ENERGY SECURITY BOARD

Post 2025 Market Design Options – A paper for consultation

Part A

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List of Abbreviations

ACCC	Australian Competition and Consumer Commission
ACL	Australian Competition Law
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
ARENA	Australian Renewable Energy Agency
CEC	Clean Energy Council
C&I	commercial and industrial
CoAG	Council of Australian Governments
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DEIP	Distributed Energy Integration Program
DER	distributed energy resources
DNSP	Distribution Network Service Provider
EAAP	Energy Adequacy Assessment Projection
ECA	Energy Consumers Australia
ENA	Energy Networks Australia
ESB	Energy Security Board
ESS	Essential System Services
ESOO	Electricity Statement of Opportunities
EV	electric vehicle
FCAS	frequency control ancillary services
FERC	Federal Energy Regulator Commission
FFR	fast frequency response
GW	Gigawatt
IRSR	inter-regional settlement residues
ISP	Integrated System Plan
LV	Low Voltage
MDI	Market Design Initiative
MMS	Market Management System
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
NEO	National Electricity Objective
NSP	Network Service Provider
PD PASA	Pre-Dispatch Projected Assessment of System Adequacy
PFR	Primary frequency response
PSSAS	Power System Security Ancillary Services
PV	Photovoltaic
RAMs	Resource Adequacy Mechanisms
RERT	Reliability and Emergency Reserve Trader
REZ	Renewable Energy Zone
RMR	Reliability Must Run
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

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. Other associated implications include the need for:

- **Resource adequacy mechanisms**: to provide the right signals which will drive investment in an efficient mix of new resources which will 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 and other resources into the system in an efficient way; and
- **Transmission and access**: to reconfigure the transmission system so that new renewable generation and large-scale storage can connect and be dispatched to meet customers' demand.

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 and beyond 2025. This paper seeks comment from stakeholders on a suite of potential reform pathways to address these implications and promote a secure, reliable and efficient energy transition while maintaining affordability for customers. The proposed pathways build on the Directions paper[1] published in January 2021. Feedback on the options in this paper will inform the ESB's recommendations to Ministers in the middle of this year.

Pathway for reforms

The reform pathways have been 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 *next reforms which are* longer term and depend on developments in the industry including technical changes.

Together, these pathways deliver reforms over time. With ongoing oversight, these pathways can be adjusted to address emerging needs and uncertainties during the transition.

Ahead of final recommendations mid-year, options within key pathways will be resolved. The pathways will be evaluated, and the pathways put forward will present a package of interrelated reforms that best achieve a fit for purpose market design for the NEM for 2025 and beyond.

Resource adequacy mechanisms and aging thermal retirement

The ESB has been considering what modifications to the investment signals in the market and related arrangements may be needed to deliver a more orderly exit of aging thermal generation and its timely replacement by a mix of new resources which will maintain reliability. Market and related arrangements need to operate effectively in the presence of substantial government investment schemes.

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1 Energy Security Board, Post 2025 Market Design Directions Paper, January 2021. Available at: https://energyministers.gov.au/publications/post-2025-market-design-directions-paper-january-2021

1. Immediate reforms

The ESB is developing mechanisms to ensure the orderly exit of thermal plants as they retire from the system – including possible changes to notice of closure requirements, improved information to market participants and policy makers and the potential for arrangements with thermal plants. The potential to undertake scenario planning to understand how such matters as unforeseen failure or sudden retirement of older less reliable plants could be managed is also considered.

We are also investigating, with governments and industry, a potential NEM-wide, common approach to integrating jurisdictional underwriting or investment schemes for new investment into the NEM – as a potentially enduring feature of the energy sector, a national approach could better facilitate consumer outcomes from such government investment.

2. Initial reforms

The ESB is exploring options for modifications to the retailer reliability obligation to ensure that retailers have an incentive to maintain a portfolio of contracts with new and existing resources, including storage and dispatchable resources, adequate to cover their customers' needs.

The current obligation only applies if triggered through analysis which shows a future shortfall in the ability to achieve reliability standards. Modifications considered include changes to the 'trigger' (including no trigger at all) and what qualifies as an appropriate contract to meet retail obligations (certain defined financial contracts for example or physical contracts for certificates). The contracts must reliably meet their customers' needs and could provide a longer duration price signal for investment in necessary resources that may not be included in government schemes.

A key question is whether, given the existence of jurisdictional schemes and an uncertain investment environment, the current market design can deliver the necessary investment signals to drive both contracting for dispatchable resources and efficient decisions around the closure of ageing large scale generation. The ESB considers that the design features of any resource adequacy mechanisms should be informed by the answer to this question.

If the current market design cannot deliver sufficient dispatchable resources this may suggest resource adequacy mechanisms should be designed as the primary driver for investment. Conversely, if the current design is able to support enduring investment signals, this may suggest resource adequacy mechanisms that instead complement and work with the existing market arrangements.

As part of developing these options, the ESB will reflect on how to address concerns raised by stakeholders regarding the RRO's complexity, cost, effectiveness at driving investment, and imposing a high compliance burden. As potential enhancements to the obligation are developed, the ESB will consider how they might contribute to ameliorating these concerns and meeting the policy objective.

Work to develop an operating reserve (through the essential system services workstream) will also help to ensure flexible, dispatchable resources are valued in the market and have an incentive to be available when they are needed.

3. Next reforms

The ongoing growth of renewable generation will mean the need for dispatchable capacity and storage of various forms will also grow. Following the implementation of the ESB's Post-2025 reforms, continued monitoring of the ability of the arrangements to deliver reliable investment and low overall costs to consumers will be necessary. A successful transition would see the right mix of resources, on the demand side and supply side, incentivised into the energy market which maintains reliability while minimising consumer costs. That mix will likely include new and evolved technologies which may require refinements to market arrangements.

Essential System Services and Scheduling and Ahead Markets

The growing role of renewable generation and battery storage in the power system will increase the need for services to maintain the security of the system. This will be exacerbated by the retirement over time of aging thermal generators who currently provide many of these services. The ESB considers that we need to specify and value those essential system services and efficiently procure those, including procurement from non-traditional and new sources. The approach proposed is to use co-optimised market-based procurement where possible and, where not possible, 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. The ESB is working closely with the AEMC on rule changes on foot which are developing these arrangements below. Stakeholder feedback received by ESB is used as an input in AEMC processes.

1. Immediate reforms:

Reforms are underway to refine frequency control arrangements and, in particular, address the potential 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). 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 for system strength and provide the system configuration needed to maintain security.

Ahead scheduling of system services will first be considered through the rule changes related to synchronous services markets and more generally by the ESB after new system services markets (including system strength, FFR, operating reserves) have been defined.

We are also looking to amend the market design to procure system strength in a structured manner; and exploring the need for a new operating reserve or ramping service.

3. Next reforms

The ESB has identified a spot market approach for valuing and procuring inertia as a long-term priority, in the first instance relying on the current arrangements for TNSPs to procure minimum levels of inertia along with the potential to use a SSM to procure additional inertia when required. While this will 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. 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 may require further refinement to the spot market and structured procured arrangements.

The ESB also identified the issues to be monitored for the longer-term development of voluntary ahead scheduling of energy and services, assessing the potential size of additional resources that could be brought into the market before proceeding with more detailed design work.

Integration of Distributed Energy Resources and Flexible Demand

The ESB is focussed on driving value for all customers from the integration of DER into the overall power system. Customers could benefit from using their resources to provide demand flexibility, compete into wholesale energy and service markets and provide network services, lowering their overall cost. This could also provide benefits to other customers through additional supply options lowering costs. In realising the potential, the roles of the various parties need to be clarified, building on their current responsibilities.

The potential opportunities for DER are still developing and a number of important trials are underway. The ESB recommends developing a transitional pathway that sets out additional action to take now for DER integration and develops further reforms for later implementation, broadening the potential uses of DER as more opportunities and new technologies emerge.

1. Immediate reforms:

A package of immediate reforms is underway, including expanding the responsibilities of distributors to hosting distributed generation and storage and introducing technical standards for DER that will 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. The ESB recognises the importance of addressing the issue of minimum demand on the system and the need to expand retail offers and provide opportunities to streamline and increase customer participation. The changing customer landscape will require new systems to ensure customers retain options to switch provider and a new risk assessment tool to test whether customer protections in place remain fit for purpose.

2. Initial reforms:

Initial reforms will 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 need 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.

3. Next reforms:

The ESB proposes that a maturity plan process is developed to progressively develop a spectrum of opportunities for customers to obtain value for the energy and services they provide and compete to lower system costs to the benefit of all customers while ensuring that the overall system can be maintained in a secure and reliable state. This approach would then progressively deliver a detailed, integrated market design consistent with directions on future roles and responsibilities.

The maturity plan is an iterative process though which six monthly ‘releases’ will identify priority issues for reform, deliver detailed analysis or solutions to address, needed regulatory change or capability development. Its ongoing governance will allow it to function as a vehicle for collaborative co-design and coordination of several significant DER related reforms relevant to immediate and initial reforms.

Transmission and access

The development of access to and operation of an enhanced national transmission system is key to a successful transition. The ESB proposes a range of measures to ensure that much needed transmission investment is delivered in a timely and efficient manner, and options to ensure that market design promotes a targeted set of supply-side investments that delivers the energy transition at least cost. It is also important to ensure that these investments, once made, are used in an efficient manner.

1. Immediate reforms:

AEMO has prepared and updates the Integrated System Plan (ISP). This 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 are proposed in this paper which would provide a development plan for Renewable Energy Zones (REZs).

REZ schemes can promote efficient location decisions by making it more attractive for generators to invest in certain parts of the network. The ESB is working with State governments to develop a framework for the efficient planning, development and maintenance of REZs.

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 ESB considers the planning and implementation of priority renewable energy zones is an important step to the efficient connection of generation to the enhanced grid. The ESB is considering approaches to implementing REZs, noting the related actions being taken by state governments.

It will also be necessary to complement and strengthen initiatives to develop REZs by introducing reforms to lessen the likelihood of the access of REZ generators to customers being degraded by the connection of other generators outside the REZ and also of other REZs. Some medium-term options to manage these issues are proposed which could form a stepping-stone towards a long-term solution for transmission access.

Going forward there will be a need for real time congestion management, and reforms to ensure that new technologies are able to be remunerated for alleviating transmission congestion. Given these issues, the ESB is exploring whole of system access options. We are also considering changes that could be made to provide more useful congestion information over time than is currently available.

3. Next reforms:

In the longer term, the ESB's preferred solution for access reform is to shift to locational marginal pricing and financial transmission rights. It is a more comprehensive access solution to the issues raised, and it is a well-established model that has been successfully applied in numerous overseas markets for decades.

Evaluation of reform pathways

Modelling is an important tool to assist with understanding how outcomes of the proposed reform pathways might vary in different states of the world and give insights into their potential impacts. The ESB is preparing quantitative analysis that informs the benefits and the costs of the proposed pathways, including the costs associated with implementing reforms, to assist with evaluating whether they are likely to promote the national electricity objective.

However, many of these reforms are subtle and complex to model. Given the complexity and limitations of the modelling tasks that will be undertaken, modelling outcomes must be supported by qualitative assessment.

Next steps

To inform this work, we have considered advice from a wide range of experts, industry and consumer representatives. Many stakeholders have committed significant time and resources to provide input into the Post-2025 reform process, and the ESB and market bodies welcome this continuing commitment to shaping the future arrangements for the NEM.

The ESB will continue to work with the Post-2025 project advisory groups, jurisdictions and other stakeholders to inform the detailed market design and evaluation of these options ahead of recommendations to Ministers in mid-2021.

This paper is accompanied by a set of appendices (see Part B) which sets out further detail on options. The ESB welcomes stakeholder feedback on proposals outlined by **Wednesday 9 June 2021**. Details for how to engage can be found in section 7.

1. Introduction

1.1. Background

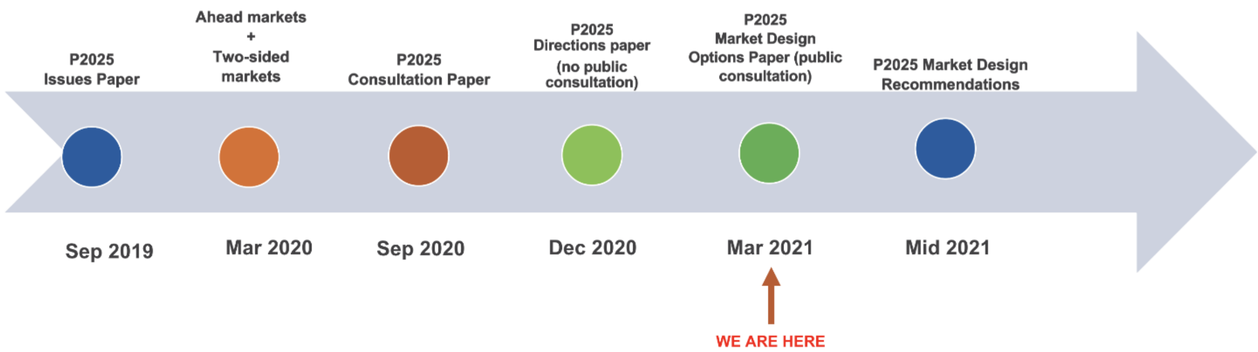
The Energy Security Board (ESB) was tasked by the former Council of Australian Governments Energy Council (COAG EC), to develop advice on reforms to the National Electricity Market (NEM) to meet the needs of the transition and beyond 2025.[2]

The Post-2025 Market Design program followed the 2017 Finkel Review,[3] which found that Australia's energy system was at a critical turning point.

> *"Managed well, Australia will benefit from a secure and reliable energy future. Managed poorly, our energy future will be less secure, more unreliable and potentially very costly."*

Progress has been made in addressing the needs of the NEM. Advances in technology are rapidly continuing to improve customer choices and change the mix of resources available to meet our future energy needs. The reform pathways proposed by the ESB can help achieve that better future.

This paper builds on earlier directions released by the ESB,[4] stakeholder feedback to date and sets out detailed reform pathways for market design and options for consultation. The ESB welcomes stakeholder feedback on these proposals to further inform recommendations to Ministers in mid-2021, as shown below.



