as ageing thermal generation exits and large amounts of variable renewable energy (VRE) continue to enter the system. The business cases for investing in traditional and new technology to provide the required services, including batteries, synchronous condensers, and other advanced technology, such as grid-forming inverters, is supported by the establishment of the missing markets. The reforms see a clear revenue stream for providing the missing services, and efficiencies of scale can be gained through co-ordinated and pro-active procurement of the needed capabilities. In addition, the implementation of these missing markets will establish signals for efficient investment going forward.

With the reforms in place, the number of interventions in the market by AEMO should decline significantly. The intent of the scheduling mechanisms being considered is to provide AEMO with the tools necessary to manage risk and uncertainty through the transition.

Without the reforms, the value of service provision for essential capabilities is missing. The absence of effective tools means scheduling the market is increasingly chaotic, with real-time dispatch unable to co-ordinate commitment effectively across all essential system services. Without an efficient means to procure and schedule the resources that are providing the necessary capabilities, AEMO may be required to consistently intervene in the market and direct participants to stay or come online. Without new tools to manage the system, AEMO has a diminished ability to learn through operating new modes of the power system without relying on directions and interventions. AEMO will always have the ability to intervene and direct resources to maintain power system security – consistent with best practice of electricity market operations. However, reliance on interventions to ensure system security is inefficient. Market-based scheduling mechanisms can instead enable a greater range of resources to participate, are more transparent, and provide greater certainty to AEMO and market participants of commitment decisions.

Further, without markets and regulatory frameworks for the provision of the necessary capabilities, the business case for new technologies needed may be more challenging, and the services may not enter the market in optimal volumes. In the absence of these missing markets, the existing thermal fleet are unable to be scheduled for their services. The exit of those resources, or changes in their operational profiles, challenge the operation of the system, creating further uncertainty for the sector and potentially driving increased costs to consumers.

A secure, reliable electricity system is fundamental to deliver the energy needs of consumers. At an operational level, this is driven by the ability to schedule the necessary resources to provide capabilities at the right times and at the right locations. Reforms to address the missing markets for essential system services, and new mechanisms for scheduling those resources will enable a smoother transition. The rest of this chapter outlines the missing services, how each will be addressed going forward, and the benefits consumers can expect from the implementation of the reforms.

3.3. The package of reforms

3.3.1. Overview

There are two key elements to this reform: making sure we get the missing services into the market and getting the right tools in place to support efficient scheduling and dispatch. We need to urgently progress with reforms to address both elements. Four areas were identified for initial focus: frequency, inertia, system strength, and operating reserve.

The ESB has considered the relevant procurement and scheduling mechanisms for those essential system services, and how these can ensure the full suite of necessary capabilities are scheduled to provide a secure technical envelope.[23] Together these form the necessary package of reforms needed to maintain secure dispatch and meet the changing dynamics of the power system operation with its evolving resource mix.

In 2020, the ESB engaged FTI Consulting to consider how to best procure the required services.[24] This report broadly characterised the options to procure services as through:

- direction or self-provision,
- structured procurement or non-spot-market contractual mechanisms, or
- spot market provision.

Ideally spot market arrangements combined with co-optimisation should be used where possible, and the market should progressively move towards spot market provision for services. However, there are some services that may be better suited to structured procurement where spot market arrangements may not be appropriate (either now or ever).

Stakeholders agreed with the ESB's assessment of the urgency and criticality of addressing these needs, and broadly with the procurement models for the identified services. This pathway has also received broad support by stakeholders. The AEMC is progressing with the consideration of changes required in the National Electricity Rules (NER) through its system services rule changes currently underway.

This paper sets out the current status for each of the reforms and expected pathway forward, including further work to be completed by the market bodies to complement those reforms being considered through rule change processes underway. The reform pathway is informed by the evaluation completed for this workstream, the outcomes of which are described in Chapter 7. Where stakeholders have provided detailed feedback to the ESB process, the AEMC will take this feedback into account in progressing the rule changes.

---

23 A secure technical envelope is one in which all elements in the power system are operating within technical physical limits and are expected to remain within these bounds after a credible contingency.

24 FTI Consulting report to ESB can be found here: https://esb-post2025-market-design.aemc.gov.au/32572/1599207219-fti-final-report-essential-system-services-in-the-nem-4-september-2020.pdf

Figure 2 Proposed transition pathway

System req'ts	Drivers	Reforms	Expected 'on the ground' timing	Next milestone
Frequency control and inertia	Controlling frequency around 50Hz under normal conditions	Primary frequency response – *mandated obligation and enhancements*	Interim arrangements in place Enduring arrangements in place from sunset (2023)	AEMC rule change draft determination Sept 2021
	Managing frequency under lower inertia conditions	Fast frequency response – *new ancillary service*	Implementation of new markets 2023	Revised Market Ancillary Services Specification by Dec 2022.
		Inertia spot market	The potential gains from introducing a cooptimised spot market for inertia will be kept under review as the power system evolves. Inertia spot market could be triggered by approaching minimum inertia levels, increased structured procurement and scheduling for inertia, expanded technical knowledge, and learnings from the WEM.	
Ramping / Operating reserves	Managing higher levels of variability and uncertainty across dispatch intervals	Ramping / operating reserves – *co-optimised market*	2025 if rule change were to recommend immediate implementation	AEMC rule change draft determination Dec 2021
System strength and Power system security	Maintaining power system security and avoiding uneconomic constraints with reduced synchronous generation Stability of inverter-based resources	Longer-term structured procurement and network development for fault levels / system strength	Pro-active TNSP-led procurement in place from 2022, with solutions required by 2025	AEMC final determination due to be published Oct 2021.
	Complementing longer-term with shorter-term structured proc. Scheduling resources for structured procurement	System Security Mechanism (SSM) - *structured procurement in operational timeframe + tool for scheduling system configurations*	As soon as possible – 2-3 years from final determination (2025). Scheduling mechanism for long-term structured procurement arrangements in place by 2025.	AEMC directions paper to be published Sept 2021, draft determinations of associated rule changes Dec 2021.
		Unit Commitment for Security (UCS) – *scheduling resources under structured procurement*		
Co-optimisation	Improving efficiency and co-ordination of dispatch	Further unbundling of services	Further unbundling could be triggered by technical understanding enabling further disaggregation of specific services and capabilities.	
		Integrated Energy and Services Ahead Market	Integrated ahead market could be triggered by learnings from experience developed through WDR and operational structured procurement and DSP and DER integration	

3.3.2. Frequency

Substantial work on frequency control frameworks in the NEM has been completed to ensure that these frameworks keep up with the needs of the transition. This places the reform at an advanced stage of implementing enhancements to the frameworks; augmenting and leveraging the current arrangements as needed.

The two immediate reforms are:

- introduction of a two (raise and lower) new fast frequency response (FFR) service to help manage system frequency following contingency events with reducing system inertia; and
- developing enduring primary frequency response (PFR) arrangements to support frequency control during normal operation.

The AEMC has recently published a final determination on FFR and is currently progressing a rule change request on incentivising primary frequency response.[25]

The consultation on rule changes for each of these work areas is supported by technical advice provided by AEMO through its frequency control work plan. This work plan provides a cohesive range of actions that AEMO is undertaking to support effective frequency control in the NEM and sets out what and when changes are required.

Fast frequency response

On 15 July 2021, the AEMC made a rule to introduce two new market ancillary services to allow for FFR to be procured by AEMO to help control system frequency following sudden and unplanned generation or power system outages. The use of these new services is expected to lower the cost of frequency control ancillary services relative to the expected future costs under a continuation of the current market ancillary service arrangements or other alternative arrangements.

The rule is supported by AEMO's technical advice including analysis of technical considerations and preliminary market analysis to inform the design of FFR market arrangements.[26]

The rule is consistent with the ESB's long term direction for essential system services and the development of spot market arrangements for the provision of FFR. Spot market-based provision of essential system services is preferred, where practicable, given it allows for full co-optimisation between services and energy, resulting in more efficient dispatch and pricing of services, driving innovation in the provision of various combinations of essential system services from different technologies. Frequency Control Ancillary Service (FCAS) markets are currently procured through co-optimised spot markets, and so it follows that a very fast FCAS service is procured through this process as well.

The majority of submissions to the AEMC's rule change process supported the introduction of two new 'very fast' frequency response services under existing arrangements. The new markets will be implemented in October 2023, which is earlier than was proposed in the AEMC's draft rule, with the date bought forward in response to stakeholder feedback. A number of submissions to the AEMC's draft determination, as well as submissions to the ESB's April Options paper, raised concerns that the

---

25 Rule change requests from Infigen Energy (Fast frequency response market ancillary service) and AEMO (Primary frequency response incentive arrangements).

26 AEMO, FFR implementation options report, March 2021.

introduction of new faster responding services may delay consideration of new markets for inertia, which stakeholders consider is an important service and should not be delayed.

There is a close interaction between the development of market arrangements for FFR services and the valuation of inertia. However, FFR and inertia are different services. Although FFR has the potential to assist with frequency management at lower levels of system inertia, FFR and inertia are delivered via different physical mechanisms, and play roles that are not directly interchangeable.

Currently, the NER includes an inertia framework that supports the provision of security critical inertia for each of the NEM regions. However, the NER does not support the full valuation of inertia above these minimum levels. It is expected that the introduction of a FFR market will likely address much of the system needs under low inertia conditions for the immediate future, but further needs may emerge over time. The consideration of reforms to value inertia services in the longer term is discussed further in section 3.3.3.

Primary frequency response

AEMO is currently in the process of coordinating changes to generator control systems in accordance with the Mandatory primary frequency response rule.[27] The monitoring of plant and power system impacts due to the implementation of this rule will inform the Commission's determination for enduring Primary Frequency Response (PFR) arrangements.

Enduring PFR arrangements are being developed in the Primary Frequency Response incentive arrangements rule change requests.[28] In its Directions paper, the AEMC identified three viable pathways for enduring PFR arrangements:

1. Maintain existing Mandatory PFR arrangements with improved PFR pricing.
2. Revise existing Mandatory PFR arrangements by widening the frequency response band and develop new FCAS arrangements for the provision of PFR during normal operation (Primary regulating services).
3. Replace Mandatory PFR arrangements with alternative market arrangements to procure PFR during normal operation.

Stakeholders expressed a range of views in relation to the PFR rule change. While most stakeholders expressed support for market or incentive-based arrangements for PFR, there was a divergence of views on the enduring role of a mandatory PFR arrangement.

The AEMC is in the process of co-ordinating the provision of technical and economic advice and analysis to inform its determination of the appropriate enduring PFR arrangements. This advice will be informed by plant and system data collated over the phased implementation of plant control system changes associated with the mandatory PFR requirement. It will include:

- technical advice from AEMO on the plant and system impacts of mandatory PFR and the operational feasibility of the identified enduring PFR pathways.
- analysis by the AEMC to measure and describe the operational impacts associated with plant operating in accordance with the mandatory PFR arrangements.

27 https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response

28 https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

- independent advice commissioned by the AEMC to inform the selection and design of enduring market and regulatory arrangements for PFR.

The AEMC intends to invite further stakeholder comment through the publication of a draft determination for the Primary frequency response incentive arrangements rule change on 16 September 2021.

3.3.3. Inertia

In the April Options Paper, the ESB identified that an inertia spot market would be considered as a 'next reform', with the potential for structured procurement arrangements in the interim if required. The reform pathway recognised that there are existing arrangements in place for inertia, as well as immediate measures underway addressing frequency control and implementing new operational scheduling and potential additional structured procurement through the Unit Commitment for Security (UCS) and the System Security Mechanism (SSM). These measures are expected to ensure sufficient inertia and frequency control capability are procured and enabled in the short and near term. They also provide mechanisms for the provision of inertia to be valued. A spot market for inertia may provide efficiencies through co-optimisation with energy and other real-time services. However, this sequencing allows time to further understand the technical aspects of the service, spot-market arrangements as technology and the system evolve, and operational learnings in new conditions after the implementation of the immediate reforms. Additional time also allows for lessons to be learned from other approaches to value inertia that are being implemented elsewhere (e.g., under the Western Australia reform program).

In feedback to the April Options paper, a number of stakeholders (including incumbent generators with high levels of synchronous generation in their portfolio) expressed a desire to see an inertia spot market progressed as a higher priority. These stakeholders consider that establishing a spot market for inertia is required to address a missing market and provide a means of valuing that specific service. Stakeholders consider this should either be given priority in the fast frequency reforms – that is, the provision of inertia should be explicitly co-optimised with fast frequency response and remunerated in line – or separate spot market arrangements should be established. The AEC also indicated that they are progressing their 'own research in a hope to trigger action'.[29]

However, other stakeholders agreed that a spot market should not yet be progressed given the overlap with other frequency services and that further consideration should first be given to the transitionary procurement options, such as a contractual approach (structured procurement).

The ESB considers a staged approach to the consideration and implementation of an explicit spot market for inertia should be progressed, noting the following:

- the immediate needs for addressing frequency control are being progressed via rule changes associated with FFR, recognising that FFR and inertia are not complete substitutes;
- an existing mechanism is in place for minimum levels of inertia to be supplied; and,

[29] Australian Energy Council (AEC) submission to ESB Post 2025 Options Paper, p6 https://energyministers.gov.au/sites/prod.energycouncil/files/publications/documents/14.%20AEC%20Response%20to%20P2025%20Market%20Design%20Consultation%20Paper_0.pdf

- arrangements for the procurement of inertia, including the SSM, will be considered by the AEMC through the Hydro Tasmania rule change.[30]
- a spot market for inertia requires further development and technical consideration. The traditional provision of inertia from synchronous resources is lumpy, because it is linked to the commitment of resources. In this situation, usual marginal pricing principles do not easily translate, and novel approaches are required for the formation of a spot market. Non-traditional provision of inertia responses, such as synthetic inertia, also need further consideration for their technical contribution to the needs, and how to best incorporate those services into a market.

As such, a spot market for inertia remains on the pathway as a possible longer-term reform. However, in recognising stakeholder feedback, the market bodies will commence work now to consider the appropriate steps to take in moving to a lower inertia system. This will involve:

- Continued analysis of the needs of the power system in managing frequency control through the use of frequency services (both primary frequency control and contingency frequency services), synchronous inertia and equivalent synthetic inertia services. This will also enable further technical understanding of the capability and availability of new technology, such as advanced inverter technology, to assist in provision of these services. The primary vehicle for the consideration of the technical requirements will be through AEMO's Engineering Framework.[31]
- Consideration of the Hydro Tasmania proposal will consider potential market arrangements for inertia. Many stakeholders remarked that the Hydro Tasmania proposal for Synchronous Services Markets is one possible means for giving explicit consideration to the benefits of inertia to the system. The AEMC will also consider the SSM through this rule change, which is a possible means for structured procurement of inertia (amongst other services).
- The reform program of the Wholesale Electricity Market (WEM) in Western Australia involves a novel approach to the explicit consideration of inertia implemented. This will see a co-optimised frequency and RoCoF service in the real-time market. Lessons can be learned from this implementation, which is due to go live in October 2022, and the ESB considers it prudent, given the other items also in train, to allow this time prior to any kind of similar implementation in the NEM.

3.3.4. Operating Reserves

Managing variability and uncertainty in forecast conditions is a key challenge for the NEM as it progresses towards very high shares of weather-dependent supply, both large and small-scale. To date, operating reserves have been provided by scheduled capacity keeping headroom available for the bundled delivery of both energy and reserves. The costs of the provision of operating reserves are built into the supply offers and recovered through energy prices. This part of the Essential System Services (ESS) workstream is considering the benefits of unbundling the provision of reserves from the energy market.

---

[30] Details on the Hydro Tasmania rule change proposal can be found here: https://www.aemc.gov.au/rule-changes/synchronous-services-markets

[31] Details on AEMO's Engineering Framework can be found here: https://aemo.com.au/en/initiatives/major-programs/engineering-framework

The ESB has worked closely on this issue with the AEMC, which is currently considering two rule change requests that propose two different reserve service options. The AEMC published a Directions paper on these two rule change requests in January 2021 and has recently extended the time to make a draft determination until December 2021.

The ESB's April consultation paper noted a range of potential benefits to unbundling operating reserves, including:

- delivering sufficient reserves for the reliability and security of the system;
- an overall efficient dispatch across the range of services required to operate the power system;
- signals for investment and resource adequacy; and
- incentives for the in-market participation and scheduling of DER.

Stakeholders held mixed views regarding the need and benefits of implementing an operating reserve service in the NEM. Most stakeholders did not support the implementation of an explicit operating reserve as an essential system service to manage security and reliability issues, for reasons that included:

- the need for such an explicit reserve service has not been established;
- the energy spot market already values operating reserves and will continue to provide sufficient incentives for participants to make reserves available when they are needed;
- the expected flexibility of the future fleet and energy market conditions should enable sufficient response to address future uncertainty; and
- such a market is not expected to be required once other changes have been implemented, including the impending shift to five-minute settlement, new resource adequacy mechanisms, and arrangements for the provision of other essential system services.

Some stakeholders, however, suggested a new reserve service could be valuable in managing peak demand and emerging uncertain operating conditions or supporting demand-side participation. There was also strong support from some stakeholders, particularly generators and gentailers, for the further consideration of operating reserves as a resource adequacy mechanism.

In order to inform these considerations, the AEMC is conducting modelling to investigate the operational impacts of increasing variability and forecast uncertainty in the NEM. Preliminary findings from this modelling were presented to stakeholders in a deep-dive session and are available via the AEMC website.[32] Further work is underway to refine this modelling, the results of which will be made available through the AEMC rule change process.

Following publication of its April Options paper, the ESB has also given further consideration to an operating reserve product in terms of its value in the investment timeframe and in meeting the objectives of the RAMs workstream. The ESB recognises that an operating reserve product could influence the value stack viewed by prospective investors. This may therefore have incremental impacts on the types of resources invested in, or the types of existing resources that choose to enter the market or change their mode of participation. For example, a demand response provider may

---

32 https://www.aemc.gov.au/sites/default/files/2021-05/Slides%20from%20technical%20working%20group.pdf

choose to participate in central dispatch. The extent to which an operating reserve product influences resource adequacy depends on a range of factors, including:

- the exact design of the operating reserve product;
- a variety of levers in detailed product design, for example the shape of the operating reserve demand curve;
- the reliability settings; and
- the implementation of any of the other reforms being canvassed under the resource adequacy mechanisms (RAMs) workstream.

As noted in Chapter 3 an operating reserve product has many similar limitations to the energy market in terms of its ability to deliver long term investment signals. This means that while an operating reserve product may deliver some reliability benefits, there are potential limitations to the extent that it could be a hedgable product that would support a business case for parties making long term investment decisions. Further consideration is needed on the form and operation of an operating reserve product, but it is likely they should be considered as a potential complement to the suite of resource adequacy reforms, rather than as a mechanism to deliver the necessary long term investment signals.

Careful consideration of these benefits and the costs and risks of introducing a new operating reserve service is ongoing. The ESB notes these issues are being considered as part of the AEMC's reserve services rule changes and it is appropriate for these matters are resolved in that forum. The AEMC's consideration of this rule change will involve working closely with the ESB and other market bodies in order to consider the costs and benefits associated with an operating reserve service. Issues to be worked through in considering whether or not to explicitly unbundle the current provision of operating reserves include detailed design aspects, such as the timing and length of the product, impact on wholesale contract markets, interaction with other reforms underway and potential implementation timings. The rule change will also consider to what extent a particular design of an operating reserve may contribute to resource adequacy in the NEM, consistent with the direction of the resource adequacy workstream outlined in Chapter 3.

Of particular relevance is the conditions where an explicit operating reserve would be expected to be beneficial, as well as consideration of potential implementation timeframes. If it is introduced, there is likely to be a relatively long lead time for the introduction of an explicit operating reserve market. This is due to the fact that this would create a new market service (as opposed to extending an existing service, like FCAS), requiring significant market design and prototyping. These are critical steps ahead of determining the full specifications for the required changes to AEMO's systems, as well as those of market participants. These considerations – and the trade-off between the costs and benefits – will be key aspects of the AEMC's consideration of these rule changes. The ESB considers that these are important matters to be considered and that the proactive work being undertaken through this rule change request will be important in considering how essential system services are provided in the NEM as the generation mix transitions.

The ESB further notes that an operating reserve service is not the only means of addressing the complex issue of meeting the challenges of operational reliability amidst increasing variability and uncertainty. As part of its rule changes, the AEMC is also considering whether enhanced market information could be a valuable complement to the introduction of a reserve service, or as standalone measures. Any reforms should, as a package, ensure sufficient reserves are efficiently provided to the system throughout the transition and beyond.

3.3.5. Structured procurement and scheduling mechanisms (and system strength)

With the changing power system and resource mix, there are some supporting system services that are currently provided predominantly as a by-product of synchronous generation. At this stage of the transition, these services may not be easily disaggregated, quantifiable or specifically definable, to allow for the formation of a spot market. In advice to the ESB, FTI Consulting categorised these services as best handled through structured procurement.[33]

System strength is one such essential system service that was identified as requiring urgent attention through the Post-2025 program of work. System strength is a complex technical topic which affects the stability of the power system and is often misunderstood or oversimplified.[34] Reduced penetration of synchronous generators, and lack of clear signals for the capabilities needed, make it difficult to maintain the strength and power system security of the integrated grid.

Considerable work is already underway by the market bodies to put in place measures to ensure critical elements of system strength are procured in the investment timeframe. Further work is underway to consider complementary scheduling mechanisms for the resources providing system strength and other essential system services. In addition, an operational procurement mechanism is also being considered. This mechanism aims to manage the full operational dynamics of the power system. That is, provide a means to ensuring the system is operated securely with the necessary system services. To support this, this may require the commitment and scheduling of units to procure necessary attributes and provide system services ahead of operational time frames.

The AEMC published a draft determination on TransGrid's rule change proposal to evolve the existing system strength framework in April 2021.[35] This draft rule would see Transmission Network Service Provider (TNSP) led procurement of system strength, better coordination of the provision of system strength between the TNSP and connecting parties, and new access standards for connecting parties to ensure they use only the efficient volume of system strength. This process aims to provide system strength in the planning timeframe, that is, in the months and years ahead of when such a need would arise. It is expected that implementation of this rule change would lead to efficient levels of system strength being provided through economies of scale of the TNSP central co-ordination. Additionally, as TNSPs would be required to provide the full amount of system strength, not just covering a shortfall, sufficient levels would be provided ahead of connecting parties, which will improve the connection process. Submissions to the draft determination were due in June, and the AEMC is working through this feedback ahead of a final determination due in October 2021.

There is also a need to coordinate the resources procured in the planning timeframes, with those in the operational timeframe, to meet the specific conditions of the day. The planning timeframe

---

33 FTI Consulting, Essential system services in the National Electricity Market, 14 August 2020, p 91.

34 Australia is experiencing system strength issues ahead of other international power grids and much is being learned about the full aspects of system strength, which go beyond fault levels as was the initial focus. Recent studies are recognising the highly interactive and complex phenomena associated with managing system strength. See, for example, the GHD report to ARENA: 'Managing System Strength During the Transition to Renewables', available at: https://arena.gov.au/assets/2020/05/managing-system-strength-during-the-transition-to-renewables.pdf.

35 'Efficient management of system strength on the NEM'. More information can be found at: https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system

necessarily requires assumptions to be made and proxies to be utilised as appropriate metrics for determining the best investment portfolio to meet the aspects of system strength obligations. Operationally, the grid configuration can be different to that used in planning studies years before, and the dynamics of the power system need to be managed at a more granular and comprehensive manner. This means the service procurement of individual services over planning horizons need to expand into the interactive aspects of the power system and must be managed as to the conditions on the day.

The need for a scheduling mechanism to best enable the activation of these resources operationally is being considered through AEMC rule changes. The ESB proposed a Unit Commitment for Security (UCS) optimisation to be run in the unit commitment timeframe (ahead of real-time) to optimise the provision of system strength via resources under contract. The ESB also proposed further consideration of a complementary operational procurement of resources, a System Security Mechanism (SSM), which could be used to fully utilise the pool of all possible providers to all resources capable of maintaining the system configuration needed for a secure and stable power system in operational timeframes. The SSM is proposed to manage emerging needs for the provision of services not handled through the spot markets, as well as the need for essential system services such as system strength and inertia, which may differ to that which was planned and contracted for.

Stakeholders provided feedback to both ESB and AEMC, and overall supported the progression of work in addressing the urgent needs of system strength and evolving the current “do no harm” and “shortfall” frameworks. that many have considered to be inefficient. Most stakeholders supported the framework that was outlined in the AEMC’s draft determination for TNSP-led procurement of system strength in the investment timeframe, with many positively noting the progress that has been made. Most stakeholders chose to give their detailed feedback to the AEMC’s draft determination. This feedback, largely related to the practical implementation of the policy positions taken in the draft determination, will be taken into account in the AEMC’s final determination.

Stakeholders generally supported the UCS as a tool that enhances AEMO’s operational capability, although mixed views were provided on the settings of the UCS. The ESB proposed that the UCS could be set to optimise for efficient levels of system strength, against pre-dispatch outcomes, to enable efficient use of inverter-connected variable energy resources. However, stakeholders expressed concerns that this could lead to central commitment.

There were mixed views on the continued development of the SSM as an operational procurement mechanism. Many did not understand the need for such a mechanism, and suggested further work was required to make an assessment. Others suggested that further work be de-prioritised in favour of other reforms under development.

The ESB supports the immediate and initial reforms advancing system strength, system security and scheduling that are currently being progressed through AEMC rule change processes. The rule changes will continue to develop and consider specific design elements of these reforms.

Since the April Options paper was published, the market bodies have continued to progress development of the UCS and SSM. These issues are being considered through the AEMC’s consideration of the *Synchronous services markets* and *Capacity commitment* rule changes. Recognising that stakeholders were not clear on the need for the SSM, and had concerns about the settings of the UCS, further work is being undertaken to better articulate the problem statement and expand on potential proposals of the mechanisms. This work specifically addresses how new technology, for example advanced inverters, will be able to be incorporated into the reforms and new mechanisms through the transition. The ESB considers there is value in the continued consideration and development of these mechanisms as evidenced by the evaluation work outlined in chapter 7.

The next expected milestone for this reform will be the publication of the AEMC's final determination of the system strength rule change in October 2021. Subsequently, subject to the final rule being made to implement this rule change, TNSPs and AEMO would undertake the process of identifying the system strength nodes leading to TNSP investment and/or procurement of services to meet the system strength standard.

The AEMC's rule change processes on *Synchronous services markets* and *Capacity commitment* rule changes will consider these matters further. These rule changes are considering mechanisms to value, procure and schedule specific services and resources that would help keep the NEM secure as the system transitions, and so will consider the matters set out above. The ESB considers that there is a need to undertake further consideration on scheduling and procurement mechanisms through the AEMC's rule change processes. Key matters that will be considered include: how such mechanisms would interact with the planning framework, what services could be procured through these mechanisms and what level of each service would be procured.

Recognising the interrelatedness between these two mechanisms, as well as the relationships with other reforms, the AEMC will publish a joint directions paper on both of these mechanisms in September 2021.

The evaluation of the benefit of this pathway has particularly focused on the nature of these reforms and is discussed in Chapter 7.

3.4. Long term reform

3.4.1. Further unbundling of services

Reforms are already underway to address frequency and system strength, with the AEMC progressing rule changes to introduce fast frequency reserves into the spot market and evolve the system strength framework to better enable investment in the needed services. Further work is also underway to manage the complex interactions of system strength in the operational timeframe to schedule the necessary resources and handle the current inability to fully disaggregate the physical phenomena which result in a strong system. As discussed, further consideration is also being given to explicitly unbundling the price of operating reserves from the energy market, and the market bodies will continue to consider how inertia should be explicitly considered through structured procurement, operational scheduling, and potentially a spot market.

As the transition continues, and experience is built in operating the system in new conditions, with increased variable renewable penetration and reduced synchronous generation, there may be an opportunity to further unbundle services to specifically value the individual requirements of a secure power system, while still considering the way in which these interact. For example, as knowledge of operating with increased inverter-based resources improves, there may be further opportunity to disaggregate the ancillary support currently provided by synchronous resources. This will allow assessment for how the unique performance characteristics of nascent technology meet the necessary capabilities, in turn allowing the evolution to more sophisticated designs with greater market efficient where and when possible.

The ESB and market bodies will continue to monitor market conditions to provide advice to Minsters on further opportunities for additional reforms.

3.4.2. Integrated ahead market

The ESB will continue to monitor and report on the potential and need for an integrated ahead market. An integrated ahead market would incorporate ahead trading and co-optimisation of energy and system services and could be used by the market to coordinate the complex and varying needs of different resources and align these with the operational conditions of the day.

The ESB's April Options Paper included the integrated ahead market as a 'next reform', to be informed by implementation of those reforms for immediate and initial progression. Current priorities for the potential use cases of the ahead market are to establish the suite of Essential System Services and scheduling mechanisms to ensure the right resources can be online when required to meet power system security; and to continue with the immediate priorities to facilitate demand-side participation.

In general, stakeholders supported the ESB's intent to de-prioritise the development of the integrated ahead market. Some stakeholders, particularly incumbent generators, considered the ESB should remove the integrated ahead market completely from the potential reform pathway, while others agreed with the ESB that there may be value in further consideration of a co-optimised ahead market for energy and services in the future and to allow intertemporal trading.

The ESB and market bodies will continue to monitor market conditions to provide advice to Minsters on the potential case for an integrated ahead market. Factors relevant to such advice will be informed by the establishment of the new Essential System Services markets and associated scheduling mechanisms. Lessons learnt from the implementation and operational experience with these reforms, as well as those already underway and nearly in operation, such as five-minute settlement and wholesale demand response, enable more informed consideration of future reforms. As the transition continues and new technology and resources, including increased active demand-side participation and penetration of storage resources, are further incorporated in the scheduling of the NEM, ahead trading may be warranted to facilitate more co-ordinated and efficient dispatch.

3.5. Recommendations

3. The ESB **recommends** Energy Ministers note that AEMC rule change requests are underway to progress the following *immediate and initial reforms* to support the availability, investment in and scheduling of the resources capable of delivering essential system services:

- a) frequency control, including a new fast frequency response service and enduring primary frequency response arrangements
- b) operating reserves services, to explicitly value reserve services separately to energy
- c) unit commitment for security and system security mechanism. These are operational and short-term procurement mechanisms allowing AEMO to value, procure and schedule specific services and resources to help keep the system secure
- d) enhanced system strength frameworks, to make it simpler, faster, and more predictable for new generation to connect to the grid and keep supply as secure as possible

4. The ESB **recommends** Energy Ministers instruct the ESB to monitor and provide advice about market conditions and the need for, *longer term reforms* for essential system services, including the need for further unbundling of essential system services, an integrated ahead market or development of inertia spot market.

4. Integration of Distributed Energy Resources and Demand Side Participation

4.1. Key points

- The sheer size of consumer-driven growth in rooftop solar PV, the projected growth of battery storage, and continued advances in digital technology, have the combined potential to revolutionize the way many customers receive and use energy. These changes have already begun for many customers today, and the increase in EV ownership will add momentum towards an even more decentralised energy system. A significant amount of electricity is already generated at a smaller scale. In South Australia this type of generation has already provided up to 77% of power demand during the day and the proportions in Queensland, NSW and Victoria are 35%, 30% and 40% respectively (maximum output figures over Q4 2020).
- In seeking to integrate these distributed energy resources (DER) into the system to deliver benefits to all customers, with and without DER, a range of different areas are addressed:
  - Customers are protected and have opportunities for new products and services: Consumers are rewarded for their flexible demand and generation, have options for how they want to engage (including being able to switch between DER service providers), and are protected in a changing retail market by a fit-for-purpose consumer protections framework.
  - Market operation: The wholesale market supports innovation, the integration of new business models and has a more efficient supply and demand balance.
  - System security: AEMO has the visibility and tools it needs to continue to operate a safe, secure and reliable system, including maintaining system security associated with minimum load conditions.
  - Network development: Networks have appropriate visibility, are able to accommodate the continued update of DER and two-way flows and are able to manage the security of the network in a cost-effective way.
- The protection of customers in an evolving marketplace requires new approaches. The range and complexity of products on offer means that measures such as listed tariffs may be of limited use in the future. The ESB considers that customers must be able to switch between retailers and aggregators without too much difficulty or cost. Data and technology are essential enablers to make this happen, but work is needed to make sure standards are in place to support effective sharing and communication of data, and market systems need to be fit for the purpose to meet the needs of the future NEM.
- System security challenges are emerging with minimum system load in some regions already with the high penetration of solar PV uptake (notably in SA but forecast for Victoria and Queensland). Backstop measures are needed as tools to maintain system security in emergency conditions, but it is critical that work continues to progress towards two-sided market measures to encourage shifting of flexible demand to times of the day where it would be most valued.
- In the short to medium term, the ESB recommends that retailers and aggregators access wholesale markets on behalf of individual customers, bundling competitive products to customers both overall and for particular energy uses or market sectors. Aggregated DER can provide a competitive alternative to large scale generation and potentially deliver low-cost system services. In a power system with a high penetration of variable renewable generation,

flexible demand delivered through DER can also contribute toward more efficiently delivering customers energy needs, reducing the need for other resources.