1.2. The changing electricity industry

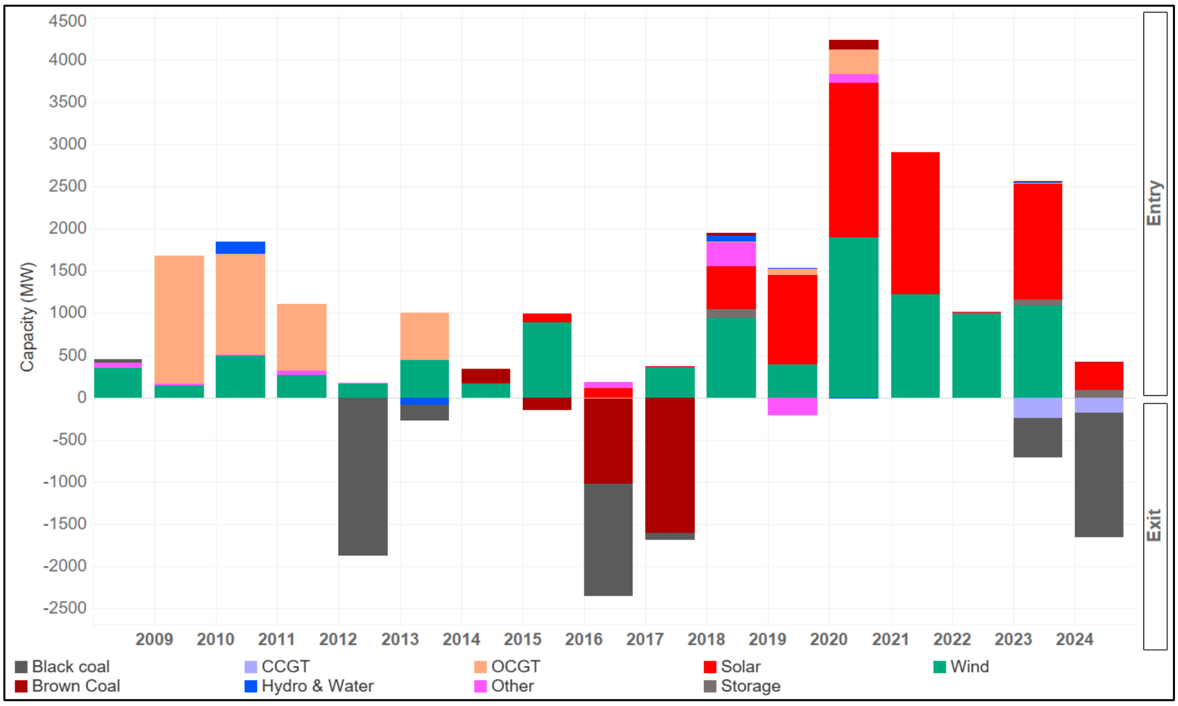
The scale and pace of change occurring across the NEM cannot be overstated. Over the past decade, the generation mix has undergone a transformation, with ever increasing renewable solar PV and wind resources coming onto the system. At the same time, the aging thermal synchronous fleet that traditionally delivered a significant proportion of the grid supply (made up of black and brown coal generators), has started to retire from the system. See Figure 1.

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

3 Independent Review into the Future Security of the National Electricity Market. Blueprint for the Future June 2017.

4 This includes the following ESB publications: September Issues paper (2019), March Directions paper (2020), September Issues paper (2020) and January Directions paper (2021); as well as accompanying papers available at: https://esb-post2025-market-design.aemc.gov.au/

Figure 1 Entry and exit of generation – historical and committed



Source: analysis of AEMO MMS database, AEMO Generator Information Page

This will continue, both at the large and small scale with 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 in the next two decades. This means there is a need for 6-19 GW of new utility scale, flexible and dispatchable resources, as up to 63% of the current coal and gas fleet in the NEM) retires by 2040.[5] To put these numbers into perspective, the average NEM demand is around 20 GW.

This trend is accelerated by recent jurisdictional investment schemes. The faster that new, more economic renewable generation comes into the market, putting downward pressure on energy spot and contract prices, the higher the pressure to exit for existing, less economic generation.

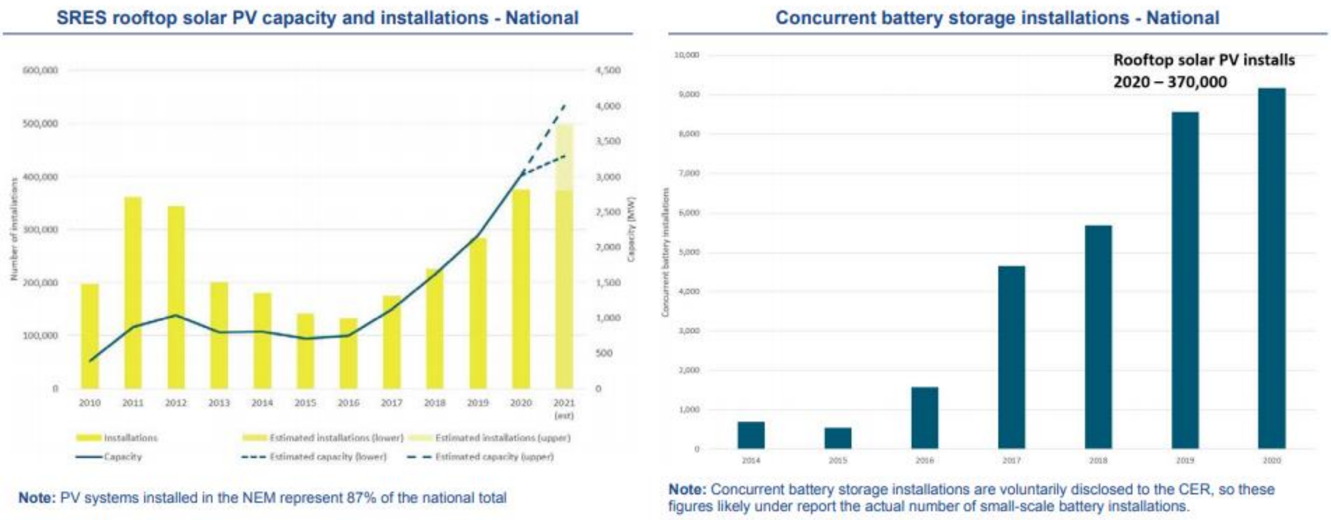
These relatively smaller and geographically dispersed renewable generators will need to connect in windy or sunny parts of the grid. Historically the transmission network was built to transport energy from coal fuelled generation to load centres. The current network has not required large amounts of transmission capacity in the areas where this new generation will need capacity. Substantial transmission investment will be needed to accommodate the forecast new large-scale variable renewable energy expected by 2040.

At the small-scale generation level, the story is just as profound with more than 2.66 million rooftop solar power systems installed across the NEM at the end of 2020. At approximately 14GW[6] of installed capacity that is the equivalent of the largest generator in the NEM dispersed through the country. This is the highest uptake of solar globally, with more than 21% of homes with rooftop solar PV. Concurrently battery storage installations are increasing, adding sophistication to the behind the meter generation and storage in households. This trend will accelerate with a number of jurisdictions offering interest free loans to install solar battery systems. Digitalisation is opening new opportunities for customers to manage and value their load and their distributed energy resources or to have them managed on their behalf.

5 Source AEMO 2020 ISP – Central and Step Change Scenario – Transmission and Generation Outlook Files

6 Based on data from the Clean Energy Regulator

Figure 2 SRES rooftop solar PV and battery storage installations



Source: Clean Energy Regulator[7]

Increases in installed PV also leads to increasing levels of passive solar PV penetration.[8] On 11 October 2020, South Australia operated for a period where over 100% of its regional demand was met by distributed and utility-scale PV generation. Distributed PV alone met over 76% of regional demand for a few periods that day and over 70% for 4 hours. By 2025 other mainland NEM regions could be regularly operating close to or above 50% instantaneous penetration.[9] When consumers' energy needs, particularly during daylight hours, are being met by their own distributed energy resources (DER) such as solar PV, there is declining minimum operational (grid) demand. This is operationally challenging for network stability in particular.

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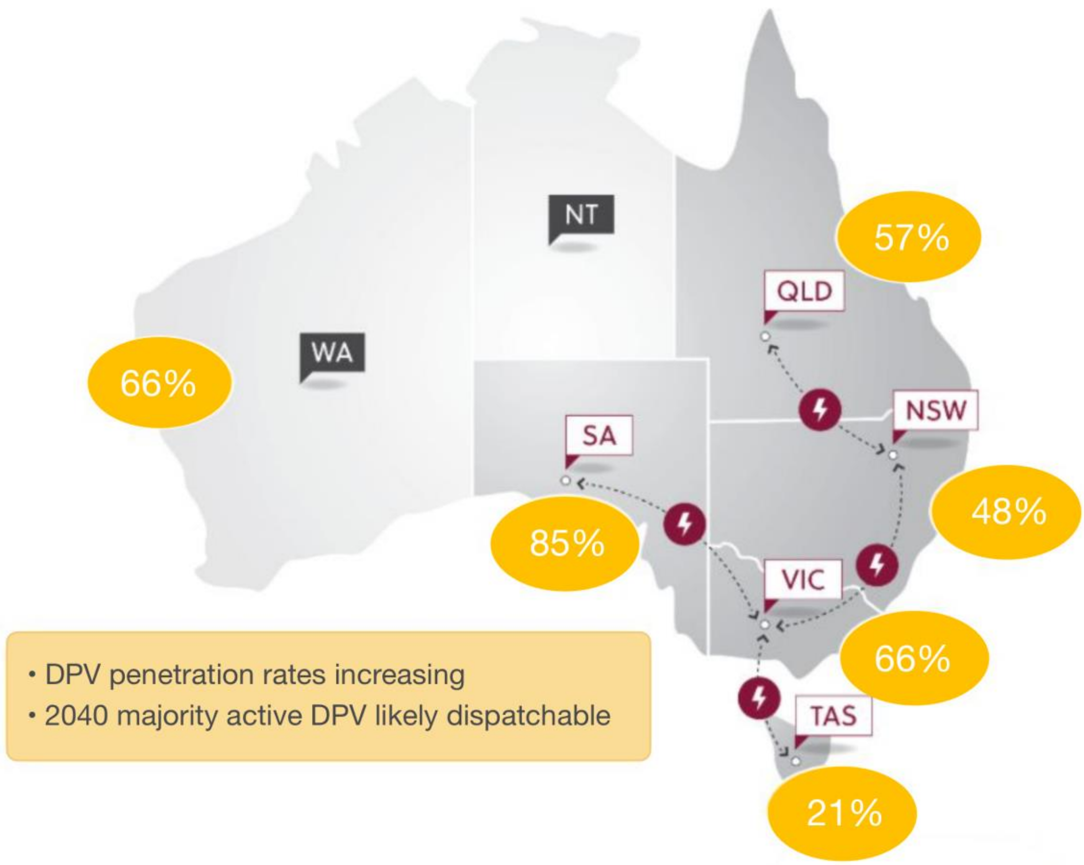
7 The Small-scale Renewable Energy Scheme (SRES) is the scheme that provides rebates for the installation of small-scale renewable technologies. Eligible installations earn small-scale technology certificates (STCs) that have a market value derived from demand for them by retailers, who must surrender certificates in proportion to their retail sales

8 Passive solar is generally regarded as PV cells that have limited ability to control energy production. Passive solar can be managed through the addition of energy management systems or through incentives on the owner/operator of DER to engage with demand side response programs. Moving from passive to active solar assumes that passive PV can be remotely controlled and managed.

9 AEMO, Renewable Integration Study https://aemo.com.au/en/energy-systems/major-publications/renewable-integration-study-ris

Figure 3 Solar PV Penetration by 2025

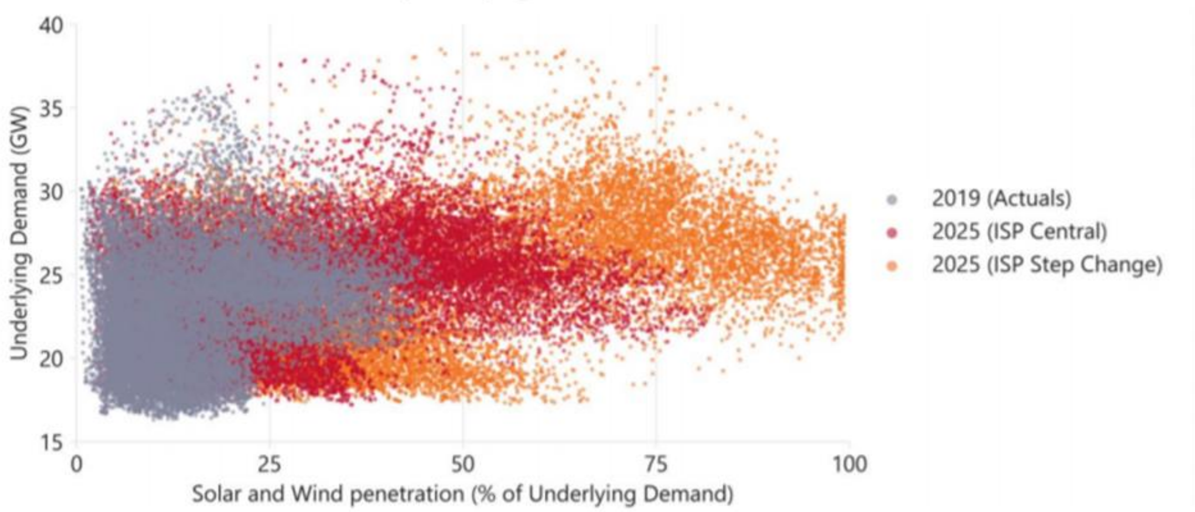


Source: Clean Energy Regulator and AEMO 2020 Renewable Integration Study

The changing resource mix sees a marked increase in asynchronous, or inverter-based resources and a reduction in conventional, synchronous resources. This is changing the envelope, the physical dynamics of the power system, and the suite of resources that can deliver the range of essential system services to maintain system security. With 63% of the existing thermal fleet due to retire by 2040, the services those generators deliver to the system need to be replaced as the fundamental physics of the power system remain the same.

The levels of wind and solar energy that can operate on the system at any time varies depending on system conditions. Increasing levels of penetration means more curtailment of those resources because of network congestion and insufficient services like frequency control system strength, voltage control, or flexibility (ramping). Without further action, the maximum instantaneous penetration of renewable resources would be limited to between 50 and 60 percent.

Figure 4 Instantaneous penetration of wind and solar generation, actual in 2019 and forecast for 2025



Source: AEMO Renewable Integration Study

1.3. Implications of the changes

To address these rapid changes a number of reforms are necessary. This is reflected in the ESB's consolidation of its 2025 workstreams into four reform directions for market design. Each has a clear objective and required outcome.

Reform directions for 2025

- **Resource adequacy mechanisms and aging thermal retirement** –
  - Objective: facilitate the timely entry of new generation, storage and firming capacity, and an orderly retirement of aging thermal generation.
  - This means: We have sufficient dispatchable resources and storage capacity in place prior to anticipated plant closures, and that plant exit does not cause significant price or reliability shocks to consumers through the transition.
- **Essential system services and scheduling and ahead mechanisms**
  - Objective: availability of resources that provide essential system services and support investment in necessary capability to balance the highly variable dynamics of the changing generation mix, without AEMO intervention. AEMO also needs the right tools to manage the greater complexity and uncertainty to schedule these resources so they are available when they are needed.
  - This means we have the resources and services when needed to manage the complexity of dispatch and to deliver a secure supply to customers
- **DER integration and demand side participation**
  - Objective: enable the integration of DER (such as rooftop solar and distributed storage) and value flexible demand so they can provide services to networks, the wholesale market and other consumers
  - This means new opportunities for consumers about how they receive and use energy and are rewarded for doing so flexibly.

- **Transmission and access**
    - Objective the addition of transmission investments to enable the new generation and market arrangements and that new generation and storage locates and operates in ways that use transmission investment efficiently.
    - This means: we have a network to meet future needs, renewable energy zones, and a targeted set of investments that can deliver the energy transition at lower cost.

Implications for resource adequacy mechanisms and aging thermal retirement

While significant volumes of new renewables are coming online driven by falling technology costs and ambitious jurisdictional renewables and emissions policies, these resources are not delivering the dispatchable capabilities required to meet future system needs.

As a large proportion of the existing synchronous thermal generation fleet retires over the next 10-15 years, falling wholesale energy prices mean these retirement decisions are likely to be brought forward. Recent company results are not surprising and suggest that owners of large coal fuelled generators are facing commercial difficulties in the current wholesale market. The announcement by Energy Australia regarding Yallourn power station in Victoria highlights the reality of these decisions for plant operators, with the retirement of Yallourn now anticipated four years earlier in 2028 (vs 2032). This follows the recent announced retirement of Liddell in NSW and earlier retirements of Northern in SA, Hazelwood in Victoria, and Wallerawang and Munmorah in NSW.

The current investment climate is uncertain, with many investors making it very clear that expectations of forward prices are not at levels or durations that would support significant investments. There is also uncertainty around technology costs for renewable and storage resources, timing of large thermal exits, demand risk and the impact of jurisdictional investment schemes. The adequacy, and source, of the long-term investment signals to bring on new generation capacity needed over the medium term needs to be considered. Existing price signals tend to be relatively short term and not beyond three years. These signals need to be stronger, more certain, and longer term if the right mix of resources is to be available.

Governments have indicated a preference to drive investment through the transition and demonstrated this preference through various jurisdictional investment schemes. These schemes are likely to be an enduring part of the electricity market for the foreseeable future, and often embody broader policy objectives than maintaining reliability. Examples include supporting community transition and jobs or delivering low emissions and renewable energy policy targets. This government involvement has implications for both real time and contract markets and the investment signals they provide. These implications will be relevant to informing the design of any changes to market arrangements to provide these signals.

Implications for essential system services and scheduling and ahead mechanisms

Security is the most concerning and urgent issue in the NEM. Challenges such as balancing the system and maintaining stability where grid demand drops to almost non-existent levels, is now an urgent reality in parts of the NEM with the high penetration of solar PV resources. These scenarios were not a concern a few years ago, but as we continue to push at the technical envelope of the grid in ways that were previously untested, we need services and tools to efficiently and securely manage these issues in ways that meet consumer needs. We also need to continue developing and proving new technologies like grid-forming inverters with battery energy storage systems. New tools (see chapter 3) may support the continued secure operation of the system as knowledge of operating the power system with the new technologies continues to grow.

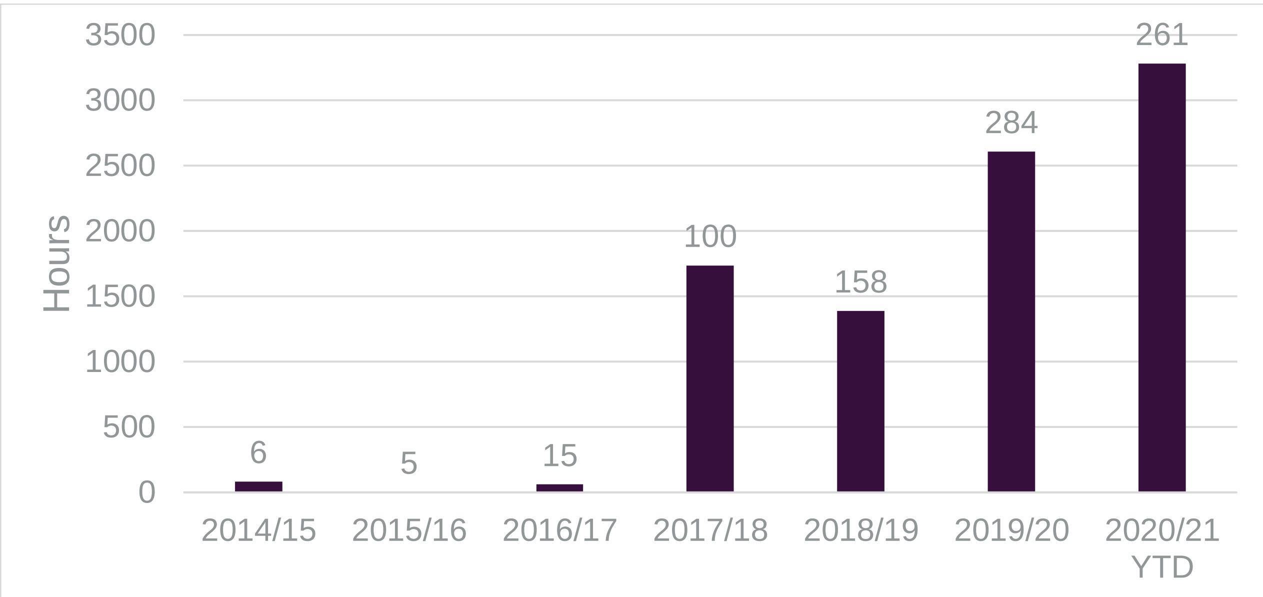
While the fundamental power system requirements remain unchanged, the type and composition of resources, and their configuration on the grid, is changing rapidly. More ‘variable’ output resources are entering the market and more 'dispatchable' resources are exiting.[10] The changing mix of resources also means the current providers of essential power system capabilities (such as frequency, system strength and inertia) are unlikely to be those delivering them in future. As technology continues to evolve, there is a significant opportunity for these dispatchable and essential system capabilities to be delivered by new resources (such as large-scale batteries or pumped hydro).

The changing patterns for demand and for new supply resources are characterised by a high level of variability. Resources with capability to ramp up or down quickly and provide flexibility to the grid, can help to balance the system. Such flexibility will become increasingly valuable to the grid and opens up opportunities for parties to deliver services to the market. Providing greater clarity of the actual capabilities required means that these services can be opened up to a broader range of service providers in future, leveraging new and emerging technologies across both supply and demand side resources.

Other power system attributes need to be managed to keep the grid stable against credible contingencies and resilient against larger disturbances. Resilience of the grid becomes more difficult with less synchronous generation available. Operational arrangements that allow us to define what these limits are, and reward resources are important to keeping the power system secure.

At the moment, we don't have the arrangements in place to provide a clear value signal to the market of all the services needed to maintain these essential system services. These capabilities are currently delivered as by-products of energy and ancillary services, but the value for particular needs is not revealed to the market. This means that in order to keep the system secure in parts of the grid, AEMO has had to more frequently intervene in the market to constrain on particular configurations of resources. See Figure 5 below. A recent example is the high penetration of renewables in South Australia where low inertia and system strength have been an issue.

Figure 5 Historical number of directions and duration, 2015-20



Source: ESB analysis of AEMO data
2020/21 = incomplete year; data current as at 25 March 2021
Note: values above each column represent number of directions issued

10 On 10 March 2021, EnergyAustralia announced Yallourn Power Station will be retired in mid-2028, with a commitment to build a 4-hour 350MW capacity battery in the Latrobe Valley by 2026. Yallourn was previously forecast to close by 2032.

10 Dispatchable resources are those resources that can ramp up or down quickly in response to a dispatch signal from the system operator.

Where we can get better signals to the market about the value of the capabilities needed to maintain the integrity of the grid, opportunities for a broader range of service providers appear. This includes opportunities for customers with flexible demand or DER assets to receive value for their flexibility. In future, we will see customers (through retailers and aggregators, being offered retail products that give them reduced energy costs in return for flexibility to ramp up or down from assets in their homes such as pool pumps, hot water systems, smart air conditioning units, batteries or electric vehicles). Where customers and new technology can provide valuable flexibility to the system, they should be rewarded for this value.

Implications for enabling the integration of DER and flexible demand

The largest generator in the NEM is now owned collectively by customers – and sits on their rooftops. The rapid uptake of domestic DER, with household solar now at over 2.6 million units across the NEM, has continued to outstrip all forecasts, even despite the dampened economic scenario over the past year

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 offerings can emerge to offer 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. Not all customers have access to DER assets, but the efficient market integration of these assets should 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 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 consumers 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 optimizing the needs at distribution level. Where they can use flexibility from their processes, 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.

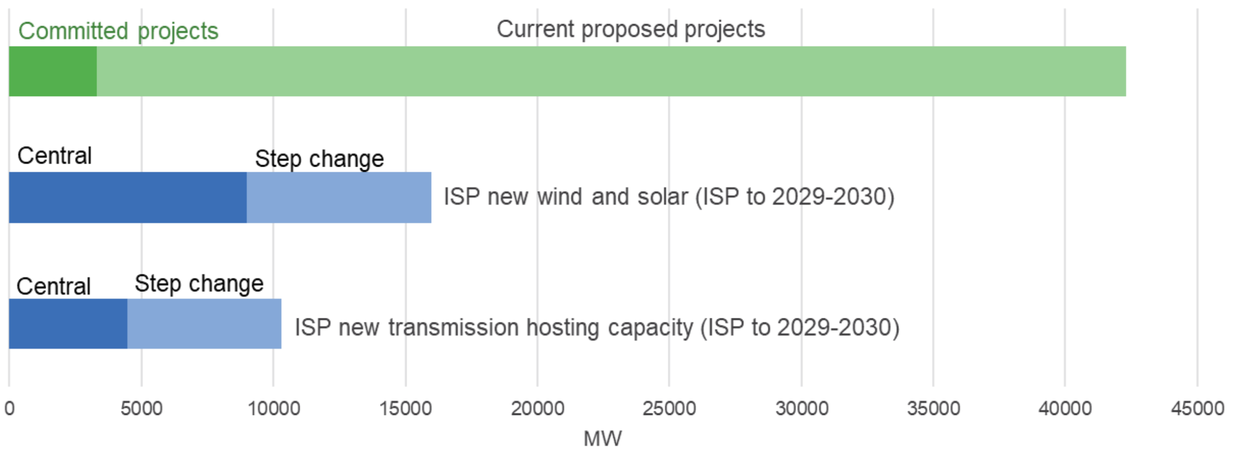
This means a different mix of resources on the system can meet our future energy needs, as well as supporting a low emissions future and economy. With energy as a significant contributor to emissions, making changes to how we produce and use energy, can deliver decarbonisation benefits and position Australian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

Implications for transmission and access

Substantial transmission investment is needed to accommodate the forecast 26-50 GW of new large-scale variable renewable energy expected by 2040. Challenges are emerging in getting the new network built and congestion is an issue in some locations.

New renewable investments often need to connect in different locations to where existing transmission infrastructure lies. REZ developments provide a good opportunity to better coordinate the renewable investment coming online. But this will not be enough to address congestion on the network and hence curtailment. Figure 6 shows how the current pipeline of wind and solar developments significantly exceeds both the amount of new wind and solar in the ISP optimal development path, and the new transmission hosting capacity that is forecast to be made available.

Figure 6 Committed and proposed wind and solar generation development relative to ISP optimal development path



Source: ESB analysis using AEMO data[11]

Transmission hosting capacity over the next decade is expected to fall short of the levels of renewable generation expected, which means congestion needs management. 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 would be 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.

In the absence of arrangements that provide clear signals about where it would be efficient to build and how to manage congestion, outcomes will continue to be uncoordinated and lead to increasing levels of congestion on the grid. New generation will locate and operate in ways that will exacerbate congestion which means electricity cannot be dispatched to meet demand at the lowest possible cost. Congestion management is already a critical and growing issue, making connecting to the grid complex. REZs will help but they are a localised solution. Due to the way electricity flows across the grid, issues outside the REZ will be felt inside the REZ. This can only be addressed through solutions that apply across the whole system, of which REZs are a part.

The right NEM-wide arrangements that coordinate transmission and generation will also reduce the risk of low marginal loss factors and facilitate grid connection. They will help us to stay ahead of the dramatic increase in large-scale battery deployment – currently 327 MWh and estimated to be 900MW by 2024 - and emerging technologies such as hydrogen. A large flexible load, grid connected hydrogen could be a source of demand response on the horizon, which can help make the system stable. These technologies need incentives that mean they charge or use energy and discharge or not use energy at the times that are most valuable. That way they work within, and not against a high variable renewable energy power system.

11 The new transmission hosting capacity in this chart does not include existing spare hosting capacity that would also be available for new connections. The current proposed projects include a group of pipeline projects that are at different states of development – including some which may not reach financial decision or connection application and as such, the actual projects that eventually seek to be connected may be much lower. On the other hand, the committed/proposed projects row includes only those generation projects that currently meet the relevant criteria and does not include new generation projects that may emerge between now and 2030. See AEMO generator information: (https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information) for more information on the proposed projects and their development status.

1.4. Post 2025 reform pathways

The implications of the changes are what the reform pathways address.

The Post-2025 market design sets out a pathway to a fit-for-purpose market design for the NEM. Given the pace of transition, changes are needed over time, so they meet the needs of the transition, while allowing for flexibility to adapt to its pace and evolving market conditions.

To inform this work, we have heard and considered advice from a wide range of experts, industry and consumer representatives. Many stakeholders have committed significant time and resources to provide input into the Post-2025 reform process, and the ESB and market bodies welcome this commitment to shaping the future arrangements for the NEM.

As a result, rather than a single 'big bang' reform, the ESB is proposing a suite of reform pathways. Each of the pathways will include a range of shorter-term actions that need to be implemented to address more urgent issues, as well as setting out a way forward to enable the market to navigate the transition and deliver long term benefits to consumers.

The reform pathways have been set out to reflect their urgency and fall into three categories:

- **Immediate reforms** – these are proposed measures for immediate implementation to address imminent problems in the NEM. As such they are reforms that are either underway or are being developed now for implementation as soon as possible.
- **Initial reforms** – these are reforms that we need to develop further in the near term for implementation. Many of these reforms will need to be implemented pre-emptively to solve emerging challenges.
- **Next reforms** – these are reforms that we may need to move to over time, given the trends and pace of the transition, or may need to be considered or revisited if certain preconditions arise.

These pathways, together, deliver reforms over time to address what needs to be done immediately, next and later. The later proposals require ongoing oversight, should be adjusted as needed to address technology change and the changing uncertainties of the transition.

Together, these pathways enable a different mix of resources on the system to 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, will deliver decarbonisation benefits as well as position Australian businesses competitively in markets shifting to tighter controls and decarbonisation policies.

In this paper we set out the ESB proposed reforms for consultation.

2. Resource Adequacy and Aging Thermal Generator Retirement

2.1. Key points

- 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 in the next two decades. This means there is a need for 6-19 GW of new utility scale, flexible and dispatchable resources, as up to 63% of the current coal and gas fleet in the NEM) retires by 2040. [12]
- This trend is being accelerated by recent jurisdictional investment schemes. The faster that new, more economic VRE comes into the market, putting downward pressure on energy spot and contract prices, the greater the pressure to exit is on existing, less economic generation. This downward pressure on prices may also undermine investment signals in the market and regulatory frameworks necessary for new resources needed to replace those that are exiting. .
- To consider resource adequacy in this context, the ESB's overall objective is to encourage the timely entry of required generation and storage, and the orderly exit of aging thermal generation. The ESB is focused on a reform pathway that ensures sufficient dispatchable resources and storage capacity are in place prior to anticipated plant closures, and that generator exit does not cause significant price or reliability shocks to consumers.
- Market participants are best placed to manage their portfolio compositions over time and will make their own decisions about entry and exit. However, jurisdictional investment schemes have the potential to work against the mechanisms (scarcity pricing) in the market that create the signals for long term investment, making these decisions difficult.
- There is also uncertainty as to whether the market is adequately equipped to make entry decisions over the time horizon necessary to ensure new resources are operating in the market when needed. Some of this uncertainty is chronic – such as the flux in the technology costs curves for renewable and storage resources, timing of large thermal exits, demand risk continues to become increasingly difficult to hedge, and the forward expectations and volatility of the average pool price remain challenging. These impact confidence to invest and contract, delaying or deferring commercial decisions.
- These dynamics reflect a need to consider the adequacy, and source, of the long-term investment signals to bring on new generation capacity needed over the medium term.
- The resource adequacy reform pathway presented in this paper provides options to:
  - empower commercial investment to do the 'heavy lifting' for the majority of new investment through national market mechanisms that drive signals in the real time and contract markets; and
  - ensure that the full mix of resources required for reliability are delivered and that real time incentives for efficient dispatch remain, so that the NEM continues to meet consumer needs of affordability and reliability
- The ESB acknowledges that new investment can supported by jurisdictional investment schemes. However, jurisdictional schemes may dampen the investment signals sent by spot and contracting markets. This potentially creates risks for investment and resource adequacy. A key question is whether, given the existence of these schemes, the current market design can deliver the necessary investment signals to drive both contracting for dispatchable resources and efficient decisions around the closure of ageing large scale generation. The design features of any resource adequacy mechanisms should be informed by the answer to this question.