- Services provided by well-located DER and flexible demand can reduce the need for investments in networks. The ESB considers that steps could be taken through general tariff reform, through targeted tariffs or rebates and through contracts with aggregators to deliver some of these services.
- The long-term interests of customers need to be at the centre of the development of these measures. The efficient and effective delivery of the new arrangements needs to involve a wide range of parties, each of whom has a role to play and a potentially valuable input into the development of the new arrangements. There are pressing needs and current opportunities that need early action. Other measures need to be developed overtime, both to ensure the measures are well developed and to take advantage of emerging technology and new business models.
- The ESB has developed a DER Implementation Plan to coordinate delivery of these reforms across the NEM. The Plan prioritises activities now to address emerging risks, and sequences technical, market and regulatory reforms over the next three years to enable co-design and collaboration with industry stakeholders and customer groups as a key part of its delivery.
- These include reforms aimed at:
    - rewarding customers for their flexible demand, enabling access to products and services that innovation offers, and managing risks to customers through the right protections, no matter how customers choose to use or receive energy, or their level of engagement
    - integrating flexible DER and flexible demand into the market at all levels, safely and effectively,
    - supporting a phased implementation of reforms where possible, to enable parties to transition earlier to new arrangements where standards are in place, and where barriers to enter the market can be safely removed,
    - development of reforms using a customer centric approach. A Maturity Plan approach will be used to consider and co-design solutions to key customer challenges, with insights informing activities and reforms across each horizon of the DER Implementation Plan pathway.
- The roles and responsibilities for various actors need to evolve to deliver the more dynamic needs of customers and the grid as the penetration of DER continues to rise. ESB has set out directions for how activities and responsibilities evolve for customers, traders (retailers/aggregators), distribution networks, and AEMO, and reforms to deliver these directions are set out in the Plan.
- Reforms identified as immediate measures include a risk assessment tool that helps to assess whether additional customer protections or other changes may be needed with the expansion of new forms of energy services. With these new energy services comes the greater potential for harmful conduct. For example, it may be more effective and flexible to replace prescriptive provisions with principles relating to conduct. Building trust with consumers in relation to the delivery of new energy services including through robust consumer protection arrangements is also a key enabler to the successful integration of DER and demand side services into the market.

4.2. The issue

The largest generator in the NEM is now owned collectively by customers – and sits on their rooftops. The rapid uptake of domestic DER, with solar now on over 2.7 million homes across the NEM, continues to outstrip all forecasts.[36] The emergence of digital and battery technologies is likely to drive further growth in batteries and electric vehicles over the coming years, supporting new choices and potential value streams for customers as they offer new forms of flexibility in their load to the grid. Excess power can be stored in batteries and sold back to the grid from the household or vehicle batteries.

Technology is changing at such a fast pace; we need to make sure we set up arrangements and remove barriers so new business models and innovative and beneficial offerings can emerge to offer greater choices to customers (while ensuring they remain protected). Much like how mobile plans have evolved – driven by customer needs and technology – customers will be offered a different range of products to what is in place today, and with these new products come new risks. Not all customers have access to DER assets, but the efficient market integration of these assets can deliver value to all customers. It is important that customers without DER assets are not disadvantaged through arrangements, and that all customers are adequately protected.

Making the market arrangements more technology neutral and getting the protections settings right means that customers can benefit from a broader range of service providers, with innovative service offerings to meet our needs in ways we cannot even imagine today.

These changes in the way customers use energy and adopt DER mean that different actors in the system will need to take on more sophisticated roles so the value of resources at the distribution level can be unlocked. For example, networks will need to cope with increasing two-way flows on their system, taking on a more dynamic role in optimising the needs at distribution level. Where energy use is flexible, businesses and aggregated customers may also be able to benefit in the form of more efficient processes, new revenue streams that reward their flexibility and reduced energy bills. Businesses that can adapt their processes and demand for power should also benefit from positioning themselves for a global market, leveraging Australia's abundant renewable power for their benefit of their production and supply chain.

This means a different mix of resources on the system can meet our future energy needs, as well as supporting a low emissions future and economy. With energy as a significant contributor to emissions, making changes to how we produce and use energy, can deliver decarbonisation benefits and position Australian businesses competitively in markets shifting to tighter decarbonisation policies.

4.3. Overview of Reforms

4.3.1. Roles and Responsibilities

The reforms are based on changing roles and responsibilities for distribution networks, retailers and aggregators, AEMO and importantly customers. Before rooftop solar PV became widespread, the roles and responsibilities of customers, retailers, generators, and networks were clearly defined and understood. With increasing installation of rooftop solar, household batteries, EVs, smart appliances and smart meters, these activities and interfaces are changing. These changes mean the roles and responsibilities of actors across the system need to evolve to meet future needs. It is important to understand these changes to ensure the future market design:

- provides opportunities and safeguards for all consumers,

---

[36] Distributed Energy Resources (DER) include a range of energy assets. These are described further here: https://www.aemc.gov.au/energy-system/electricity/electricity-system/distributed-energy-resources

- facilitates innovation by service providers,
- enables networks and AEMO to maintain a secure and reliable energy system, and
- delivers an efficient market that drives down costs for all consumers.

In the April Options Paper, ESB set out the current roles and responsibilities of actors across the energy system and sought feedback from stakeholders regarding how these roles may evolve to meet future needs. Four main actors have been identified: the customer, the trader, the distribution network service provider, and the market and system operator (AEMO). Having considered feedback received, the ESB has set directions on how the future roles and responsibilities of each of these actors should evolve to support the effective uptake and integration of DER and flexible demand. These directions are discussed below, with further details in Part C.

Role of the Customer

Successful integration of DER resources and flexible demand delivers benefits to all customers – not just those with DER. The goal is to enable the full spectrum of customer choices into the future. This means:

- unlocking value for those customers who choose to have their DER and flexible demand active in the market while ensuring that those customers also meet the costs of providing for DER,
- addressing risks to the system from greater customer DER participation, so that all customers (regardless of whether they have DER or smart appliances) can still benefit from a more reliable and secure electricity grid and cheaper electricity bills, and
- ensuring the consumer protections framework supports the various choices customers will make.

Customers that do not invest in DER or take up new flexible demand products will continue their existing relationship with their retailer of choice. An example of this is outlined in the box below. Customers who do take up these products will, in the majority of cases, participate via an aggregator or retailer. These aggregators and retailers will have important obligations that they need to meet on behalf of the customer to ensure the safe and reliable operation of the system.

Customer example – customer without DER sticking with their traditional retailer option

Steven and Alina are a young working couple without children. They moved into their premises four years ago and have been with the same retailer, on a standing offer contract (Default Market Offer price) since then. While they know they can switch retailers, they are satisfied with the service from their current retailer and time poor so their motivation to investigate other offers or switch is low.

Where customers do choose to invest in DER or take up products that value their flexible load (such as from air conditioning units, hot water system or pool pumps) it will be important for them to understand from the outset how these obligations will be managed for them. This includes the extent to which their PV systems, electric vehicles, home storage or flexible demand can and cannot be used flexibly.

A customer’s key obligation currently is to simply pay for energy services received from their retailer, which includes all the costs associated with the supply of energy, such as network costs. In future, consumers may choose to engage a trader (retailer or aggregator) to operate devices on their behalf so they can receive additional value streams or cheaper electricity. It is expected that the net benefit for the consumer would be positive, but there would be an obligation for the consumer to pay for any services supplied. This may include two-way tariffs in the future.

As the penetration of DER continues to rise, the need for constraints on DER devices is already emerging to manage congestion on the system and ensure the safe and efficient operation of the network for all energy users. One example of this is where system security is challenged by minimum system load conditions, and emergency measures may need to be taken to stabilise the grid by restricting the output from solar PV assets (discussed further below). Such measures are similar in nature to current under frequency load shedding arrangements, i.e., in place as a backstop measure to maintain system security when other market-based measures have been exhausted. The ability to coordinate devices that could materially impact system security is inherently technology neutral; whilst it might be applied today to solar PV assets, it might also apply to resources such as EV's in the future. An example of how this might impact a customer is outlined below.

Customer example – customer export limits being managed by the DNSP

Mai is a customer who installs rooftop solar panels on her house. She receives a small feed-in tariff for the excess solar electricity that the system exports during the day when she is not at home. Sometimes, on mild clear days in spring, her solar panels stop generating in the afternoon as there is too much output in the local network and the inverter shuts down as it is required to (because of high voltage).

The ESB proposes that Distribution Network Service Providers (DNSPs) publish Dynamic Operating Envelopes (DOEs) that consumer DER devices, or connection points will have to comply with. This is to help coordinate access and increase network utilisation. ESB anticipates that consumers could choose to enter into an agreement with Traders to operate their devices, which would include their compliance with the DOE, in a way that minimises their energy costs or brings them increased revenue streams.

Consumers will have choices to invest in a range of DER devices in the future. A range of technical standards need to be updated to enable consumers to be able to easily switch between DER service providers (e.g., communications and interoperability standards). Once updated standards are in place, only compliant devices should be offered to consumers. While this work is necessarily complex, it all sits 'under the hood' and, once in place, will enable consumers to take up offers and switch service providers seamlessly and without complexity.

The final fundamental change to the customer is an evolution in consumer protections. Where service providers enter the market, it is important that customers remain protected from dodgy providers who may seek to take advantage of customers. As products and services offered by Traders evolve in sophistication, complexity and value to the customer, existing customer protections will also have to evolve to ensure that consumers are appropriately protected. This will be particularly important where customers may choose to have more than one service provider at their premises (e.g., with a retailer delivering their home energy needs and potentially a separate aggregator managing their EV supplies), or where the promised benefits are contingent on market prices or ongoing behavioural changes by the consumer.

Role of the Trader (Retailer Aggregator)

Traders operate in the energy market on behalf of customers, and this includes both retailers and aggregators. Traders also have a direct relationship with customers. To achieve this, traders will develop market offerings to sell energy to consumers or sell a consumers' energy or services to the NEM, to networks or as off-market services on their behalf. These market offerings may take a variety of pricing formats (e.g., bundled services, monthly subscription fees etc), and will include any network tariffs that apply. Traders may also provide energy management services via existing arrangements or flexible trading arrangements. This could include switching a customer's appliances and thermostats on or off, up and down, or managing when a consumer exports energy to the grid. It may also take into account other customer motivations, such as lower emissions, more autonomy over electricity costs or wanting to support the community through local energy trading schemes.

In future, it is anticipated that the products and services that traders offer to consumers will be more sophisticated (and possibly complex) than those currently offered as new opportunities emerge to lower electricity costs or deliver new revenue to consumers. It is important that consumers continue to be protected as energy product and service offerings evolve. Traders are currently required to comply with Australian Consumer Law (ACL) and can voluntarily comply with the New Energy Tech Code of Conduct (NETCC).[37] If Traders are selling energy to a customer, they may be an authorised retailer under the National Energy Consumer Framework (NECF) and will need to comply with the energy-specific obligations in the NECF. Alternatively, the AER can exempt them from being authorised under the NECF. This framework was not designed with these new products and services in mind and the implications for the consumer regulatory framework are discussed below (see further discussion below on retailer authorisations).

Aggregators providing market services will be market participants.

The NEM market arrangements will evolve to the 'Trader-Services' model, whereby participants register not on a per 'asset' basis, but instead as 'Traders' who can participate in delivery of a range of services recognising the capabilities they can deliver. Under this model, an aggregator will register in the universal category as a 'Trader' and classify the services it provides to customers. To support this:

- Settlement is at a market connection point,
- Traders need to ensure that communications enabled DER (in the portfolio of assets under their operation) meet technical cyber standards,
- Traders need to ensure DER meets technical standards so that it can operate in markets as part of aggregations,
- The Trader may voluntarily opt in to participate as 'scheduled lite' so that its participation in the energy market is visible to the market operator, which contributes to the efficiency of the market,
- The Trader's customer offerings need to comply with any relevant export limits. Traders ensure that the DOE limits set out in customer connection agreements are followed,
- Traders need to follow any requirements set out in connection agreements associated with financial failure /end of contract to ensure DOE are observed,
- Traders need to comply with relevant consumer law and NECF consumer protections,
- Where the Trader is selling energy to a consumer, it will need to be an authorised retailer under the NECF, unless it receives an exemption from the AER. The Trader will also need to comply with the ACL.

Role of the Distribution Network

The transition to 'active' DER devices creates many challenges and opportunities for DNSPs. This future creates a need to dynamically plan and operate the distribution network and require a higher level of coordination to maintain the safe and efficient operation of the network.

[37] The NETCC provides a voluntary framework to raise standards of consumer protection in the sector, strengthen consumer experience, and encourage innovation and the development of choice for consumers.

The management of network capacity becomes more complex, as more consumers choose to both import and export electricity. To increase the utilisation of, and coordinate access to, the network, it is proposed DNSPs publish DOEs that consumer DER devices, or connection points, will have to comply with. It is expected that Traders will manage the DER device compliance with the DOE.

As the penetration level, and types of DER devices requesting connection to the network increases; the complexity of the connection agreements DNSP's will be required to develop also increase.

DNSP's are required to develop connection agreements for active DER assets (e.g., Solar PV, Storage, Electric Vehicles) in accordance with future technical, communications and interoperability standards.

Active DER devices also create opportunities for DNSPs, as they can operate as flexible demand and generation to provide network services as non-network options for planning and managing the distribution network. Providing more readily available and cost-effective non-network options as an alternative for capital investment should increase the efficiency of network development, which benefits all consumers.

While direct load control (e.g., controlling hot water systems and air conditioners) is identified as a service that Traders are able to deliver, and access the maximum value stream from, it is also acknowledged that there is existing network infrastructure that provides direct load control operations by networks. The development of markets for flexible demand needs to take this into account, allowing customers to maintain their existing relationships if they choose to do so. The DNSP is also currently responsible for providing tariffs for Direct Load Control that recognises the network and system benefits appropriately.

It is proposed that the DNSP assumes the following responsibilities and operates as the distribution system operator (DSO). This enables the dynamic management of the distribution system and coordination of the uptake in DER in a safe and efficient manner, while maximising customer outcomes. The responsibilities of the DSO include:

- Allocation of capacity and publishing the DOEs to National Metering Identifiers (NMIs) and Traders where appropriate,
- Support more dynamic network tariff designs that will result in automated responses from DER and flexible load,
- Registration and sharing of new DER connection metadata, to AEMO to allow for the development of both short- and long-term forecasts, and
- Disconnection of load, or DER devices, under the direction of AEMO to maintain the safe operation of the network.

With the evolution of the network towards a DSO role, it will need to work with AEMO to co-ordinate local and whole of system issues, and market participate registration and market offerings.

Role of the System and Market Operator (AEMO)

Similarly to the DNSP, the continued integration of DER into the grid system provides AEMO (as the system and market operator) both challenges and opportunities. The key to enabling AEMO to continue to operate a secure and reliable energy system is enhanced visibility of DER to both AEMO and the market.

AEMO manages the future two sided markets that DER devices are active in. The increase in variability and lack of predictability in these markets may mean it is more challenging to maintain the supply and demand balance; but having more flexible, dynamic loads and generation resources provides more tools for AEMO to call upon to achieve that balance. It is recommended that AEMO register Traders into market services including existing and new market participants. It will also be necessary for AEMO to redevelop its retail and wholesale market systems and processes to facilitate the trading of market services by DER.

AEMO will need to analyse the changing requirements of the power system for operation during periods of very high distributed solar penetration. In future, AEMO will be required to provide directions to TNSPs and DSOs to ensure that minimum system security is maintained in a high DER system. This is in addition to existing requirements to ensure that maximum system load is safely supplied. Consistent with existing market arrangements, it is intended that this is achieved through market mechanisms first, before issuing directives out of market. In future, AEMO needs to provide notification to the market of a predicted minimum system load event, as well as the consequential system risks, to facilitate this market response.

It is critical that AEMO has access to relevant information to be able to forecast, manage, and operate the system. Increasing DER visibility, predictability, long-term and short-term forecasting and improving operational coordination between AEMO and DSOs improves the efficient management of the energy system. AEMO should also play an important role in providing guidance to inform standards for DER to safely connect and operate on the system.

The existing responsibilities to manage the Load At Risk, Under Frequency Load Shedding, and Black Start capabilities remains with AEMO and are recommended to be reviewed and updated under the future market design.

Role of data and technology as an enabler

In a high-DER, decentralised system with millions of actors and devices, digitalisation is a necessary capability. These capabilities are necessary for AEMO to maintain system security in an increasingly uncertain and complex environment, enhancing visibility and transparency to manage complex system needs across locations and time, and enable data to be shared at interfaces with network businesses as they carry out management and operation of their own network needs. Access to accurate and granular information also enables optimising and efficiently balancing supply and demand over operational and planning timescales from 5 minutes to 50 years.

There is currently poor visibility of the increasing volume of DER resources connected to the grid, as well as the challenge of not being able to send signals so devices can adapt their output where they could be rewarded for doing so and help address system needs. This means it is difficult to efficiently leverage the significant volumes (~50GW) of latent flexibility that currently exists on the grid (and in customer homes). It also means it is harder to unlock benefits for customers from their flexibility, relying instead on backstop measures to keep the grid stable when system security is threatened, while at the same time building capabilities for future market-based approaches.

The cyber-physical threat is a significant operational challenge, where sophisticated but ill-intentioned actors may attempt to exploit the NEM's legacy IT systems. Building new digitised infrastructure, with fit for purpose technical and communications standards for the DER devices now making up a significant proportion of our resource mix, is critical.

Importantly, digitalisation is about more than modernising the energy supply chain. Improving timely access to data will make sure consumers are at the centre of the new market arrangements.[38] With access to clear and simple information to make better choices and enabling greater agency and control over their energy use and devices. Feedback from energy consumers and user groups has been

[38] This has already been partially recognised with the extension of the Consumer Data Right provisions to the energy sector, which will allow consumers to require their retailers share their data with prospective service providers to get more tailored, competitive services. For more information, see the ACCC's website, CDR in the energy sector https://www.accc.gov.au/focus-areas/consumer-data-right-cdr/cdr-in-the-energy-sector

unequivocal about the need to get this right to address concerns about complexity in the market and the risks of information overload.

As seen in other sectors, data is a critical input for innovation, revealing opportunities to create value for customers through new interactions, energy applications and business models. This is not about overwhelming customers with more data and complexity but enabling service providers to innovate and offer new products and services that can better meet customer needs.

Data and information about the performance of energy companies will be a critical tool for regulators and consumer protection agencies. This is because innovative new propositions are likely to sit outside established regulatory service definitions and precedent, and to be safely permitted, requires regulators to adopt principle and risk-based approaches to compliance and enforcement. Given the pace of change underway, this sees market bodies and regulators constantly monitoring service standards and consumer outcomes, identifying potential or actual detriment early, and acting quickly to stamp out poor behaviour to protect customers before it becomes systemic. Regulators and consumer protection agencies will need to have the right tools and frameworks in place to ensure they can manage these risks effectively, and this is highlighted as a priority in the Data Strategy accompanying this report.

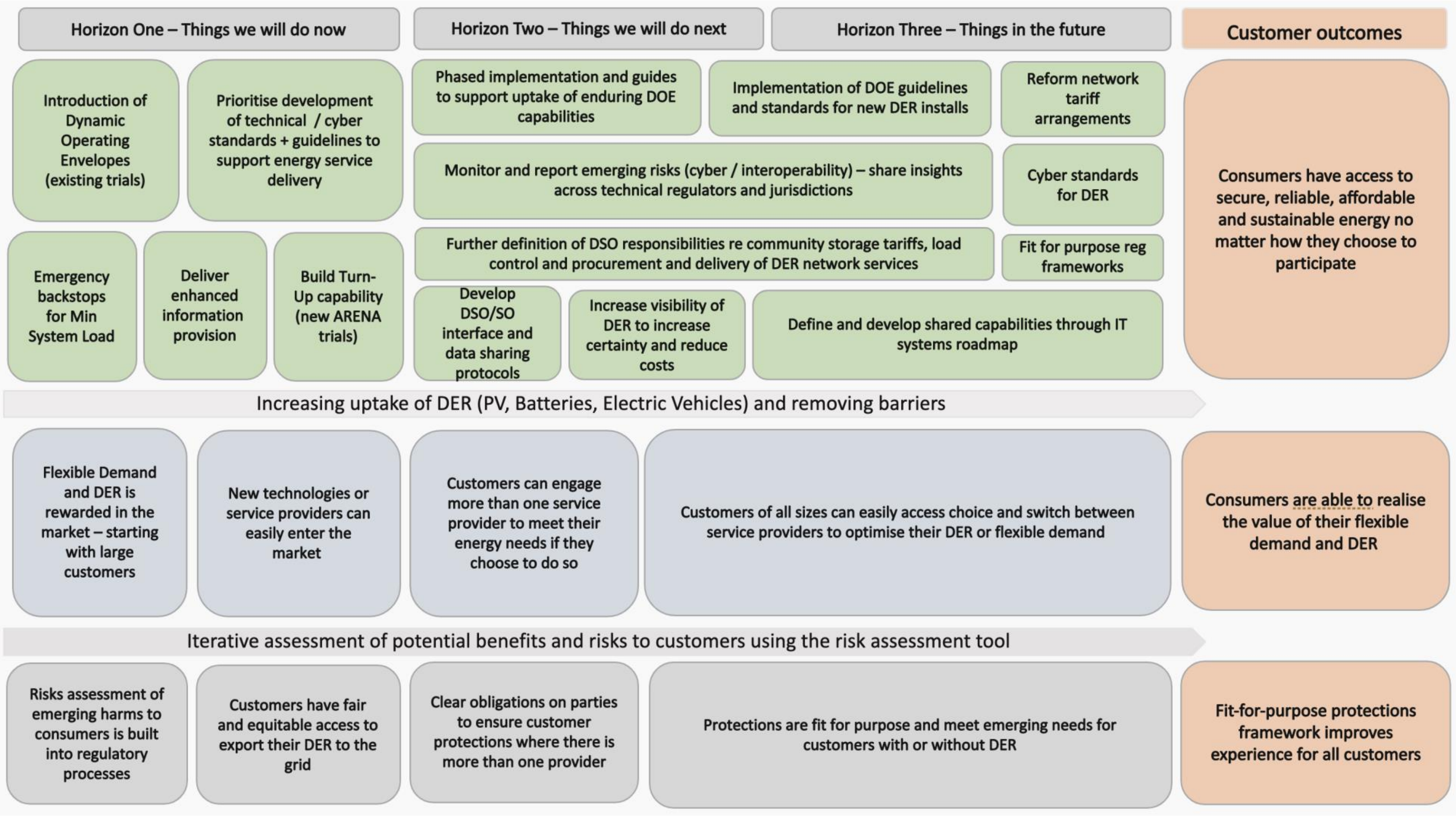
The risk assessment tool that we have developed with consumer groups is modelled on world-leading practice and helps agencies perform this risk identification and assessment function. To support these activities, foundations need to be set with processes to access and share data across market and regulatory bodies.

4.3.2. The Implementation Plan

The ESB has developed a DER Implementation Plan (the ‘Plan’) to integrate the evolution of roles and responsibilities into a suite of technical, market and regulatory reforms from now until 2025. Reforms are intended to leverage technology and data, improve access and efficiency, enhance market participation, and strengthen customer protections and engagement.

Recognising the different stages in the elements of reform, the Plan sets out activities across new and existing workstreams, including contributions from market and industry bodies. The Plan sequences key dependencies to ensure these reforms are introduced quickly, and timed to address urgent needs associated with the rapid take-up of DER. It highlights where interim measures may be introduced to support the industry through the reform process. A summary page view of the Plan is set out in Figure 3 below, with further detail set out in Part C.

Figure 3 DER Implementation Plan



Effective implementation of these reforms will support the following outcomes for all energy consumers:

- Consumers have access to secure, reliable, affordable, and sustainable energy no matter how they choose to participate
- Consumers are able to realise the value of their flexible demand and DER
- Fit for purpose protections framework improves experience for all customers.

To ensure customer insights remain central in informing the development of the reforms, a Maturity Plan approach is used to complement delivery of the DER Implementation Plan. The Maturity Plan provides a vehicle to work with customers and stakeholders to test assumptions and understanding of customer behaviour and experience, with priority issues to be considered over each release.

The ESB has heard stakeholder feedback and our intention is for this to be an integrated approach to implement these reforms, recognising the need to collaborate on designs, and adapt with customer insights and priorities as we progress. This is intended to support getting the balance right on providing clear direction on reforms and priorities, and enabling customer advocates, stakeholders and interested parties to engage on the detailed design to inform consumer outcomes. Where existing adjacent processes can inform these reforms (e.g., via the DEIP work program or other rule change processes) these should also complement delivery of the Plan.

Further information regarding the Maturity Plan approach and how it will support delivery of the DER Implementation Plan activities is set out in Part C. Reforms to be delivered over each horizon are discussed below.

4.4. Immediate reforms

To address a range of pressing needs, and to get ahead of the curve on other emerging issues, several reforms are underway now. These include:

Development of technical standards governance

On 21 September 2020, the ESB submitted a rule change request to the AEMC regarding the governance of DER technical standards. This request asked the AEMC to consider creation of 'DER Technical Standards' in the Rules or subordinate instrument, provide for the enforcement of those standards and other relevant Australian Standards, and establish the AEMC as the responsible decision maker for setting DER technical standards. This proposal is intended to support greater alignment and enforcement of DER technical standards. The AEMC intends to initiate this rule change in August 2021 and will publish a Consultation Paper to seek stakeholder feedback on the request.

Standards for new technologies / devices

Significant work has been carried out in updating inverter standards which has helped bring a better response to voltage and frequency disturbances, consistent with international standards.[39] Adapting standards to an Australian context takes into account NEM factors (e.g., a fully contestable market) so that customers with DER can switch service providers and to enable devices to communicate and operate more effectively in the NEM. This adaptation will also need to consider that differences between international and Australian standards could create additional costs and barriers to competition.

---

[39] Work carried out in Australia includes in relation to AS 4777.2:2020.

Development of these standards should be informed by insights about how customers may choose to use their DER. Standards need to reflect the minimum level of functionality to support interoperability and switching and be supported by all service providers offering DER services. Getting these standards in place is a critical path dependency to enable effective switching outcomes for customers, while supporting the development of a competitive market for service providers. Standards should also not unnecessarily discourage innovation that may be in the long-term interests of consumers.

As we transition to policies requiring two-way communications with DER devices, there is a need to implement cyber policies and processes through this transition period to ensure we do not inadvertently open security vulnerabilities. This includes both short term and enduring needs for monitoring of risks and breaches, until broader standards conformance can be reached.

Work is underway to develop these standards as part of the Distributed Energy Integration Program (DEIP).[40] In the first instance, this work is an adaptation of the Institute of Electrical and Electronics Engineers (IEEE) 2030.5 standard for inverter based solar and storage DER but is likely to embrace other standards as the policies are extended to EVs and smart devices.

To support this, the following priority activities in the DER Implementation Plan are being progressed:

- an ESB proposed rule change to provide further governance for DER technical standards under the NER (with the AEMC for consideration),
- the ESB is developing policy advice about interoperability to provide direction on technical standards (via relevant DEIP Interoperability, communications, Dynamic Operating Envelopes and EV workstreams). Initial policy advice to DEIP by December 2021 to support implementation of incoming standards by June 2022,
- Based on this advice, support the phased introduction of mandatory technical standards (interoperability and communications), initially for new inverter based solar PV and battery storage installations, and a subsequent phased rollout for other DER categories,
- ESB and DEIP to identify related processes needed to enable DER interoperability alongside standards, such as registration, telemetry data collection and management of identity and access control,
- DEIP workstreams for DER Communications and Interoperability to include considerations of cyber security, including development of preliminary security design for DER interoperability. ESB to coordinate with the Federal Department of Industry Science Energy and Resources (DISER) on enduring policy and interim measures needed,[41]
- ESB / Market bodies to confirm policy on EV smart charging standards, and timing for their introduction, based on advice from the DEIP interoperability and EV working groups, by June 2022.

Development of Dynamic Operating Envelopes

To manage growing minimum load issues at a system level, and local congestion at different points within the distribution grid, there is a need for a system-wide standard to apply limits to the import and export at DER connection points to the grid. At present, these limits are static, but dynamic limits have the potential to better manage congestion on the distribution network and allow for more

---

[40] Work in the DEIP is coordinated by ARENA together with market bodies, consumer advocates and stakeholders.

[41] This is part of the cyber security strategy work program underway coordinated by Dept of Home Affairs. More details can be found: https://www.homeaffairs.gov.au/reports-and-publications/submissions-and-discussion-papers/cyber-security-strategy-2020

flexibility in exporting. These are referred to as dynamic operating envelopes (DOEs) where maximum levels or exporting and importing are set and change over time.

DOEs have been developed through a number of industry trials (including SAPN, Evo Energy and others), to better understand how these limits should be implemented, and support a consistent approach, underway via the DEIP DOE workstream.

To enable implementation of DOEs as a mandatory requirement for all new DERs connecting to the grid, coordination of several key reform activities is necessary. These include:

- Establishing new connection agreements with customers that refer to these dynamic limits, and the obligations of the customer, via the retailer / aggregator to maintain these limits;
- DNSPs to develop capacity allocation principles on how to fairly allocate these limits to different customers at times when constraints are required;
- New obligations on the retailer / aggregator to operate DER within these limits, where they are operating DER on behalf of customers;
- Creating new standards for interoperability and cybersecurity such that DER devices can be communicated with in a standard manner, supporting a simple process to switch from one provider to another, and enable any provider to ensure compliance with DOEs.

To support the efficient and timely implementation of DOEs, the ESB recommends coordination of a phased policy rollout for new mandatory obligations, alongside best-practice guidelines to allow all market participants and DNSPs to transition towards communications and interoperability standards. This may involve some jurisdictions to move sooner than others based on need, adopting draft standards as part of jurisdictional programs, and recommend forward compatibility for new installations to meet DOE specifications.

For example, market trials currently underway can provide short-term guidance to inform best-practice for how DNSPs should determine capacity allocation for customers with DER exports. These policies should, in parallel, inform longer term regulation by the AER. Similarly, the mechanisms for DER registrations for systems with two-way communications capabilities should be further refined and standardized, taking learnings out of the SA Smarter Homes program to help upskill installers.

To facilitate these reforms, ESB will progress the following priority activities in the DER Implementation Plan:

1. The phased introduction of mandatory technical standards (interoperability and communications), initially for new solar PV and battery storage installations, and phased rollout for other categories of low voltage and medium voltage connected assets.
2. Based on outcomes from DEIP DOE workstream, ESB, AEMC and AER to fast-track best practice capacity allocation rules, monitoring and compliance arrangements and connection agreement terms and conditions to meet the enduring policy objectives and provide appropriate protections for consumers. An important component of this work will be the need to consider the role of aggregators and retailers within the connection agreement framework, noting that connection agreements are between customers and networks.
3. ESB and market bodies to work with CEC and other industry bodies to establish guidelines on the DER registration process and standardized data capture (e.g., guidelines on DER install configurations that enable finer grained control to preserve self-consumption at times of congestion).

DER access and pricing

On 25 March 2021, the AEMC made a draft determination to integrate DER, such as small-scale solar and batteries, more efficiently into the electricity grid. The draft rules are expected to harness the benefits of DER by clarifying networks' role in efficiently providing two-way services, while enabling benefits to accrue to all electricity system users. The draft determination addresses the problem of 'traffic jams' on the electricity network, which will get worse as more solar connects. This is because networks were built when power only flowed one way. Shutting off power exports because the grid is under strain will cost both solar and non-solar customers more in the long run, because it means less renewable, cheaper energy gets into the system and solar customers will bear the cost of being able to export less energy into the grid. The key parts of the proposed reforms are:

- making distribution networks accountable for delivering services that help people send power back into the grid,
- clarifying that networks can use pricing to reward customers when their actions improve the operation of the grid (negative or reward pricing) and charge them for sending energy when it is not needed,
- flexible pricing solutions at the network level.

The intent of this rule change is that over time, more new customers with DER will be able to connect to the grid and existing customers can access the grid to export if they choose. All of this will be done so that all energy users benefit from DER, whether they have those systems or not.

The AEMC received a lot of diverse feedback to the rule change and is currently exploring a number of different options to design a long-term solution that works for all energy consumers. The AEMC plans to release a final determination on the rule change on 12 August 2021.

Wholesale Demand Response Mechanism

From October 2021, large consumers will be able to sell demand response in the wholesale market either directly or through specialist aggregators for the first time, via the new wholesale demand response mechanism (WDRM). The WDRM will enable greater visibility of larger loads who opt in. It involves larger participants being compensated for offering their flexible load in dispatch, like generating resources. The compensation comes in the form of a payment for when they reduce demand below a baseline in response to dispatch instructions. The WDRM is only suitable for loads that are large, controllable, and predictable. This means that small loads and those which are very price responsive (unpredictable) are not able to participate. The WDRM is a first step in enabling greater demand side response, and further participation is being supported through reforms such as flexible trading arrangements and scheduled lite.

4.4.1. Addressing system security challenges associated with minimum system load

In the April Options paper, ESB discussed the emerging system security challenges associated with minimum system load conditions.[42] These conditions are already being observed in South Australia, and AEMO has forecast the occurrence in other regions (i.e., Victoria, Queensland) in its Electricity Statement of Opportunities (ESOO) modelling.[43]

---

[42] In its April Options Paper, the ESB referred to this issue as 'Minimum Demand'. Following feedback via the Maturity Plan Pilot and via stakeholder submissions, the ESB has updated terminology to reference these issues in respect of 'Minimum System Load'.

[43] Information on AEMO ESOO modelling for the NEM can be found here: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo

The issues we are currently observing with minimum system load in South Australia are a symptom of a high penetration of DER devices (notably solar PV installations) not being well integrated into the system. As we transition into the future where the penetration levels of EV's, home storage, and Solar PV are predicted to rise to significant levels, the interaction between the system and consumer devices will need to be coordinated to maximise benefits to all customers.