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12 Source AEMO 2020 ISP – Central and Step Change Scenario – Transmission and Generation Outlook Files

- If the current market design cannot deliver sufficient dispatchable resources this may suggest resource adequacy mechanisms could be designed as the primary driver for investment, leaving the role of the spot market to ensure efficient dispatch of existing capacity. Conversely, if the current design is able to support enduring investment signals, this may suggest resource adequacy mechanisms that instead complement and work with the existing market arrangements. The options for immediate measures and initial reforms included in this proposed reform pathway can accommodate either of the choices set out above.
- **Immediate measures** in the proposed reform pathway include:
  - the provision of additional two-way advice to jurisdictions on what dispatchable resources will be needed in a jurisdiction in future years, given anticipated development, and
  - principles and practical contract structures to inform the design of government long-duration contract schemes and to incentivise investment in classes of resources.

  Both will facilitate such potential government intervention being at least cost to consumers.
- The ESB has also developed three proposed exit mechanisms. As prudent backstops implemented immediately, they can address reliability risks that might arise with exits that occur before the 42 month Notice of Closure expires.
- The exit mechanisms are aimed at providing timely information relevant to mothballing and seasonal shutdowns of generators. Building on existing exemption processes, the ESB has also developed an integrated process to manage early exits. A complete System and Market Impact Assessment is proposed to consider what would happen to the system if a generator decides to close before the 42 month Notice of Closure expires. Options for actions to manage early closure, including possible intervention, can then be examined.
- **Initial reform steps,** to be implemented in the near term on the proposed transition pathway, focus on the spot and contract markets.
- Modifying the Retailer Reliability Obligation (RRO) is an initial reform step, though not all jurisdictions will need to rely on it. Modifying the RRO is intended to:
  - manage investment in reliability without government needing to underwrite reliability risks
  - reduce the likelihood of a generator unexpectedly exiting the system; and
  - ensure there is a minimum amount of liquidity and contracting in the derivative market to support transparency of future price expectations.
- Two options for modifying the RRO are being developed:
  - removing the T-3 trigger from the existing RRO to promote an increase the duration of the price signal for investment and a higher level of enduring contracting by retailers. This option uses existing arrangements that the RRO was based on.
  - changing the definition of qualifying contracts to newly created physical certificates that provides a more direct link to physical resources could encourage more timely and earlier contracting. Design choices for such a 'physical RRO' can either replace the current market signals for reliability investment or work in parallel with them.
- Both approaches will be developed ahead of final recommendations mid-year. The impacts of each on small retailers and commercial and industrial (C&I) customers will require careful consideration, particularly in the case of a physical RRO, which will require the regulation of the supply of certificates and the imposition of additional compliance, enforcement and implementation costs.
- The ESB is also considering an operating reserve in the Essential System Services, Scheduling and Ahead work. Depending on its design an operating reserve could provide a positive externality for resource adequacy. The interactions between an operating reserve and its contribution as a resource adequacy mechanism will continue to be investigated.

- Following the implementation of the immediate and initial reforms, continued monitoring of reliability and overall costs to consumers will be necessary. In particular, it will be necessary to monitor the presence of various types of resource, and any future needs to strengthen investment signals (e.g., through future modifications to the RRO).

2.2. Proposed transition pathway

Building on the January Directions paper, this section sets out proposed reforms along a reform pathway to manage the orderly exit of the majority of aging thermal generation and facilitate the timely entry of the right resources to lower overall costs to consumers.

Immediate reforms need to be done now and implemented as soon as practical. Initial reforms will need to be developed further in the near term for implementation. Next reforms are ones that we need to move to over time, given the trends and pace of the transition, or may need to be considered if certain conditions arise.

2.3. Immediate reforms

In March 2020, the then COAG Energy Council implemented interim measures to deliver further reliability by establishing an out-of-market capacity reserve and amending triggering arrangements for the Retailer Reliability Obligation (RRO), with both triggered to keep unserved energy to no more than 0.0006% in any region. The then Council agreed that these were interim steps needed to improve reliability in the immediate term while a market design is developed in the post-2025 work program. These measures will be reviewed as part of an expanded RRO review required by 1 July 2023 by the AEMC and the Reliability Panel.

NEM-wide information provision and financial principles

As noted in the January Directions paper, given the risks facing investors, broader government policy objectives at play and the desired speed of the transition, some form of government investment for renewables and storage is likely, and possible for other dispatchable resources as well. Any such jurisdictional investment scheme will have enduring impacts on the market. The ESB continues to see value in supporting how government underwriting schemes are designed to best provide for the long-term interests of energy consumers.

There are a variety of government schemes that provide longer term investment support for new generation. The policy priorities of these schemes are often broader than reliability and the long investment certainty they provide is not easily replicated by market mechanisms. Given these schemes are likely to be a feature of the market for the foreseeable future, it is prudent they be complemented by immediate measures and initial reforms detailed in the proposed transition pathway. These measures help ensure that the full mix of resources required for reliability are delivered and that real time incentives for efficient dispatch remain, so that the NEM continues to meet consumer needs of affordability and reliability.

The ESB considers that a coordinated approach to government underwriting schemes will ensure investment driven by these schemes is better integrated with existing market design. Coordination may reduce the possibility that jurisdictions face adverse risk or liability later on, while providing that the benefits inherent in a national market are internalised into the structure of jurisdictional schemes – such as resource sharing through interconnection. The ESB's focus is on 'how' to support governments' policy agenda as best and efficiently as possible. This would see in the market, at a minimum, the co-existence of government-backed investments and non-government-backed investment, and government-backed resources having incentives to respond to real-time prices.

A NEM wide approach to jurisdictional investment schemes could have advantages by:

- Increasing policy certainty (particularly around how government backed resources will interact with the contract and spot market) through a uniform and transparent framework. This transparency and consistency would support confidence for commercial decisions and may minimise implementation and on-going scheme costs, and

- Preserving the benefits of a national electricity market including its ability to minimise costs to consumers through trade between regions.

In the January 2021 Directions paper the ESB foreshadowed the development of a spectrum of NEM-wide approaches, ranging from a light touch, principles-based approach at one end, to a scheme with common institutions and greater levels of centralisation at the other. While the latter options could be pursued with jurisdictional appetite, the ESB considers there to be reform options which can be recommended regardless as to whether a more formal and comprehensive arrangement is adopted.

The ESB is proposing to develop two approaches:

- Enhancements to information provision on resources to be underwritten
- Agreed national principles for contract design

Enhancements to information provision on resources to be underwritten

To the extent that governments provide incentives for investment, these investments will need to be coordinated with transmission investment, firming and storage needs, REZ development and market developments. Consistent with our overall approach, the ESB's preference is to utilise market frameworks to achieve this coordination. To support market frameworks, there is likely considerable benefit from the market bodies providing additional information on market impacts and least cost implementation pathways.

AEMO currently provides market information concerning reliability and security needs and the ISP provides a comprehensive least cost expansion plan for resource development, including firming and storage resources, and transmission infrastructure to support this resource development. It does so by looking across a broad range of scenarios of possible futures and considers all currently known and projected technologies for this resource and transmission development.

Additional advice could be provided to governments on the resources of various types needed in a jurisdiction in future years given anticipated developments – this would include information above and beyond what is in the Electricity Statement of Opportunities (ESOO), Integrated System Plan (ISP) and Medium-Term Projected Assessment of System Adequacy (MT-PASA). This information could be provided separately to the relevant jurisdictional government or incorporated into existing information documents, such as the ESOO and ISP.

It would look to support government decision making on the necessary firming or storage resources required to support reliability and security given a particular penetration of renewables at the time governments are considering supporting these resources. Crucially, it would include the NEM-wide system impacts of any scheme or support for individual resources, and account for the potential development of markets for operating reserve(s) and other security services under consideration in the Post-2025 project.

Such advice will likely need to be scenario based and/or probabilistic. The duration of advice will be a key issue to determine.

Further, the ESB considers it prudent to recommend that jurisdictions seek to improve transparency regarding the volume and the resource characteristics targeted within underwriting and investment schemes so that market participants possess improved certainty to assess the viability of new and existing projects. Information provision could mirror existing information provision formats, where registered participants provide key connection information (such as plant name, plant type, technology, location, capacity and completion date) to AEMO for publication on the generation information page, and would seek to be provided as soon as possible, or preferably within a defined window. Options for improved information provision to the market will be advanced towards mid-year.

The ESB will continue to work with jurisdictions and stakeholders to define how market bodies can better support government decision making for investment schemes.

Agreed national principles for contract design

Agreed principles for contract design could facilitate underwritten resources integrating with the NEM's existing resource adequacy arrangements and support efficient dispatch. Importantly, principles aimed at maintaining alignment between both the physical needs of the electricity system and the financial interests of generating resources that are party to long duration underwriting agreements will assist such contracts 'dovetailing' with existing arrangements. In doing so they would minimise the risk that is born by consumers or governments on their behalf.

The following high-level principles could inform the design of long-duration contracts to incentivise investment in classes of resources:

- participants that are party to these contracts are incentivised to make operational decisions based on wholesale price signals. Such a contract provides a financial incentive for the generator to bid into the market as a way of backing the financial derivative contract. Derivative contracts are used in the NEM and support generators and retailers to minimise price shocks in the real time market.
- incentivising the investor to enter a bilateral contract with a market participant rather than rely on an underwriting contract with the government. One way to do this is to design the underwriting contract as an option so that it provides a safety net which the generator can rely on at a later point in time. Current mechanisms that incorporate this principle include the Underwriting New Generation Investments scheme managed by the Commonwealth Government which proposes a *"final fallback option which allows the generator to service its debt agreements"* [13] and the NSW Electricity Infrastructure Roadmap which intends to provide agreements that *"will be option contracts which give the project optional access to a competitively set minimum price for their energy service"*[14]. These structures are intended to provide a low price that protects some of the investor's downside whilst retaining the incentive to find better price and terms in the wholesale market.

These principles are particularly important for variable renewable energy resources that have very low marginal cost and can only run when their fuel is immediately available – wind or sunlight. Some early examples of power purchase agreements (PPAs) paid the same price regardless for all output and whether the market needed the power. Since then, PPAs have evolved and provide a greater incentive to respond to market signals by for instance passing negative price risk back to the generator. For example, the NSW Electricity Infrastructure Roadmap[15] intends to put in place Long Term Energy Services Agreements that *"encourage projects to meet the physical firming needs of the system"*[16] and mitigate the risk that generators are not incentivised to reduce output when spot prices are negative through the use of fixed volume/fixed shape contracts.

The ESB proposes to continue working with jurisdictions and stakeholders to develop and agree principles and practical contract structures that align financial incentives with the physical needs of the system.

13 Underwriting New Generation Investments – Public Consultation Paper, October 2018, Commonwealth Department of Energy and Environment, p.6

14 NSW Electricity Infrastructure Roadmap - Building an Energy Superpower Detailed Report, November 2020, NSW Department of Planning, Industry and Environment, p29

15 NSW Electricity Infrastructure Roadmap - Building an Energy Superpower Detailed Report, November 2020, NSW Department of Planning, Industry and Environment, p37

16 Electricity Infrastructure Investment Safeguard - Long Term Energy Service Agreements – January 2021 update, NSW Department of Planning, Industry and Environment

Intersection with the RRO

Jurisdictional investment schemes should dovetail with the RRO to support reliability, particularly given the significant amount of energy likely to enter the market from these schemes. To support reliability at the lowest cost to consumers, investors must have the ability (and incentive) to participate in selling RRO qualifying contracts – whether that be financial or physical.

The ESB will provide advice on any implications for jurisdictional investment schemes that seek to underwrite resources in light of our final recommendations on the RRO.

Questions for consultation

1. What types of information provision regarding jurisdictional investment schemes would benefit participants the most?
2. Which financial principles are most important in establishing means to integrate jurisdictional investment schemes with market arrangements as smoothly as possible?
3. Are there financial principles missing, or that have been included but shouldn't be?

Enhanced exit mechanisms

As new VRE places downward pressure on future expected energy spot and contract prices, the commercial viability of thermal generation continues to erode. This creates a real risk of lumpy thermal exits occurring earlier than anticipated.[17] While the proposed reform pathway looks to support the market to sufficiently manage anticipated changes and challenges over the course of the transition, robust exit arrangements - which can be implemented immediately -may help to ameliorate concerns regarding very near-term unexpected exits.

The January 2021 Directions Paper identified various options to address the event of early exit, including changes to notice of closure requirements, regulated or negotiated arrangements with thermal generators, and contingent scenario planning. Building on this the ESB has developed three proposed exit mechanisms which are prudent backstops to address reliability risks that arise with earlier than expected exits.

These proposed mechanisms support existing backstops and are additional to the contingent scenario planning option previously identified in the January Directions paper. This planning option recommends jurisdictions undertake contingency planning for the possibility of sudden exit due to technical failure. Governments would work with transmission network service providers (TNSPs), the market bodies and market participants to identify appropriate sites for replacement capacity for critical plants and to identify what barriers there are to authorities and governments acting swiftly to determine if any interventions are needed. This could involve obtaining planning pre-approval to shorten construction times in the event of a sudden plant exit that threatened reliability or security, or the consideration of locational constraints due to network congestion and identifying suitable replacement options. This process – while led by jurisdictions with the cooperation of market bodies, will benefit from the information provision and detailed analytical exercises proposed as part of the integrated process for managing early closure.

A brief description of each option is outlined below. Further explanation of the detail within each option is set out in Part B. All options are expected to be relatively straightforward to implement as they build on existing systems and processes.

Increased information around mothballing and seasonal shutdowns

Any action to manage the orderly exit of a large, retiring thermal generator requires accurate information made available in a timely manner. Over time the ESB expects that the energy transition will drive further

17 On 10 March 2021, EnergyAustralia announced Yallourn Power Station will be retired in mid-2028, with a commitment to build a 4-hour 350MW capacity battery in the Latrobe Valley by 2026. Yallourn was previously forecast to close by 2032.

changes to plant operating regimes whereby owners of legacy thermal generation seek to reduce their overheads if low wholesale prices are expected. This could include mothballing of units for prolonged periods of time and/or seasonal shutdowns or cyclical running regimes e.g., weekday/weekend, day/night.

Existing information processes may not be fit for purpose for the future, given they were created without managing exits in mind. Under existing arrangements, generators are required to provide AEMO information on their expected operations via two key processes: the MT PASA and AEMO's Generator Information Surveys, the latter being a key input into AEMO's ESOO.[18] Neither process may be granular enough to allow for a sufficient understanding of a generator's unavailability given new types of operating regimes or how long generating units would need to return to service.

Given the potentially opaque obligations surrounding the mothballing or seasonal shutdown of a generating unit(s), the ESB considers information provision from generators could be amended to extend the current obligations under existing process to address these issues.

Expanding the notice of closure requirements to include mothballing

Under current notice of closure requirements, generators are able to seek an exemption to the 42 months advance notice period required if they intend to close. In deciding on these exemptions, the AER has regard to, among other things, reliability and security impacts and it seeks to consult with AEMO and specific relevant stakeholders.

There is a spectrum of different mothballing arrangements from permanently unavailable all the way through to potentially being available within a short period of time if prices rebound. Across this spectrum a generator is not required to seek an exemption from the AER for early closure.

The ESB considers there could be merit in broadening the AER's notice of closure exemption requirements to include mothballing such that any significant early withdrawal of capacity from the market in the notice period requires an exemption.

An integrated process to manage early exit

Under the current notice of closure requirements, the onus is on the retiring generator to provide the AER with pertinent information so that, after consultation with stakeholders, including AEMO and governments, it can determine whether to grant an exemption or not to allow plant to close without being subject to the full suite of compliance obligations set out in the notice of closure framework.