With Australia leading the world in its uptake of DER (with more than 2.7 million households now having solar PV on their rooftops), emerging system security issues associated with minimum system load are a new challenge for maintaining stable grid operation. More work is needed by AEMO on characterising how the problems and consequences of system security issues associated with minimum system load emerge in each region to better inform when and what solutions are implemented and how they are used. These insights need to be communicated with stakeholders to build greater understanding of the contributing factors. Enhanced transparency of this information will help the market respond with cost-effective solutions.

Enhanced information regarding the conditions that lead to minimum system load events / conditions would assist the market in developing a clearer understanding of factors contributing to when and why these events may occur, improving community awareness and understanding of the changing system needs and conditions (and how they can assist).

Emergency backstop solutions that are used to curtail exports from solar PV are in place in South Australia, and it is likely that similar tools are required (given the forecast for system security challenges) in all mainland NEM jurisdictions in the coming years, given forecast system security challenges. More immediate action may be required for Queensland, followed by Victoria. The most appropriate backstops may differ by region, depending on the existing infrastructure and technology, and the size and likelihood of the risks.

However, emergency backstops (on their own) are a blunt instrument and need to be complemented with measures to support market response to the system needs, such as the development and implementation of enduring solutions such as DOEs and two-sided market reforms (including scheduling lite and flexible trading arrangements). Many of the reforms in the DER Implementation Plan such as development of communications standards and technical regulation, cyber-security, and evolved roles and responsibilities inform both the implementation and operation of some backstop measures, as well as support the move towards more enduring responses.

Stakeholder feedback

The ESB received a great deal of feedback from stakeholders on issues surrounding minimum system load, its impacts on social licence with customers, and how to address the issue. Feedback from stakeholder submissions also complemented the direct stakeholder engagement that was part of the Maturity Plan Pilot, which sought to consider these issues from a customer perspective.[44]

This feedback has informed the development of a suite of solutions to address these system security needs. These solutions can be viewed as a package, intended to address needs at different points in the operational and planning timescales, and are discussed in turn below.

Levers to enable emergency backstop measures

The ESB recommends jurisdictions put in place emergency backstop measures to ensure AEMO has the tools necessary to manage system security issues associated with minimum system load

44 The ESB ran a Pilot of the Maturity Plan over April-June with input from a diverse group of stakeholders. This process was facilitated by RPS Group and the UTS Design Innovation Research Centre. A knowledge sharing report capturing insights from the Pilot can be found here: https://esb-post2025-market-design.aemc.gov.au/reports-and-documents#consultant-reports

conditions. In implementing such measures, there is value in reflecting on insights emerging from the SA experience and stakeholder feedback to enhance implementation outcomes, and build social licence, in other states.

Implementation of backstop measures should consider:

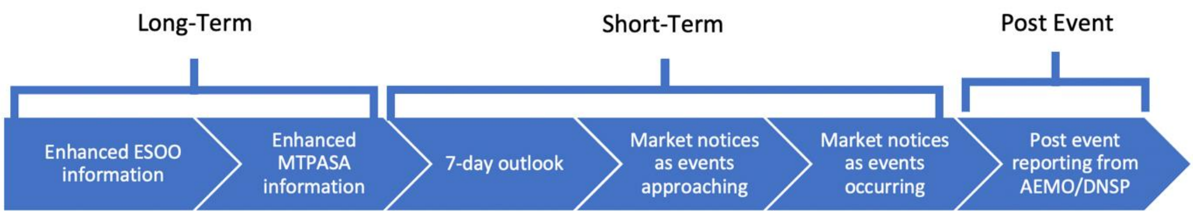
- Use of existing technology and infrastructure, to minimize costs imposed on consumers,
- Where mechanisms to directly curtail small scale solar are considered, we recommend API based solar curtailment through an agent,[45] similar to the SA solution with adaptations to encourage implementations that will align with future initiatives such as two-sided market reforms,
- Include the enrolment of retailers and aggregators to opt-in to the new responsibility for emergency switch-down of solar PV,
- DNSPs to transition away from the role of the Relevant Agent (or similar construct),[46] as the new obligations for aggregators are defined,
- Potential to partner with peak bodies (e.g., the Clean Energy Council) to establish guidelines on registration process, standardized data capture,
- Increasing the priority for AEMO to enable automated API for minimum system load limits, and have aggregators and retailers respond dynamically to emergency limits is a deliberate first step towards DOEs.

Enhanced information provision

Enhanced information regarding the conditions that lead to minimum system load events or conditions would assist the market in developing a clearer understanding of factors contributing to when these events may occur and when there is value in shifting flexible load to support the system needs.

Information provision is an enduring solution to support future market price signals for services and provide transparency on the development of risks, solutions and costs imposed on consumers of managing minimum system load events. There is potential for information to be provided across planning (e.g., ESOO) to operational (minimum system load forecasts) timeframes and post-event reporting.

Figure 4 AEMO information provision



45 API = Application Programming Interface

46 The Relevant Agent framework was put in place by the SA Government, as the party required to comply with new technical requirements for new solar and storage installations from December 2020.

Immediate measures to include:

- AEMO to develop guidelines to support greater understanding of factors contributing to system security challenges with minimum system load conditions.
- AEMO to work with industry stakeholders to develop market event reporting framework (e.g., MSL (Minimum System Load) – similar to Lack Of Reserve (LOR) event reporting.
- AEMO to work with industry stakeholders to improve post-event market reporting for minimum system load (MSL) events.

To support enduring outcomes:

- AEMO to provide greater clarity regarding assumptions of duration and frequency of minimum system load occurrences in ESOO (annual data)
- AEMO to consider opportunities to enhance MT PASA information reporting (consistent with guidelines)
- AEMC/AER to review consumer impacts, costs, and market impacts of minimum system load interventions over time

Market Development and Trials of Turn Up Solutions

A key challenge associated with the introduction of emergency 'back-stop' measures has been the lack of corresponding market-based measures or incentives introduced at the same time. While emergency levers are likely to be important as enduring solutions, it is critical they become a genuine 'back-stop', with an increased focused on encouraging the shifting of flexible load into periods of low or negative wholesale prices.

Market development of 'turn up' solutions should be pursued to increase the capability and capacity of load to respond to low or negative price signals during times of abundant variable renewable energy, which is correlated to periods of minimum system load. A turn up service is a demand response mechanism that facilitates an increase or shifting of load. A turn up service could be activated commercially to allow consumers to benefit from increasing their load during periods of low prices or it could be activated as a security service to provide minimum system load for secure operation of the power system.

Demand response mechanisms have in the past focused on load reduction services that are activated in response to high energy prices or due to a projected shortfall in generation reserves. Demand response mechanisms like Wholesale Demand Response Mechanism (WDRM) and RERT do not facilitate a turn up service. A trial program could test the feasibility of a turn up service and consider important design components such as technology, baselines, pricing, and settlement arrangements.

The ESB recommends that AEMO work with ARENA, to pursue development of a trial to enhance demand response capabilities within the NEM. Trials could be developed with both in-market and out of market solutions, with a preference for in-market options where this would likely be less costly and would support development of enduring market arrangements.[47]

[47] Another opportunity to consider market-based tools, to help manage minimum system load, is the Reliability Panel's review of the reliability standards and settings, due to commence in mid 2021. This will assess and consider whether the current form and level of market floor price remains suitable for expected and evolving market conditions, including emerging issues for minimum system load. The Panel may recommend changes to the market floor price – and other settings- to ensure they continue to meet their intended purpose as well as the requirements of the market, market participants and consumers.

Jurisdictional support schemes

Governments have been early and proactive supporters of the uptake of solar PV, and more recently, other DER assets (such as batteries). This financial support has been a driver of community uptake of DER assets and has helped Australia become a world leader in the uptake of rooftop Solar PV. These measures have been implemented to support delivery of renewable generation or emissions reductions targets, with households and businesses readily taking advantage of the discounts.

The vast majority of existing solar PV are 'passive' devices – meaning they do not have the capability to moderate their output in response to system or market signals (that is as 'active' devices). Existing PV systems are however AS4777 compliant and respond to voltage fluctuations as a protective safety mechanism.

There is considerable value in jurisdictions providing subsidies or incentives which align with the long-term interest of all energy users. This would encourage investment and behaviours to support the safe and efficient operation of the system and market. Incentives that facilitate the continued effective integration of renewables into the system, and support emission reduction targets via transport electrification, may have additional conditions than the current incentives.

Potential policy steps by jurisdictions could include providing incentives:

- To solar PV inverters that enable the device to be 'active'.
- To solar PV firmed with batteries, or batteries on their own.
- For DER assets that will take part in a Virtual Power Plant (VPP) or peak / minimum system load program.
- For EVs where 'active' managed charging occurs.
- For tariff reforms that encourage load turn-up and solar PV self-consumption.

4.4.2. The consumer experience

The ESB has engaged closely with customer advocates to form principles intended to guide the development of protections in the future market. This is intended to protect consumers using new types of energy services and monitor the conduct of retailers and aggregators as the market evolves. These principles have been well received by stakeholders and customer advocates.

The ESB has incorporated the consumer protection principles in an updated version of the consumer risk assessment tool, set out in Part C.[48] The tool's purpose is to ensure market bodies explicitly consider consumer benefits and risks as part of, and alongside, design and development of market reforms. The risk-based approach also identifies where new consumer protections or other measures may be needed, reflecting the potential of a new arrangement, product, or service to cause harm.

Stakeholders commented favourably on the proposed consumer risk assessment tool with some, such as Energy Consumers Australia (ECA), noting support for the proposed risk-based approach for assessing consumer protections along with the set of guiding principles. Some stakeholder suggestions for changes to the tool include:

1. Expanding the benefits assessment so it not only considers individual consumer benefits but also customer-side and system wide-benefits.

48 Having considered feedback received to its April Options paper, the ESB has made an adjustment to the principles to be 'no cost dispute resolution', rather than 'low-cost dispute resolution'. This is to ensure that residential and small business customers across the NEM should continue to access free, fair, and independent dispute resolution via Energy Ombudsman schemes into the future.

2. Incorporating an assessment against the consumer risk protection principles.
3. Greater clarity on what is involved in each of the steps in the process, including the importance of focussing on the type and severity of harms. As PIAC noted in its submission, types of harm can range from inconvenience to financial loss, to detriment to health or well-being.
4. In applying the risk assessment tool consider a diverse range of customers and their needs. The ECA notes in its submission that this includes vulnerable or disengaged customers, and how proposed measures to mitigate risk are proportional to the impact on customers.

The Consumer Risk Assessment Tool has been updated to reflect these stakeholder suggestions. This tool will be used by all market bodies immediately and will apply to the reforms being progressed under the DER Implementation Plan.

Immediate next steps on consumer protections

The AER and the AEMC will undertake a review of the existing retailer authorisation process. The energy-specific consumer protections under the National Energy Customer Framework (NECF) stem from whether the person is sold energy for premises by a retailer.[49] As the market transitions, different products, services, and business models are likely to emerge with customers able to choose services to meet their energy needs. This might include services that optimise their energy use, their flexible demand, or the value of their DER assets in addition to buying energy.

A review of the retailer authorisation process is an important next step because the level of consumer protections that apply to these business models depend on whether the AER provides a full retail authorisation or an exemption (from all or parts of the NECF); and if it provides an exemption, what (if any) conditions are attached to it. The review may also identify where business models are out of scope of the NECF (for example, because they do not involve the sale of energy to customers for premises) and are covered by Australian Consumer Law (ACL) only, and what risks this may pose for consumers and effective retail competition.

This process is critical for striking the right balance between consumer protections and encouraging innovation in the market. With the expected entry of a wide range of new energy services and business models, it will be important for the process to be fit for purpose.

Initial work on consumer protections

For energy service providers to hold and maintain a social licence for managing and operating customers' DER and appliances, consumers need to trust these providers. Consumer trust in these new products and services is also a key enabler for the success of the products in driving more active DER within the energy system.[50] There are existing supports for this through the consumer protections under the ACL as well as the energy-specific protections under the NECF. Together the consumer protection framework:

- prohibits certain conduct that harms effective competition, fair trade, and commerce (ACL)
- sets out requirements relating to obligations to offer, disconnections, financial assistance and hardship provisions, protections for consumers on life support and information requirements, where there is sale of energy (NECF)

---

49 NERL section 5.

50 The ECA's consumer sentiment study from June 2021 notes 46% of consumers believing that the market is working in their long term interests. This can be found here: https://energyconsumersaustralia.com.au/publications/energy-consumer-sentiment-survey-findings-december-2019

Consumers of these new energy services are also supported by the obligations under the voluntary New Energy Tech Consumer Code (NETCC) if their service provider is a signatory. The NETCC[51] includes minimum standards of consumer protection including:

- providing clear, accurate and relevant information to help consumers make informed choices
- ensuring sale practices are responsible
- being responsive to consumer needs and take prompt, appropriate action in response to complaints.

These existing protections may need to evolve to ensure they remain appropriate and fit-for-purpose as new, more diverse range of energy products and services, and service providers emerge. The risk assessment tool will form part of the analysis of the flexible trading arrangements rule change proposal. Then, as the market develops, new risks or gaps in the existing regulatory framework may be further identified. Market bodies will continue to monitor emerging business models and assess whether they pose risks to consumers that cannot be managed appropriately under existing frameworks. This is critical to give consumers the confidence to engage in the market how they choose.

Depending on the level of risk identified with services covered by the ACL only, market bodies may decide to commence a review of whether the scope of the NECF should be amended to encompass these new business models, and how it should be amended.

These further steps could include consideration of ways to best regulate the sale of these new and innovative products, such as longer cooling-off periods to allow consumers more opportunity to decide if an energy management product is right for them, constraints around the types of products that can be offered to consumers (for example where there is a significant risk consumers may suffer losses) and how they are sold (for example to ensure consumers are only offered products that are appropriate for them). This is particularly relevant for the majority of customers that may have little interest or indeed difficulties in engaging with the energy market.

Alternatively, further steps could include changes to the way the retail market is monitored and regulated, including taking a more principles and risk-based approach to supervising service providers and enforcing compliance. One of the strengths of more principles-based and outcomes focussed regulation is that it can avoid prescriptive detail that can stifle innovation which is important in new and transitioning markets. It is possible that some protections may be able to be reduced where they have become outdated or ineffective, or the risk is much lower due to the consumer being more knowledgeable or sophisticated. A market design and customer protections that work for all customers is clearly important, and the ESB's consumer risk assessment tool provides a structured approach to identifying where protections should evolve.

Additional measures to enhance customer experience

As discussed in previous Post-2025 consultation papers, and noted by consumer advocates, the energy transition and uptake of DER may increase issues of equity amongst consumers. The reforms proposed by the ESB involve an assessment of both the direct benefits to consumers who own DER or are able to respond with flexible demand, but also the indirect benefits to flow to all consumers through a more efficient market and lower electricity prices. It is critical to ensure that consumers who receive

51 Signatories that do not comply with these obligations will have their membership revoked. The NETCC was developed by the Clean Energy Council (CEC), the Australian Energy Council (AEC), the Smart Energy Council (SEC) and Energy Consumers Australia (ECA).

direct benefits from their DER and flexible demand also bear their fair share of the costs of the reforms.

Alongside the benefits from the reforms the ESB has proposed, there are also additional measures or policy instruments that can be implemented outside the energy regulatory framework. These measures are discussed in the ACIL Allen report published alongside the April Options paper,[52] and include improving access to energy efficiency programmes and cheap sources of electricity for renters through other means, such as community batteries, solar gardens, and other shared infrastructure. Consideration of such measures by jurisdictions and policy makers could help deliver direct benefits to the 32 per cent of Australians living in rental properties.[53]

4.5. Initial reforms

Trader Services Model

Some customers can currently participate in the energy or ancillary service markets in the NEM. However, barriers exist in the current rules that mean it is not easy for market participants to provide new products and services that customers value.

Over recent years, the market rules have been amended to add new categories of participants. If a participant wants to provide a range of services to customers and the market, it must register in multiple categories. This adds complexity and potential ambiguity for market participants and new entrants. There is also an increasing overlap of formerly distinct categories. For example, Market Customers who represent 'load' connection points can also be net exporters of energy at some intervals from solar PV and other DER.

A new approach is required to better enable all types of customers to be rewarded for how they choose to participate (whether passively or actively) in energy and other markets. The challenge is to ensure the arrangements keep pace with the transition taking place. Instead of making *ad hoc* and incremental changes to address new business models and technologies emerging, the ESB recommends a trader-service model that reflects the broader changes occurring in the NEM.

The trader-services model seeks to evolve the participation framework to ensure it can integrate new technologies and business models and make it easier to provide new services to customers. The model involves creating a single, universal registration category ('Traders') for all entities who want to engage in the wholesale energy and energy services markets. This approach would enable 'traders' to deliver a range of services to customers without registering in multiple categories. Services-based regulation would attach appropriate obligations to the services provided rather than the assets.

For example, if a market participant wants to trade energy and FCAS today from some of its DER customers, energy only from others, and also has non-DER customers, it would have to register in three different market participant categories: generator/MSGA,[54] market customer and ancillary service provider. Each category is subject to different fees and registration requirements, and only certain services could be traded from each customer connection point. Under the new model, the Trader would register once as a Trader and classify the services it intends to trade from each connection point. As the Trader wants to provide new services to its customers, it would not have to register again. Instead, it simply classifies that new service.

---

52 The ACIL Allen report looking at two-sided market consumer archetypes can be found here: https://esb-post2025-market-design.aemc.gov.au/reports-and-documents#consultant-reports

53 Australian Bureau of Statistics, housing statistics 2019: https://www.abs.gov.au/statistics/people/housing

54 Market Small Generator Aggregator = MSGA

Obligations attach to an entity depending on which services it provides, rather than the category in which it registered. Compliance would be assessed by the AER in the usual manner.

The trader-services model would make it easier for customers to choose different providers for different services. Stakeholders have generally been supportive of an approach that streamlines participation and removes barriers for both service providers and customers. Some stakeholders noted that the ESB should use caution when moving towards the model so as not to introduce complexity for consumers by requiring them to have multiple services providers for various services. Stakeholders also noted that there are still many issues to work through.

The ESB notes these proposed changes also facilitate a future transition from the WDRM to a more fully two-sided market. This will help to address concerns raised by customers and stakeholders regarding some of the practical limitations of the WDRM.

While the ESB considers that there are benefits in implementing this model, it also acknowledges that the model is a considerable change for the current regulatory framework and industry. The design and implementation of such a model must be well sequenced with new service-based regulations to ensure market participants continue to meet the relevant operating standards and technical requirements and appropriate consumer protections. It needs to be phased in over time and may, in part, co-exist with the 'old NER' provisions before these are eventually phased out.

Moving towards the trader-services model

The AEMC is actively considering the first steps towards the trader-services model in its draft determination for the 'Integrating Storage' rule change.[55] The Commission has made a draft rule introducing a new participant category that accommodates various participants with bi-directional energy flows that may offer (and consume) energy and ancillary services. This includes grid-scale storage, hybrids and aggregators of small generation and storage units.

Following the final determination, the market bodies will need to work with stakeholders to determine the next steps in moving to the trader-services model. Some of the key issues to be addressed in moving beyond rule change to the model include:

- when and how to move current market participants into the new category
- moving the IRP to be more services-based, including looking at whether and how technical performance standards could be set for services rather than assets.
- how investments made in systems and process improvement can be leveraged for future initiatives.

Flexible Trading Arrangements

With increasing access to various types of DER and the range of services that flexible forms of generation, storage and load could support, the ESB has considered how the market can provide customers with greater choice in accessing services.

Flexible trading arrangements are a way to enable the separation of controllable load (for example solar PV, batteries, EVs, pool pumps) from uncontrollable resources (the primary source of electricity to a customer's home or business). In doing this, customers can be rewarded for their flexible demand and generation while not making significant changes to their behaviour for their conventional energy usage. By separating controllable resources, customers can choose additional energy services for their

55 Detail regarding the Integrating Energy Storage Systems into the NEM rule change can be found here: https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem

flexible demand or generation while remaining on their current retail plan for all other energy produced, consumed, or stored.

The current regulatory framework does not support many customers easily engaging with more than one energy service provider at their property. It requires the establishment of a second connection point to the grid with associated metering, connection costs and complex electrical work. Some networks do not allow small customers to have a second connection point. Flexible trading arrangements provide simple models that enable the separation of controllable resources at a customer's premises, providing greater flexibility and the opportunity to engage more specialised energy service providers and plans to suit customers' needs.

Stakeholders had a range of views on the proposed flexible trading arrangements. Customer representatives and market participants emphasised the importance of applying proportionate customer protection. Both groups also note that it is essential to provide scope for service providers to innovate and be nimble, while ensuring that customers are appropriately informed and protected. Retailers and distribution networks highlighted the risk of creating arrangements that introduce an unreasonable level of complexity for customers. The progression of these arrangements needs to continue to prioritise customer engagement, assessment of consumer risks and protections.

Although much of the focus for flexible trading has been on how it could be utilised by small customers, benefits can be accessed by larger commercial and industrial (C&I) customers as well. Flexible trading could provide an alternative method of accessing benefits to the WDRM.

Box 6 Electric Vehicles – the next frontier

The numbers of electric vehicles (EVs) on our roads are set to increase exponentially in the next decade, as more and more customers shift from internal combustion engine vehicles to EVs and reduce their transport emissions. As distributed energy resources, EVs are likely to be central to the power system of the future. They can double as a home battery and potentially earn money for households who sell battery power back to the grid and lower home energy bills. EVs can also be used to help manage supply and demand across the broader grid and provide low emission transport.

In the same way other DER assets are being integrated into the NEM, it is important that technical standards support the effective integration of EVs to deliver the greatest value to customers and the grid system. This involves putting in place flexible trading arrangements so customers can choose to have their EV charging and supplies managed by service providers separate to their standard household or business energy consumption. It can also see innovative new business models emerge for car-parking services, with fees for parking based on charging (or discharging) your EV at the site. To enable these integrated solutions, greater visibility of EV assets is needed, with data sharing processes and standards in place to support secure and efficient outcomes for customers.

Two Models for Flexible Trading Arrangements

The ESB proposes two models to enable flexible trading, both based on amendments to features of the existing regulatory framework. This means the models have limited system implementation costs, with upfront costs to establish flexible trading borne by the service providers and/or those consumers that choose to engage with multiple service providers.

- **Flexible Trader Model 1 - SGA+:** Model 1 extends the existing Small Generator Aggregator (SGA) framework. The main change moves the SGA design from generation only to cater for bi-directional energy flows and participation in the ancillary services market. Doing this will enable SGAs to provide new products and services to customers.

- **Flexible Trader Model 2 – Sub-meter connection point**: Model 2 proposed provides a specific category of connection arrangement, a Private Metering Arrangement (PMA), that enables a National Meter Identifier (NMI) to be established within a customer's electrical installation.

Both models reduce barriers to entry for aggregators that can help consumers obtain value from their DER assets or their flexible demand. This allows the aggregator to participate in the wholesale market or provide network support on behalf of small customers with EV chargers, batteries, and other controllable devices. The management of controllable resources can also provide a market-driven response to issues affecting the energy system, such as minimum system load and directly benefiting the customer.

Detail regarding both models is set out in Part C.

Implementation of flexible trading arrangements

Both models require amendments to the NER and the National Energy Retail Rules. The rule change process can be used to test both the outstanding technical matters relating to Model 2 and the application of consumer protections. Several issues need to be considered further to accommodate the new arrangements in the rules. These include:

- the application of the consumer protection framework for PMA connection points.
- the precise linking of connection points for accurate wholesale settlement.
- the application of network charges (if any) to the NMI within the PMA and how these would be reconciled across both connection points between the traders.
- a requirement for data access for market participants.
- de-energisation rights and responsibilities.

The ESB recommends that AEMO consider these matters and develop a rule change request to implement Model 2 within six months of publication of this report, for the AEMC's consideration.[56]

In the meantime, the AEMC is conducting a Review of the Regulatory Framework for Metering Services. This is looking at access to data and the roles and responsibilities of metering co-ordinators that would help to facilitate the flexible trading arrangements.

Scheduled Lite

The ESB has developed the concept of Scheduled Lite for resources that are currently not scheduled in the market. This includes smaller generators between 5 and 30 MW and demand side resources such as C&I loads and aggregations of DER. Scheduled Lite uses a mix of lower barriers and incentives to encourage these resources to 'opt-in' to either:

- provide greater visibility to the market operator about intentions in the market, or
- to participate in dispatch with lighter telemetry.

Providing greater visibility over these resources supports increased certainty, benefiting all customers via more efficient market outcomes. Enabling greater participation of non-scheduled resources in dispatch provides additional benefits, including more accurate scheduling for all participants and the

[56] Noting that both models can co-exist as options in the rules, Model 1 will also be considered as part of the Integrating Storage rule change process.

possibility of additional revenue streams for responsive resources. This can provide greater opportunities for consumers to obtain more value from their DER.

There is stakeholder support for enhancing visibility and efficiency in scheduling and dispatch through voluntary mechanisms. Stakeholders agree that it is an important step given the challenges associated with increasingly higher proportions of variable and price-responsive resources in the market. Many noted that a lack of visibility leads to inefficient scheduling and operational decision making in the context of peak demand events, and to interventions during minimum system load events.

Stakeholders largely supported the objectives of Scheduled Lite. Most stakeholder submissions acknowledged that the 'opt-in' approach was a proportionate response to the emerging issues and supported work to progress the reform. Some concerns are noted about the possibility of low take up rates and suggestions that aggregators of DER should have equivalent scheduling obligations as other generators. Peak bodies representing large customers (such as the EUAA and the Aluminium Council) also raised concerns about Scheduled Lite becoming a mandatory requirement at some point in the future. Peak bodies representing smaller generators, such as the Smart Energy Council and the Clean Energy Council sought more clarity on the circumstances where scheduled lite would become mandatory.

The ESB notes the concerns about scheduling obligations applying to a larger range of resources in the future and considers this issue requires ongoing assessment during the transition. Greater visibility of flexible resources helps AEMO better forecast and operate the market efficiently. If there is limited take up of voluntary participation for scheduled lite we will not see the benefits. In that case, the market bodies need to assess if any barriers to participation, including high transaction costs, remain. This work needs to be done before any consideration of moving to more mandatory participation.

Details of the models and approach for implementation are set out below.

Design principles for implementing Scheduled Lite:

- applies on a voluntary basis to loads and generation resources that are not currently scheduled
- additional information obtained through scheduled lite improves the efficiency of operational decisions
- design must be congruent with the existing NEM design and the Post-2025 reforms
- benefits of greater participation must be considered relative to implementation costs
- obligations and risks should be balanced against incentives for participation
- frameworks should enable customer choice (it should be flexible and consider the consumer experience, such that consumers are not adversely impacted or required to change behaviour)
- design should facilitate resources offering new system services where appropriate.

These principles are supported by stakeholders, with the ECA emphasizing its agreement with the principle that the costs of Scheduled Lite are not borne by small consumers and the obligations should be managed by retailers and aggregators on behalf of small consumers.

The ESB proposed two different forms of Scheduled Lite. These are the 'visibility' and 'dispatchability' models. The key features of each model are as follows:

- The **visibility model** involves resources providing self-forecasts of future behaviour or intentions to the market operator. This option does not require telemetry requirements, but only 5-minute meters. While there may be consequences for inaccurate forecasts, these would not be financial. Incentives to participate include reduced FCAS causer pay allocation and (if introduced) reduced operating reserve cost allocation. Participants that are most likely to opt into the visibility model are those that are already preparing their own forecasts such as aggregators and non-scheduled VRE generators. C&I loads may also be incentivised to provide information to the market operator if they are not interested in the wholesale demand response mechanism.

- The **dispatchability model** involves resources providing bids using lighter telemetry such as SCADA light and reduced consequences for not complying with dispatch instructions compared to fully scheduled participants. Incentives to participate include reduced FCAS causer pay allocation, avoided RERT costs (for loads), resource allocated firmness factor for RRO obligation and, if introduced, reduced operating reserve cost allocation and potential to bid into operating reservice market. Participants that are most likely to opt into the dispatchability model include aggregators of small, unregistered batteries that are interested in co-optimising energy and FCAS flows, and C&I loads that would be attracted to being exempt from the RERT and being able to sell qualifying contracts under the RRO.

Some of the stakeholder submissions that commented on the detail of the models noted that the less onerous 'visibility' model is the most likely model that participants would opt into. In addition, there are some interesting suggestions for penalties for non-compliance, ideas for incentives that AEMO could consider in its development of the models. Suggestions for more stakeholder consultation, a detailed cost-benefit analysis and consideration of the impacts of the incentives on the operation of the market will be considered as part of future rule change processes.

Proposed implementation

The ESB is proposing a phased implementation approach that introduces an **'initial visibility model'** first, which would be managed without changes to the rules or AEMO systems. This pathway approach enables AEMO to factor in other market changes and incorporate lessons from trials before implementing enduring visibility and dispatchability models. It also provides for coordination with other DER initiatives, with sequencing of reforms set in the DER Implementation Plan. Further details are set out in Part C.

Network Services

To support the continued uptake of DER by distribution networks, regulatory frameworks will also need to adapt to be fit for purpose.

Cost reflective network tariffs and network targeted procurement of energy services are complementary measures which, together, can deliver significant benefits to networks and customers. Work commissioned from Baringa indicates that the network investment cost savings from a combination of these measures may be as large as $9.9 billion over 20 years (to 2040). To realise this value both tariff reform and energy services procurement must be advanced from where they are today.

Network tariff reform is under way and will continue to evolve price signals to reflect times of network congestion. As the tariff reform program matures it will increasingly incorporate locational prices signalling actual or future periods of network constraint. However, there are limits to the ability of network tariffs to fully reflect actual costs to serve all customers connected to the shared network. This is most apparent in remote areas where the cost to serve customers is high compared to customers in denser parts of the network.

To augment network tariffs, networks will need to undertake targeted procurement of energy services. This will particularly be the case in locations where network tariffs are constrained in their ability to accurately reflect the cost to serve, such as in thinly populated areas. Energy services procurement may also play an important role in bringing forward responses that would otherwise take time to realise through the ongoing tariff reform program. And energy services procurement can represent an efficient means of eliciting responses in addition to those that can be achieved by tariff signalling, to optimise customer assets such as rooftop solar, batteries and EVs in place of undertaking expensive network investment.

Community storage is an area where reforms are likely required to support jurisdictional policies and considerable consumer interest. Consideration needs to be given to the introduction of forms of Local Use of System (LUoS) charging to enable community storage projects to become viable, and more broadly scalable.

As DNSPs take on new responsibilities as part of the reforms, such as specifying and managing dynamic limits as part of connection agreements with consumers, more work needs to further clarify the role of the network as the Distribution System Operator. Whilst the high-level principle is to continue to use the Trader for participation in markets and interactions with customer DER, there are a number of situations where network owned assets can participate in supporting the grid, such as direct load control, that need further clarity on where the consumer's interests are best served.

Alongside the added powers for DNSPs to be able to dynamically constrain the import and export of energy from DERs at the connection point, there should be a corresponding focus on the transparency and reporting requirements by networks to justify the reasons for constraints that are applied via DOEs. This should include regular data reporting to the AER, similar to the Regulatory Information Notices (RIN) frameworks for reliability reporting.[57]

To address these issues, the ESB recommends the following immediate priority actions to ensure that regulation frameworks remain fit for purpose:

- The AEMC is taking a first step towards tariff reform through the DER access and pricing rule change. Further work on tariff reform will be done in a later review by the AEMC to look at the regulatory frameworks connected to tariff reform, procurement of network services, community storage and LUoS, and ringfencing issues pertaining to responsibilities and obligations as the DSO. This review could outline an agenda and timeline for regulatory reform commensurate with the growth of DER, and associated benefits flowing back to customers.
- As part of the groundwork for the AEMC review, a study to be undertaken by December 2021 into the different business models for community storage, and potential models for LUoS tariffs that could facilitate better outcomes for consumers.
- The AER is currently undertaking a distribution ring fencing guideline review.[58] These guidelines consider the role of battery storage within the context of ring fencing. The AER also intends to commence a review of the transmission ring fencing guidelines.
- Networks and the AER to continue work on the introduction of cost reflective tariffs, such as time-of-use, and those that can facilitate the automated response of DER to improve the capital efficiency and utilisation of the network.
- The AER is currently consulting on a DER integration expenditure guidance note, which sets provides guidance on DNSP proposals for capital expenditure in relation to increased DER hosting capacity and how certain benefits should be quantified.
- The AER and ESB to carry out work to better understand what data is available to networks with the implementation of DOEs by December 2021. Based on the findings, it should inform

[57] This is to be further explored and defined through the ESB Data Strategy workstream by Dec 2022

[58] The AER published draft ring fencing guidelines (Electricity Distribution) in May 2021. This can be found here: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-review

the enduring data reporting and transparency requirements that are formalised through regulation consistent with the Data Strategy.

Data sharing at System Operator / Distribution System Operator interface

As the penetration of DER grows, it is expected that there will be an increase in interactions between the distribution network and the bulk supply system level. For example, the growing system security challenges associated with minimum system load, and the enhancement of market information provision prior to any use of emergency backstop measures, together with enabling DER to access market services via aggregators, require formalisation and digitalisation over time to yield better responsiveness and social licence of DER assets.

There are other scenarios where closer interactions and communications between AEMO, TNSPs, and DNSPs are already needed. At present many of these are *ad-hoc* processes and simply phone calls between operation centres but may need further consideration as part of a broader data sharing and communications capability at the SO / DSO interface.

In addition to System Operator and DSO interfaces, data sharing and communication will also be important in the context of retailers and aggregators' participation in the broader ecosystem. Data and communication is a key enabler for these parties to have access to the data needs to participate in local and wholesale markets, but also ensure aggregated DER resources are able to operate within the system limits.

To meet these increasing demands, the ESB proposes further work to explore the following use cases:

- Expression of minimum system load level constraints at the transmission (TNI) connection points.
- Identification of weak points emerging from a lack of system strength that sit across a SO/DSO boundary and can cause issues for SO and DSO operations.
- AEMO reporting of load / generation changes out of WDRM scheduling to inform networks of significant changes / consistency with dynamic limits at the grid level.
- With the implementation of Schedule Lite, AEMO reporting on significant load movements at the distribution level.
- With an increased reliance on distribution connected resources for primary and contingency FCAS, publishing of any distribution level constraints or reconfigurations that may restrict market participation.
- For the growing number of grid connected generation assets (i.e., solar farms), integration of SCADA feeds already provided to the DNSPs to improve situational awareness.
- Other requirements with respect to visibility at the bulk, network and aggregated level, and how these interface and work together to understand both DER performance and delivery.

The ESB notes there are trials (including Project Edge in the NEM and Project Symphony in WA) that are working though the type of data needed, how they are best exchanged, and where interfaces intersect between actors in the ecosystem.

4.6. Long term reform

It is important that the measures outlined as immediate measures are expedited to address a range of pressing needs. Doing so also opens some additional opportunities for DER and puts in place measures to manage some fast-emerging issues. Delivery of the initial measures in the DER Implementation Plan, including implementation of the evolving roles and responsibilities of different players, broadens the opportunities for DER and the benefits its integration can bring. As we move forward, new business models emerge, new technology becomes available at the customer scale and new players are likely to emerge.

It is important then that the activities under the DER Implementation Plan adapt to emerging issues or changing needs. The information gathered on customer experience, the potential of the new technologies and retail products, and the knowledge gained from operating a system with a greater proportion of active DER all inform the priority activities in the longer term.

Some pragmatic decisions made in the early stages of the DER Implementation Plan may need to be revisited as the number of participants taking advantage of certain opportunities grow, and as trading across the distribution network and into the wholesale market become more complex. Ongoing review and adaptation is considered the only realistic approach in such an environment allows the market to benefit from ongoing innovation.

Particular areas of focus include:

- The potential for enhanced systems and optimisation approaches as the scale of DER and range of applications grow.
- The potential to better procure network services while providing layering opportunities for DER through markets
- Opportunities for widespread deployment of smart devices and appliances, such as smart thermostats, pool pumps and hot water, perhaps through mandatory standards for their remote operation and management, to bring forward more options for demand flexibility.
- More sophisticated integration of electric vehicles into the system including standards for vehicle to grid (V2G) and vehicle-to-home (V2H) scenarios that can provide additional utility of electric vehicles for customers, and increased load shifting and flex capacity in the system. This includes appropriate tariffs and control to avoid the impact of electric vehicle fast charging driving network augmentation expenditure.
- Reducing barriers for local or peer to peer marketplaces to provide further choices to consumers and potential community energy solutions.

4.7. Recommendations

7. To enable the effective integration of high volumes of DER and flexible demand into the NEM the ESB r**ecommends** Energy Ministers support the DER Implementation Plan (see Section 5). The Plan sequences *immediate and initial* regulatory, technical and market reforms that address emerging risks and builds capability to deliver benefits to all consumers from high levels of distributed energy resources and new energy services. The ESB will provide Energy Ministers with advice on additional reforms that will be developed in customer focussed stakeholder co-design and consultation processes as part of the Plan. The Plan will deliver the following outcomes:

a) Consumers are rewarded for their flexible demand and generation, have options for how they want to engage (including being able to switch between DER service providers), and are protected by a fit-for-purpose consumer protections framework.

b) The wholesale market supports innovation, the integration of new business models and has a more efficient supply and demand balance.

c) Networks are able to accommodate the continued update of DER and two-way flows and are able to manage the security of the network in a cost-effective way.

d) AEMO has the visibility and tools it needs to continue to operate a safe, secure and reliable system, including maintaining system security associated with minimum load conditions.

8. To support system security and improved transparency at times of minimum system load, the ESB **recommends** Energy Ministers adopt a jurisdictional Ministerial lever for emergency backstop measures, as an *immediate reform*. Enduring measures to address system security challenges associated with low minimum system load are being prepared as part of the Plan.

9. To support ongoing fit for purpose consumer protection, the ESB **recommends** Energy Ministers note the ESB has developed a Consumer Risk Assessment tool as an *immediate reform*. The tool will be used by the ESB and market bodies in work identified in the Plan.

5. Transmission and Access

5.1. Key points

- The current transmission network was designed to transport energy from gas and coal fuelled and hydro generation to load centres. The step change scenario in the 2020 Integrated System Plan (ISP) envisages that up to 50 GW of new large-scale variable renewable energy is required by 2040, with Queensland and New South Wales each forecast to add over 16 GW and Victoria over 7 GW.[59] In practice, the current rate of investment in variable renewable energy substantially exceeds the rate required to achieve the step change scenario.
- Going forward, energy can be supplied at a lower overall cost by building transmission to access new renewable sources of generation. A targeted set of investments can deliver the energy transition at lower cost. While future transmission has been planned through the ISP cost minimisation approach there is an uncoordinated approach to generation location. The current access regime results in investment signals that do not align with underlying power system conditions. It can be profitable for generators to locate in places that cause significant congestion, as the party that causes the congestion only bears a fraction of the associated costs.
- The transmission investment driven by the ISP does not, and should not, seek to remove all congestion from the system. Building in sufficient capacity to avoid congestion is highly prohibitive in cost and inefficient. How the transmission networks are used and accessed needs to change, to complement the transmission infrastructure expansions foreshadowed by the ISP.
- The ESB's transmission and access pathway seeks to deliver a transmission system that supports the transition and maximises benefits to meet the needs of customers at least cost. It seeks to put in place market frameworks that encourage generators and storage providers to connect to and utilise the system in a way that minimises total system costs.

Transmission investment

- Changes in the energy supply mix and the location of new generators are driving a wave of major new transmission projects.
- The ESB has already completed reforms to give effect to whole-of-system transmission planning (rather than the previous incremental approach) and developed a framework for the planning and implementation of renewable energy zones (REZs). These reforms are designed to deliver an orderly transition in accordance with the ISP.
- As the current wave of transmission projects progress, challenges are emerging in delivering them in a timely and efficient manner. The AEMC has commenced a Transmission Planning and Investment Review to determine whether current regulatory frameworks maximise benefits to consumers through the timely and efficient delivery of major transmission projects (including ISP projects), and whether changes are required to improve and support the timeliness and efficiency of transmission project delivery. The AEMC will provide advice on further reforms at the conclusion of this review.
- AEMO is also considering a number of options to enhance the information it provides about existing and forecast congestion on the grid. Better information for the market about existing and forecast congestion should lead to better decision making for participants about where to locate in the grid.

---

[59] AEMO, 2020 Integrated System Plan, 30 July 2020, pg 44. Available at: https://www.aemo.com.au/energy systems/major-publications/integrated-system-plan-isp

Access reform

- The ISP provides a blueprint for the efficient development of the network and the ESB has established the 'actionable ISP' Rule changes to facilitate its implementation.
- As a developing part of the network, REZs help to coordinate generation and transmission investment through the planning framework. REZs deliver the capacity to host new generation while helping to manage congestion, losses, and connections. The ESB has developed a framework for the efficient planning, development, and maintenance of REZs and to create incentives for generators to locate where the network has capacity.
- Modelling for the ESB suggests that if transmission, generation and storage investment occurs in line with the ISP step change scenario, by 2030 congestion will increase substantially in all regions except Tasmania.
- Reforms are needed to the access regime to build on those measures and overcome the following flaws in the current market design:
  - The current access model provides incorrect and incomplete signals to generators about where to locate. Even an investment that causes heavy congestion may still be profitable for an individual investor because the costs of a resulting increase in congestion or lower loss factors are largely borne by other parties. This increases uncertainty for investors and ultimately results in higher costs for customers.
  - Whilst the ISP provides a framework for investment, the existing access regime does not provide signals for generators to locate in places where there is spare network capacity. This means that low cost VRE generation that has located in congested parts of the network is often unable to get their generation to market.
  - The market design rewards generators for bidding their energy into the market, in the presence of congestion, in a way that prevents the demand for energy being met at the lowest overall cost. The planned development of the national network with a number of REZs being developed along new or augmented interconnectors will exacerbate these issues.
  - Batteries, hydrogen, and other large flexible loads are not able to capture the full value they can provide to the power system.
- The ESB recommends the consideration of a whole of system Congestion Management Mechanism (CMM) that complements REZs. The mechanism is known as the CMM(REZ). It supports REZs, addresses the underlying access reform objectives, and can be designed in a way that responds to some of the concerns raised by stakeholders in relation to Locational Marginal Pricing and Financial Transmission Rights (LMP/FTR). The latter LMP/FTR approach is not part of our recommended reforms.
- Under the CMM(REZ), generators face a congestion charge based on their impact on congestion at the time. Eligible generators also receive a congestion rebate funded from revenue collectively from the congestion charges – where “eligible generators” includes incumbent generators, and new generators that locate in accordance with the planning framework (such as in a REZ). This results in the benefits below, but also in financial outcomes for market participants that replicate the status quo arrangements, recognising in practice that changes in bidding behaviour could have some effect on outcomes.
- The CMM(REZ) supports and strengthens the REZ framework by:

- Strengthening incentives for new entrants to locate and participate in REZ investments.
- Improving connection as pro-active and scale efficient actions can be taken to manage system security issues including system strength.
- Giving REZ participants confidence that their investment case will not be undermined by subsequent inefficient investment decisions outside the REZ and
- Removing opportunities for subsequent connecting generators to free-ride on REZ investments without contributing to them
- Promoting the efficient use of REZ infrastructure by creating a market design that rewards storage providers for alleviating transmission congestion and providing firming services for renewable generators.

- The ESB has not included a long-term access model in its recommendations. Instead, the ESB's recommendations for transmission access reform are focussed on immediate and near-term measures. In particular, the CMM(REZ) should be progressed expeditiously, with fulsome stakeholder engagement, through a rule change process, in which the detailed design of the CMM(REZ) will be further developed.
- The ESB's initial analysis suggests that the benefits of the CMM(REZ) are likely to be well in excess of the costs. Further analysis of the benefits and costs associated with the proposed access model can be undertaken in the rule change process to progress the CMM(REZ).

5.2. The issue

The ESB's transmission and access reform pathway seeks to deliver a transmission system that has benefits and meets the needs of customers at least cost, and to put in place a market framework that encourages generators and storage providers to connect to the grid and utilise the system in a way that minimises total system costs.

This workstream is a core area of focus given the substantial investment in both transmission and generation required to deliver the energy transition. The step change scenario in the 2020 ISP envisages that up to 50 GW of new large-scale variable renewable energy is present by 2040. Queensland and New South Wales are each envisaged to add over 16 GW and Victoria over 7 GW.[60] In practice, actual investment levels substantially exceed this scenario, with current registrations running at 27 per cent above those anticipated in the step change scenario.[61]

These macro-level trends mean that it is necessary to change how the transmission networks are used and accessed, to avoid new transmission capacity foreshadowed in the ISP becoming congested earlier than necessary. The anticipated trend is also likely to lead to technical issues in connecting generators and lower marginal loss factors. These challenges are already evident in some locations and are increasing costs to the long-term detriment of customers. The transmission and access pathway seeks to enable large quantities of cheaper renewable energy to connect to the system and get access to the market. It is designed to deliver:

- Better signals for generators to locate in areas where there is available generation capacity - namely in the REZs that are being delivered through the ISP and state government policies,

---

60 AEMO, 2020 Integrated System Plan, 30 July 2020, pg 44. Available at: https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp

61 AEMO, Making the Grid Future Ready, presentation by Alex Wonhas to Australian Energy Week, 25 May 2021

- Reduced uncertainty for investors, through measures that give rise to more predictable future patterns and levels of congestion,
- A more orderly and predictable connections process,
- Better use of the network, resulting in more efficient dispatch outcomes and lower costs for consumers, and
- Batteries locating where they are needed most and being paid to operate in ways that benefit the broader system.

To deliver this pathway, the ESB considers that there is a need to implement a more orderly and structured approach to the development of the power system, connection to it and its utilisation. Under our recommendations, the proposed access model is essentially a tool to drive the implementation of the ISP and realise the benefits and outcomes forecast under that approach.

The ESB has and continues to support augmentation and development of the grid to allow it to host the vast amount of renewable energy connecting to the system over the next two decades. The actionable ISP reforms are already helping to deliver needed transmission investment, however there is scope for further improvement in this space.

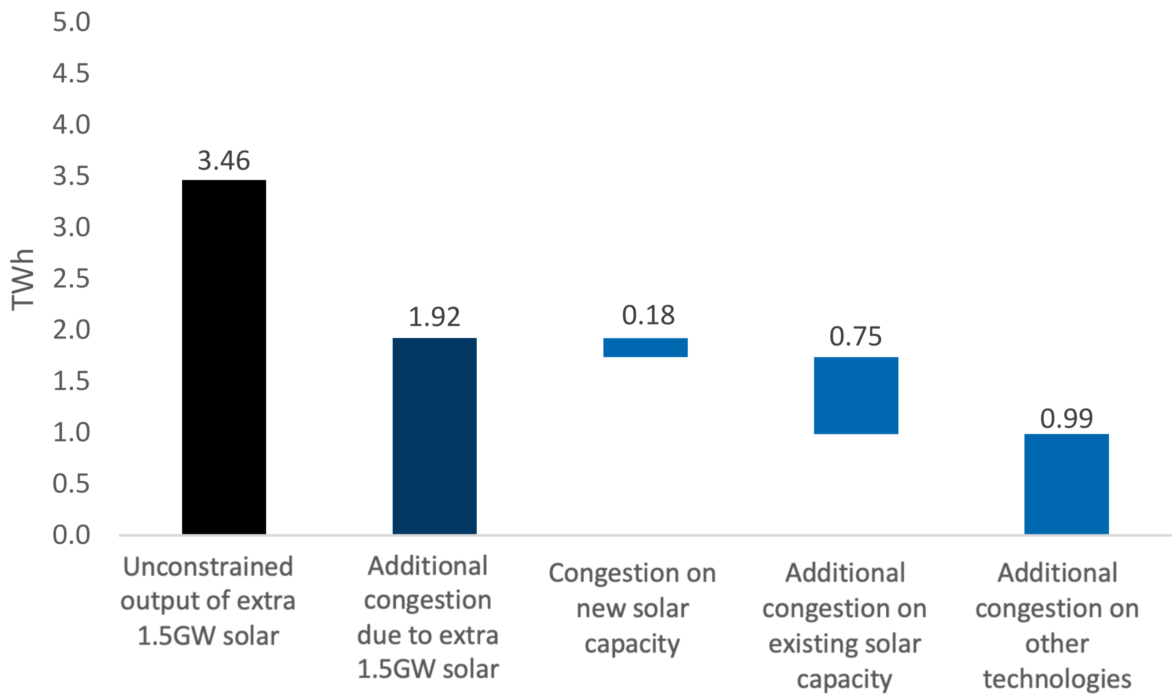
Some of the technical issues with generator connections to the grid can be better handled through well designed REZs and through those, the efficient dealing with system security issues.

The current access regime is driving chaotic outcomes on the generation side, which, if left unaddressed, may reduce investors' appetite to invest in the NEM. A more ordered connection of plant to an augmented grid will better manage the risk of congestion and low loss factors, reducing risks and costs which will reflect in long term better outcomes for customers.

The access regime lies at the heart of problems with generator connections. Delays and uncertainty in the connections process arise because Transmission Network Service Providers (TNSPs) and AEMO need to juggle large numbers of simultaneous connection applications. These connection applications interact with each other and may collectively exceed the capacity of the local network.

The NEM's current access regime permits any generator that meets the relevant technical standards to connect – irrespective of whether the investment provides value to the broader power system – and then the new generator competes with existing generators for access to available network capacity. An investment that causes heavy congestion may still be profitable for an investor, because the costs of congestion are borne in part by pre-existing generators or consumers rather than fully by the party that caused the congestion.

Figure 5 Impact of additional solar generation capacity on congestion volumes



Source: FTI Consulting[62]

To stress test the impact of generation investment in excess of the levels forecast in the ISP, FTI Consulting modelled the impact of adding additional solar capacity to assess how much that would increase congestion rather than provide net additional capacity to the system. For the test, FTI added 300 MW of additional solar generation to the most productive regime in each region (1.5 GW additional capacity in total) for the year 2030. All other inputs and assumptions were derived from the ISP step change scenario assuming no additional major transmission capacity. The additional solar generation provided 3.46 TWH of energy to the system but increased congestion by 1.92 TWH, i.e., only one third of the additional energy was a net gain to the system. While the parties investing in that additional generation suffered some reduction in output from congestion, the majority of the impact of congestion was on third parties.

Figure 5 shows how, when generation and transmission investment get out of sync, much of the additional output of the extra generation is offset by additional congestion. Further, only a small fraction of the additional congestion is borne by the party that caused it, with the remainder being borne by pre-existing generators. This inefficient congestion affects the profitability of existing generators and has the potential to result in disorderly market exit.

Investors have expressed concern about the uncertainty they face when seeking to connect in the NEM. In an interconnected power system, each connection affects everyone else. The only way to provide more certainty to investors on matters such as marginal loss factors, congestion and constraints is to adopt a more coordinated approach to connections to the transmission network.

There is also a need to better utilise the network in real time so that the current wave of investments, particularly storage investments, can deliver maximum value for money for consumers. Current

[62] FTI Consulting, Forecast congestion in the NEM, prepared for ESB, August 2021. Available at: https://esb-post2025-market-design.aemc.gov.au/all-about-2025

market structures are a poor reflection of conditions on the physical power system. These market structures are expected to come under increasing strain as variable renewable generation increases and power system flows become more complex.

The ESB expects the management of congestion in operational timeframes to become increasingly critical in the future as variable renewables, batteries, and flexible loads (such as hydrogen) increase and power system flows vary in accordance with the sun and wind. However, investors and generators have told us that they regard congestion-related operational challenges to be a lower priority than the difficulties they encounter getting a connection.

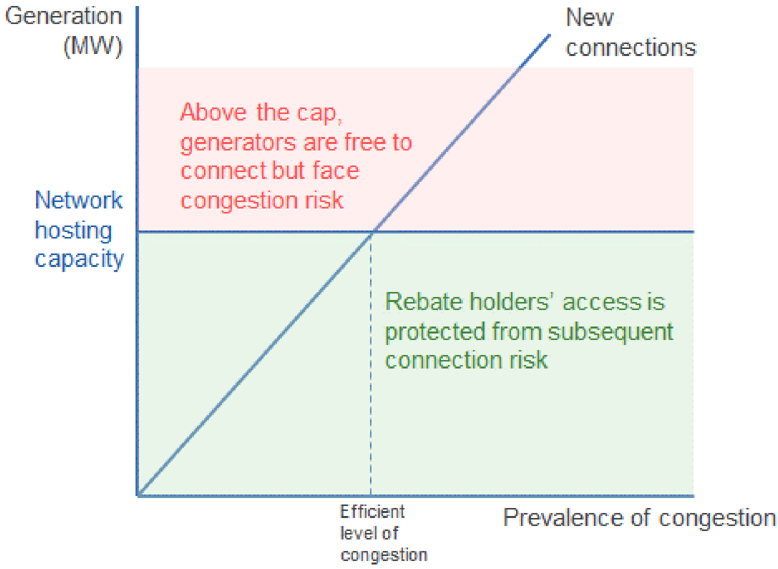
In light of stakeholder feedback, the ESB has done further work to explore whether there is a case for reform to better manage congestion. The ESB engaged FTI Consulting to examine the prevalence of congestion in the NEM in 2030 assuming that transmission, generation, and storage are built in accordance with the 2020 ISP step change scenario. FTI's modelling suggests that congestion will become significantly more frequent in all regions except Tasmania. If the current market design is retained, issues associated with congestion mean that interconnectors will not be fully utilised, and consumers will not receive the full anticipated benefits of these investments. FTI Consulting's findings are discussed more fully in chapter 4 of Part C, and their report is available on the Post 2025 microsite.

Given the challenges associated with the open access regime, the Clean Energy Investment Group concluded that "for long term investment certainty, the focus should be on REZ development, the build out of sufficient transmission capacity to implement the ISP and a restricted access regime across the NEM".[63] The ESB's recommended access model aligns with the first two elements of this proposal. With respect to a restricted access regime, the ESB recommends a variation, which is outlined below.

Proposed solution - a more orderly approach to generator connections

The ESB's proposed access model – the CMM(REZ) – will provide increased investor certainty through more predictable future patterns of congestion, and a more orderly and predictable connections process. It involves a dual mechanism of congestion charges and congestion rebates, where only incumbent generators and those who locate in accordance with the planning framework (i.e., in REZs planned by the ISP) receive the congestion rebate. The model supports and strengthens the REZ framework by rewarding generators who locate in the "right" place as determined by the planning framework (as supplemented by government policy). Through the congestion rebates, they receive greater certainty on matters such as marginal loss factors, congestion, and constraints.

Figure 6 Availability of congestion rebates under CMM(REZ)



Generators would still be entitled to connect where they wish (subject to meeting agreed technical standards). However, if they wish to connect in a location that is inconsistent with the planned development of the system, then they would face the associated congestion risk.

This model is described in more detail in section 5.3.2, and Part C.

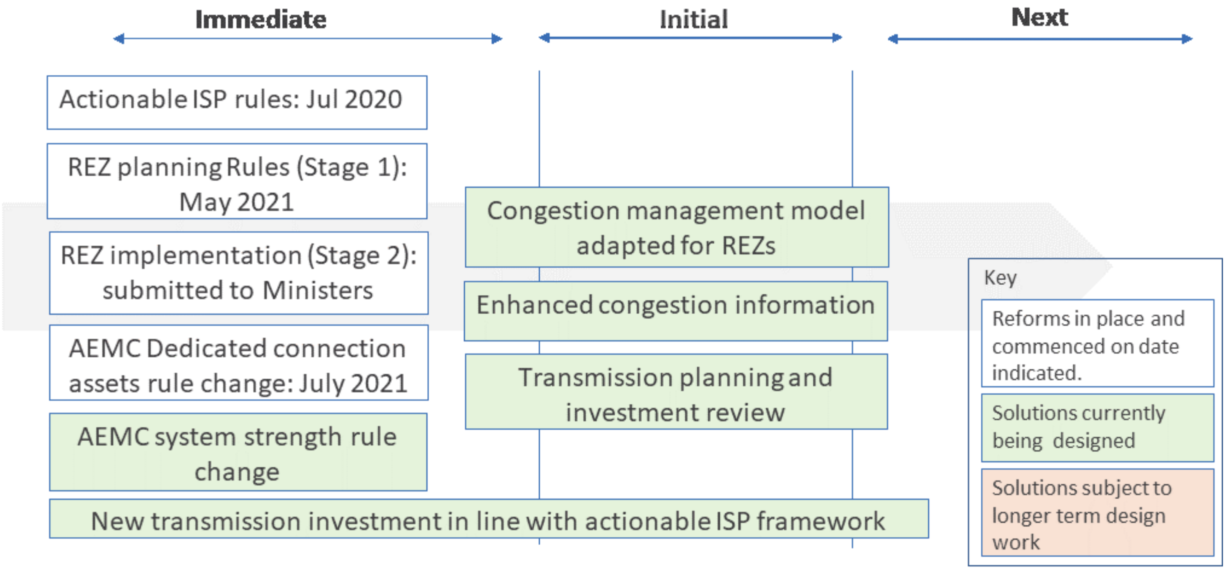
5.3. The reform package

The ESB's package of transmission and access reform includes a range of measures to get transmission and generation built when and where it is needed. On the transmission side, it encompasses work already complete, such as the actionable ISP reforms, and the ESB's interim REZ recommendations. The ESB has also identified a need for further work which is being progressed by the AEMC in its Transmission Investment and Planning Review (see Part B, section 5.3.2).

This section sets out the proposed transition pathway to deliver transmission and access reforms. The reform pathway is informed by the evaluation completed for this workstream, the outcomes of which are described in Chapter 7.

Figure 7 outlines the ESB's package of reforms.

Figure 7 Overview of the transmission and access reform pathway



In parallel to the ESB's package of reforms, major programs are being undertaken by State governments. The reforms described below are intended to complement and support the work of State governments.

5.3.1. Immediate reforms

Considerable progress has already been made in introducing measures to coordinate transmission and generation, including

- New transmission investment and the actionable ISP rules,
- The ESB's recommendations for an interim REZ framework - including access within a REZ,
- The AEMC's dedicated connections assets rule change and system strength rule change, which complement the ESB's reform pathway.

New transmission investment and the actionable ISP rules

The actionable ISP rules have introduced a 'whole of system' transmission planning framework. One consequence of these changes is to overcome the "chicken-and-egg'' problem[64] associated with the previous incremental planning approach.

Under the actionable ISP framework, the ISP models plausible combinations of generation and transmission solutions required to meet power system needs over the 20-year outlook period at least cost. It provides a whole of system plan that includes the optimal generation mix, and the transmission required to support it.

This change of perspective towards whole-of-system planning means that the regulatory test for transmission can now be met before generation projects become committed. If a transmission investment associated with a REZ is classified as an actionable ISP project and it passes the RIT-T, it can proceed on a regulated basis. Put simply the assets would be built, owned, and operated by the local TNSP and funded by consumers.

New transmission investment – latest developments

AEMO has prepared two ISPs which describe a least cost pathway for the development of the power system, taking into account demand, supply and network costs. They are well progressed with the preparation of the 2022 ISP, with consultation on the inputs, assumptions, and scenarios underway, and a draft ISP scheduled for publication in December 2021.[65]

The Group 1 projects identified in AEMO's 2018 ISP are now under construction or in commissioning. The 2020 ISP identifies six actionable ISP projects that are critical to address cost, security, and reliability issues. In addition, there are six actionable ISP projects that require preparatory activities and future decisions as to whether to proceed based on necessary pre-conditions. These twelve projects are in addition to the three Group 1 projects from the 2018 ISP underway and three future ISP projects that need to deliver additional REZs.

Recent developments include:

- VNI Minor is under construction, and work has recently passed the halfway mark,
- A final investment decision was made for Project Energy Connect, following receipt of all regulatory approvals,
- The regulatory investment tests for VNI West, Marinus Link and HumeLink are underway.

Work is underway to develop committed and actionable ISP projects in accordance with the 2020 ISP. However, challenges are emerging in getting the new network built. These include planning issues, community concerns, difficulties getting access to land and reluctance by networks to take risk and cope with financing very large projects. Unaddressed, these issues have the potential to result in delays and increased costs. In some cases, the Commonwealth and relevant State jurisdictions are underwriting and supporting these projects.

64 Under the previous Regulatory Investment Test-Transmission (RIT-T) framework, it was problematic for a TNSP to justify investments required to connect new generation due to the scale of the modelling exercise involved. The TNSP is required to demonstrate that the proposed investment maximises net market benefits, recognising that there are any number of alternative locations elsewhere in the NEM where the generation might locate. For this reason, TNSPs found it necessary to wait until the relevant generation projects became committed before they could be formally included in a RIT-T assessment. As a result, generation could not become committed before the transmission was committed and vice versa.

65 https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp

While some of the issues outlined above are beyond the scope of the National Electricity Rules, the AEMC is reviewing whether there is scope to amend the Rules in ways that improve and support the timely and efficient delivery of transmission projects. This review is discussed further in section 5.3.2.

Interim REZ framework

Ambitious government renewable programs and the development of state REZ schemes are accelerating the pace of the transition. Several State governments have announced policies to develop REZs in their State. These include:

- NSW is implementing its legislated Electricity Infrastructure Roadmap, which involves the development of five REZs,
- Victoria is consulting on a REZ development plan involving six proposed REZs backed by a $540 million REZ fund, and
- Queensland has identified three REZ corridors and has established a $500 million renewable energy fund.[66]

The ESB is working closely with the governments on these matters.

The CMM(REZ) outlined in this paper is designed to support these initiatives by ensuring that investors can confidently make long term investments in REZs. In the absence of access reform, current problems affecting investor confidence in the NEM would affect REZs, just as with other areas of the meshed transmission network. To overcome these issues for investors, a whole of system approach is required.

Most submissions to the options paper that mentioned REZs were supportive of the REZ model in principle. The Energy Users Association of Australia considered that the ESB's proposals were sensible but questioned how the framework would be applied given that State governments are developing their own policies. Several stakeholders, including the Clean Energy Investors Group and RWE, agreed with the ESB's view that REZs need to be accompanied by access reform to provide an incentive to locate within a REZ, however others felt that REZs could work as a standalone model.

In response to a request from Energy Ministers, the ESB developed a framework for the efficient planning, development and maintenance of REZs. The project involved a two-step process:

1. The implementation of Rule changes to require the jurisdictional planner to develop a detailed and staged development plan for each priority REZ identified in the ISP. These changes build on the actionable ISP Rule changes; and
2. the development of a policy framework for the staged development of REZs within a REZ development plan.

Step 1 – REZ planning Rules

The ESB’s REZ Planning Rules have been approved by Energy Ministers and came into effect in May 2021.[67] The Rules support the design of REZs in a way that has regard to the needs of communities and developers, and also aligns with the optimal development path for the power system as set out in the ISP.

In light of the potential for significant local community impacts associated with REZs, REZs are now subject to a special planning regime that include measures to take into account information from

66 For further information, see: https://energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap, https://www.energy.vic.gov.au/renewable-energy/renewable-energy-zones, https://www.dnrme.qld.gov.au/energy/initiatives/queensland-renewable-energy-zones

67 See https://energyministers.gov.au/reliability-and-security-measures/renewable-energy-zones

potential generation developers and the views of local communities. The objective of the process should be to design a REZ that strikes an appropriate balance between technical, economic and social licence considerations. The Rules promote the timely delivery of transmission projects by ensuring that social licence issues are understood and taken into account at an earlier stage in the planning process.

Step 2 – REZ implementation

The ESB finalised its recommendations for REZ implementation and these are currently being considered by Energy Ministers.

The ESB recommended a set of overarching principles for the development of REZs that is compatible with the efficient development of the power system as a whole, together with practical guidance on how these principles should be implemented.

Box 7 Recommended principles for the interim REZ framework

The ESB's recommended principles address the following matters:

- **Planning.** The recommended principles for REZ planning build on Step 1 of the interim REZ review. They are designed to maintain the cohesive development of the power system as a whole, while also recognising the role of government policy in driving power system outcomes.
- **Connections.** Where a REZ development involves the construction of new transmission lines, parties wishing to connect to a REZ should participate in a coordinated tender process. Parties wishing to become part of a REZ after the coordinated process has occurred should be subject to some form of access regime. The REZ scheme should also clearly specify what happens to any incumbent generators or pre-existing developments that are located in the REZ.
- **Funding and economic regulation.** Where shared transmission infrastructure within a REZ is funded by customers, and a tender process for that REZ produces surplus revenue, then that surplus revenue should be returned to customers in the form of a reduction in network charges. This is in contrast to the shared infrastructure being funded (in almost all cases) exclusively by consumers. In addition, if a REZ scheme involves investment in transmission assets that are larger or earlier than those that would be built under the integrated system plan, those additional costs should only be recovered from customers to the extent that they benefit from the investment.
- **Access.** We have identified challenges in applying an access regime that applies only within a REZ, particularly in a meshed network. As power generated outside the REZ will flow across REZ assets, it may be difficult to incentivise generators to participate in a REZ process, particularly if they are expected to make a contribution towards the cost of the REZ. We see value in a consistent set of arrangements that applies across the NEM. Our preference is that the CMM(REZ) outlined below is adopted for REZs. However, this model is still under development and it may not be ready in time for some REZs. Where a REZ-specific access scheme is required, the ESB suggests a simple scheme that can be integrated into (or applied in conjunction with) the CMM (REZ).

These principles provide flexibility to enable jurisdictions to pursue REZ schemes in accordance with required timeframes, while also maintaining consistency across the National Electricity Market with respect to core aspects of the market design. The interim REZ framework is designed to align with key areas of market reform that will ultimately form part of the National Electricity Rules, including the transmission access regime and system security frameworks.

The ESB will continue to collaborate with State governments to explore different REZ models and ensure that these parallel processes deliver a cohesive national framework.

Other related reforms

There are several other reforms underway that relate to the pathway outlined in this chapter.

On 8 July the AEMC made a final rule which enables a generator, a group of generators, merchant investors or governments to fund designated network assets – assets which are used to connect generation to the 'shared network'. This new framework offers an opportunity to commercially develop a limited but similar scheme to a REZ. In practice, designated network assets could form the radial parts of REZs or could be stand-alone small REZs.

The AEMC has also recently published its draft determination on the system strength rule change, with a final determination expected by October 2021.[68] The reformed system strength regime has the potential to complement the coordinated process used to deliver REZs. AEMO could identify a system strength node within the REZ and planning for system strength could occur as part of the REZ design process. The ESB notes that even under the reformed system strength framework, if generators' investment patterns deviate substantially from the developments forecast in the ISP, as may be the case given the incentives to locate consistent with the ISP are compromised by regional pricing, then the system strength remediation associated with these unplanned developments will continue to need funding from the connecting generators, via the system strength mitigation requirement to avoid potential curtailment. The ESB's proposed access reforms support the revised system strength framework by strengthening the incentives for generators to connect in line with the ISP.