To provide government and market bodies with a holistic understanding of the potential risks associated with early exit of a generating unit, the ESB has developed an integrated process which complements the AER's exemption process. The purpose of this new process is to gather all relevant information as early as possible so that a timely comprehensive risk assessment can be conducted that allows a state government to act if they consider the risks are too great.

The ESB recognises that state governments are best placed to deal with the risks of early closure within the 42-month notice of closure window, and that such an integrated process would dovetail with the suggested contingency planning for sudden exits suggested in the January paper. State governments can make the trade-off between the risks that they are seeking to mitigate and the costs of intervention – acknowledging that although an early closure is not an optimal outcome as considered by the notice of closure framework, allowing an early exit as notified may practically remain an optimal and prudent outcome for all stakeholders.

18 A generator owner may have financial market disclosure obligations where there are material changes to its operations. Financial market disclosure requirements will differ amongst participants subject to their ownership model and the materiality of a generator's operating regime on their business. What this means is that there is no consistent or specific obligation to report that a unit has been mothballed or is in a seasonal shutdown and the level of recall available (e.g., 1 week, 1 month) may not be clear.

Under this new process, additional information would be collated to allow a complete System and Market Impact Assessment, alongside the AER's exemption decision. A System and Market Impact Assessment would consider, for only certain *designated* coal and gas fired generators, the operational risks and challenges to reliability and security that may arise from an earlier closure, and its likely impact on wholesale prices. The assessment could also extend to considering whether the generating plant could be operated safely, reliably and commercially for a period beyond the early closure date.

A System and Market Impact Assessment would be a useful framework for considering all potential alternative options to address the risks identified, before any decision to intervene is made. As a last resort a government may seek to enter into an Orderly Exit Management Contract (OEMC) with the retiring generator to keep it running until the risks of exit reduce to an acceptable level. While the integrated process does not include a recommended OEMC structure, it considers:

- there are key contract terms and provisions that would need to be addressed as part of any negotiation, including:
    - Obligations on generators to:
        - bid into the market and make the specified capacity / services available at the required times; and
        - ensure sufficient fuel supply was available and maintenance undertaken to meet output requirements until the end of the agreed term.
    - Payment structures for performing the required obligations e.g., capital injection, availability payments, contract for difference, cost + margin, incentive payment at closure date;
    - Cost recovery of these arrangements would need to be funded by the state government e.g., through distribution use of system (DuOS) charges.
- any OEMC type arrangement entered by a state government should be kept separate from RERT arrangements, to allow an assessment of whether any additional RERT would be needed, over that already included in the System and Market Impact Assessment.

The ESB is not considering that such an intervention would be the only option at the end of the integrated process, being mindful of the moral hazards that may arise from maintaining any such expectation. It will continue to consider ways to mitigate this risk ahead of its final recommendations mid-year.

Questions for consultation

In relation to the mechanisms set out in Part B:

4. What are some of the market-based signal challenges, if any, with mothballing/seasonal shutdown?
5. What additional costs or process burden may the disclosure of such information place on stakeholders?
6. What concerns do stakeholders have around the commercial sensitivities associated with disclosing information?
7. Do stakeholders perceive the disclosure of mothballing / seasonal shutdown information as limiting a participant's flexibility in operating their plant?
8. Do stakeholders agree the notice of closure exemption process should be extended to include mothballed generation? If so, should it apply to all generators or just to large designated thermal generators?
9. What suggestion do stakeholders have for defining mothballing?
10. How can governments, market bodies and market participants better work together to be prepared for exits?

11. Do stakeholders agree governments are best placed to enter into a contract with a respective participant in the event of early exit?
12. Do stakeholders agree that any future contract arrangements should be kept separate to existing RERT mechanism?

2.4. Initial reforms

Modifying the Retailer Reliability Obligation (RRO)

As foreshadowed in the January Directions paper, the ESB is considering modifications to the current RRO so the market is best prepared to preserve reliability, in the face of uncertainty, throughout the transition.[19] Jurisdictions are in different phases of transition and rely on different technology types. However, an effective investment signal will be important across the NEM.

The current RRO started on 1 July 2019 and has been triggered in South Australia for reliability in the first quarters of 2022, 2023 and 2024 by the South Australia Minister. Also, following a request from AEMO, the AER has made a T-3 Reliability Instrument for NSW from 1 January to 29 February 2024. This request was made on the basis of the interim reliability measure.

Since the commencement of the RRO (and the ESB's Post-2025 project), many of the market dynamics that induced its introduction have altered. A considerable number of stakeholders have continued to express concerns about the adequacy of longer-term investment signals, and uncertainty around technology costs, demand, policy and exit that continued to influence leads to delays or deferment of investment decisions. Meanwhile, governments have agreed to, and implemented, interim reliability measures until the RRO can be reviewed. Further, jurisdictions have continued to announce ambitious renewable energy targets along with mechanisms to underwrite existing or new dispatchable capacity. These mechanisms have the potential to dampen investment signals from the NEM spot and contract markets and so shift investors' risk out of the energy only market and distort the signals for others. This may lead to reduced contracting for investment in dispatchable resources and potentially impact on exit and closure decisions in relation to large scale ageing generation plant.

These dynamics reflect that there is a choice to be made on where the signal to invest should best come from and so the role of the RRO. The 'heavy lifting' for investment could come through signals in the real time market[20] together with the support of a modified RRO. There is a spectrum of RRO modifications, including amending it so it becomes the prime driver of investment in the NEM with the existing arrangements being relied upon to ensure efficient dispatch. This may prevent the need for government underwriting for dispatchable resources and instead drive commercial investment incentives from market participants.

In Chapter 3 the ESB presents a proposed transition pathway for the reform of the way that essential system services are procured. While such reforms assist the current market design valuing dispatchable capacity, this alone may not be enough to signal the longer-term investment needed for sufficient dispatchable resources and storage capacity. Consequently, it remains, prudent to revisit the RRO framework to ensure it is fit for purpose, and best prepared to support this goal.

By modifying the design of the RRO it can operate more flexibly to respond to changing market conditions and support the specific market outcomes sought. Modifying the RRO means it can be used as a lever to:

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19 See the ESB's January Directions paper and September Consultation paper for more information on why the ESB is considering enhancing the current RRO.

20 The reliability settings provide an important price envelope to the real time market and are set to achieve the reliability standard to support efficient operational and generation decisions, while protecting market participants from excessive high prices. This is essential to maintaining the integrity of the market. The Reliability Settings will be reviewed by the Reliability Panel by 30 April 2022. The current settings, and any adjustments to the Reliability Settings would impact other aspects of the proposed market design pathway for resource adequacy. Meanwhile, the Reliability Panel's review will observe outcomes of the Post 2025 work and the ESB will work closely with the Panel on this issue.

- Promote commercial investment to improve reliability, rather than government underwriting reliability risks, and/or
- Reduce the likelihood of a generator unexpectedly exiting the system, and/or
- Ensure there is a minimum amount of liquidity and contracting in the derivative market to support transparency of future price expectations.

In considering these modifications, the ESB considers it is preferrable for the 'heavy lifting' for investment to come through signals in the real time market,[21] together with the support of an RRO but this would likely require governments to cease intervening in the market along with greater confidence over the drivers of future revenues in the energy market (supply, demand, technology costs etc). Alternatively, if the market is unable to deliver enduring signals for investment and contract (and orderly closure) the RRO could be designed to become the primary driver for investment in dispatchable resources.

Defining objectives for modifying the RRO

The ESB considers there to be six key measures of success that a modified RRO can practically achieve, while seeking to minimise unnecessary increases in consumer bills:

- Seek to support longer term investment signals
- Encourage commercial risk-taking for investment (and so minimise the need on reliability grounds for government underwriting dispatchable resources)
- Seek to avoid disrupting price signals in the real time market as much as possible
- Ensure market participants bear risk for wholesale reliability gaps experienced by customers
- Financial incentives or capacity commitments are sufficient to deliver the physical needs of the power system
- Help ensure new resources are operating in the market when they are needed.

It may be that no one modified RRO can achieve all these six measures equally successfully. Different RRO designs can have slightly different strengths and weaknesses which need to be considered.

While modifying the RRO should seek to advance the measures of success described above, the ESB acknowledges that pursuing these outcomes can come at a cost of increased regulatory burden that should be minimised by:

- establishing a compliance regime that is enforceable and not unwieldy
- designing to minimise implementation costs
- designing a mechanism that minimises the impact on electricity costs, recognising the differences in jurisdictions in respect to reliability risks and projections.

Any decision to enhance the RRO, will be compared against possible outcomes associated with maintaining the current RRO (without amendments), coupled with other market reforms that may have positive externalities on resource adequacy. These other reforms will include amendments to the real time market through valuing essential system services the possible implementation of an operating reserve, enhanced exit mechanisms and broader market reforms.[22] This analysis will be undertaken ahead of the ESB's final

21 The reliability settings provide an important price envelope to the real time market and are set to achieve the reliability standard to support efficient operational and generation decisions, while protecting market participants from excessive high prices. This is essential to maintaining the integrity of the market. The Reliability Settings will be reviewed by the Reliability Panel by 30 April 2022. The current settings, and any adjustments to the Reliability Settings would impact other aspects of the proposed market design pathway for resource adequacy. Meanwhile, it is likely the Reliability Panel's review will observe outcomes of the Post 2025 work and the ESB will work closely with the Panel on this issue.

22 Including 5 Minute Settlement Wholesale Demand Response Mechanism, future reforms from DER

recommendations mid-year, together with the development of a 'strawperson' for each of the enhanced RRO options outlined below.

Specific design options to modify the RRO

The ESB will further consider and develop two broad options for modifying the RRO:

- ***Option 1:*** Modifying the current RRO by removing the T-3 trigger and maintaining the use of financial contracts, thereby increasing the duration of the price signal for investment and promoting a higher level of enduring contracting by retailers. This may also help to simplify the current RRO.
- ***Option 2:*** An enhanced RRO that changes the definition of qualifying contracts to newly created physical certificates. Depending on the design of this option, it could reduce or remove the need for governments to underwrite dispatchable investment.

Both options are intended to supplement and support the real time market and lengthen and strengthen investment signals for resource adequacy. In developing these options, the ESB considered the common policy settings or 'design levers' for an RRO, which can each be 'pulled' to different levels and combined to form different modified RRO options.

A brief description of each option is provided below. Given the complexities of option 2 and it being a departure from existing arrangements, a more detailed overview is set out in Appendix B.

<u>*Option 1: The current RRO, but with no T-3 trigger.*</u>

This option seeks to improve the current RRO's focus on encouraging retailers and large load to contract earlier, while concurrently looking to simplify some of the current RRO's complexities. The option maintains the existing definition of a qualifying contract and contracting requirements to POE50+ but looks to remove triggers where it is practical to do so. With limited forewarning when an assessment day may fall, retailers and large loads will be encouraged to closely monitor the reliability of the market and the net position of their contracting book. In developing this option, we are considering how a lack of warning at T-3 may impact liable parties (including commercial and industrial customers) and whether it imposes an unnecessary increase in costs.

The potential architecture for this option is presented below. It stands as an example to be improved and further developed after stakeholder feedback. Table 1 below presents a comparison of the architecture for the current RRO, option 1 and option 2.

- **<u>Financial contract</u>:** the definition of qualifying contracts stays the same.
- **<u>Remove T-3</u>:** Removing the trigger and gap identification at T-3 means retailers are likely to maintain a higher level of hedging in the event a T-1 trigger is called.
- **<u>Keep T-1 trigger</u>:** This maintains the focus of the RRO on remediating a reliability gap before it occurs.
- **<u>T-1 contract assessment:</u>** Maintaining contract compliance assessment at T-1 will support earlier contracting by retailers.
- **<u>Market Liquidity Obligation (MLO) re-considered and possibly removed</u>:** As T-3 is no longer used as a trigger, the MLO will need to be re-considered. It is proposed that the AER will monitor a range of measures of liquidity that would be developed in consultation with stakeholders. If these measures fell below a defined threshold then the AER could trigger the MLO.
- **<u>Opt-in customers</u>** – the current opt-in register triggered at T-3 would become a standing register, i.e., customers will be considered to have opted in unless they opt out.
- **<u>Assessment</u>:** Assessment remains for all trading intervals where system demand exceeds the POE50 forecast during the compliance window.
- **<u>Penalty</u>:** As per the current RRO; non-compliant liable entities would pay a share of RERT costs plus face the risk of AER civil penalties.

Costs and Benefits of a modified Financial RRO

By minimising triggers so that retailers are encouraged to contract more regularly, the investment signal for new resources is strengthened. The proposed architecture would also simplify and streamline the existing RRO and is likely to pose minimal intrusion to the market. Further, the design and consultation processes for this option can be completed in the short-term, and hence the benefits of such an option can be impacting the market prior to periods in the transition where resource adequacy is expected to be challenged.

However, the efficacy of a financial RRO may be reduced to the extent that it is reliant on NEM spot and contracting markets to drive investment signals, in circumstances where these signals have been weakened and where market participants continue to face an uncertain investment environment. The ESB is interested in stakeholder views on this. The ESB acknowledges that stakeholders remain concerned about the need for any further changes to the RRO, particularly given the amount of time that the current RRO has been in place.

Option 2: A physical RRO with no or minimal triggers

The physical RRO being considered for development is not intended to link originating physical assets to a derivative contract.[23] Instead, it involves redefining qualifying contracts under the current RRO to newly created physical certificates that could be created by dispatchable resources in the NEM. Liable entities would need to buy enough of these certificates to meet their RRO obligations.

In the January directions paper, the ESB noted it would not consider a decentralised capacity market as a separate option but would consider a similar mechanism using physical certificates. Consideration of this option, described below and in Part B, borrows features from other decentralised capacity markets, such as the French Capacity Mechanism,[24] and applies them as they are practical in a NEM context.

The physical certificate would not provide retailers with insurance against energy spot price outcomes. Prudent retailers would still need to hedge to cover their spot price exposure and hence contract market liquidity is not expected to change. Suppliers of physical certificates would be able to sell a derivative contract as well as a physical certificate – with the risks associated with each independent of one another. Similarly, retailers could decide to buy derivative contracts to manage their spot market price exposures, whilst the purchase of a physical certificate for compliance will be guided by the probability of RRO assessment and the associated penalties for non-compliance.

The potential general architecture, and key design choices, for this option is presented below. While both the current RRO and a physical RRO place obligation on retailers and large loads, a physical RRO additionally requires a process for the regulation of the supply of the physical certificates. The design of a physical RRO therefore needs to provide enough time for AEMO to certify the new physical resources available to the market. The ESB is currently considering two alternatives for a physical RRO – one that could operate continuously, or alternatively one that is triggered (for example at T-3) on the basis of (for example at T-3) by governments or by AEMO according to forecast reliability concerns.

The following represents a hypothetical example of how a continuous physical RRO could work and alternatives for key design choices. It is intended to aid further discussion with stakeholders as the ESB refines the key elements of the physical RRO 'straw person'. More detail on 'what' a physical RRO could be is provided in Part B.

- **Physical:** as noted above, the definition of qualifying contract would change.

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23 There is a range of reasons why it is undesirable to attempt to identify the originating physical aspect of derivative contracts, not least of which it will be very difficult for retailers or other third parties to make this assessment and it will negative impact liquidity in the derivative contract market.