5.3.2. Initial reforms

The ESB proposes three further reforms to follow in the near term:

- the AEMC is undertaking a review of transmission planning and investment to examine the challenges associated with the efficient and timely delivery of new major transmission projects,
- AEMO is considering a number of options to enhance the information it provides about existing and forecast congestion,
- the ESB recommends reforms to the transmission access regime to give effect to the CMM(REZ).

The first two reforms are underway and are described below. The remainder of the chapter is concerned with the transmission access recommendation.

Transmission Planning and Investment Review

Submissions to the ESB's options paper raised several issues relating to the transmission investment framework that will be considered as part of the AEMC's Transmission Planning and Investment Review.

There was general support for a more timely and streamlined process for transmission investment decision making, especially from renewables investors. Some respondents noted that there was an important role for the RIT-T in exploring the merits of different options. The Energy Networks Association proposed to streamline the process by removing the ISP feedback loop.

The Australian Energy Council, Essential Energy, AusNet Services and several customer representatives expressed concern at any moves to expand the classes of benefits to be considered in the RIT-T, particularly in relation to wider economic benefits. In contrast, the Clean Energy Investors Group, some renewable generators, TransGrid, Spark Infrastructure and Snowy Hydro supported an

[68] https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system

expansion of the RIT-T. The Energy Networks Association supported further consideration of the issue while noting that previous reviews had recommended against expanding the classes of benefits.

While few submissions addressed the issue of transmission cost allocation, Grattan Institute and TasNetworks noted that it was a critical issue to be resolved if new transmission investment is to proceed in a timely fashion.

ATCO and Jemena expressed their support for more competition in transmission procurement, whereas Spark Infrastructure highlighted the potential for higher costs under a contestable model.

The Grattan Institute suggested that "…It may be that a more radical solution, such as ownership of the shared system by a national transmission company should be considered". Similarly, the Network of Illawarra Consumers of Energy proposed the establishment of a national transmission operator owned by the government.

The purpose of the Transmission Planning and Investment Review is to determine whether current regulatory frameworks maximise benefits to consumers through the timely and efficient delivery of major transmission projects (including ISP projects), and whether changes are required to improve and support the timeliness and efficiency of transmission project delivery.

The review will examine the current state of network planning and the investment regulatory frameworks that are intended to support the timely and efficient delivery of major transmission projects. Stage 1 of the review will focus on identifying and testing issues associated with the frameworks for planning, funding, financing, and delivering major transmission projects. Stage 2 will focus on identifying and developing solutions to address the issues identified in Stage 1. Ministers will be provided with advice on additional reforms that may be necessary at the conclusion of this review.

A consultation paper is anticipated in Q3 2021.

Enhanced congestion information

Enhanced information for the market about existing and forecast congestion should improve coordination of transmission and generation investment, as it enables more informed location decisions.

Under the current regulatory framework, AEMO is required to develop and publish a Congestion Information Resource. The intention is to provide information in a cost-effective manner to registered participants to enable them to understand patterns of network congestion and make projections of market outcomes in the presence of network congestion. AEMO is consulting on the Congestion Information Resource Guidelines, and in particular:

- Whether the quality, relevance and frequency of information provided in the Congestion Information Resource remains appropriate,
- What additional information stakeholders consider should be included in the Congestion Information Resource, including explanations of the value to stakeholders,
- What current congestion-related information AEMO could stop publishing in the Congestion Information Resource with no or little loss of value for stakeholders (for example because it is published elsewhere or no longer relevant),
- AEMO's proposal to revise the Congestion Information Resource Guidelines to include a clear requirement for TNSPs to publish their limit advice on their website or on AEMO's limits advice page.

This consultation process is currently in train, with a draft guideline planned to be published in July 2021.[69]

The Congestion Information Resource is focussed on the publication of operational data. There may also be scope to enhance the forward-looking information made available in planning timeframes. AEMO is considering this matter in the context of its work to develop a sequencing rule change proposal. This proposal contemplates the sequencing of connection applications in situations where the current regulated approach cannot deliver the necessary outcomes for ongoing power system security or reasonable certainty for proponents. AEMO is currently engaging with key stakeholders in advance of submitting its Rule change proposal to the AEMC.

In addition, AEMO and the Clean Energy Council are jointly progressing a connection reform initiative which is intended to improve connection processes for new investors.[70]

Transmission Access Reform

The initial reforms proposed for the interim REZ framework, and jurisdictional schemes developed in line with that, should allow the implementation of a number of early REZs to proceed. However, these arrangements will not be sufficient to ensure efficient development of the grid and connection to it in the medium to longer term. Broader, network wide, access reform is required for this.

In the ESB's April Options paper, five access reform models were put forward for consultation. Having considered stakeholder feedback, the ESB considers the CMM(REZ) is the preferred solution. Stakeholders have been relatively supportive of a transmission development model based around REZs and several State governments have adopted policies to develop REZs. Generator and investor groups have indicated that they have concerns with a full locational marginal pricing and financial transmission rights (LMP/FTR) model. The CMM(REZ) supports REZs, complements the ESB's interim REZ framework, addresses the underlying access reform objectives, and responds to concerns raised by stakeholders in relation to the LMP/FTR model.

The next section sets out the ESB's recommended access model, which is designed to drive the implementation of the ISP. This discusses stakeholder feedback to the Options Paper, and how the ESB took this feedback into account in order to arrive at the preferred access model straw proposal.

The ESB recommends that Energy Ministers agree to the ESB preparing a rule change for submission to the AEMC that progresses the CMM(REZ) described below. There is a need for further development and consultation on a detailed design for the CMM(REZ). Both these requirements can be accommodated in an AEMC rule change process. Subject to Ministers' response to the recommendation, the ESB anticipates that a rule change could be submitted before the end of 2021, with the process taking approximately 12 months. Subject to the sequencing of the implementation of reforms to be completed by AEMO (see Chapter 6), a CMM(REZ) could be implemented around 2025. An overview of the detailed benefits of the proposed model have been considered using existing modelling completed to date. Further analysis of the costs and benefits can be undertaken as part of any rule change process.

Given the speed with which REZs are being developed, timely implementation of a CMM(REZ) will be important and can be best achieved through the AEMC process.

---

69 See https://aemo.com.au/consultations/current-and-closed-consultations/2021-congestion-information-resource-guidelines

70 See https://www.cleanenergycouncil.org.au/advocacy-initiatives/energy-transformation/connections-reform-initiative

Overview of the CMM(REZ)

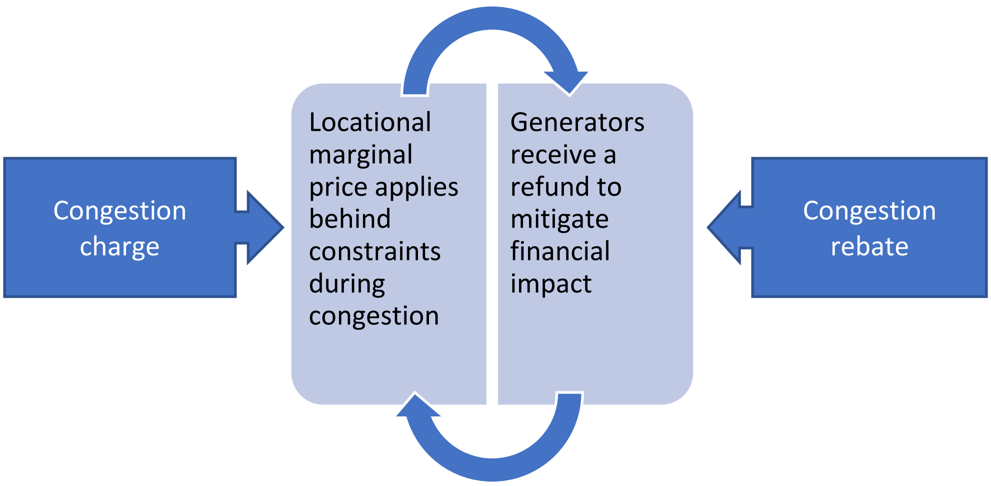
The ESB's recommended medium term access model uses REZs to co-ordinate generation and transmission investment and deliver an orderly transition. It is designed to resolve the problems associated with the current open access regime, while avoiding the adverse outcomes identified by stakeholders in relation to the LMP/FTR model.

It supports and strengthens the REZ framework by:

- Strengthening incentives for new entrants to locate and participate in REZ investments,
- Improving connection as pro-active and scale efficient actions can be taken to manage system security issues including system strength,
- Giving REZ participants confidence that their investment case will not be undermined by subsequent inefficient investment decisions outside the REZ,
- Removing opportunities for subsequent connecting generators to free-ride on REZ investments without contributing to them, and
- Promoting the efficient use of REZ infrastructure by creating a market design that rewards storage providers for alleviating transmission congestion and providing firming services for renewable generators.

The CMM(REZ) achieves this through the selective availability of congestion rebates. The underlying charge/rebate mechanism is outlined in Figure 8.

Figure 8 Vanilla congestion management model



This model introduces two changes to the settlements arrangements which work in tandem. First, all scheduled and semi-scheduled generators would face a **congestion charge**, calculated each dispatch interval on a $/MWh basis as the generator's marginal impact on the cost of intra-regional congestion in the dispatch interval.

Second, eligible scheduled and semi-scheduled generators would receive a **congestion rebate**, calculated each dispatch interval, funded from the collective revenue received from the congestion management charges. The size of the rebate is determined in accordance with a pre-determined allocation metric, such as availability. The rebate, in combination with the congestion management charge, is designed to result in financial outcomes for market participants that broadly replicate the status quo arrangements. This reduces much of the cost and disruption associated with previous proposals for access reform.

The congestion management model uses locational marginal pricing to create a market design that incentivises generator to bid more closely with their true costs of generation based on their location (that is they bid in line with their short run marginal cost). This removes the incentives that generators have now to bid in a way that tries to avoid the generator from being constrained off (being prevented from dispatching as much electricity as they wish to), because of the congestion on the grid. Better incentives to drive operational behaviour means congestion across the grid is managed efficiently and maximises the value derived from new transmission investments. These better operational incentives also create new business opportunities for batteries and other types of storage to be paid to alleviate transmission congestion.

Further, these operational signals, combined with the locational signals from REZs, will also provide stronger locational signals for generators. This will encourage generators to locate in the right parts of the grid, realising the benefits that were forecast under the ISP.

However, stakeholders have expressed concern that exposing generators to locational price risk could drive up costs. The congestion rebates included in the CMM(REZ) mitigates this locational price risk.

The CMM(REZ) enhances the vanilla congestion management model by restricting the availability of congestion rebates to generators that locate in the right places from a whole of system perspective, as determined by the planning framework. This enhancement increases the value of the congestion rebates to eligible generators (as the total congestion rent will be divided between a limited and specified quantity of participants, as opposed to between all current and future participants) and creates a tool to provide locational signals to generators. The ESB's reasons for preferring a model that restricts the availability of rebates are discussed further below.

Generators that would be eligible to receive congestion rebates would include incumbent generators and new generators that connect in locations that align with the Integrated System Plan (as supplemented by government REZ policies).

Table 2 Selective availability of rebates under CMM(REZ)

Participant	Rebate	Comment
All incumbent generators	✓	Location decision has already been made Rebate provides financial access during congestion, replicating existing profitability.
Foundational REZ participants*	✓	Rebate provides financial access during congestion Rewards REZ participants for locating in the right place
Non-foundational REZ participants	✗	Prevents free-riding on REZ capacity Receive local price in event of congestion (this is the efficient price signal) Creates incentives for generators to participate in REZ process
New generators connecting outside of the REZ	✗	Generators may still connect outside REZs Receive local price in event of congestion (this is the efficient price signal) Creates incentives for generators to participate in REZ process.

* Including generators connecting in locations that are deemed eligible to receive rebates, which may be outside a formal REZ scheme. The exact definition of foundational REZ participants will depend on how the REZ is set up, and who the funders are

Table 2 above uses the term "REZ" as shorthand to refer to locations where generators can invest and receive a rebate. In practice, these locations could be broader than the current REZs under development now. As coal generators retire, new capacity may become available on the existing network, and there may be scope for some targeted investment in locations outside REZs. Going forward, it will be critical to ensure that the planning processes for the ISP and REZs, and the implementation of REZs, ensures that good projects have plenty of opportunities to be part of the overall solution. If implemented, the framework for allocating rebates would need to be designed in a way that supports efficient use of the network.

As a group, generators are better off under the CMM(REZ), because they share in the efficiency gains achieved via improved dispatch outcomes. Customers also benefit from the efficiency gains. However, as several submissions noted, further detail is required to fully assess the impact of the model on various market participants.

A critical design choice relates to the allocation metric, as it is used to determine each generator's share of the congestion rebates. There is a range of options for the allocation metric, which can be tailored to meet various objectives, such as:

- Maintain status quo outcomes,
- Improve on status quo outcomes (For example by moving away from "winner takes all" outcomes, where tiny differences in participation factors have a large bearing on the profits of individual generators on a looped flow), or
- Provide revenue certainty.

The key design choices for the CMM(REZ) straw proposal, and the impacts of different choices on different parties, are discussed in more detail in Part C of the ESB's final recommendations.

Implementation impact

The ESB has evaluated the operational efficiency benefits of the CMM(REZ) using two different techniques. First, we extracted the relevant elements of previous bottom-up analysis undertaken for the AEMC as part of the COGATI review. Second, we considered historical experience of similar reforms in other jurisdictions and calculated the potential benefits for the NEM if the same results applied. Both techniques yielded similar results – benefits in the vicinity of $1 billion in net present value terms. The ESB is yet to fully quantify the benefits of improved locational signals and investment certainty arising under the CMM(REZ) model. However, previous analysis undertaken for the AEMC would suggest that the potential benefits are large. This work is discussed further in the evaluation chapter (Chapter 7).

Further development and evaluation is required to assess the costs of the CMM(REZ). Stakeholders have submitted that access reform, including a CMM, could have additional implementation costs if the reforms trigger the need to reconsider long term contracts such as power purchase agreements. This concern has been considered in detail. A CMM is likely to be benign for the parties to the contract because the design of the CMM leaves much of the foundational pricing arrangement since the NEM, on which these contracts are based, unchanged. Further the CMM(REZ) is likely to improve the ability of generators to enter into power purchase agreements in the future, as parties who receive rebates will be protected from the risk of inefficient congestion caused by subsequent connections. Further detail on this analysis is set out in Part C.

The rule change process to progress CMM(REZ) would consider this risk further, and address it, if necessary as appropriate through the rule change process.

Reasons for preferring the CMM(REZ)

The options paper consulted on five medium term access models:

1. The basic congestion management model or vanilla CMM
2. CMM(REZ)
3. Generator transmission use of service charges (GTUOS)

4. Connection fees
5. Hybrid CMM/connection fee model.

The CMM(REZ) is preferred to the other models outlined in the options paper.

Stakeholder submissions presented varied views, with limited support for any one model. Around half of submissions addressed the issue of transmission access reform. A number of generator and investor representatives remain opposed to locational marginal pricing (LMP) in any form, though opposition is not universal. A range of customer, generator, network, academics and other stakeholders expressed support for LMP in some form.

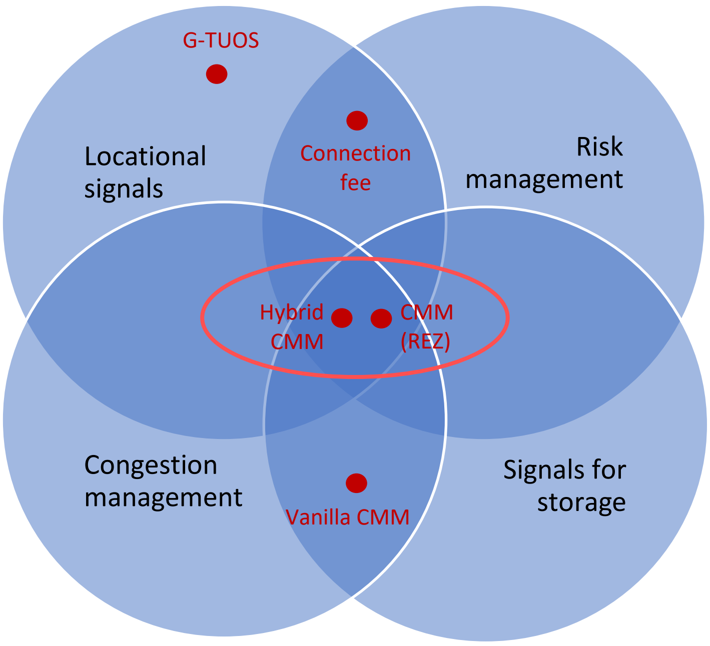
Among those that supported some form of LMPs, support was fairly evenly spread between the proposed long-term solution of LMP/FTRs, the CMM(REZ) and the hybrid CMM (i.e., option 5). However, only a small group expressed support for a stepping-stone approach involving both LMPs/FTRs and the CMM. Additionally, several respondents who were not ready to express a preference for any specific model were willing to support further work to explore the options.

In this context, the ESB assessed the options with respect to a range of primary and secondary objectives. In the first instance, the ESB assessed the options with respect to the primary access reform objectives, since they are the core drivers for undertaking access reform in the long-term interests of consumers. These objectives are to:

- Provide locational signals for investment
- Efficiently manage congestion in operational timeframes
- Provide efficient signals for the operation of storage
- Help generators manage their risk.

Of the five models outlined in the options paper, only two met all of the ESB's primary objectives for access reform.

Figure 9 Assessment of options against the ESB's primary objectives for access reform



Generator transmission use of service charges (G-TUOS) and connection fees both rely on administered pricing frameworks to provide locational signals to investors. As prices are determined in advance via a regulatory process, they do not provide price signals to participants in operational timeframes. As a result, they are not dynamic enough to accurately reflect congestion in response to changing power system flows. They are also not dynamic enough to incentivise batteries to charge and discharge in a way that benefits the broader power system. To efficiently manage congestion and provide efficient signals for storage, some form of real time, localised pricing is required. For this reason, the ESB's preference is for one of the congestion management models. These models incorporate LMPs whilst protecting investors from the additional risk and complexity that stakeholders have raised as concerns with the full LMP/FTR model.

G-TUOS also performs poorly in relation to helping generators to manage risk. While high locational TUOS charges can help to dissuade generators from connecting in congested parts of the network, under the G-TUOS model those fees would continue to be paid by incumbent generators, creating an administrative risk similar in nature to the risk associated with marginal loss factors.

Under the basic or "vanilla" CMM, all new and existing generators receive congestion rebates. The rebates are a form of hedge against congestion risk, which means that they mute the locational signals faced by investors. As a result, investors may still be incentivised to make locational decisions that are individually profitable, but inefficient from a whole of system perspective.

This characteristic reduces the value of CMM as a risk management tool. As the pool of congestion rebates is shared among more parties, the portion available to each generator declines. As a result, generators still face subsequent connection risk. In this regard, the vanilla CMM is equivalent to the status quo. Under the status quo, congestion risk manifests in the form of reduced dispatch volumes. As more generators connect and the local network becomes congested, the profitability of incumbent generators – who may have connected when the network was unconstrained – is undermined by their new neighbours. As the current access regime and the vanilla CMM both share this trait, both fail to meet the ESB's primary access reform objective of providing improved locational signals and risk management for investors.

Only two options – CMM(REZ) and hybrid CMM– met all four of the ESB's primary objectives. These options were assessed with respect to the ESB's secondary objectives, namely:

1. **Support REZs** by ensuring that REZ schemes are not undermined by unfettered connections elsewhere in the grid. The model also needs to be capable of being implemented in a timely fashion, given the pace at which REZs are being identified and developed.
2. **Address stakeholder concerns** in relation to the LMP/FTR model including concerns about exposure to basis risk, high implementation costs and uncertainty.
3. **Help share the costs** of new transmission, given that at present the costs of the shared transmission network are wholly borne by customers, even if the investment benefits generators.

The key difference between the CMM(REZ) and hybrid CMM is the mechanism that they use to provide locational signals to generators. The CMM(REZ) uses the selective availability of congestion rebates to provide locational signals, whereas the hybrid CMM gives rebates to all generators, and relies on a connection fee to disincentivise new entry in congested part of the grid.

Table 3 Comparison of CMM(REZ) and hybrid CMM

	CMM(REZ)	Hybrid CMM
Overview	Uses selective availability of congestion rebates to create locational signals	Uses connection fee to create locational signals
Advantages	• Provides accurate locational signals to generators, including non-REZ generators who face the efficient price. • Few ongoing costs over & above CMM. • Supports REZs. • REZ tender proceeds offset costs borne by customers.	• Easy to understand price signal at the time of investment decision. • Supports REZs. • Connection charges offset costs borne by customers.
Disadvantages	• New connecting generators who are not eligible for rebates are required to form their own views on the cost of future congestion as it is contingent on wholesale market outcomes. • New connecting generators who are not eligible for rebates would be subject to unhedged LMPs and hence not readily able to manage congestion risk.	• Less accurate locational signals as based on forecasts. • Slower and more costly to design and implement due to the need to design a connection fee regime. • AEMO/TNSPs would need to administer a connection fee regime – potential impact on timeliness of connections.

On balance, the ESB considers that the CMM(REZ) is preferable. Since the CMM(REZ) leverages existing processes to develop and implement REZs, our preliminary assessment is that its implementation involves a similar level of complexity as the vanilla CMM. In contrast, the hybrid model entails the development of both the vanilla CMM and a connection fee regime, which is likely to be complex and contentious. Given these issues, we expect the implementation costs associated with the hybrid model to be significantly higher.

A further concern associated with the hybrid CMM is that it requires case-by-case calculations to determine the correct price signals for a given location at a given point in time. This has the potential to add complexity and delay to the connections process; an outcome that the ESB is keen to avoid. The risk of delay could be reduced by using a simplified methodology, however, this would reduce the accuracy of the locational signal.

The CMM(REZ) also has the advantage that it reduces the risk of inaccurate locational signals driven by an administered pricing mechanism. Under the CMM(REZ), generators wishing to locate outside a REZ would be subject to the efficient price signal (namely, the locational marginal price). It would be open to commercial parties to invest outside the locations selected for development by grid planners, however, they would face congestion risk. Essentially, this is the same risk that all generators face under LMP/FTRs, except without the ability to purchase FTRs. This may still be a worthwhile investment strategy if the project proponent is confident that the level of congestion is likely to be low, or they have a strategy to deal with congestion (such as a battery). In contrast, under the hybrid CMM model, connection applicants would face a fixed fee determined by an administrative process.

Some stakeholders have expressed concern about this feature of the CMM(REZ) and the ESB is exploring options to deliver a balanced outcome. Part C outlines some of the outstanding issues that will need to be resolved as part of any future consultation process. A key issue for further consideration is how to determine which new developments should be eligible to receive rebates.

There is scope to make the rebates more widely available by conferring "REZ" status on areas with spare network capacity outside regions currently classified as REZs. However, there is a trade-off between giving investors more flexibility in terms of their location decisions and the level of certainty that they obtain from the congestion rebates.

5.3.3. Long term reform

In previous documents, the ESB explained that locational marginal pricing and financial transmission rights is its preferred model in the long-term and proposed a stepping-stone approach to reach that goal. However, a strong theme of submissions to the options paper was that it would be disruptive to introduce successive access models to move to an LMP/FTR regime.

The ESB's view that the full LMP/FTR model is a preferred solution is based on it averting the need for other market design features that are required to overcome the distortions that arise under a regional market design. Examples of such distortions are discussed in Part C. The LMP/FTR reduces the costs borne by consumers by removing the wealth transfer that currently gives the value associated with intra-regional settlement revenues to generators rather than consumers.

However, a strong theme of submissions to the options paper was that it would be disruptive to introduce successive access models or change the access framework after a medium-term access solution has applied for a relatively short period of time. While the Australian Energy Council and several other generators have noted that a commitment to the LMP/FTR model in the distant future could drive many of the desired market responses in the short term, many stakeholders have continued to express concern at any steps towards this model due to the uncertainty it may create. The prospect of a future shift to LMPs and FTRs, even in the long term, is making it difficult to progress options to resolve the pressing problems facing the market.

Customer groups expressed mixed views with respect to the ESB's long term proposals for access reform. The ECA and their consultant, Finncorn Consulting, expressed strong support for a shift to LMPs and FTRs as soon as possible on grounds that it would provide "very material affordability benefits to consumers".[71] However, the EUAA and MEU were doubtful that the proposed approach would deliver the anticipated benefits, and PIAC and ACOSS supported PIAC's alternative REZ model in preference to LMP/FTRs.

The ESB recognises that it is difficult for investors to make long term investment decisions in the context of shifting sands. For this reason, the ESB has not included a long-term access model in its recommendations. Instead, the reform pathway for transmission access reform is focussed on immediate and near-term measures. In particular, the CMM(REZ) should be implemented expeditiously following a fulsome stakeholder engagement process to develop the detail.

The CMM(REZ) implicitly recognises the need for a more planned approach, and the role of governments, in driving the transition towards a predominantly renewables-based power system. In the future, once the disruption associated with the energy transition has subsided, stakeholders may wish to explore a more market-based approach to the development of the power system.

To provide stability and clarity to the market, the ESB's view is that implementing the CMM(REZ) should be the priority reform at the current time to address congestion. While it does not form part of the ESB's recommendations, the ESB continues to hold the view that the full LMP/FTR model could be a long-term solution given that it is used successfully in many jurisdictions. This market design is in long term interests of customers because it is the most realistic representation of what is happening on the physical power system, as well as being internationally accepted as best practice.

71 ECA submission, page 10.

In the event that a change to the market arrangements is needed in the future, then the CMM(REZ) has the potential to be readily transitioned into a full LMP/FTR model at a relatively low cost, should that be necessary.

5.4. Recommendations

5. To support the integration of renewable energy zones (REZs), the ESB **recommends** Energy Ministers agree a number of *immediate and initial* reforms:

a) to adopt the REZ Planning Rules and the Principles for an Interim REZ framework to address the urgent planning implications for REZs.

b) instruct the ESB to prepare a rule change for submission to the AEMC to progress the congestion management model, adapted for integration with REZs. This model complements the Interim REZ framework and will address the emerging congestion management needs of the system. Comprehensive consultation, with a wide range of industry, consumer and government stakeholders on the detailed design of the model will be undertaken as part of the rule change process.

6. To support timely and efficient transmission investment, the ESB **recommends** Energy Ministers seek advice from the AEMC on what initial reforms are necessary to current regulatory frameworks to improve the timely and efficient delivery of major transmission projects (including ISP projects). This advice will be prepared as part of the AEMC's current Transmission Investment and Planning Review.

6. Enabling Implementation

6.1. Key points

- Delivering the reforms in this paper enables a move from 20th century technology and traditional energy and data flows to an industry that is digitally enabled and able to adapt for the future energy system.
- There are risks in the implementation. These include governance, management of the reforms, recognising the interdependency in the four reform pathways, implementation costs, and possible policy changes.
- The three market bodies have important roles to play and must be adequately funded to enable delivery of the reforms. The ESB work must continue to maintain the momentum of reform; the increasing load of market development work and rule changes should be recognized; changes in regulatory arrangements and compliance requirements under new market arrangements are evolving rapidly; and the fast-changing operational challenges in the NEM must be managed. All these changes within the market bodies need funding to enable reform implementation.
- Identifying the costs of the Post-2025 reforms across the NEM for all participants, and for the market bodies, is impossible without more detail about the reform design and its timing. This is particularly the case for the more significant reforms. Nevertheless, a cost range can be developed to provide preliminary information.
- One of the main enablers for the reforms is a change in IT systems and business processes. The impact of IT system changes stretches widely across all sectors in the NEM, and such changes need to be planned, staged, sequenced, and analysed carefully.
- Implementation of the reforms incurs significant costs for market participants. AEMO will consider how to deliver these changes together with industry stakeholders as part of an integrated roadmap approach for NEM regulatory and IT systems implementation. This will enable careful sequencing of reforms, avoid unnecessary or duplicative costs, test key assumptions for system design and identify where strategic investments can be made to deliver efficient outcomes for AEMO, market participants and customers.
- Just as current technical standards and market arrangements are not fit for purpose post 2025, neither are the current market systems and processes. These systems require a step change in what is in place today.
- AEMO has developed an indicative cost estimate to implement its system changes to support the reforms and this estimate is between $250 to $330 million. AEMO's current funding mechanism may not be adequate for the longer-term upgrade that is necessary for existing systems and business processes, and changes to it may be necessary.
- AEMO, the AER and the AEMC will provide indicative funding proposals for consideration by 31 August 2021.
- The reform directions on 'what' needs to be delivered is identified in the pathways. The 'how' to deliver these reforms is critical.
- Initial analysis carried out indicates that the enduring benefits of the proposed reform pathways will quickly outweigh the one-off and any ongoing costs associated with their implementation.

6.2. Risks

The Post-2025 reform pathways set out 'what' needs to be done to meet the needs of the transition. The 'how' of the reform implementation is critical for delivery and involves *inter alia* the management and mitigation of the delivery risks. The more important risks include governance, the management of the reforms, recognising the interdependencies between the reforms, implementation costs, and possible changes in policy.

6.2.1. Governance

Given that the ESB arrangements are due to be reviewed, following both the Edwards Report last year[72] and the delivery of the Post-2025 market design proposals, the ongoing responsibility for delivery of these reforms in coming years must be addressed. To this end the ESB has delivered suggestions to the Energy Ministers. Given that the changes in the industry are not stopping, the momentum of the reform process needs to continue. The features of the ESB work that should be retained include good cooperation between the market bodies, extensive consultation with industry participants, and quite detailed input from those participants, customer advocates, academics, and others. To ensure that appropriate governance continues Energy Ministers are recommended to decide on the future of the ESB or its replacement as soon as possible.

6.2.2. Management

To manage the uncertainties around these major reforms in the NEM it is essential that the approach to reform management is adaptive. This means first that the reform process should occur across time as recommended for each pathway and not be attempted in some 'big-bang'. Progressive implementation of the Post-2025 reforms provides a managed evolution of the market and allows participants the opportunity to adapt to reform. While some early and interim measures will be (and have been) delivered to address needs already emerging within the system, an adaptive approach for delivering initiatives enables the market to respond to each set of measures before building further on these with additional reforms. This approach also enables a continued focus on the changes needed to support the transition at least cost to consumers.

Second, each reform should undergo thorough preparation and careful planning before implementation, and reviewed and monitored after. This needs to occur at a detailed level as well as more generally. At a more general level, the type of industry change happening here has not been experienced anywhere before. The speed and scope of the change in the NEM is unparalleled, particularly with the entry of large scale VRE and small-scale rooftop solar PV. As we learn more there is a need to adapt and modify to ensure that the changes are benefiting the long-term interests of consumers. The delivery program for each reform needs to accommodate this approach.

6.2.3. Interdependencies

While each of the reform pathways have been designed to address the four key challenges for the NEM as it transitions, there are clearly interdependencies between them. As the reforms progress to a more detailed level, we need to be cognisant of evolving market conditions and the implications of the interrelated nature of the reforms. The reform pathways are designed to, together, deliver a coherent, fit for purpose design for the NEM - but the outcomes from each pathway are interrelated.

The interdependencies have been depicted below in Figure 10. At a high level the interdependencies are reasonably well recognised but the four key interdependencies that were relevant in developing the reform pathways here were:

---

[72] This report can be found: https://www.energyministers.gov.au/review-energy-security-board

- *Resource adequacy mechanisms and ageing thermal retirement* and *Effective integration of Distributed Energy Resources (DER) and flexible demand (DER Implementation Plan)*

  The degree to which flexible demand is harnessed and DER is integrated over time, may diminish the need for new capacity from utility scale generation resources. As noted, the largest generator in the NEM is now owned collectively by customers – and sits on their rooftops. The uptake of DER and harnessing flexible demand from over 50GW of controllable assets, like hot water, air-conditioners, and pool pumps, provides significant potential to meet the NEM's capacity need. In the medium term, a capacity mechanism provides critical support to ensure that resource adequacy is not contingent on the uptake and effective integration of DER and flexible demand. However, a capacity mechanism will also provide further opportunity to better value the flexibility demand-based resources can offer to the market and leveraging this latent flexibility will drive down costs.

- *Transmission and access reform* and *Resource adequacy mechanisms and ageing thermal retirement*

  The more we co-ordinate REZs and generation locating within them, the more we better use network capacity and support more predictable connections processes. This allows the over 50GW of renewable capacity forecast by 2040 under the ISP step change scenario, and the related firm and flexible resources needed to support it, to enter faster in time for anticipated exits of the existing fleet. Better coordination of transmission and generation resources is intrinsically linked with addressing the NEM's capacity needs. Under our current access regime, an investment in new generation that causes heavy congestion may still be profitable for an investor, because the costs of congestion are borne in part by pre-existing generators (regardless of technology) or consumers, rather than fully by the party that caused the congestion. Impacts on the profitability of affected generators could in turn drive exits and a shortfall in resource adequacy.