24 https://www.services-rte.com/en/learn-more-about-our-services/participate-in-the-capacity-mechanism.html

- **Triggerless (no T-3 or T-1 trigger**): Unlike the current RRO no gap is required to be identified by AEMO. Physical resources would need to be assessed and certified by AEMO in advance. Liable entities would need to purchase certificates in advance to manage their potential compliance obligations in the event that RERT is procured by AEMO (and demand exceeds a given 50POE level or particular supply/demand conditions are met). Methodologies for assessing and certifying dispatchable capacity should be consistent with those used by AEMO in the ESOO and ISP.
  - Alternatively, the ESB is considering **maintaining the <u>T-3 trigger and reconsidering the role of the T-1 trigger</u>:** as with the current RRO a reliability gap would be identified by AEMO in the ESOO or by the relevant jurisdiction. Physical resources would need to be assessed and certified by AEMO in advance. Liable entities would need to purchase certificates to manage their potential compliance obligations. Given the role of the T-3 trigger in encouraging new investment and physical certificates being a separate fungible product, the role of a further T-1 trigger or gateway is likely to inhibit rather than provide the additional incentive for new investment.
- **Contract assessment at T**. After an assessment day occurs retailers must submit their certificate position to the AER
  - <u>Alternatively, **T-1 contract assessment is maintained**</u>**:** At T-1 retailers must submit their certificate position to the AER. The AER will only review and assess compliance of the T-1 position if a T assessment day occurs in the identified window.
- **Market Liquidity Obligation**: modifications to the current MLO framework would need to occur to ensure sufficient confidence for liable entities in their access to contracts the newly created physical certificate market
  - <u>Alternatively, if this option is triggered</u> modifications to the current MLO could be made to ensure liquidity in physical certificates following the trigger of the obligation at T-3.
- **Assessment**: the compliance window could change to be the annual peak period (summer for most regions) when the demand is likely to exceed a given level (eg POE50, with the assessment day also including the need for actual use of RERT, as a proxy to capture tight reliability days with the assessment day unchanged from the above.
  - <u>Alternatively, if this option was triggered</u> assessment days should remain at POE50+ trading intervals during the compliance window. If there is no T-1 trigger, the assessment day being unchanged from the above.
- **<u>Penalty</u>:** As per the current RRO; a portion of RERT plus the risk of AER civil penalties.
- **<u>Compliance for the supply of contracts</u>:** Physical certificates will need an ex-ante certification process. Following this certification one approach is that the physical resources have no further assessment of whether they were available at the time of the gap. Alternatively, the supply of physical capacity could be verified on the day, and if insufficient physical capacity was available (e.g., the generator had more capacity offline than expected) then the AER could take enforcement action. In practice, it is likely that a middle ground may need to be explored for compliance of supply-side certificates, this could include a requirement on certificate suppliers to inform AEMO if they are unable to meet supply obligations and any failure to be available as desired could impact future certification volumes.

Costs and Benefits of a Physical RRO

A physical RRO could be beneficial for a number of interconnected reasons:

- there is a risk that governments may not be accommodating of the high prices or price volatility in the energy only market, which are necessary to incentivise dispatchable investment. Conversely, the impact of jurisdictional investment schemes may dampen spot market prices, which may undermine investment signals in the contract market. Both create a significant risk of reducing investment signals for dispatchable resources. If there is such a risk throughout the transition, then a physical certificate could either:

    - replace the current market signals for investment in the case of an 'always on' physical RRO, leaving the spot market to ensure efficient dispatch of existing capacity; or
    - support or work in parallel with the current market signals for energy with a parallel price for reliability on certain days, through a triggered physical RRO.

- By addressing this risk, a physical RRO can strengthen incentives on retailers to contract for dispatchable resources and to efficiently manage the closure of existing plant. In doing so it could minimise the need for RERT, some backstop measures (exit mechanism) and possibly government intervention for reliability risks.
- For effective investment signals, high prices or price volatility in the energy only market need to be coupled with a well-functioning contracts (derivatives) market. For the reasons outlined below, confidence in future revenues from the contract market may be insufficient to drive new investment, which is addressed by a physical RRO.
    - The current interaction between the wholesale contract prices that drive incentives to invest by linking the physical needs of the system to financial outcomes may not be as reliable a relationship during the transition as it has been historically.
    - Electricity derivative contracts are financial and are cash settled against the real time spot price. The NEM incentivises participants to manage their risk at lowest cost. In the NEM, this risk can be managed by a physical presence in the real time market or by risk management techniques that require no physical backing.
    - As market uncertainty increases through the transition, and with increasing interventions through jurisdictional schemes, physical positions become riskier, which creates more opportunity for speculative, non-physical contracts to support risk management at lowest cost.
    - Therefore, the reliance on an indirect incentive through derivative contract trading may not provide the necessary signals for investment in reliability.

These benefits then need to be considered in relation to the costs of a physical RRO:

- The additional value of physical certificates is likely to be small if the energy market can effectively deliver for reliable investment. That is if the market price settings in the spot market, (which the Reliability Panel will review by 2022) are consistent with factors such as reliability expectations, the costs of investing in dispatchable resources and the expected profile of their use, then there will be little 'work' for a physical RRO to do as a driver of investment
- a physical RRO is likely to have a larger regulatory burden than the current RRO or its modification. Choices around certain design elements identified above will have different implications on the extent of this burden. A physical RRO that was 'always on' would increase compliance obligations on liable entities. However, unlike a triggered option, it would benefit from an enduring mechanism that ensured that the market infrastructure was in place, in advance of the certificate scheme needing to supplement the market.
- A physical RRO is likely to impose increased barriers to retail competition and product innovation than modifying the current RRO. It may also lead to possible overcompensation of existing thermal generation assets and detrimental impacts to liquidity in financial markets. The ESB will be considering these impacts further (see below) and how they can be mitigated.

Table 1 Comparison of Options 1 and 2 to the current RRO

RRO Design Element	Current RRO	Current RRO + Remove T-3	Physical Certificates
Problem to be solved	Impending reliability gap.	Timely entry and orderly exit	Timely entry and orderly exit (as per current)
Triggered when?	In 3 years	In 1 year	For further consideration - Triggered or ongoing
Affects whom?	Retailers, large market customers and opt-in customers	(as per current)	Current RRO + Generators
How?	Liable entities enter financial contracts	(as per current)	Generators seek to have generation certified by AEMO. Liable entities purchase certificates
Initiation of mechanism	ESOO shows a gap at T-3, T-1 or SA govt initiates	ESOO shows gap at T-1	For further consideration – Reliability gap at T-3 or govt initiated. - Ongoing obligation assessed at T - Role of T-1 for compliance or not.
Actions at T-3	MLO kicks in. Voluntary Book Build	Re-consider MLO	Generators apply to create certificates which they can then sell. Possible MLO
Actions at T-1	Liable entities surrender net contract position to AER	(as per current)	Options to be considered - see part B
Actions between T-1 and T	Some variations to net contract position. AEMO procures RERT	(as per current)	Options to be considered - see part B
Actions at T	Liable entities can reduce their demand AEMO may use RERT	(as per current)	Options to be considered - see part B
Assessment Period	If system demand > P50 forecast in defined compliance trading intervals	(as per current)	Options to be considered - see part B
Definition of non-compliance	If liable share > submitted net contract position	(as per current)	(as per current)
Consequence of non-compliance	Bear higher share of any RERT costs. AER enforcement.	(as per current)	(as per current)

Consideration of impacts on smaller retailers and large customers
The ESB acknowledges the stakeholder feedback from these classes of market participants - both during the development of the current RRO and now through the P2025 work – that highlight the importance of ESB reforms not eroding competition in the retail and wholesale market.

The current RRO incorporates specific measures to safeguard competition, and to enhance liquidity and pricing transparency in the retail and wholesale markets. If modifications to the RRO are recommended by the ESB mid-year 2021, it is intended that the key elements that were included to achieve these will remain or be modified as needed to reflect the need to safeguard competition and liquidity. To address these concerns, the following key design elements of the current RRO will be considered further in modifying the RRO:

- Recognition of the importance of voluntary demand response in meeting reliability requirements at least cost. In considering the design of a physical RRO, consideration will be given to incentivise the participation of demand response in the market.
- The option 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. The removal of the T-3 trigger will require consideration of options for establishing a standing opt in register.
- Exemptions for small retailers and market customers with annual energy consumption equal to or below 10 GWh (eg small retailers). This is not expected to be impacted by any of the proposed enhancements outlined in options 1 and 2.
- Liable entities can adjust their net contract position in a region, within a compliance period, if their maximum demand will increase by more than 10% as a result of having more small customers or by 1% as a result of having more large customers (who are below the opt-in threshold of 30 MW). This is not intended to be changed if any enhancements are recommended.
- The grandfathering of contracts that were entered into pre 13 December 1998. The treatment of this element will be considered further in the context of a physical RRO.
- The MLO placed on the largest generators between T-3 and T-1 when the obligation is triggered. The removal of the T-3 trigger may require an alternative approach to be considered to ensure liquidity in the relevant contracts remain. A physical RRO with certificates may require a liquidity obligation to minimise barriers for smaller retailers to access physical certificates.

Questions for consultation

Proposed measures of success

13. Do stakeholders agree with the proposed principles and measures of success? Are there others that should be considered?
14. Are there any obvious priorities given current and plausible likely future market scenarios?
15. What options are there to encourage contractual compliance among retailers without adopting higher punitive penalties?
16. Would one RRO option over another better suit particular types of market conditions anticipated over the course of the transition?

Option1 - RRO financial option:

17. How could you strengthen the signal? Could minimising the triggers do this? What are the unforeseen consequences or implications with this?
18. What are options to make the RRO simpler, while still advancing some measures of success?
19. What other impacts on small retailers and C&I customers need to be considered? How can they be best mitigated?

Options 2 - RRO physical option:

20. Should it be a triggered mechanism, or be developed as a rolling one?

21. How should the physical certificates be regulated?
22. How would a physical RRO impact contract market liquidity?
23. What other impacts on small retailers and C&I customers need to be considered? How can they be best mitigated?

Operating reserves

Separately procuring some services, including essential services and operating reserves in the spot market, can present complementary benefits to resource adequacy outcomes. The Essential System Services workstream is exploring the services the NEM needs, or will soon need, in addition to energy, to ensure the reliability and security of the system as the generation mix changes. Operating reserves is part of this consideration.

Currently, the ESB is considering the extent to which an operating reserve has the potential to provide a positive externality, at the very least, for resource adequacy. This will, depend on the extent to which the proposed mechanism is hedgeable (i.e., delivers long term investment signals) and in practice add to the buffer of resources held in reserve for unexpected events. This interaction, will be considered further over the coming months, including in developing the final recommendations for the resource adequacy pathway.

2.5. Next reforms

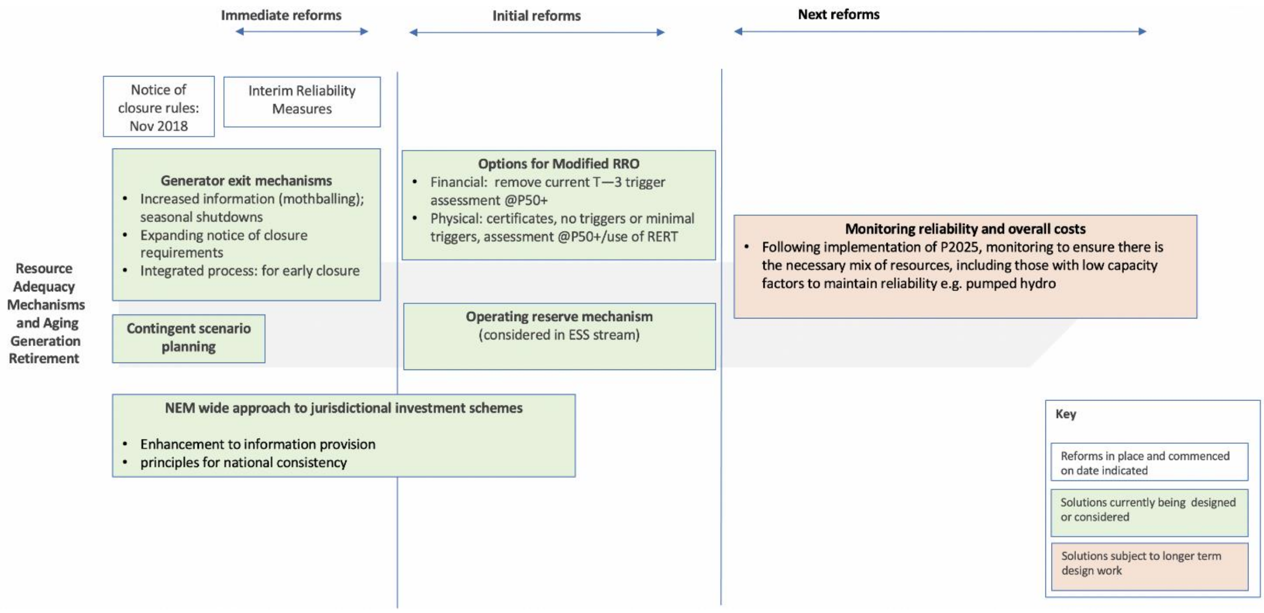
Following the implementation of the ESB's P2025 reforms, continued monitoring of reliability and overall costs to consumers will be necessary. A successful transition would see the right mix of resources incentivised to enter and exit the energy market consistent with reliability expectations and minimising 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 aging thermal units or hot and/or cold weather.

In particular, it will be 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 modified RRO could be designed to lengthen the investment signal but the decentralised nature means it may make it not possible to provide 10 to 15 year contracts.

Also, the modified RRO only provides value for the capacity and availability nature 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 then just generation (e.g., operate in a way that alleviates congestion, provide essential system services). This may require further observation and consideration after the impact of the ESB's Post-2025 reforms are known.

2.6. Illustrative pathway

The proposed reform pathway for resource adequacy can be summarised below:



3. Essential System Services, Scheduling and Ahead Mechanisms

3.1. Key points

- The NEM currently has over 17GW of wind and solar capacity installed. By 2025, even under the current ISP's central scenario, this is expected to increase to 27GW of wind and solar capacity (including grid scale and domestic rooftop solar). Coupled with the exit of large aging thermal synchronous plant, this changing generation mix will press the limits of current system security and operational experience
- In its October 2020 paper 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 recent *Health of the NEM report* [25] noted that system security remains 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 to provide a pathway to operate 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 are currently being progressed by the AEMC in close collaboration with ESB. Where stakeholder feedback is sought as part of the ESB consultation, these insights will be shared and inform the AEMC considerations of rule change proposals.
- The ESB has prioritized for **immediate reform**
  - 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, including for system strength, and
  - 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 new reserve service market could provide an explicit value for flexible capacity to be available to meet these net demand ramps spanning multiple dispatch intervals.
- Solutions over the short and longer term are included as part of the reform pathway for security.

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25 http://www.coagenergycouncil.gov.au/publications/2020-health-nem

- **Initial reforms** in the short run also need to be taken to address system strength and the scheduling of resources to support power system security needs during the transition. As aging thermal plant exits the system, and inverter-based resources displace synchronous generation, services to maintain system security must be procured efficiently. It is also important that efficient scheduling of resources can continue and that there is clarity regarding what resources will be available ahead of time without relying on system operator interventions.
- Proactive procurement of system strength in the investment timeframe, potentially coupled with structured procurement and scheduling at 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.
- In the longer term, next reforms may include:
  - **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 TNSPs, contracting of resources and structured procurement mechanisms. As we progress to higher penetration of 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 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 build confidence in maintaining a secure system with instantaneous variable renewable penetration up to 75% in 2025, as identified by AEMO in its Renewable Integration Study.
- As technology advances and operational understanding grows, there will be benefit from further unbundling the procurement of combinations of synchronous generating units for the provision of 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 even higher penetrations (i.e., beyond 75%) of IBR generation. Enabling each of these services to be provided independently of 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 support this unbundling process and 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.