- *Resource adequacy mechanisms* and *Essential system services and scheduling and ahead mechanisms*

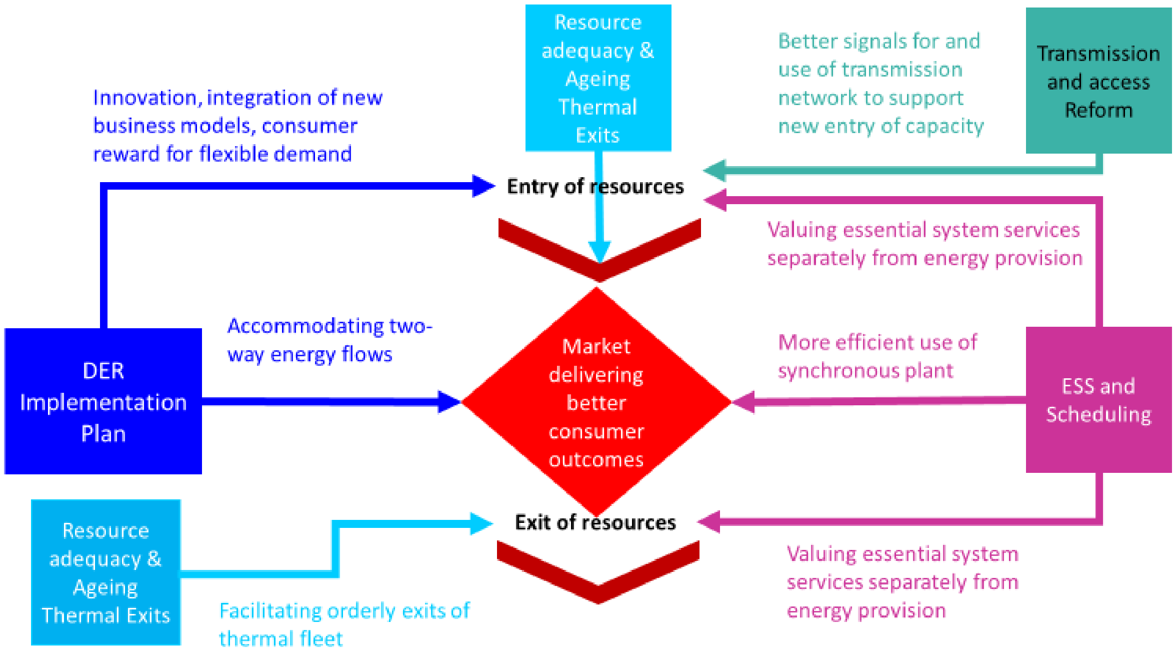
  Creating markets that value essential system services not only secures the needs of the power system but supports efficient entry and exit of generation. Generators (existing and new) may receive revenue for their currently unpriced services, helping them make more efficient decisions about entry and exit. These new services may support the uptake of batteries and other new technologies or minimise earlier than expected exits of existing generation.

- *DER Implementation Plan* and *Essential system services and scheduling and ahead mechanisms*

  Supporting networks to manage the two-way energy flows that come from effective integration of DER and providing AEMO visibility of DER and the tools it needs to manage system security, including minimum system load conditions, increases the mix of resources available to provide the essential system services that manage security. The right scheduling tools and procurement mechanisms for AEMO open opportunities for these new technologies and resources with capabilities to deliver these essential services needed as the existing generation fleet that provided these services in abundance exits.

Monitoring the staged delivery of pathways and their market impacts will be critical to the detailed design and delivery of many of the reforms.

Figure 10 The Interdependence of the Four Policy Pathways



The interdependencies and linkages are even more apparent at an operational and functional level when the reforms are being put into practice. Delivery requires changes in operations by AEMO and others in the NEM, changes to regulatory and compliance arrangements, and ongoing market development with accompanying rule changes and consultation. The ESB Data Strategy, delivered alongside this report, also emphasises the greater importance of data and information availability for policy makers and market participants as the system becomes more digitalised and decentralized.

6.2.4. Affordability

The linkages between the reform pathways and implementation timing are also important to affordability. As new markets for the right mix of capacity or essential system services are implemented it is important that reforms are coordinated across pathways to open up opportunities for as many sources of competitive supply as possible. Engaging flexible demand from large and small customers is important in minimising the cost of reliability. The cost of retaining the essential system services required will be minimised if the new markets created are open to the full range of technologies from both utility and distributed resources. Developing markets that more specifically value the capacity and services needed will drive dynamic efficiencies and support innovation that can lower costs. While the NEM is leading the world in key areas, the challenges faced here are replicated in many advanced economies.

6.2.5. Implementation costs

The present work of the ESB has been heavily supported by many in the industry, and by the market bodies in particular. The AEMC has provided accommodation and administrative management, AEMO has provided IT support, and the three market bodies have all had numerous staff closely involved in the reform development for some time. This has been managed within the existing budgets of the market bodies and the ESB but should be formally recognised in future budgets and adequately funded.

Measures that enable the implementation of the reforms also require adequate funding. An assessment of the likely costs to market participants (to be borne by them) and for the market bodies have not been undertaken in detail, and generally cannot be, until more detail on the reforms is developed and the precise timing and manner of their introduction is decided. While the estimated costs of some reforms (like transmission construction) have received some attention, the costs of most other reform measures are awaiting more detail before costings and the timing of those costs are developed. Nevertheless, the broad parameters of annual budgets for the market bodies over several years into the future can be formulated within a range. The market bodies are able to provide their initial views on their budget requirements for the reform process by the end of August 2021. Noting that as implementation of reforms will occur over time, these cost estimates will be set out on a year-by-year basis. The important point is that without these budgets being funded, the reforms cannot be implemented, and this is a major risk.

6.2.6. Changes to policy

Policy changes can be expected over the years ahead as the changes are implemented. The effect of such changes on the delivery of the reforms must be monitored but one policy area that would have a profound impact is emissions reduction targets. At present, each jurisdiction has a target for emissions reduction and a trajectory, implied or specified, about how to reach that target. Typically, the target is 'net zero emissions by 2050' though some jurisdictions have more challenging targets and trajectories. Should policy move to a more rapid and deeper emissions reduction target the reforms may need to be implemented with more speed and aggression.

6.3. The enabling role of market IT systems

6.3.1. The impact of the reforms on IT systems and business processes

IT systems and processes are a critical enabler in this reform process and the reforms bring changes to systems that are felt right through the NEM. An impact assessment of AEMO run IT system changes is summarised in Figure 11 below. It shows how the multiple reforms in the Post-2025 design are accompanied by necessary IT changes and business processes in many different areas and systems. The heat map provides the estimated impact of the reform initiatives on AEMO IT systems and business process requirements. As the figure shows various core IT systems and processes across wholesale and retail systems are affected.

Figure 11 The impact of reforms on AEMO IT system and business processes

Reform pathway	Reform initiative	Wholesale							Retail	DER
		Registration	Offers	Dispatch	PASA	Settlements Billing & Prudentials	Causer Pays	System operations		
Resource adequacy and exit mechanisms	Increased MTPASA information									
Essential system services and scheduling	Ramping/operating reserves									
	Primary Frequency Control									
	Fast Frequency Control									
	Operational scheduling mechanisms for security (UCS + SSM)									
Integrating DER and flexible demand	Integrated Energy Storage Systems									
	Flexible trading arrangements									
	Scheduled lite									
	Dynamic operating envelopes									
	Turn up services									
	DER data exchange and registry services									
	DER system operator integration									
Access and transmission	Congestion Management Model									

Source: AEMO. Note: green = low impact to IT market system, amber = medium impact to system, and red = high impact to systems.

The most heavily impacted functions are registration, settlements and system operation tools and interfaces. While a smaller number of reform initiatives impact the retail functions, those reforms have a more significant impact on IT systems.

Most of the initiatives require changes to settlements. These changes may require coordination and need to be considered in a sequence and bundled for efficient delivery. The uplift to settlement systems from the implementation of five-minute settlement mean that the underlying system architecture can be readily leveraged.

The potential changes required to systems and processes are assessed here by covering the needs across all reform initiatives and their impact on a particular functional area. The lifecycle state of the underlying systems must also be considered so that investments are not made to an IT system that is not fit-for-purpose for implementation at a later change.

6.3.2. Considering the cost

One of the most important and costly changes to facilitate the reforms is in IT systems throughout the NEM. Work underway by AEMO for the sequencing of these IT system changes suggests that the risks and costs to market participants is best addressed by:

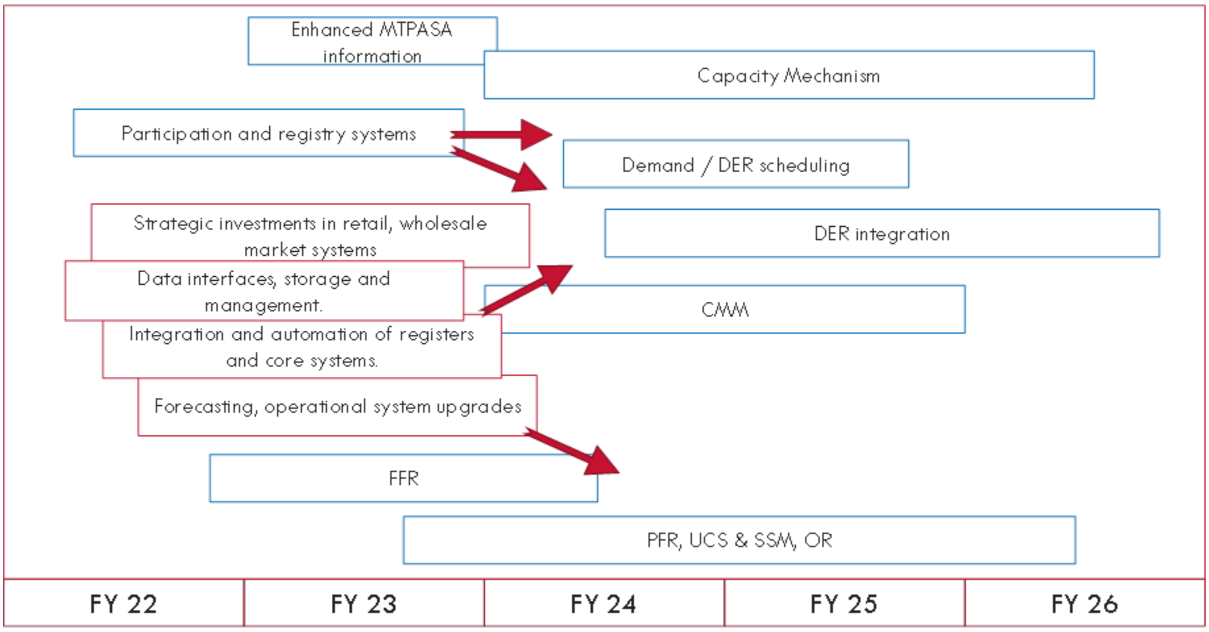
a) Appropriate transition periods ahead of reforms commencing, which will also be necessary for notice for financial markets. These notice periods will need to be considered in detail as part of relevant rule change processes.

b) Development and consultation by AEMO of a forward looking NEM market systems and business processes roadmap. This roadmap enables future systems needs and assumptions to be tested and considered with market participants and interested stakeholders.

Careful sequencing for implementation of the proposed reforms means having a well-considered bundling of the necessary ‘incremental changes’ to the one system or business process to avoid unnecessary or duplicative costs. This, of course, is also subject to the sequencing of changes that would be required from a policy and regulatory perspective.

An indicative timeline for the proposed market system development activities is shown in Figure 12. It highlights the considerable amount of development work and preparation that must be commenced now to facilitate timely delivery of the Post-2025 reforms. Further detailed assessment of the sequencing of activities will be carried out in developing the NEM market systems components of an integrated regulatory and systems roadmap.

Figure 12 Sequencing of market system development activities



This example is a guide to the breadth and depth of implementation required. There is stakeholder concern around the risk of implementation failure because of the complexity of the system changes, the need for new systems to work together effectively, and for the design to be efficient particularly following the introduction of five-minute settlement. Careful planning and development can mitigate these concerns. At present AEMO estimates the cost of implementing the reform pathways to be in the range of $250-$330 million. Section 4.1 in Part C provides a more detailed breakdown of the indicative cost estimates of each of the reform pathways

Identifying the costs of the reform is obviously an important input when evaluating benefits. The costs of the IT systems considered include the likely costs for changes needed to AEMO systems and business processes to implement key reforms identified in each pathway.

While the reform pathways are to be implemented over time, considering the accompanying implementation of the reforms as a 'package' now, allows for effective sequencing and planning. This assists in maximising opportunities to consider how reform outcomes can be delivered with efficient investment, minimise delivery risks and costs and improve outcomes to customers.

Given the scale and nature of the reforms, and noting that further detailed design is required, it is not possible to estimate implementation costs with any degree of certainty. In considering the scale of implementation AEMO have developed an indicative cost estimate range for necessary changes to AEMO IT market systems and processes to implement key reforms identified in each pathway. These are planning level cost estimates only, providing a range of indicative costs for system changes.

6.3.3. Developing the cost estimates

The method used for determining the estimates is in brief:

- Identify the key solution requirements based on the regulatory design of the reforms as set out in this report.
- Conducting an impact assessment to identify the functions impacted by the reforms and assess the nature and size of the changes required holistically across the program. The impact assessment helps identify where the changes across the program can be accommodated by extending current capabilities and legacy systems, or leveraging recently established or planned digital capabilities, or whether new capabilities are required.
- Identify the main cost drivers, uncertainties, limitations and assumptions for each reform.
- Identify functional dependencies. The systems and process interdependencies of each reform is considered in the context of implementing individual reform initiatives, new pre-requisite capabilities, and other work AEMO has planned or has underway.

As part of this estimation process a number of assumptions have been made about the reforms. An overview of these assumptions is set out below:

- Only immediate and initial reforms proposed in each pathway are considered.
- The scope and design of the proposed reforms are assumed to be as set out in this report and are subject to final rules and detailed design and specification. As the design of the reforms is further refined as part of rule changes or detailed design processes, the estimates may need to be revisited, particularly if reforms evolve beyond the scope set out in this report.
- Fundamental market frameworks and structures are preserved. Market structures for information and settlement flows are maintained.
- The implementation costs of a future capacity mechanism have not been costed and will depend on a number of key design choices.
- The cost estimates generally assume AEMO build-own-operate.
- Systems implementation costs reflect one-off capital expenditure. These estimates therefore do not include costs associated for ongoing operating costs.
- The estimates do not account for delivery risk associated with complexity of program execution. The delivery schedule is also subject to regulatory imperatives rather than simply a sequence that optimises technology development.

As estimates, they are of course subject to change. Changes in the policies, designs, timing, and other assumptions could result in a material change to estimated costs. The extent to which the projects can be sequenced or bundled and run in parallel will be subject to more detailed planning.

6.3.4. Managing the IT systems implementation

In 2020, in partnership with the AEMC and industry, AEMO developed a Regulatory Implementation Roadmap that maps out all the current and upcoming regulatory reforms and implementation timing.[73] This is intended to provide transparency and clarity on how best to deliver the regulatory reform agenda and manage risks and emerging issues as a whole, rather than in a piecemeal manner.

[73] The Regulatory Implementation Roadmap can be found here: https://aemo.com.au/en/initiatives/major-programs/regulatory-implementation-roadmap

The roadmap now needs to be reviewed and updated to reflect the ESB Post-2025 reform program and consider systems implementation as part of an integrated approach.

It is important to engage openly and transparently in how best to update existing systems and ensure they appropriately support future capabilities and needs to minimise overall costs. The ESB notes that with the sheer scale and nature of the transformation underway across the NEM, there are costs associated with the transition, regardless of whether these reforms take place. The transition itself comes with significant uncertainty. It is prudent to proactively consider what could be done now to address these uncertainties and build flexibility into current systems and business processes to address it.

To deliver the reform outcomes in a way that best meets the needs of the future NEM (that is to take it from 20th century technology and traditional energy and data flows, to one that is digital enabled and adaptive to meet the needs of the future energy ecosystem), there is value in taking a planned, strategically staged implementation. This is particularly relevant given some systems are largely outdated and will need a replacement plan in any case.

AEMO will consider how to deliver these future systems together with industry stakeholders as part of an industry roadmap. Changes to the core assumptions mean that there are legacy IT systems and business process which are so heavily impacted by the needed changes that it is no longer cost effective to proceed with 'incremental' adaptation to a core system or process, but that it is cost effective to replace it to be fit for purpose for future needs. For example, replacing one or more of these core ageing legacy systems once active DER is operating at scale injects material risks and exponential expense compared to taking a strategic approach now and having platforms that change and grow as active DER scales up.

Building consideration of NEM IT systems as a key component of implementation into the roadmap, supports a more strategic approach to designing the systems needs for delivery of the Post-2025 reform outcomes, and enable existing legacy systems to be modernised to meet the needs of the future NEM. Undertaking strategic investment now can unlock capabilities to ready systems and processes for when they are needed and could avoid larger costs for AEMO and fee-paying participants (and ultimately customers) later.

Benefits of this approach include:

- An outline of the triggers or preconditions that necessitate the replacement of core systems and business processes.
- Proactive consideration of the shared AEMO and industry capabilities that are needed to facilitate the DER Implementation plan.
- Greater transparency in the assumptions that inform the design of the 'target state' and subsequent cost estimates and roadmap.
- Stakeholders (and fee-paying participants) have an interest in how these costs are incurred and future consumers of the services AEMO is delivering, require greater input and opportunity to provide feedback and influence the assumptions being made.
- Enable industry to develop a better view of timing for future system needs so they can plan their own future upgrades and better understand cost implications.
- To work with industry to explore opportunities to develop shared systems and processes.
- Systems costs are a significant input into considering the benefits of reforms. Where these can be further refined via stakeholder input it is likely to deliver benefits to how changes are implemented.

- Better visibility and planning alignment for AEMO, market bodies and industry stakeholders with an integrated roadmap for regulatory and IT systems implementation. This can support more effective decision making for design, implementation, and sequencing of regulatory reforms.

6.4. Next steps

The first recommendation in our report concerning the need for ongoing monitoring and review of the reforms should also be applied to each of the risks discussed in section 6.2. The governance, management, interdependency between reforms, and the costs of implementation and the reforms themselves need ongoing monitoring and review by Energy Ministers, the ESB, and senior officials. This is the way to mitigate and manage these risks going forward. Technology, costs, policy, and practical issues will change as implementation proceeds and this evolution must be managed carefully.

AEMO will consider how to deliver the IT system and business process changes together with industry stakeholders as part of an integrated roadmap for NEM regulatory and IT systems implementation. This will enable careful sequencing of reforms, avoid unnecessary or duplicative costs, test key assumptions for system design and identify where strategic investments can be made to enable more efficient outcomes for AEMO, market participants and customers.

The ESB notes market bodies will provide initial views on budget requirements and funding proposals for consideration by 31 August 2021.

6.5. Recommendations

10. The ESB **recommends** Energy Ministers instruct the ESB to monitor each of the reform pathways in light of changing market conditions and provide reports at least annually or more regularly if required.

11. To enable the Post-2025 reform pathways, the NEM of 2025 and beyond requires modernisation of critical market systems and business processes (see Section 8) and adequately resourced market bodies. These are costs and risks associated with the scale and nature of the energy transition rather than costs of the Post-2025 reforms. The ESB **recommends** Energy Ministers:

a) instruct AEMO to provide more detail of their required funding on a year-by-year basis (to 2025) by end August for the longer-term upgrade that is necessary for AEMO's existing systems and business processes to enable these reforms.

b) instruct the AER and the AEMC to provide proposals on a year-by-year basis (to 2025) by end August about additional resources they need to implement the Post-2025 reform pathways.

7. Benefits of Post-2025 reform pathways

7.1. Key points

- The ESB has undertaken a high-level indicative evaluation of the benefits of the reform pathways supported by some modelling. To understand the benefits of a pathway, key reforms from each pathway were selected to distinguish between a:
  - no reform scenario i.e., the state of the NEM as it is now, with the trends and challenges described in this paper continuing with no change; and
  - reform scenario, in which we assume that the intent of the market design changes proposed in each pathway is achieved, because of the key reforms selected.
- The direct costs to AEMO of implementing the key reforms have also been assessed. Other costs, such as those to market participants, have not been assessed at this stage. Minimising the transaction costs and regulatory burden of new reforms for market participants will be considered as part of the detailed design for each reform.
- The objective of the high-level evaluation is to understand the magnitude of benefits that could be expected from the breadth of the market design package. Understanding the magnitude of these benefits allows the direct costs of reform to be considered relative to the benefits.
- The modelling of costs and benefits for each reform pathway is based on current understanding of the proposed reform measures. In key areas of each pathway, further detailed development of recommended measures is proposed and further modelling (such as likely impacts on wholesale energy prices) may be warranted as those detailed designs are finalised.

Benefits of Resource Adequacy Mechanisms and Ageing Thermal Retirement pathway

- The analysis undertaken by NERA shows that, to achieve the acceptable reliability in the face of uncertainty as to when generators will exit, there are potential benefits of a new capacity mechanism of $1.3 billion (NPV), when compared to adjusting the current market signals for capacity by raising the market price cap and increasing price volatility in the energy market. This modelling suggests that, with reform (an appropriately designed capacity mechanism) it will be cheaper to deliver capacity under new market arrangements that reduce the uncertainty for investment in capacity. Without reform to the way that plants enter and exit the system to smooth the transition, there will be costs to consumers. The timely entry of generation to replace gaps in available capacity is also crucial to maintaining reliability
- The introduction of a mechanism to value capacity more directly is consistent with action taken over recent years in a number of transforming markets in the UK, Europe and the US. In its five-year review of the UK capacity market, the Department of Business, Energy and Industrial Strategy concluded that the "Cost-effectiveness of the Capacity Market (CM) has been good"; that "CM costs have turned out to be at the lower end of the range predicted"; and that "the deployment of a range of technologies through the CM, including flexible technologies, has helped to minimise whole system costs".

Benefits of Essential System Services, Scheduling and Ahead Mechanisms pathway

- The reform pathway provides mechanisms to address the emerging challenge of operating the power system in an environment of high VRE penetration. Implementing reforms to procure and directly value the system services essential to system security would improve the operation of the power system and drive innovation and investment in the supply of these services. The benefits of the TNSP procurement of system strength and introduction of the proposed scheduling mechanisms alone would yield benefits of up to $1.2 billion (NPV). The magnitude of benefits exceed the likely implementation costs. AEMO has estimated its costs for the full reform pathway to be in the range of $100-125 million[74] of which $8-$14 million are AEMO's implementation costs for the procurement and scheduling mechanisms.

Benefits of Integrating DER and flexible demand pathway

- Distributed generation and storage resources in the NEM are expected to continue to grow and be a major source of supply in the future. The opportunities to unlock flexibility in demand will also grow. The analysis undertaken shows that the potential benefits of harnessing flexible demand and integrating DER into the overall system are around $6.3 billion over the next 20 years. In contrast, in the absence of reform, these new technologies will be misaligned with, and potentially operate against, the needs of the system. The benefits of reform substantially outweigh the implementation costs for AEMO (estimated at being in the range of $140-185 million).[75] Though there will be costs for industry as well, we expect that these costs would be incurred in the no reform case in any event and are likely to be greater without the reforms to integrate these new technologies. Moreover, these reforms deliver a more diverse, flexible power system that is well-placed to capture all the potential benefits that may emerge from the advent of new technologies.
- The identified benefits of the reforms depend on some consumers choosing to become more active in the energy market. The ESB does not expect customers to participate in person, but rather that a portion will accept energy products and services that adjust how they use energy. Having a consumer-centric approach to the design of the market reforms and review of existing consumer protections is therefore fundamental to harnessing these benefits.

Benefits of transmission and access reform pathway

- The ESB has reviewed previous analysis to estimate the magnitude of the benefits that arise from the provision of efficient locational signals for generators. This earlier analysis estimated that the NPV of benefits of more efficient siting of future generation and storage over the period 2025-2040 was $1.7 billion. The more efficient locational signals modelled were based on the incentives of locational marginal pricing and an efficient response to those price signals by investors. The Congestion Management Model (CMM)(REZ) delivers similar benefits through the planned development of the system and renewable energy zones and by exposing generators to locational prices, albeit only at the margins.
- Experience in parts of the NEM has shown the high costs and potential impacts to generators connecting to the grid in a haphazard manner. The ESB considers that a more ordered approach to the connection of new generation and the timely construction of the transmission required to host it will deliver significant benefits to investors and long-term benefits to customers.
- Historic analysis of the Californian and Texan electricity markets suggest that the savings associated with efficient congestion management are between 2-4% of the variable costs of generation. Applying the average of these results in the context of the NEM managing

[74] This cost estimate includes the strategic technology uplift of applications in the forecasting, operational, and dispatch systems necessary for the delivery of the reforms on this pathway. These investments benefit the implementation of reforms on Integrating DER and flexible demand pathway and the Congestion Management Model (CMM)(REZ) in the Transmission and access reform pathway. This is discussed further in Part C

[75] In addition to this cost estimate, the DER implementation leverages strategic investments of between $70-$100million for applications in the forecasting, operational, and dispatch systems necessary for the delivery of the reform on this pathway as well as the implementation of reform in essential system services and CMM. These strategic investments, for the purposes of the benefits assessment, have been included in the estimates for Essential System Services, Scheduling and Ahead Mechanisms pathway. This is discussed further in Part C.

congestion in operational timeframes would suggest potential benefits of around $1 billion over the period 2024-2040. This finding is broadly consistent with the bottom-up analysis of the potential dispatch efficiencies associated with a move to locational marginal pricing in the NEM.

7.2. The objective in evaluating the reform pathways

The power system has and will continue to change rapidly as the market transitions with increasing levels of more competitive variable renewable energy generation and storage entering the market. The challenges for the NEM's market design have been discussed elsewhere in this paper. The ESB has developed reform pathways for each of these challenges. As a set of interrelated reforms, they provide a detailed strategic assessment of these major challenges and provide recommendations as to the steps that need to be taken to ensure that our market design remains fit-for-purpose.

A changing generation mix, technology advances, the scale in the uptake of new digital devices and DER assets, new product offerings and the electrification of the transport sector means there cannot be debate about whether change in market design is necessary. The costs of the transition are inevitable and will occur with or without reform to market design. Reform is necessary if we are to harness the opportunities that the transition offers and avoid the costlier outcomes that will come without reform.

In this context the ESB has completed a high-level illustrative evaluation of change in market design, noting that fundamental change is not without risk or cost. On the other hand, failure to adapt the market to the emerging realities will also have costs, potentially very severe costs in terms of reliability, security, and affordability. The objective of doing this evaluation was to understand the magnitude of benefits that could be expected from the breadth of the market design package. Understanding the magnitude of these benefits allows the direct costs of reform, to AEMO and market participants, to be considered in perspective. There will be implementation or adaptation costs regardless of whether the reform occurs or not – but what can change is the nature of those costs and how they are managed through the right market design and forward planning for implementation.

7.3. The approach to evaluation

To understand the benefits of a pathway, key reforms from each pathway were selected to distinguish between a:

- no reform scenario i.e., the state of the NEM as it is now, with the trends and challenges described in this paper continuing with no change; and
- reform scenario, in which we assume that the intent of the market design changes proposed in each pathway is achieved, because of the key reforms selected.

The benefits of the key reforms modelled then give a sense of the 'size of the prize' that implementation of each reform pathway has the potential to deliver.

The modelling that has been undertaken seeks to capture the benefits of complex reforms, versus the case where these reforms are not implemented. Many of these reforms are not well-suited to benefits assessments, and so there are many caveats on the modelling involved. Nevertheless, the high-level modelling has been completed because understanding the benefits are an order of magnitude greater than the costs of implementation, gives confidence for the case for change.

Importantly, the modelling completed was, in some cases, done in relation to reforms which are subject to further detailed design. Detailed design may impact the assessment of the costs and benefits of each reform. Next steps for each of the reforms recommended have detailed design processes in which more modelling and impact analysis can be completed where necessary and will inform key design choices to be made.

In understanding and considering the costs involved with each reform pathway, the focus has been on the likely cost of implementation of the reforms for AEMO's business systems and processes which have been discussed in Chapter 6. The ESB is cognisant of the scale of implementation costs for market participants that comes with new reforms. As noted in the previous chapter the development of an integrated roadmap for regulatory and IT systems implementation enables careful sizing of changes, as well as bundling and sequencing of reform implementations to avoid unnecessary or duplicative costs to industry. Minimising the transaction costs and regulatory burden for market participants of new reforms will be considered as part of the detailed design for each reform and the implementation roadmap.

7.4. Benefits of Resource Adequacy Mechanisms and Ageing Thermal Retirement pathway

7.4.1. With reform

This pathway is designed to deliver:

- new market-based arrangements to unbundle the value of capacity so clearer investment signals ensure the competitive provision of the right mix of variable, firm and flexible capacity as the market transitions
- market arrangements that continue to encourage the behaviours that can support efficient allocation of investment risk between participants, jurisdictions, and consumers for the investment needs of the NEM
- tools that provide jurisdictions sufficient confidence that reliability will be maintained in a way that preserves market signals.

7.4.2. Without reform

As noted in Chapter 2 the ESB remains concerned around the sustainability of the current arrangements, and whether they are fit-for-purpose over the medium and long term. There is doubt that in the current environment commercial incentives to keep existing plant in the market will be sufficient, and whether investors in replacement technologies will be confident enough in their expected revenue streams to invest over the medium and long term.

The investment risks driven by the current market dynamics and trends discussed in Chapter 2 suggests that the uncertainty and volatility of revenue yielded by dispatchable capacity, and revenue for periods of scarcity – i.e., times where the price in the spot market exceeds $300 per MWh – are sporadic and difficult to forecast and the increasing volatility of high price events suggest that investors will discount the contribution of these events to revenue streams in their business case analysis for new firm generation or investments in existing plant. The high level of supply reliability expected in an advanced economy means that the incentives for investment in capacity have to be sufficient to retain or build some resources which are only used for a few hours per annum on average and not called on at all in some years. The value of cap contracts, or contracts to cover the risks to customers of extreme prices, is a measure of the market's perception of those risks and the return available to low capacity factor[76] generation, storage or demand side response.

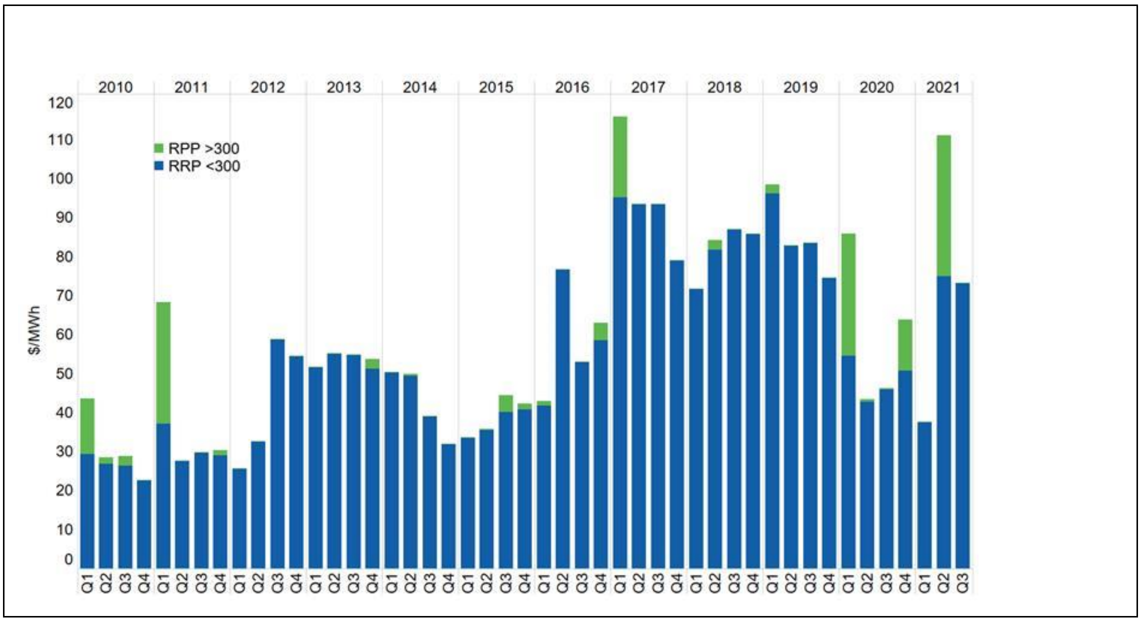
Figure 13 shows the contribution of prices exceeding $300 per MWh to the average spot price in NSW on a quarterly basis since Q3 2010. There are long periods where the 'value in the cap' is negligible, followed by events where there is considerable value available for dispatchable generation. Such volatile outcomes can be a source of profound uncertainty for investors in dispatchable capacity. At

---

[76] Capacity factors measure how often a plant is running on maximum power. Low capacity factor generation often produces less of the time relying on high price events to cover their fixed costs

the same time, the vast majority of these low-capacity factor assets' costs are fixed and incurred irrespective of their level of output. Investors may therefore face substantial risk as to the recovery of their capital and a reasonable return on it, may not occur.