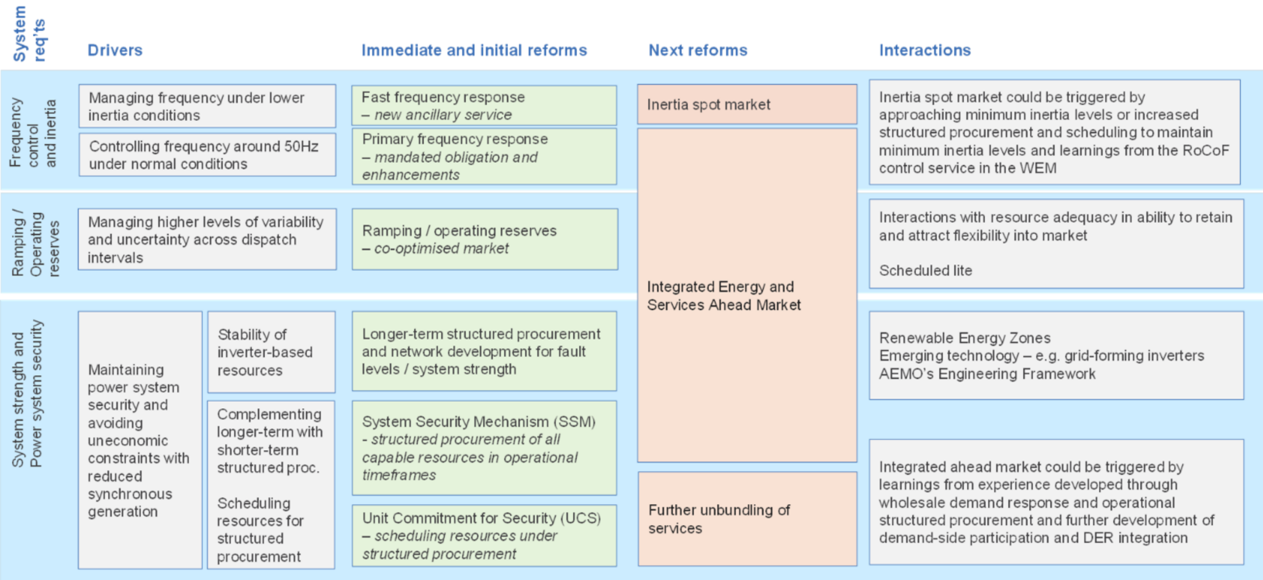
3.2. Proposed transition pathway

To maintain a secure and stable grid system, a number of core power system requirements need to always be met, through the provision of certain technical capabilities, which can be described as essential "system services". These system services include frequency control, inertia, system strength and ramping capabilities/operating reserves, all of which are critical to maintaining overall power system security and reliability. The availability of these 'services' allow the system to operate effectively; any shortfall in their provision will change the way that the system is operated, to ensure that it remains secure.

The rapidly changing mix of resources on the grid is impacting the availability of the resources that have traditionally provided many of these essential system services. To meet these system needs in future, we need a set of clearly defined services and new frameworks to procure these services, which will include TNSPs procuring some services, as well as enabling AEMO to procure capabilities from the market.

Figure 7 below summarises the ESB's current thinking on the proposed transition pathway to deliver reforms associated with the procurement of essential system services and accompanying scheduling mechanisms.

Figure 7 Proposed Transition Pathway



These measures and their pathway have been informed by the framework recommended by FTI in its report on Essential System Services[26] that the ESB commissioned in 2020. This report broadly categorises options to procure ESS along an axis of market efficiency:

1. 'Directions and self-provision of services' without market-based remuneration (currently used for system strength, inertia and operating reserves).
2. 'Structured procurement' via non-spot-market mechanisms (currently used for emergency out-of-market reserves, voltage control, and system strength and inertia under minimum level frameworks).
3. 'Spot market-based' provision of services (currently employed for energy and frequency control ancillary services).

Ideally, spot market arrangements combined with co-optimisation would be used where possible. The ESB considers the market should move progressively in that direction. Although there is a preference for real-time signalling, there is also recognition that not all system services are suited for spot market-based procurement given current technology and understanding. Structured procurement would be used in cases where spot markets are not currently appropriate and may provide important insights on the pathway towards the incremental development of spot markets.

The reform pathway includes immediate and initial reforms where these are identified as being required to support the transition of the power system in the immediate and near term. Immediate reforms need to be done now and implemented as soon as practical. Initial reforms will need to be developed further in the near term for implementation. This includes establishing procurement (for both investment and operational timeframes) and scheduling mechanisms in line with when they are likely to be required. Next

26 https://esb-post2025-market-design.aemc.gov.au/32572/1599207219-fti-final-report-essential-system-services-in-the-nem-4-september-2020.pdf

reforms are ones that we need to move to over time, given the trends and pace of the transition, or may need to be considered if certain conditions arise.

New procurement and scheduling mechanisms should be coupled with long term planning processes and transparency mechanisms, to develop them over time so they are meeting needs. By being flexible with feedback loops between operational mechanisms and planning processes, short term measures can be continually improved to deliver outcomes at lowest cost to consumers.

In the January Directions Paper, the ESB highlighted that it intends to use the AEMC rule change processes on foot to accelerate this agenda consistent with this direction. The analysis and assessment done as part of developing the direction for this reform pathway, including the technical input from AEMO, will be integrated by the AEMC as inputs into its rule determinations. These rule changes provide an opportunity to action these urgent system security issues. Where stakeholder feedback is sought as part of the ESB consultation, these insights will be shared and inform the AEMC considerations of rule change proposals. The reform pathway for each service is discussed below, and further details for consultation are set out in Part B.

3.3. Immediate reforms

Frequency Control

The ESB and market bodies have recently undertaken a substantial amount of work on frequency control frameworks in the NEM, 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 these frameworks; augmenting and leveraging the current arrangements as needed.

The two immediate measures are:

- consideration of a 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 is progressing this work via two rule change requests.[27] Further information is provided in Part B highlighting stakeholder responses and the status of these rule change requests.

The consultation on changes to the NER for each of these work areas is supported by important 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 to support effective frequency control.

Fast Frequency Response

The ESB considers that the development of spot-market arrangements for the provision of FFR is preferred. The high-level market options for the provision of contingency FFR are:

- Option 1 – new market ancillary services to procure FFR FCAS, using existing contingency FCAS arrangements.
- Option 2 – reconfiguration of the FCAS arrangements to procure FFR through the existing service classifications.

27 Rule change requests from Infigen Energy (Fast frequency response market ancillary service) and AEMO (Primary frequency response incentive arrangements). On 17 December 2020, the AEMC published a directions paper seeking stakeholder feedback on its assessment of these rule change requests. See here: https://www.aemc.gov.au/sites/default/files/2020-12/Frequency%20control%20rule%20changes%20-%20Directions%20paper%20-%20December%202020.pdf Stakeholder responses to this paper are being considered and incorporated into the development of the ESB's recommendations.

In response to the AEMC's Directions Paper, most stakeholders agreed with option 1.

The ESB acknowledges the close interaction between the development of market arrangements for FFR services and the valuation of inertia provided above the minimum security -critical levels. 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. While the frequency measures identified above will address much of the system needs under low inertia conditions for the immediate future, they may not over time. The ESB's reform pathway therefore includes a next reform for valuation of inertia services for the longer term.

The AEMC intends to invite further stakeholder comment through the publication of a draft determination for Infigen's rule change request, *FFR market ancillary service* on 22 April 2021.

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.[28] The monitoring of plant and power system impacts due to the implementation of this rule will help inform the Commission's determination for enduring PFR arrangements.

Enduring PFR arrangements are being developed in the *Primary Frequency Response incentive arrangements* rule change requests.[29] 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.

Unlike stakeholder feedback to the above FFR rule change, 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.
- 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.

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

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

3.4. Initial reforms

System Strength

High penetration levels of variable renewable energy (VRE) and distributed energy resources (DER) has led to AEMO intervention in the market to maintain 'system strength'. System strength is important for the stability of the power system with reduced operation of synchronous generating resources. AEMO intervenes to ensure particular units and generating resources are online to maintain a secure and stable grid. To date these interventions have been location specific (e.g., in SA)[30], and steps have been taken to address immediate challenges (i.e., via investment in synchronous condensors). However similar system strength challenges are emerging across the NEM and are likely to increase in future given the changing composition of resources on the grid.

Current system strength frameworks provide minimum security - critical levels of system strength but they do not value system strength above these minimum levels. There is a need for mechanisms to provide system strength services above these levels to enhance security. The ESB continues to prefer a structured procurement approach for these services and is considering what is needed in both an investment timeframe and an operational timeframe. As system strength is addressing a localised need, a real time spot market is not suited for this service at this time but may, over time, become so.

Below we explore how system strength can be procured across both the investment and operational timeframes. Procurement across the two timeframes must be coordinated, to ensure that system needs are met, at the lowest overall cost to customers. It is important to balance the need for operational certainty and maintenance of system security with measures to ensure that the total cost and volumes of services procured across both timeframes are efficient.

Investment timeframe

Consistent with this direction, the AEMC is progressing a rule change submitted by TransGrid for proactive TNSP provision and procurement of system strength[31] which supports an operable system, based on the projected generator connections from the ISP.[32] This follows the AEMC's Investigation into system strength frameworks in the NEM[33], which concluded in September 2020.[34]

In its final report, AEMC set out a model of an evolved TNSP-led approach for the provision of system strength. Part of this framework is a TNSP-led planning process, incorporating a network planning standard, which will require TNSPs to proactively provide efficient levels of system strength based on forecast amounts and locations of new generation, and other resources that demand system strength as set out in AEMO's Integrated System Plan (ISP).

The planning process is intended to consider all available technologies to provide system strength as new generators connect. This may include building network assets or contracting with synchronous generators in an investment timeframe and retuning generator control systems as more system strength is required. Interactions with other essential services, such as inertia, can also be considered as part of the planning process. This provides a pathway to incrementally work towards reducing reliance on traditional

30 Other system strength gaps have been declared in Tasmania, Victoria and Queensland where the TNSP has gone through a structured procurement.

31 Used here to refer to the provision of fault level contribution and managing inverter-driven instability

32 *Efficient management of system strength on the power system* rule change; https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system

33 Available at: https://www.aemc.gov.au/market-reviews-advice/investigation-system-strength-frameworks-nem

34 In that report, the AEMC defined system strength as a service that is primarily based around the provision of minimum fault levels to support the effective operation of protection equipment, as well as supporting the effective operation of IBR resources (management of inverter driven instability). The AEMC also recognised that while system strength overlaps with and impacts general power system stability, it is a subset of this broader concept.

synchronous generation, enabling service provision by new supply and demand-based technologies, while making the most of the existing resource fleet through the power system transition.

The AEMC intends to invite further stakeholder comment through the publication of a draft determination on the *Efficient management of system strength* rule change on 29 April 2021.

Operational timeframe
To complement the above long-term structured procurement, the ESB considers that an operational scheduling mechanism (described below), and potentially short-term procurement, should also be considered. A short-term procurement mechanism could support operations through the transition, while developing an understanding of system configurations needed for security. It could also help maintain broader power system stability, in conjunction with that provided by the TNSP led, investment timescale procurement mechanisms. Learnings through operating in these new system conditions may allow the unbundling of new services in the future in a more technology neutral way. Services from inverter-based generation can be used when they are proven to meet system needs, and so reducing reliance on aging thermal plant for security needs.

A short-term procurement mechanism could be designed to complement and support efficient utilisation of the portfolio of solutions procured by the TNSP in the investment timeframe. The ESB will consider how short-term procurement may interact with the longer-term planning frameworks, as well as any interactions between essential system services, in considering this mechanism.

Short-term procurement could add value through the potential utilisation of all available resources (not just those procured in the longer-term). It would also assist managing security in all system conditions, including where the planning framework has not been able to account for this. For example, planning studies will consider forecast development of new generation and reasonably 'normal' operating conditions – including single outages of generation or transmission elements (n-1) – but they are unable to cover all the complexities of real-time operation. Actual development of the system is likely to differ from planning expectations and actual system conditions will include different configurations, with generation or network plant on planned or forced outage.

Additionally, system limits are continually revised in operational timeframes when detailed models are used and so operation within these limits may be optimised by the use of a different set of resources than those identified in the higher-level assessments necessary in planning studies. Short term procurement may therefore assist in the procurement of additional services needed to maintain general power system stability, to complement those that are provided through the TNSP led, investment timescale procurement mechanism.

Scheduling mechanisms (a unit commitment for security and system security mechanism)

The ESB remains committed to some form of mechanism to support efficient scheduling of resources providing system security services that are not accounted for in the real-time market prices or settings (including constraints). These scheduling mechanisms were described in detail in the January Directions Paper and have been further developed. A summary is provided here, with further material presented in Part B. The ESB welcomes stakeholder feedback on the design of those mechanisms, noting that the specific designs will influence the reform pathway.

The unit commitment for security (UCS) is a mechanism where AEMO, can schedule resources contracted through structured procurement ahead of time to keep the system secure when dispatch and real-time price signals do not, by themselves, support such operation – such as for the provision of system strength. The UCS will not define or procure the services, but rather schedule additional resources that have already been procured outside of spot markets (e.g., via contracts) to an efficient level of system service, which could be over and above security-critical minimum levels. For example, in the current operation of the system, AEMO has identified must-run combinations of units to support a secure system. The UCS could be used to support this required unit commitment. The UCS can schedule those contracts that have been procured by the TNSP in the planning timeframe (as described above) and also via short-term procurement – a system security mechanism (SSM).[35]

Over and above a UCS-only option, a system security mechanism (SSM) could also being considered as an operational tool to complement planning-based solutions for system strength and provide the system configuration needed to maintain security. Such a potential tool could be particularly important as the resource mix on the grid changes (i.e., with the retirement of synchronous thermal generators and entry of large volumes of inverter-based resources (IBR)), resulting in ongoing changes in the secure technical envelope. In practical terms, this option means that AEMO can access services from a broader range of service providers able to deliver these security capabilities increasing the pool of possible providers and maintaining competitive pressure for service delivery.

As discussed above, the potential drivers for consideration of an SSM over a UCS-only option centre around the following two objectives:

- providing operational flexibility to manage system conditions using all available resources that offer in to address the system constraints that apply on the day. The SSM could be used to enable the required configurations of the system are online to maintain power system security – including for system strength, potentially inertia, and general power system security[36] that do not have a real-time price. This could support the procurement of additional services needed to maintain general power system stability, to complement those provided through the TNSP led, investment timescale procurement mechanism.
- facilitating more efficient dispatch outcomes by providing a means for structured procurement of system services on a short-term basis via some form of ahead auction for commitment (adding to any longer-term contracts)

In the context of moving to high levels of VRE, an SSM could provide additional support for operations through the transition, allowing for evolving configurations as experience and confidence builds with operating the system securely with increasingly higher instantaneous penetrations of non-synchronous resources. It could also allow for the development of future services that reduce reliance on aging thermal plant – as and when non-synchronous plant (e.g., via grid-forming converters or other technology) are able and proven to provide the services required for keeping a system stable. Such a mechanism could also support a more technology neutral approach for service delivery. For example, the mechanism could enable limits and constraint formulations to be revisited after unbundling the characteristics that existing plant provide and linking them to the four identified essential system services if an SSM was developed. For the transparent operation of the SSM AEMO would develop and maintain a procedure, through consultation specifying matters such as the types of system constraints that it would be used to manage.