Figure 13 Average spot prices in bands, NSW, FY2011 to FY2021

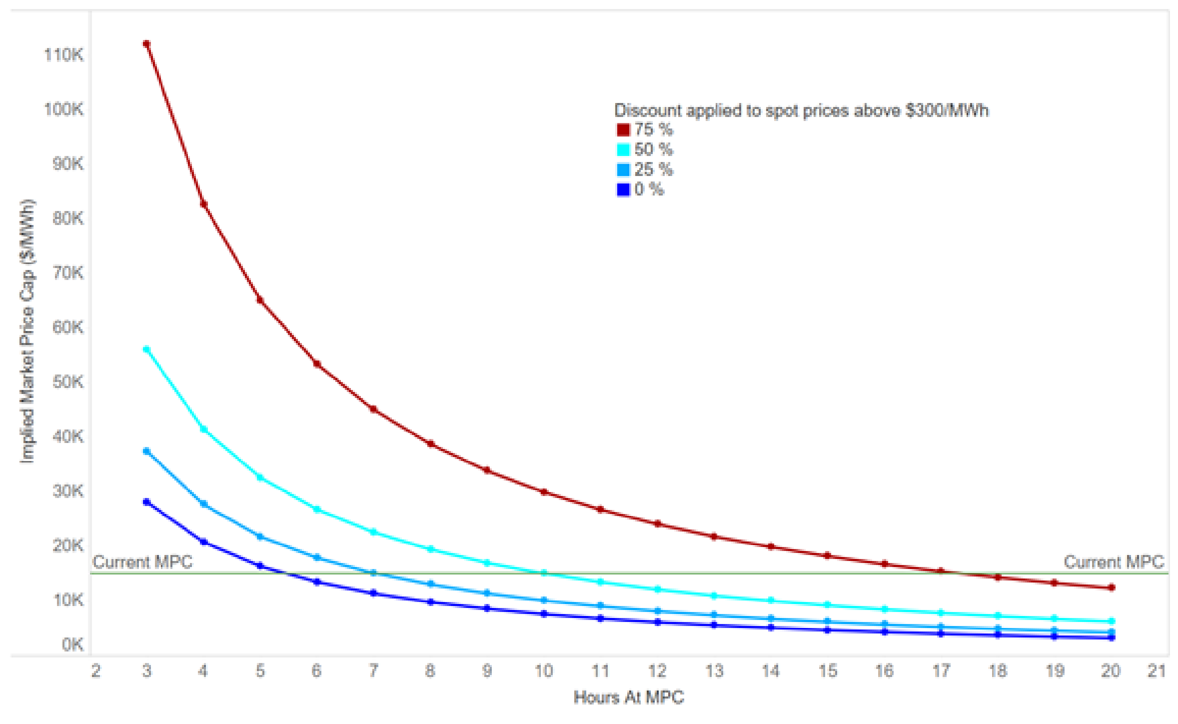


Without reform we must drastically lift the market price cap to achieve the targeted reliability outcome

While we do not have clear quantification of the extent to which potential investors in low capacity factor dispatchable capacity discount spot prices above $300 per MWh, it is logical that the volatility and unpredictability of those price peaks would drive some discounting or require a higher rate of return to justify spending. Quantitative analysis conducted by the ESB has assessed the level to which the market price cap must be lifted to achieve the same level of reliability, under the assumption that participants are discounting spot prices above $300 per MWh. Figure 14 shows the implied market price caps when different discounts are applied to spot prices above $300 per MWh; namely discounts of 25 per cent, 50 per cent, and 75 per cent. The dotted green line shows the current value of the Market Price Cap. As the discount factors increase, the implied market price cap grows markedly even assuming that the resource operates for a reasonable number of hours. For the purposes of this analysis an Open Cycle Gas Turbine (OCGT) has been used as the marginal capacity resource although we expect that battery storage, demand side or aggregated DER would be competitive options. Assuming that the marginal capacity resource receives market price cap for 5.5 hours, the implied market price caps are:

- around $20, 000 per MWh assuming a 25 per cent discount factor,
- around $30, 000k per MWh assuming a 50 per cent discount factor, and
- around $60, 000 per MWh assuming a 75 per cent discount factor.

Figure 14 Market price caps implied by assumed number of hours and assumed discount applied to spot prices above $300 per MWh



Such high market price caps may even exceed the value of customer reliability (values different customers place on having a reliable supply of energy), suggesting paradoxically that the only way to achieve the optimal level of reliability is to set the price cap above the value of customer reliability. Setting a level of the market price cap to achieve a specific reliability outcome – a process which can be challenging at the best of times – may become increasingly complicated given the uncertainty of the future of the system. As noted in Chapter 2, governments (and indeed consumers) have shown little enthusiasm for periods of such high prices (particularly with sustained periods of higher prices $100-300/MWh), and neither is there confidence in market participants' willingness to act.

A new capacity mechanism may alter the profile of cashflows for investment in dispatchable capacity by signalling the requirement for capacity through a more stable capacity price rather than through an uncertain, volatile energy price.

Without a new mechanism that explicitly values capacity there is doubt that current arrangements will deliver the right mix of capacity needed to support a transitioning fleet. Over the next two decades, the current ISP forecast is for 26-50 gigawatts (GW) of new large-scale variable renewable energy and 13-24 GW of distributed PV – in addition to existing and committed projects – forecast to come online. This means there is a need for 6-19 GW of new utility scale, flexible and firm resources, as up to 63% of the current coal and gas fleet in the NEM retires by 2040. On current performance, the transition is likely to occur at an even faster rate than this modelled step change scenario.

A new mechanism that aligns the decisions faced by the participants with the expectations of the jurisdictions should ensure investment in the right mix of variable and firm/flexible capacity that meets reliability expectations at lowest cost. Government and community confidence about resource adequacy should increase. Further, the need for interventions should decrease.

7.4.3. Assessment of the benefits of reform

The ESB engaged NERA Economic Consulting to model the effects of the introduction of a new capacity mechanism in the NEM.

Method

In order to model the benefits of a potential capacity mechanism, NERA modelled two opposing scenarios. These were as follows:

- a factual scenario characterised by a (perfectly-functioning) and appropriately designed capacity mechanism that can be assumed to address the shortcomings in the NEM's market design identified above. This scenario assumes the full or actual Value of Lost Load (VoLL) (described further below).
- a counterfactual scenario, which assumes a discounted VoLL to represent the inefficiencies in current arrangements - and assumed to be the case as described above. Given the assumptions made under this scenario we can expect a lower, less efficient build and so a greater amount of unserved energy.

The difference between these two scenarios can be considered to be the benefit of a potential capacity mechanism. Using the outputs of the modelling exercise, it is then possible to determine the net benefits to consumers from the adoption of an appropriately designed capacity mechanism.

The construction of the factual and counterfactual scenarios assumes two things:

- Inefficiencies exist in the current energy only market that influence participants to discount revenue from high price events because of their increasing volatility in terms of size, duration, and frequency.
- The introduction of an appropriately designed capacity mechanism would address these inefficiencies.

The modelling does not seek to validate these assumptions. The reasoning for the case for a capacity mechanism (see Section 7.4.2 and Chapter 2 more generally) outlines the ESB's consideration of these assumptions and why there is a need for a capacity mechanism for a future NEM. Based on the assumption that these inefficiencies in the current arrangements exist, the NERA modelling provides guidance as to the potential benefits of introducing a capacity mechanism.

Assumptions used in the modelling

Value of Lost Load (VoLL) was used as a proxy for the impact that introducing a capacity mechanism would have on the market price. This is because VoLL is an indication of how much consumers would be willing to pay to increase security of supply through some form of increased capacity. That is, the higher the VoLL, the higher the implied willingness to pay for the increase in capacity.

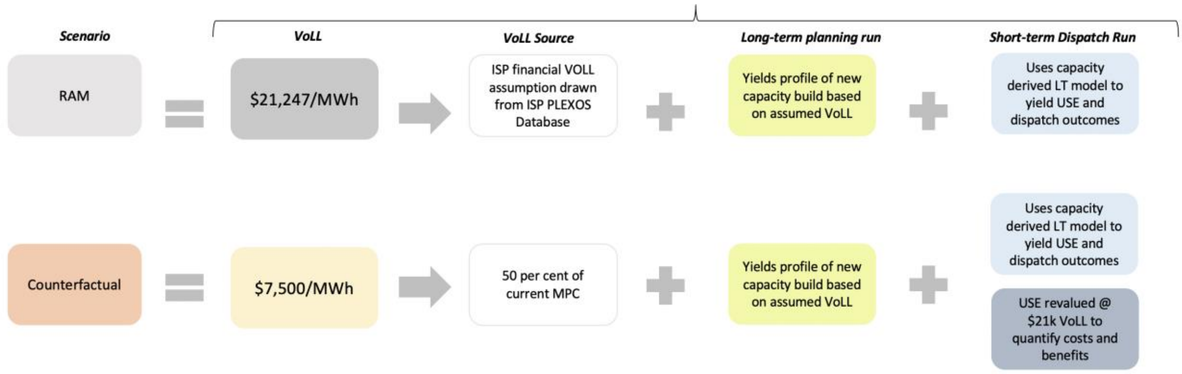
A VoLL of $21,247 per MWh was used to imply a world with a capacity mechanism. The value of $21,247 per MWh was chosen because it is the value used in the 2020 ISP assumptions and so it is consistent with outcomes from AEMO's modelling. We note that this differs from other estimates of Value of Customer Reliability (VCR). What is important for the modelling exercise is that this VoLL is substantially higher than the current market price cap, set at a level which is expected to deliver close to the reliability standard. The VoLL of $21,247 per MWh contemplates a world where the market price cap must be raised in order to achieve the reliability standard.

In contrast, the counterfactual VoLL used was $7,500 per MWh. This is approximately 50 per cent of the market price. The choice of this VoLL was selected to understand the impacts of 'discounting' on build profiles and in turn on reliability. Of course, different levels of discounting will reflect different levels of impact from a capacity mechanism.

The driver for a capacity mechanism is uncertainty, and the effect of uncertainty on potential investors behaviour. The modelling also tested the benefits of a capacity mechanism in the face of uncertain exit times by ageing coal plant.

Figure 15 shows the outcome of the modelling with a non-discounted spot market (a proxy for the introduction of a capacity mechanism) and a discounted VoLL.

Figure 15 Varying VoLL inputs as a proxy for introducing a RAM



Benefits generated by a proposed capacity mechanism

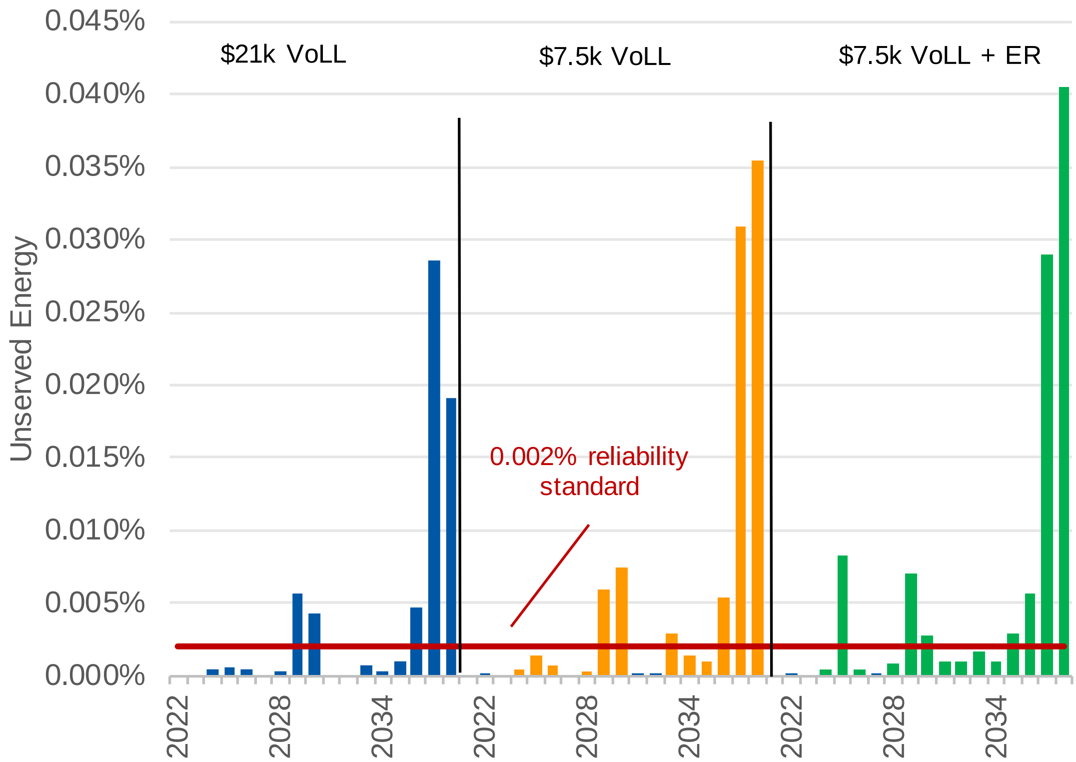
A capacity mechanism could lead to an increase in capacity and in turn reliability but does so in an efficient manner by minimising overall system costs (including the cost of lost load).

A capacity mechanism better meets reliability expectation at lowest cost.

The proposed capacity mechanism leads to an increase in reliability. This is shown in Figure 16, which measures unserved energy (USE) as a percentage of total load. The different coloured bars are indicative of the VoLL and retirement assumptions. Blue corresponds to a world with a capacity mechanism, orange to a world without a capacity mechanism and green to a world without a capacity mechanism and early retirement of key generators. The 0.002 per cent reliability standard, which measures the effectiveness of installed capacity to meet demand is also shown in red. The bars above and below the reliability standard are indicative of lower and higher levels of reliability respectively. The chart shows that a proposed capacity mechanism would lead to better reliability expectations in the market.

NERA notes in its report that in all cases, even with a capacity mechanism in place, they model excessively high levels of USE in the final years of the period modelled. This is primarily a function of how PLEXOS sequentially optimises the system, which uses more simplified assumptions when planning capacity expansion (in the long-term module) than when choosing how to dispatch plant (in the short-term module). NERA notes that the long-term module gives excessive credit to batteries for meeting demand, which is not effective when a reliability event lasts longer than the storage duration of a battery. NERA highlights that this is an area that requires further investigation, and which should be considered more in any analysis underpinning the detailed design phase of the capacity mechanism

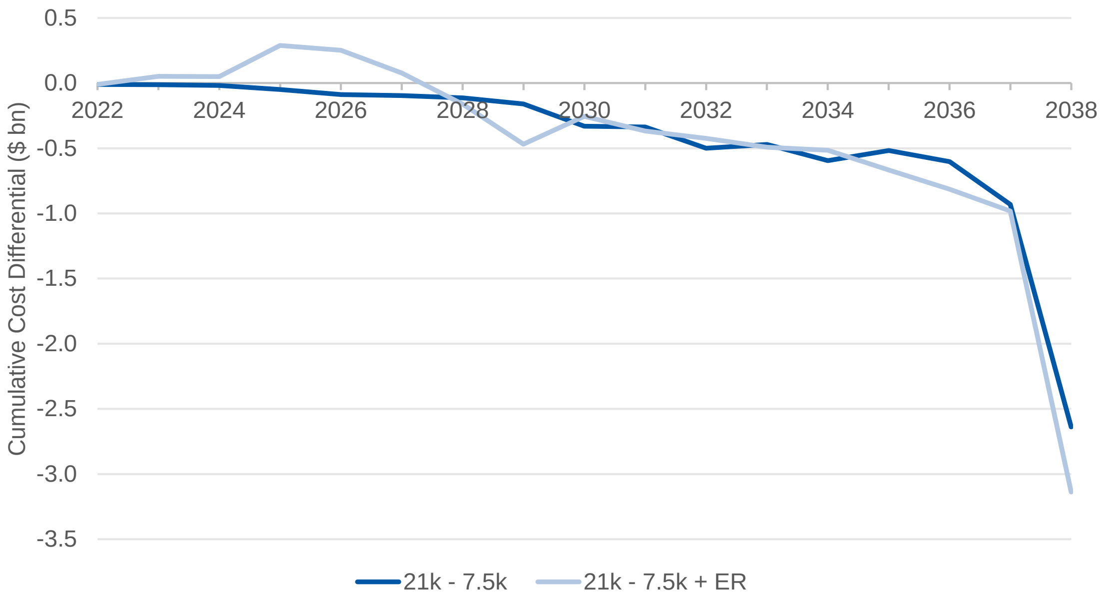
Figure 16 Unserved energy as a percentage of total load across the different levels of VoLL and timing of retirement



A RAM delivers lower overall system costs

The proposed capacity mechanism satisfies the condition of lower overall system costs. This is reflected in Figure 17. The dark blue line shows the cumulative difference in total systems costs in a world with and without a RAM. The light blue line also shows this but assumes early retirement of key generators. Costs in a world without a capacity mechanism are greater than costs in a world with a capacity mechanism, i.e., the lines fall below zero over time. The differential is amplified when early retirement of key generators is assumed.

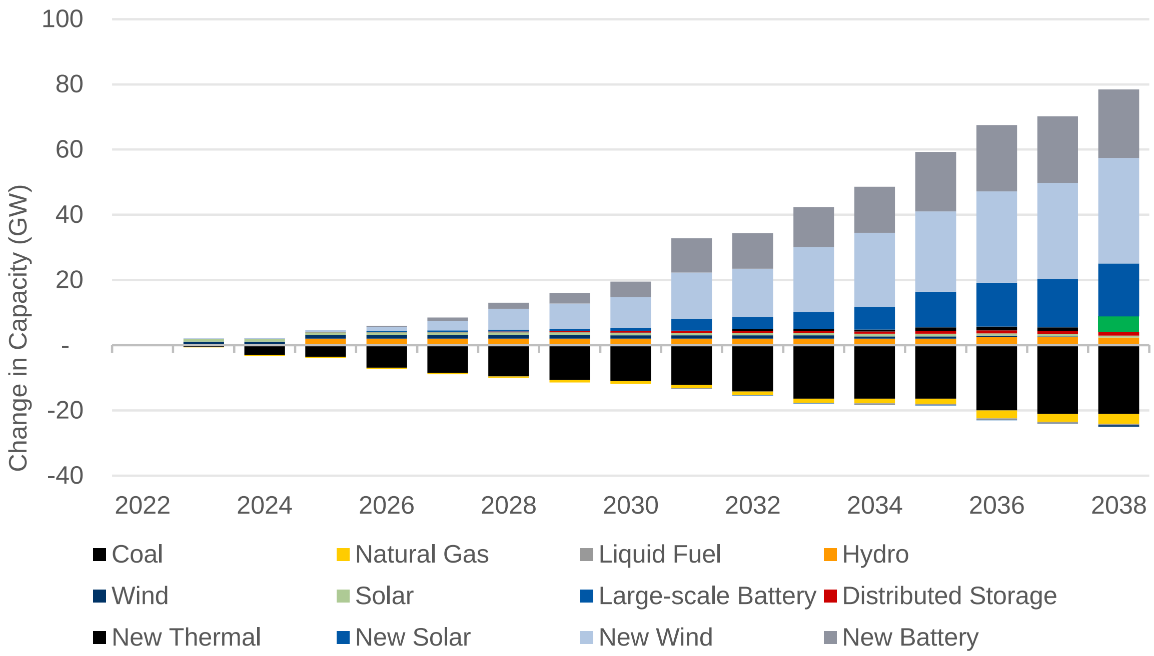
Figure 17 Cumulative difference in system costs in a world with and without a RAM



The cumulative change in new build capacity

Figure 18 below shows the cumulative change in new-build capacity over time resulting from the introduction of a capacity mechanism, as modelled by NERA. There is a substantial increase in the penetration of wind and large-scale solar, as well as the construction of batteries and pumped hydro. At the same time there is a steady inexorable exit of coal-fired generation, as well as exit of gas-fired plant (mainly thermal gas). The figure shows that over the modelling horizon over 50 GW of new installed capacity enters the system, replacing retirements of around 20 GW – the difference between the two figures is accounted for by the differing capacity factors that the new generation has relative to the retiring generation.

Figure 18 Cumulative change in new-build capacity



An overview of the modelling completed by NERA is include in Part C.

7.4.4. Costs of the reform pathway

As noted above, AEMO has not estimated the likely costs of implementing a capacity mechanism. The likely implementation costs of a future capacity mechanism will depend on a number of key design choices, the costs of which will also be assessed as part of the recommended detailed design process.

In the interim, the ESB has looked to the costs of other similar, certificate schemes as a guide, to understand the indicative costs that could be expected for evaluation purposes.

- the NSW Greenhouse Gas Reduction Scheme (GGAS) commenced on 1 January 2003 and closed on 1 July 2012. In July 2013 IPART found the “cost of administering GGAS over its 10-year lifetime to be around $18 million. This estimate includes salaries, wages, and associated oncosts of staff, as well as general administrative costs from use of contractors, consultants, office accommodation and consumables. It represents a cost of $0.125 per certificate created under GGAS. These costs were recovered through fees charged for the registration of each certificate, as well as the accreditation application fees.[77]

- The Energy Savings Scheme (ESS) was established in 2009 under the NSW Electricity Supply Act 1995. The ESS reduces energy consumption in NSW by creating financial incentives for organisations to invest in energy savings projects. A July 2013 report to IPART on the ESS scheme found that the IPART administration fee cost $0.70 per certificate.[78] In 2021 the cost of registering a certificate under the scheme is $0.89 per certificate.[79] In 2019 4.9m certificates were created providing an estimate of $4.3m per annum for the cost of running the ESS scheme.
- The Large-scale Renewable Energy Target (LRET) incentivises the development of renewable energy power stations in Australia through a market for the creation and sale of certificates called large-scale generation certificates (LGCs). The Clean Energy Regulator currently charges $0.08 per certificate for the creation and $0.08 per certificate surrender of LGCs.[80] It is estimated that in 2020 the fees recovered for the creation and surrender LGCs were just over $5m.[81]

Using the above as indicative estimates, the ongoing annual cost of administering a certificate capacity mechanism, such as that set out in this paper, are expected to be in a similar range but will depend on the final design of a certificate capacity mechanism.

These are initial high-level estimates and subject to detailed cost estimates. The costs associated with participants managing their liabilities under the scheme will require further consultation with stakeholders. However, there are expected to be some synergies with existing risk management processes already in place for liable entities. This will be developed further through the detailed design phase.

7.4.5. Overall assessment of the merits of implementing the reforms

Further modelling to be completed as part of the detailed design of a capacity mechanism will be important. However, the analysis undertaken by NERA shows that there are potential benefits of a new capacity mechanism of up to $1.2 billion. This modelling suggests that, with reform (an appropriately designed capacity mechanism) it will be cheaper to deliver capacity under new market arrangements that reduce the uncertainty for investment in capacity. Without reform to the way that plants enter and exit the system to smooth the transition, there will be costs to consumers. The timely entry of generation to replace gaps in available capacity is crucial to maintaining reliability, and so delivering the best outcomes for consumers.

7.4.6. International experience

Over recent years, capacity mechanism of different forms have been introduced in a number of international electricity markets. The ESB reviewed international experience during its work and noted the resource adequacy mechanism applying in California and the capacity market in France as

---

77 https://www.ipart.nsw.gov.au/files/sharedassets/website/trimholdingbay/nsw_greenhouse_gas_reduction_scheme_-_strengths_weaknesses_and_lessons_learned_-_final_report_-_july_2013

78 https://www.ess.nsw.gov.au/files/sharedassets/public/hprm/ess-scheme-administrator-ess-website-publications/reports/ess-cost-of-participation-report-databuild-july-2013.pdf

79 https://www.ess.nsw.gov.au/Accredited-Certificate-Providers/Operating-as-an-ACP/Costs-of-being-an-ACP

80 http://www.cleanenergyregulator.gov.au/OSR/REC/Fees

81 http://www.cleanenergyregulator.gov.au/About/Pages/Accountability%20and%20reporting/Administrative%20Reports/Annual-Statement.aspx.

examples of decentralised capacity markets. Other capacity markets were developed in Ireland and the United Kingdom (Part C, section 1.2). These are all designed to operate with high and growing levels of variable renewable energy and their experience is relevant to the NEM.

The Department of Business, Energy and Industrial Strategy in the UK undertook the first, statutory 5-year review of the Capacity Market in 2019. To aid the review, the Department sought input and evidence from stakeholders in addition to its own work. In regard to cost effectiveness, the review concluded that:

There was overwhelming support amongst respondents…. for continuation of the CM. This supports the Government's view that there is a strong need to maintain the CM, given that many of the underlying issues that led to its introduction continue. In particular, the significant coal and nuclear plant closures expected in the 2020s, the persistence of the 'missing money' problem and the rapid evolution of the GB electricity system.

and

Respondents …agreed that the CM has been cost-effective and liquidity and competition high. In addition, the deployment of a range of technologies through the CM, including flexible technologies, has helped to minimise whole system costs.

7.5. Benefits of Essential System Services, Scheduling and Ahead Mechanisms pathway

7.5.1. With reform

This pathway is designed to deliver:

- New market-based arrangements to unbundle the value of the services needed to support the changing mix of resources in the NEM. These capabilities are currently 'bundled' in the provision of energy by the exiting thermal generation fleet. Four essential system services were identified for initial focus: frequency, inertia, system strength, and operating reserves.
- New market mechanisms to support efficient procurement, scheduling, and dispatch by AEMO. Learnings from the operation of these new markets and mechanisms will be important to understand how new technologies and resources with capabilities can continue to deliver these essential services and whether defining and unbundling additional system services would be warranted.
- A range of supply and demand-based technologies and resources with capabilities to deliver these essential services.

The reforms to deliver the pathway are discussed in detail in Chapter 3. In order to understand the benefits of the reform pathway the counterfactual of no reform needs to be considered.

7.5.2. Without reform

In contrast to the reform pathway, the no reform case sees continued reliance on overriding the market through inefficient interventions. Intervention becomes the norm rather than the exception, with AEMO persistently forced to direct participants to stay online, particularly in the middle of the day.

Initially these interventions come in the form of directions to thermal plant to stay online, but it rapidly emerges that there is a need to curtail VRE output, often inefficiently. Without markets and regulatory frameworks for the provision of essential system services, new technologies that can support the transition find it challenging to make their business cases and entry into the market is less than is optimal.

Without the explicit provision of the essential services, the early exit of large thermal generators becomes a substantial threat to the system while there are no signals to drive new investment. AEMO's role in balancing the system becomes increasingly challenging because of a lack of tools to operate the power system, and because it is unable to plan and 'learn by doing'.

The exit of plants becomes a chaotic process that presents periods of profound uncertainty in the market that undermine new investment in renewables and storage. So great is the level of uncertainty that investors find it hard to make business cases for both new and existing generation and other resources with the right capabilities, hampering new investment in the sector.

7.5.3. Assessment of benefits

The ESB engaged Cornwall Consulting to model the effects of the introduction of three of the key reform on this pathway: Unit Commitment for Security (UCS), System Services Mechanism (SSM) and the recent system strength framework for procurement of system strength by TNSPs over the long-term announced in a draft rule made in April 2021. The other reforms on this pathway were not included in the modelling described below.

Method

Cornwall has modelled two reforms. These are as follows:

- A TNSP-led procurement mechanism whereby an efficient level of system strength is met through a combination of network and non-network options. This targets the provision of system strength at an investment timeframe / level.
- A dispatch mechanism that efficiently schedules all available assets. The ESB is exploring two potential mechanisms through AEMC rule change processes. These are the UCS and the SSM. This targets the scheduling of system strength (and potentially inertia) at an operational timeframe / level.

In order to estimate the benefits of the proposed system strength reforms, Cornwall has modelled two cases:

- A 'Reform' case, which assumes the take up of both TNSP-led procurement and the dispatch and operational timeframe procurement mechanism.
- A 'No Reform' case, which assumes the take up of none of these reforms, representing the status quo arrangements for system strength.

Assumptions used in the modelling

Cornwall were asked to model the TNSP-led procurement and the UCS/SSM mechanism together. This is because the reforms are likely to be highly complementary and adopting one mechanism without the other might lead to a reduction in overall efficiency of the provision of system strength.

The modelling does not seek to assess the UCS and SSM separately on the grounds that the model does not differentiate between the type of resources (i.e., resources that are allowed to participate under each mechanism) that are procured and are activated to provide system strength.

Cornwall has modelled AEMO's 2020 ISP 'Step Change' scenario. This assumes a future where the transition to renewables occurs more quickly than other ISP scenarios and is closest to current experience. It is this world in which the timely provision of system strength services will be most relevant, and so presents the best indication of the 'size of the prize'.

Key assumptions made by Cornwall in their modelling include the following:

- Assumed committed projects not included in the ISP as follows:

    - NSW government's electricity infrastructure roadmap to deliver close to 12 GW renewable and 2 GW storage capacity by 2030.
    - The newly announced Tallawarra B (316 MW) and Kurri Kurri OCGT plant (660 MW), both assumed to start operation in NSW from FY23/24.
    - Kidston pumped hydro to start in Feb 2025 and Snowy 2.0 in Dec 2026 based on AEMO's May 2021 Generation Information data.
- System strength requirements in each region are represented by:
    - A minimum requirement, which is modelled as a minimum fault level plus associated IBR hosting capacity.
    - Incremental capacity above the minimum requirement is modelled as requiring 3 MVA of fault level for each additional MW of IBR online.

These assumptions were developed in consultation with AEMO, the AER and the AEMC.

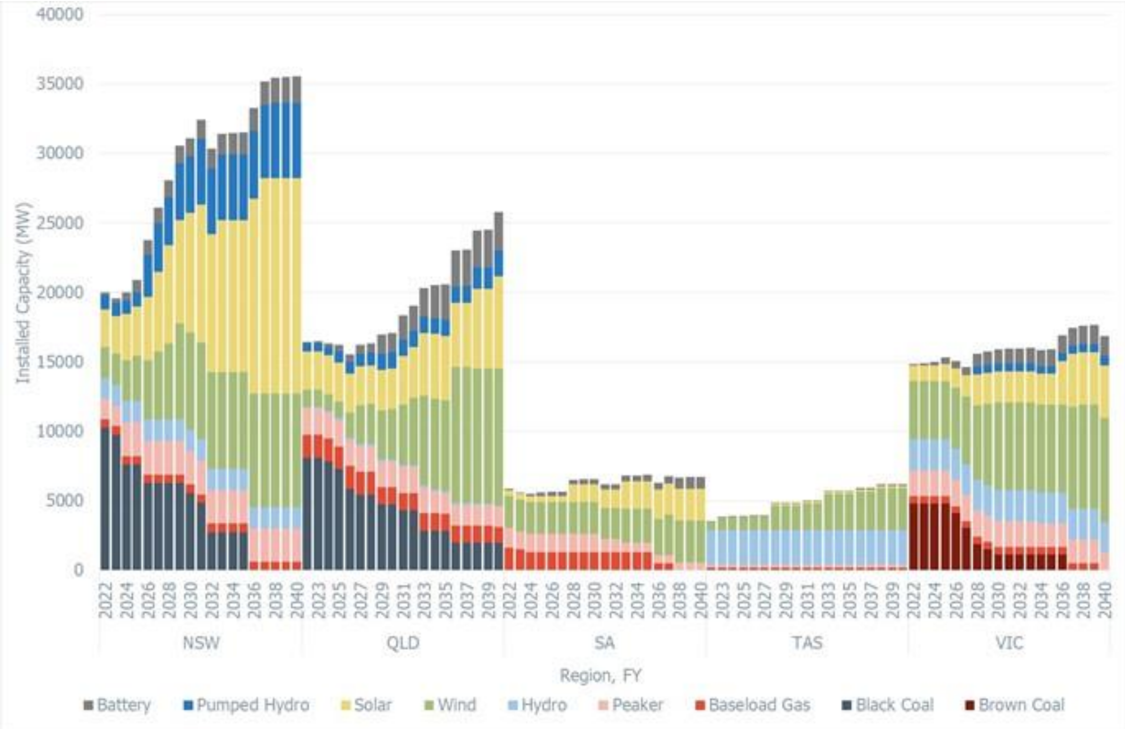
It is worth emphasising that the assumptions used in modelling reflect a conservative view of the amount of system strength services required by inverter-based generation to connect and operate stably. These assumptions result in an upper bound of system strength services required in a region for the associated amount of generation connecting. It is highly unlikely that these would be realised in practice. Innovation and technological development over time, and the fact that different solutions can be utilised will mean that the requirements for system strength will be lower. This will necessarily mean that the results here represent an upper bound on benefits that could occur. A sensitivity was also modelled assuming 0.5 MVA of fault level for each additional MW of IBR online.

Benefits generated by the proposed pathway

Figure 19 below shows the long-term capacity mix by technology and region that was modelled by Cornwall. Importantly, these results differ somewhat from the modelling in other workstreams – it has not been feasible in the time available to complete a single, unified study, and so we have had to accept some degree of differing results across the evaluation of each work stream. A key example of the need to proxy results in this modelling is the highly conservative assumptions that have been used as set out above.

Each colour corresponds to a different technology type and each panel to a different region. The height of the bars is indicative of the level of installed capacity in megawatts for a given year. The chart shows that Cornwall models reflect an increase in VRE and pumped hydro investment, which more than offsets the decrease in black and brown coal investment. The net effect is an increase in overall capacity for all states – a result that is consistent with the findings from the work completed for the above pathway.

Figure 19 Long term capacity mix by technology under upper bound scenario



The reform delivers increased levels of systems strength provision, as can be seen in Figure 20, which measures the change in synchronous condensers, IBR, and synchronous capacity. The different coloured bars reflect each of these key variables:

- orange corresponds to changes in synchronous capacity,
- green reflects changes in invertor based resources (IBR), such as wind and solar generation as well as batteries,
- the synchronous condenser investment path is represented by the black line.

Figure 20 shows how synchronous condenser investment is a function of both synchronous capacity retirement and IBR entry. Overall, in large NEM regions such as NSW, QLD and VIC synchronous condenser investment increase markedly around 2030 to meet system strength requirements following the retirement of large-coal units. As noted above, this represents a highly conservative assessment of synchronous condenser investment, based on an assumption of 3 MVA of fault level for each additional MW of IBR online.

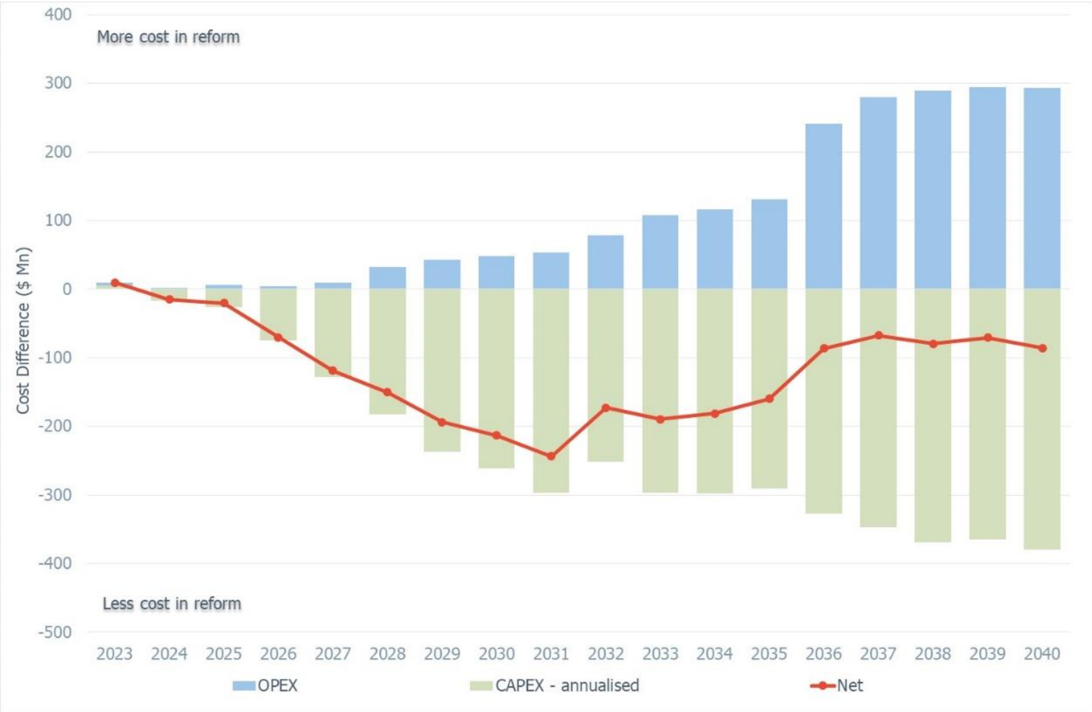
Figure 20 Synchronous condenser investment, IBR, and synchronous generation capacity by region and year in upper bound scenario

The reform path leads to significant capital cost savings – see Figure 21– as a result of more efficient system-strength procurement mechanisms, because it takes advantage of economies of scale and reduced duplication of system strength assets. The different coloured bars reflect the different type of expenditures, namely:

- blue indicates OPEX;
- green indicates annualised CAPEX payments; and
- the red line signals the net expenditure.

In Figure 21, the bars that are above and below the horizontal axis are associated with higher and low levels of expenditure. The chart shows that the proposed reform would lead to net savings as the decrease in CAPEX outweighs the increase in OPEX. The increase in OPEX is driven by the efficient use of existing synchronous generation resources, i.e., the 'switching on' of existing synchronous generators to provide the optimal level of system strength. Overall capital cost savings would be up to approximately $2.1billion in NPV terms – this represents the upper end of the range that Cornwall has modelled.

Figure 21 Overall cost difference by year and expenditure type for upper bound scenario



More detail is provided in an overview of Cornwall's modelling, which is included in Part C.

7.5.4. Costs of the reform pathway

AEMO has estimated the costs of implementing the immediate and initial reforms on the pathway, including the key reforms that have been modelled. Costs of implementing the reforms on the pathway have been estimated at $100-125 million.[82] Note that:

- the costs of implementation of the UCS/SSM are in the order of $8-$14 million; and
- other costs such as the cost associated with TNSP procurement and likely market participants costs of implementing the reform have not been included in this estimate.
- this cost estimate includes the strategic technology uplift of applications in the forecasting, operational, and dispatch systems necessary for the delivery of the reforms on this pathway. These investments benefit the implementation of reforms on Integrating DER and flexible demand pathway and the Congestion Management Model (CMM)(REZ) in the Transmission and access reform pathway.

If these reforms were not to be implemented, there would likely be additional costs borne by AEMO in addressing the system strength shortfalls without the reforms. Initially, this might take the form of directions, which distort market signals and are costly as discussed elsewhere in this paper. Over time without relevant tools like the UCS and SSM, the more 'ad hoc' approach of addressing system strength may require increased power system studies and lead to delays in connections. Moreover, it could present the risk of shortfalls in the provision of system security services that require AEMO to undertake more and more directions to keep the power system secure.

82 See Part C for a breakdown of these indicative cost estimates.

7.5.5. Overall assessment of the merits of implementing the reforms

The reform pathway provides mechanisms to address the emerging challenge of operating the power system in an environment of high VRE penetration. Implementing these reforms could yield substantial benefits. In the case of the reforms whose benefits we have quantified (i.e., the UCS/SSM and TNSP procurement reforms), we estimate benefits of up to $1.2 billion (NPV). These benefits arise both from improved operation of the power system and more efficient investment in capital equipment. The magnitude of benefits exceed the potential implementation costs. Moreover, these reforms deliver a robust power system that can endure the transition to a low emissions system and harness the benefits that renewable energy has to offer.

7.6. Benefits of Integrating DER and flexible demand pathway

7.6.1. With reform

This pathway is designed to deliver:

- Frameworks that enable consumers to be rewarded for their flexible demand and generation, facilitate options for how they want to engage (including being able to switch between DER service providers), and remain protected by a fit-for-purpose consumer protections framework.
- Wholesale market arrangements that support innovation, the integration of new business models and a more efficient supply and demand balance.
- Networks the ability able to accommodate the continued update of DER, two-way energy flows, and manage the security of the network in a cost-effective way.
- AEMO the visibility and tools it needs to continue to operate a safe, secure, and reliable system, including maintaining system security associated with low minimum system load conditions.

The reforms to deliver the pathway are discussed in detail in Chapter 4. In order to understand the benefits of the reform pathway the counterfactual of no reform needs to be considered.

7.6.2. Without reform

Without reform, we never unlock the full value of the demand side and distributed resources. DER and demand-side resources inhabit the periphery of the market, never quite becoming integrated. Instead, business models emerge where small-scale technologies must make their business case based on reducing bills for customers on conventional retail tariffs. Innovation is stifled.

The largely passive operation of DER is creating system security challenges that make the power system harder to manage. Regulations are introduced to manage minimum demand that pay no attention to the potential power of the demand-side and DER to provide solutions to this problem and provide an additional source of flexibility that can support the power system and reduce overall operating costs for all customers. Batteries and other technologies are perpetually being subjected to piecemeal regulatory reforms that seek to address problems that have emerged because these technologies have never been properly integrated into the system.

In the long term, consumers have limited choice as to how they consume and use electricity. Costs are higher than they need to be because the value in the demand-side and DER are never truly unlocked.

7.6.3. Assessment of benefits

Method

In order to model the benefits of system flexibility, NERA has modelled two separate scenarios:

- A 'No Reform' or the 'Low Flex' scenario, whereby load flexibility has been disabled. This scenario is characterised by relatively low levels of uptake and utilisation of demand response technologies (i.e., batteries, EV) due to high barriers to adoption and integration of these technologies.
- A 'Reform' or the 'High Flex' scenario, whereby load flexibility has been enabled. Here, reform would work to substantially lower the barriers to uptake and utilisation of demand response technologies. Consequently, there would be relatively higher levels of uptake and utilisation of these technologies.

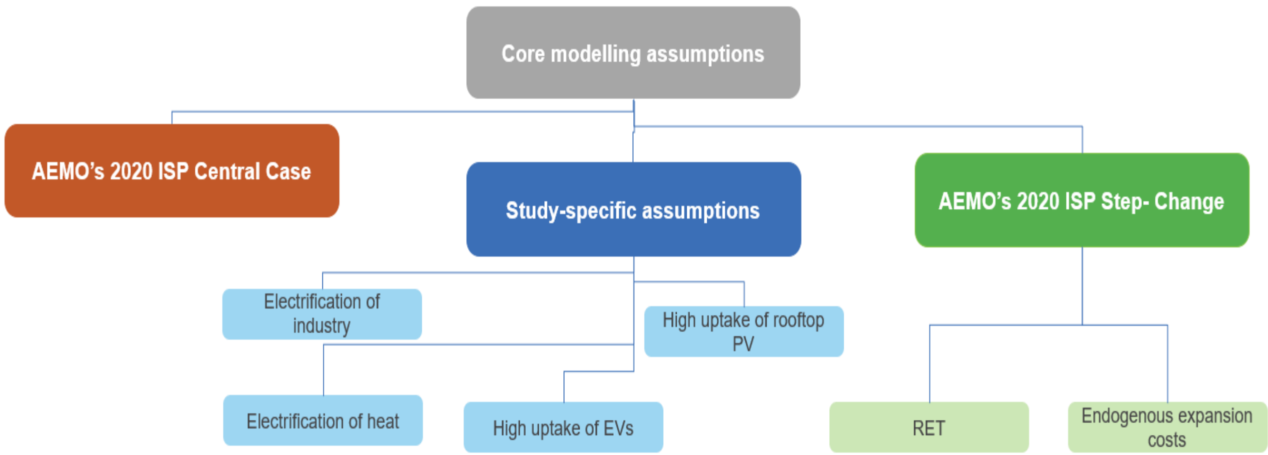
Assumptions used in the modelling

NERA's modelling for the ESB has assumed the fourth 'State of the World' adopted in the ARENA modelling. This is an environment with high uptake of renewable and DER technologies – see Figure 22 below.

The baseline model is closely based on AEMO's 2020 ISP 'Central Case'. The central case was used for many assumptions because this was the basis for another study that NERA undertook for ARENA, which we have leveraged off. Although ideally, we would have liked to have used the Step Change scenario for all assumptions, in the time available it was not feasible for NERA to update its model.

NERA then incorporate dynamics from AEMO's 2020 ESOO model to capture savings from the changes in dispatch patterns that demand flexibility can bring. The different sources of demand and load flexibility that define the state of the world are derived from findings of a separate analysis by Energy Synapse. Analysis for the ESB indicates that the outcomes, in terms of large-scale build of renewables, in the NERA high flex scenario are not dissimilar from those of the step-change scenario of the ISP.

Figure 22 Outline of assumptions used in the NERA modelling for the DER workstream

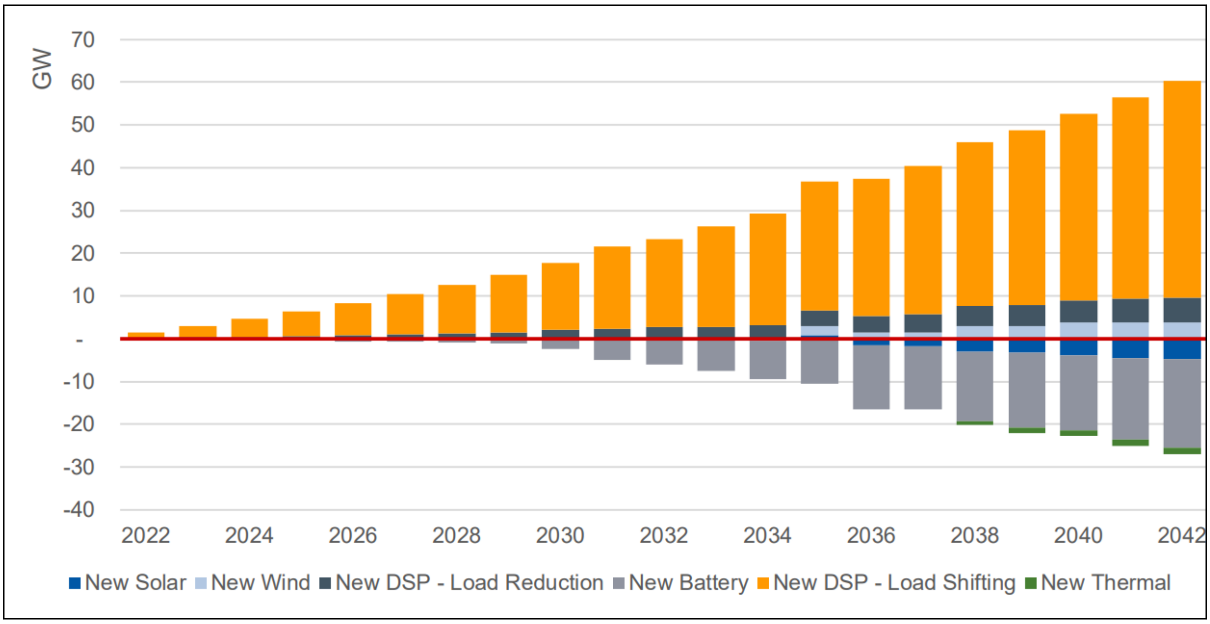


Benefits generated by the proposed pathway

NERA has estimated the benefits of the reform scenario at $6.3 billion. The important observation is that the reform case, where large amounts of DER enter the system, diminishes the need to build new capacity, most notably battery capacity.

This is highlighted in Figure 23 below, which shows the change in installed capacity by technology. An increase or decrease in installed capacity is indicated by whether the bar is above or below the horizontal axis. Each colour corresponds to a different technology. The chart shows that available demand response technology substitutes for the construction of new solar, thermal plant and battery capacity.

Figure 23 Net new capacity differential by fiscal year – High Flex minus Low Flex



High flexibility also changes the generation mix on peak demand days. Figure 24 shows this, measuring the different levels of half-hourly generation during the 2031/32 NSW Summer peak under the reform and no reform cases. In order to manage peak demand, the reform case sees the use of EVs and behind-the-meter storage while the no-reform case uses large-scale storage and peaking gas.

Figure 24 Half hourly generation pattern in peak demand day: Fiscal Year 2031/32

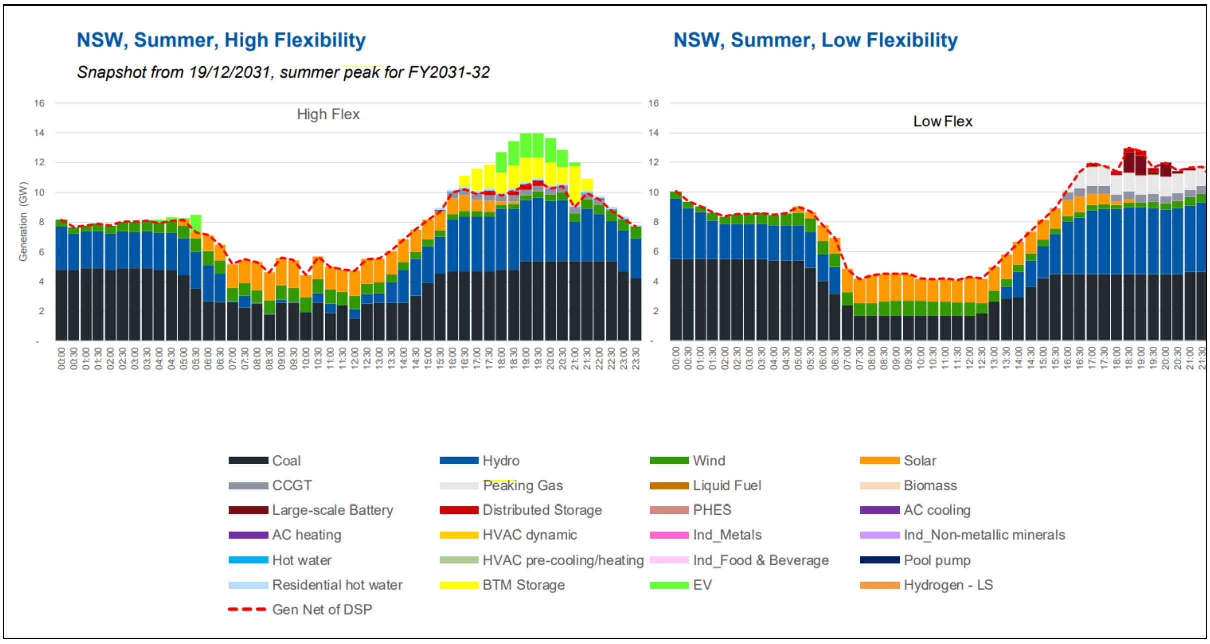
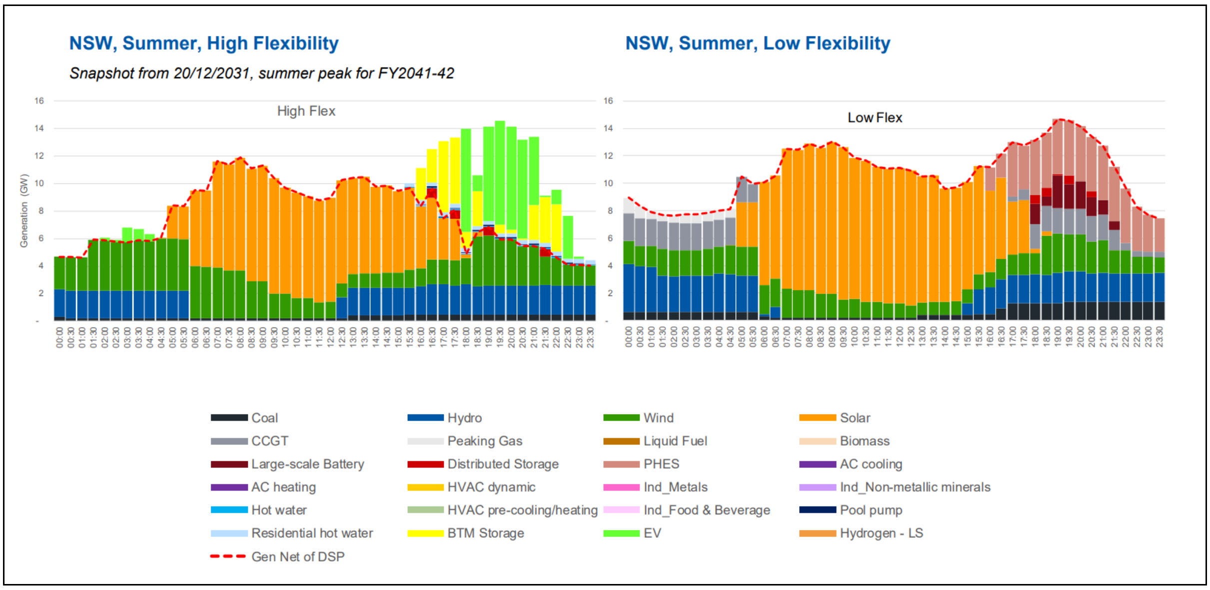


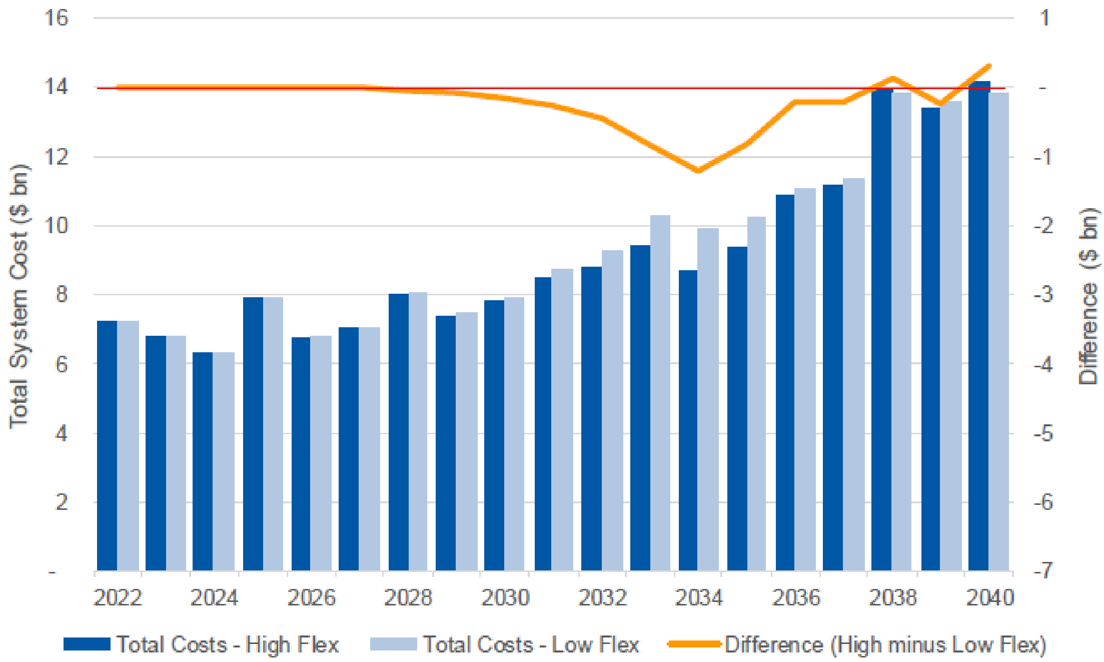
Figure 25 highlights that a similar trend occurs in the 2041/42 NSW Summer peak.

Figure 25 Half hourly generation pattern in peak demand day: Fiscal Year 2041/42



The proposed reform results in a massive differential in costs, highlighted in Figure 26. The dark blue and light blue bars indicate total costs under the reform and no reform scenarios, respectively. The orange line shows the difference in total costs between the two scenarios. The chart shows that from approximately 2026 onwards, total costs under the no reform scenario exceed that under the reform scenario – this differential expands over time.

Figure 26 Summary of cost differentials between reform and no reform pathways



More detail is provided in an overview of NERA's modelling which is included in Part C.

The identified benefits of the reforms also depend on some consumers choosing to become more active in the energy market and accepting energy products and services that adjust how they use energy. Specifically, the modelling has assumed that 75% of the derived benefits from load shifting behaviour occur from consumers that have made active choices. The ESB does not expect that consumers will personally make active choices but rather that retailers and aggregators will develop new products and services that realise value for customers through active participation and that a portion of customers take up those products. Having a consumer-centric approach to the design of the market reforms and review of existing consumer protections is therefore fundamental to harnessing these benefits.

7.6.4. Costs of the reform pathway

AEMO has estimated its costs of implementing a number of the immediate and initial reforms on the pathway. The proposed market system changes necessary for the reforms would have the ability to scale to support the forecast growth in active DER and new market participants. Costs of implementing the relevant reforms have been estimated at $140-185 million.[83] Market participants costs of implementing the reform have not been included as part of this indicative analysis.

7.6.5. Overall assessment of the merits of implementing the reforms

The analysis undertaken by NERA shows that the potential benefits of harnessing flexible demand and the successful integration of DER are around $6.3 billion over the next 20 years. In contrast, in the absence of reform, these new technologies will be misaligned with, and potentially operating against the needs of the system. The benefits of reform substantially outweigh the implementation costs, and indeed these costs may be lower than the costs of no reform. Moreover, these reforms deliver a more diverse, flexible power system that is well-placed to capture all the potential benefits that may emerge from the advent of new technologies.

7.7. Benefit of Transmission and Access Reform pathway

7.7.1. With reform

This pathway is designed to deliver:

- Better signals for generators to locate in areas where there is available generation capacity - namely in the REZs that are being delivered through the ISP and state government policies,
- Reduced uncertainty for investors, through measures that give rise to more predictable future patterns of congestion, and a more orderly and predictable connections process,
- Better use of the network, resulting in more efficient dispatch outcomes and lower costs for consumers, and
- Batteries locating where they are needed most and being paid to operate in ways that benefit the broader system.

7.7.2. Without reform

Without reform, actual levels of congestion are likely to be greater than the efficient levels forecast by FTI Consulting (set out in Part C). This is because the current market design systematically incentivises generation investment at locations that are inconsistent with the least cost development path identified by the ISP. Currently, generators are paid the regional reference price, which does not reflect the marginal cost of energy at their specific location. When FTI ran a sensitivity to explore the

[83] In addition to this cost estimate, the DER implementation leverages strategic investments of between $70-$100million for applications in the forecasting, operational, and dispatch systems necessary for the delivery of the reform on this pathway as well as the implementation of reform in essential system services and CMM. These strategic investments, for the purposes of the benefits assessment, have been included in the estimates for Essential System Services, Scheduling and Ahead Mechanisms pathway. This is discussed further in Part C.

impact of additional solar capacity over and above the amount modelled in the ISP, the potential incremental solar output arising as a result of the additional generation was reduced by over 20 per cent due to constraints. These modelling results are discussed in more detail in section 5.2.

If generation investment is poorly located from a whole of system perspective, one likely consequence is elevated congestion, which means electricity cannot be dispatched to meet demand at the lowest possible cost. In turn, this will drive the requirement for more transmission investment to alleviate the congestion, which would not have been needed if the investment and operation of generation and storage had been efficient. The cost of this additional transmission investment is borne by consumers**.** As congestion undermines the profitability of existing generators, there is also a risk of disorderly exit and the consequent risks to reliability, security, and price volatility.

Without reform, there is also a risk of underutilisation of interconnectors which is set out in detail in Part C.

7.7.3. Assessment of benefits

As part of the AEMC's earlier work on access reform, the AEMC completed comprehensive analysis of the benefits to the NEM that would arise following the implementation of Locational Marginal Pricing (LMP) and financial transmission rights. A CMM(REZ) allows the NEM to realise a subset of the benefits previously modelled by the AEMC. These include improving dispatch efficiency by reducing incentives for disorderly bidding, as well as providing improved locational signals for generation and storage investment compared to the status quo.

Two approaches were taken to considering the magnitude of the benefits of the CMM(REZ).

Firstly, the ESB has adapted analysis undertaken by NERA Economic Consulting that quantified the likely benefits of introducing LMP to the NEM by using a bottom-up electricity market model. This work focusses on the CMM element of the CMM(REZ) model.

The ESB considers that the introduction of the CMM(REZ) would result in the same improvements in dispatch efficiency as the LMP/FTR model because the CMM will expose generators to their locational marginal price at the margin. This will provide the same incentive for generators to bid at their short run marginal cost (SRMC) in the face of congestion rather than the market price floor, as would occur under the model considered by NERA.

The methodology that NERA employed was to compare the results from their model under the current regional pricing model where generators have an incentive to disorderly bid, to a scenario where generators face their LMP, and these incentives are removed. This comparison was for the financial year 2025/26. The results were then indexed to the variable costs of coal production over the modelling horizon, given that coal generation was identified in the NERA model as the major contributor to higher system costs due to disorderly bidding. NERA estimated that the benefits over the period from 2025-26 to 2040 ranged from $897 million to $1,152 million in $2020 NPV terms.

Adjustments can be made to these estimates for a proposed earlier starting date of 1 July 2024 for the CMM(REZ). To estimate the benefits for the 2024-25 financial year, the benefits in the 2025-26 were adjusted to reflect the change in predicted black coal production between 2024-25 and 2025-26 in the 2020 ISP.[84] This is consistent with the approach used by NERA to estimate the costs of disorderly bidding in the years after 2025-26, however it has been applied in the other direction, i.e., for years before 2025-26.

[84] AEMO, 2020 Integrated System Plan, 2020 ISP Generation Outlook, https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp

These changes allow the benefits of the CMM(REZ) between 1 July 2024 and 2040 to be estimated in $2020 NPV terms. The ESB has used the same 7 per cent discount rate as NERA, and the results are as follows:

Range	NPV of benefits 2024 to 2040 (2020 $A m)
Low	897
High	1152

The analysis indicates that the additional benefits in NPV terms of introducing the CMM(REZ) on 1 July 2024 rather than 1 July 2025 is approximately $40 – $70 million.

Secondly, the ESB has collated studies which estimate or measure the benefits of improved dispatch efficiency following the implementation of LMP in other electricity markets. NERA Economic Consulting completed a report assessing the costs and benefits of implementing LMP in other jurisdictions for the AEMC as part of its earlier work on access reform. NERA collected cost-benefit analyses from several other markets. The most relevant of these were completed for the Electric Reliability Council of Texas (ERCOT) in 2008 and the California Independent System Operator (CAISO) in 2011.

The analysis completed for ERCOT in 2008 was an ex-ante analysis of the benefits of improved dispatch efficiency that would arise implementing LMP. LMP was implemented among other changes in ERCOT in December 2010.[85] LMP and FTRs were introduced in CAISO in 2009 following the exposure of a number of problems with its zonal pricing market during the California energy crisis. Additionally, the ESB has considered a recent paper describing an ex-post analysis of the benefits of the introduction of LMP in ERCOT, published in 2021.[86]

NERA assessed the cost-benefit analyses from the implementation of LMP in these markets, and found the benefits as a percentage of variable costs of generation to be as follows:

Market	Ex ante or ex post	Benefits as a % of variable costs of generation
ERCOT (Texas)	Ex ante	0.60%
CAISO (California)	Ex post	2.1%
ERCOT (Texas)	Ex post	3.9%

Based on these benefits as a percentage of variable costs of generation, NERA estimated the benefits for the NEM by applying the benefits to the variable costs of generation in the NEM in 2018-19.[87] When comparing to the NEM, NERA adjusted the figures for exchange rates as well as for characteristics of the NEM including size and variable costs of generation. To incorporate the 2021 ERCOT paper into the analysis, the ESB applied the same methodology used by NERA. The annual benefit that occurred from the result of the 2021 ERCOT paper was calculated by scaling up the result of the other studies to reflect the increased percentage benefit to the NEM. The benefits estimated were as follows:

---

85 The analysis completed for CAISO was part of an academic paper published by Frank Wolak.

86 Wolak, Triolo. 2021. Quantifying the benefits of nodal market design in the Texas electricity market. Available at https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/BenefitsOfNodalDesignERCOT.pdf

87 Variable costs are defined as the sum of fuel costs and variable O&M costs.

Market	% Benefit	Annual Benefit in the NEM (2019 $A, m)	NPV July 2024 – 2040 (2020 $A, m)
ERCOT (Texas) (2008)	0.60%	31.12	226
CAISO (California)	2.1%	101.96	741
ERCOT (Texas) (2021)	3.9%	189.35	1376

The work done to date shows that the benefits from improved dispatch efficiency that will arise under the CMM(REZ) are substantial. The analysis completed provides a range of NPV benefits from $226 million (the low estimate from the benchmarking study) to $1376 million (the high estimate of the most recent ex post analysis). While this is a large range, it demonstrates that even the low estimates indicate that the benefits of implementing the CMM(REZ) are likely to be substantial.

Analysis	NPV July 2024 – 2040 (2020 $A m)
ERCOT ex ante applied to NEM	226
CAISO ex post applied to the NEM	741
NERA ex ante	897-1152
ERCOT ex post applied to NEM	1376

The ex-post analyses conducted on the benefits of improved dispatch efficiency resulting from introduction of LMP generally result in larger benefits than the ex-ante analyses. Ex-post studies are generally a more reliable indication of the benefits that may arise from the introduction of LMP to the NEM, given that they are measuring the benefits that have arisen, rather than estimating the benefits that may arise.

Likely benefits of the CMM(REZ) – locational signals

The ESB has reviewed previous analysis to estimate the magnitude of the benefits that arise from the provision of efficient locational signals for generators. As part of the AEMC's earlier work on access reform, NERA analysed the impact of introducing LMP on the incentives of generators to make economically efficient investment decisions from a whole of system perspective. NERA modelled the potential benefits by using a model that compared the total system costs under a scenario where LMP, and therefore efficient locational signals, were introduced, to a scenario where the status quo pricing arrangements were kept intact. Total system costs were defined as fuel costs, non-fuel fixed and variable costs of generation, and annuitised capital costs of generators. These are additional benefits on top of the benefits of improved dispatch efficiency discussed above. Based on this analysis, NERA estimated that the NPV of benefits in terms of total system costs over the period 2025-2040 in real $2020 terms was approximately $1.7 billion.

The CMM(REZ) will provide locational investment signals for new entrant generators. The method for providing locational investment signals to generators will be different to the method modelled by NERA for the AEMC. Under the LMP/FTR model, market participants make decisions about the availability of network capacity based on their own assessment of the signals provided by locational marginal prices. In contrast, under the CMM(REZ), generators receive rebates in return for locating in accordance with the central planners' view of where in the network generators should locate, based on the optimal development of the power system.

The CMM(REZ) has not been modelled. However, it is clear that there are significant potential benefits to be gained by providing improved locational signals to new entrant generators compared to the status quo. As noted above, any benefits realised due to improved locational investment

7.7.4. Costs of the reform pathway

AEMO estimates likely implementation costs for the CMM fall in the range of approximately $10 million to $20 million,[88] based on the following assumptions:

- there are no changes to the National Electricity Market Dispatch Engine (NEMDE) in order to facilitate the CMM.
- there is no change to the settlement residue auction, but there are changes to the settlement of residue auction units.
- it is assumed that local prices will not be forecast in ST or MT PASA.

It is important to note that these costs are for the CMM on its own, and do not consider the REZ adaptation. This cost estimate will need to be revised once the detailed design for the CMM(REZ) is developed in a rule change process. The estimate is helpful in identifying the order of magnitude in difference between the benefits and likely costs of this reform.

The proposed rule change request would take into account more specific cost information, such as more refined costs from AEMO, as well as how participant costs can best be minimised

7.7.5. Overall assessment of the merits of implementing the reforms

Further analysis on the costs and benefits, including implementation costs and timeframes will be undertaken in the rule change process considering the implementation of the CMM(REZ). The analysis undertaken assessing the benefits of improved dispatch efficiency under LMP in the NEM are a reasonable reflection of the benefits that the CMM component of the CMM(REZ) would deliver, and substantially outweigh the implementation costs that were considered. The benefits of the REZ adaptation may be an area for further investigation. It will be necessary to consider the costs and benefits of the REZ adaptation in the context of reforms being pursued by State governments.

[88] In addition to this cost estimate, the DER implementation leverages strategic investments of between $70-$100million for applications in the forecasting, operational, and dispatch systems necessary for the delivery of the reform on this pathway as well as the implementation of reform in essential system services and CMM. These strategic investments, for the purposes of the benefits assessment have been included in the estimates for Essential System Services, Scheduling and Ahead Mechanisms pathway. This is discussed further in Part C.

Contact details:
Energy Security Board
Level 15, 60 Castlereagh St
Sydney NSW 2000
E: info@esb.org.au
W: http://www.coagenergycouncil.gov.au/market-bodies/energy-security-board