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35 Rule change proposals can be found here: UCS https://www.aemc.gov.au/rule-changes/capacity-commitment-mechanism-system-security-and-reliability-services and SSM https://www.aemc.gov.au/rule-changes/synchronous-services-markets
Note the name of the SSM has been updated since the January Directions Paper from “Synchronous Services Market” to “System security mechanism”. In January, the ESB recognised that “synchronous services” was being used as a placeholder term to reflect any services under structured procurement, that have been traditionally provided by synchronous generators. The term has been updated to “system security” to one, recognise that in the future these services may not be delivered only by synchronous resources, and two, to reflect that, through use of configurations defining the demand for the mechanism, each service may not be perfectly distinguishable in the short term, noting the expectations that has the power system develops and knowledge evolves, the SSM would be used to inform where services can be more easily distinguished and separate procurement mechanisms should be defined for these. The term “market” has been changed to “mechanism” to reflect that the SSM is not a spot market, but instead a structured procurement mechanism. An additional change from January 2021 is that the SSM has now been restricted to the procurement of services without a real-time price.

36 For example, through extensive studies of the power system and stability analysis, there may at times be specific combinations of units that must be online to support secure power system operation. The SSM could be used to enable these combinations to be online, while remunerating them for this service.

The UCS and SSM could be built around existing processes so the mechanism is used as efficiently as possible. For example, TNSP and AEMO determination of system limits, currently used to develop constraint formulations, could be leveraged to provide information as to where and when the SSM may be used to enhance the efficiency of market operations. Through the consideration and development of the proposals, the ESB will consider the interactions between the UCS, the potential SSM and existing pre-dispatch and dispatch processes to map out and assess the impact on participants' incentives and commitment decisions into the real-time market. Further information on these is discussed in Part B.

AEMO's reporting on constraint costs, coupled with cost information from the USC and a potential SSM, will provide useful information that can be fed into the existing joint planning processes. AEMO's system strength reporting process already provides medium term projections of minimum levels of system stability. Similarly, this can then be used to determine whether network solutions should be developed to support the transition, helping to deliver needed system stability and support efficient dispatch outcomes at a lower cost to consumers, by taking advantage of economies of scale and scope.

Noting the interactions between the form of the scheduling mechanism and the longer-term planning frameworks, the ESB is of the view that the UCS and SSM need to be considered together and in conjunction with the four areas of essential services, in order to assess any potential benefits associated with coordinated implementation, (including costs of implementing together or separately). The AEMC is considering Rule changes that would be used to implement the UCS and SSM to align with the ESB's recommendations.[37] Meanwhile, AEMO is undertaking analysis to assess the potential market system impact and implementation cost estimate to be used in the evaluation phase of the options. It is expected further stakeholder workshops will be held in the coming months to inform these designs and evaluation, ahead of the final ESB recommendations and AEMC determinations.

Questions for consultation

24. What are stakeholder views on what specific design issues should be considered for an operational system security mechanism (SSM) to support the objectives of providing secure operations through the transition of the power system and to support efficient dispatch outcomes?
25. What additional information should be considered to assess the complementarity and materiality of an operational structured procurement mechanism (SSM) in the context of a TNSP-led solution in the investment timeframe?

Further detailed questions are provided for consultation in the attachment regarding the interactions between the procurement and scheduling mechanisms and the details of the scheduling mechanism.

Ramping / operating reserve

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.[38]

To date, operating reserves have been provided by scheduled capacity keeping headroom available. The costs of the provision of operating reserves are built into the supply offers and recovered through energy prices.

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37 Delta Electricity ERC0306 which has a draft determination by mid-year 2021, and Hydro Tasmania ERC0290 with a directions paper due mid-year 2021, and draft determination in September 2021.

38 Discussed in detail in the ESB's September 2020 Consultation Paper and AEMO's Renewable Integration Study Stage 1 report

Without a separate and explicit signal for their provision, the level of operating reserves available to the system is dependent on the expected distribution of energy (and FCAS) prices and participant risk appetites. The expected increase in net demand variability and forecast uncertainty as the power system transforms raises concerns that participants providing reserves based on the risks they see in the energy market may not be the most efficient approach to meeting the system need for reserves over the long term.

Addressing the challenge of providing reserves in the most efficient way requires actions across multiple fronts, including continual improvements to forecasting and resource visibility (for example, as being explored in the demand side participation stream, see Chapter 4). This would reduce the rate at which forecast uncertainty will grow (which contributes to the need for reserves), as well as ensuring that a mix of flexible resources is operationally available when needed to meet unexpected ramping requirements (which contributes to the supply of reserves). These requirements will vary across different timescales and increase in magnitude as the penetration of VRE increases (particularly solar PV without significant storage) and the flexibility of the scheduled capacity on the NEM changes.

In its report on Essential System Services in the NEM, FTI Consulting offered a number of principles:

- to deliver an overall efficient dispatch, "*the market design should provide efficient price signals in operational timeframes to ensure availability and utilisation of existing resources. Where services are provided, but not remunerated, this may need to be reviewed to ensure that this does not lead to inefficient outcomes*"
- "*In general, the market design should seek to maximise market-based outcomes, such that the required interventions by AEMO are kept to a minimum*."

Consistent with these principles and the increasing value of flexible, responsive resources, the ESB is considering establishing an explicit price signal for reserves that would reflect their real value at any point in time. The ESB is principally considering reserve services as an essential system service, while also noting that a reserve service could present a scarcity pricing signal for dispatchable capacity that could incentivise investment or the use of off-market resources in market – and so have implications for resource adequacy – as well as interact with proposals under the Demand Side Participation workstream.

The ESB is working closely with the AEMC, which is currently considering two rule change requests[39] that propose two different reserve service options. The AEMC published a directions paper on these two rule change requests in January 2021,[40] which:

- outlined the power system need for operating reserves and the materiality of the need for a new operating reserve product as the power system transforms
- discussed the ability of a new product to support investment in flexible capacity, and
- set out the high-level design parameters of four possible reserve service product options.

The AEMC concluded that a new reserve service may be needed to address unexpected changes in net demand. That is, changes in net demand that were not forecast and therefore were not expected by market participants.

Stakeholders largely agreed that reserves may be required to address such unexpected changes in net demand and would not be required to address expected changes in net demand. Stakeholder views differed considerably on whether these issues are material and with respect to the urgency of implementing a new reserve service outlined in further detail in Part B.

The ESB considers that the most important principle upon which to determine whether and when a new reserve service should be implemented to address these issues is that the expected benefits to consumers of implementation should outweigh the expected costs, over the long term.

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39 Infigen Energy *Operating reserve market* rule change and Delta Electricity's *Introduction of ramping services* rule change.

40 Ref https://www.aemc.gov.au/sites/default/files/2021-01/Reserve%20services%20directions%20paper%20-%205.01.2021%20-%20FINAL.pdf

On the benefits side, valuing operating reserves through an explicit product could provide greater assurance than current frameworks that:

- an efficient mix of resources is applied to system needs for reserves, FCAS and energy
- costs associated with intervention or direction are minimised.

The materiality of these benefits depends on the extent to which current arrangements would result in an inefficient mix of capacity or an increase in interventions. These benefits are therefore closely linked to the question of how participants would respond to increased variability and uncertainty in investment and operational timeframes under current arrangements. Given there is uncertainty in both the future power system dynamics and participant response to those dynamics, the ESB considers that an additional benefit of an operating reserve product is a reduction in risk compared to relying on current frameworks to deliver efficient levels of reserves as a by-product. A further benefit in unbundling this product from energy delivery is that it would provide direct incentives to providers of the service (rather than the energy price which is recovered by all energy providers) and to those that contribute to the demand for the service (e.g., through causer-pays recovery).

The costs of explicitly valuing operating reserves through a separate market mechanism are required to be considered too. Unbundling this as an essential system service requires implementing one or more new markets which will result in a range of direct and indirect costs. Direct costs would include the costs of any hardware or systems changes across the supply chain to implement the new service. Indirect costs could come in the form of flow on effects of implementation, such as any costs associated with breaking and renegotiating financial arrangements that were underpinned by the energy only market structure.

Stakeholders have expressed diverging views on whether the benefits would outweigh the expected costs at this time, and how this may change as variable renewable energy penetration increases and the flexibility of the capacity in the NEM changes.

The ESB proposes to consider this issue in some detail. The proposed approach will be to:

- define the circumstances in which a reserve service would be of value to consumers, and
- consider the appropriate timing of implementation based upon an outlook of whether and when these circumstances are likely to arise in the NEM, and the risks of implementing or not implementing a reserve service.

Part B sets out and includes further discussion on:

- the growing need for operating reserves to manage increasing variability and forecast uncertainty in net demand over timescales of minutes to hours
- benefits and costs of explicitly valuing operating reserves through a new product
- stakeholder feedback on the AEMC's directions paper; and
- the principles upon which the reserve service options should be assessed, as well as key issues to resolve in the design of any reserve service.

The AEMC intends to invite further stakeholder comment through the publication of a draft determination on the *Operating reserve market* and *Introduction of ramping services* rule changes mid-year 2021.

Questions for consultation

26. How do stakeholders view a ramping or operating reserve as fitting within the overall framework for essential system services?

3.5. Next reforms

The need for further scheduling mechanisms and markets for specific system services will evolve through knowledge of the operation of the power system as it transitions, and the accompanying market dynamics.

Further unbundling of services

The immediate and initial reform steps above are aimed at addressing the power system needs and maintaining power system security through the next phases of the energy transition in the short to near term. However, that is not the end state. As experience is built in operating the system at very high levels of VRE penetration (and very low levels of synchronous generation), through demonstrations of the capability of new technology and learnings from the operation of the earlier services and mechanisms, new technologies may be able to provide individual essential services that are currently provided as a bundle by synchronous generators. This will allow the evolution to more sophisticated designs with greater market efficiency where and when possible.

Inertia spot market

The January Directions paper outlined an approach to continue to work on a spot market approach for valuing and procuring inertia as a long-term priority, but to first assess the value of procuring inertia under structured procured arrangements if required in the near term.

This section outlines a pathway of progression towards an inertia market, commencing first with the establishment of structured procurement arrangements for system services (e.g., a UCS and/or SSM (as above), with subsequent opportunity to explore spot-market arrangements as technology evolves, confidence grows in operating the system at very high levels of VRE penetration (and very low levels of synchronous generation). Detailed investigation on inertia in order to understand the technical aspects of it is still required.

The immediate measures addressing frequency and an initial reform step of a UCS and/or SSM [41] are aimed at ensuring that sufficient inertia and frequency control capability is procured and enabled in the short and near term. While an inertia spot market is not for development now, as the power system develops and as operator confidence increases in these arrangements, the ESB is of the view that there may be benefits of progressing towards greater market efficiencies for the procurement of inertia through a spot market mechanism. These may be initially explored within the structured procurement framework, and then subsequently via exploration of introducing a spot market for inertia.

Potential pre-conditions to monitor for progressing this next reform could include a review of:

- The must-run unit-combinations for inertia requirements uncoupled from other requirements (e.g., resources providing inertia that are brought online via the SSM due to a lack of real-time signal),
- The volume, competitiveness and efficiency of structured procurement and contracting arrangements in the NEM,
- The implementation of minimum inertia safety-net considerations for the NEM,
- Lessons from the implementation and performance of WA RoCoF Control Service market
- Capability and availability of grid-forming technologies and synthetic inertia, which would reduce the level of overlap from multiple services being provided by the same asset; and
- The potential for the communication of clear inertia service specifications in incentivising investment the frequency with which minimum inertia levels are the binding constraint in structured procurement

41 These mechanisms could coordinate the provision of system-strength, inertia and broader power system security, for which any may be the binding constraint at dispatch.

arrangements, total volumes of inertia procured, and/or levels of maximum instantaneous IBR penetration as the energy transition progresses.

Integrated ahead market and energy trading

In the September 2020 and January 2021 papers, the ESB set out the potential for an integrated ahead market. The integrated ahead market would incorporate ahead trading and co-optimisation of energy and system services.

An integrated ahead market 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. There are a number of potential uses for an integrated ahead market; some of which could benefit from simple trading of energy in the ahead timeframe, others of which would need more sophisticated scheduling and optimisation processes to be integrated with the market design. These use cases include coordination and co-optimisation of energy and system services, hedging of system service costs, setting a profile for energy storage and demand resources as well as the orchestration of DER and provision of network services.

We note from stakeholder feedback, that customer groups in particular see value in having greater ability to schedule and commit resources ahead of time as this supports planning for large loads and potentially unlocks greater volumes of flexible demand.

However, the ESB recognises that the benefits of introducing an integrated ahead market are difficult to quantify at present and could be further informed after immediate and initial reforms are taken. As described in the January Directions paper, the majority of stakeholders did not consider the further design of an integrated ahead market to be a priority compared to other reforms on the pathway.

Current priorities for the potential use cases of an integrated ahead market could include:

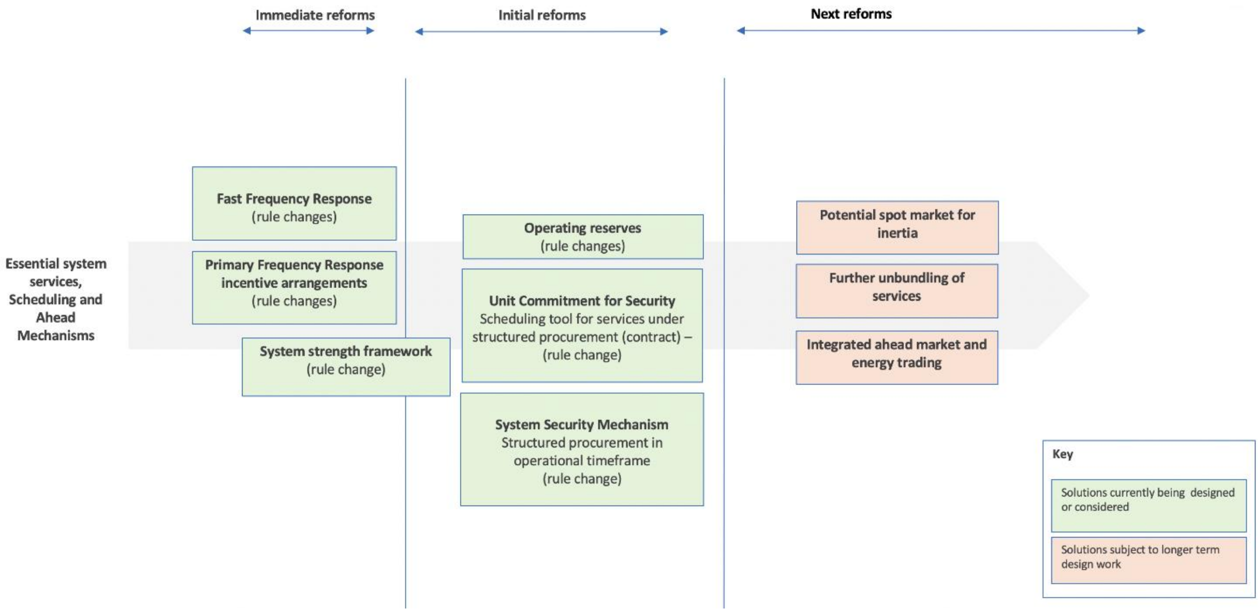
- Establish the suite of ESS and scheduling mechanisms to ensure that the right resources can be online when required to meet power system security and to, as far as possible, increase dispatch efficiency. This work is focussed on value streams for the relevant resources and will include consideration of the associated cost recovery mechanisms, particularly where this may see the continued move towards a greater proportion of costs associated with energy to be through the services markets, rather than energy.
- Continue with the work focussed on immediate priorities to facilitate flexible demand participation, managing minimum demand, visibility of demand-side, trials associated with integrating DER, and understanding the nature of the demand-side resources in the future.

The ESB considers the case for an integrated ahead market to orchestrate the various resources and services and potentially improve efficiency will need to be informed by future market and system developments, as well as the costs and benefits of implementation. Understanding the impact of the immediate and initial reform steps will inform the future potential for introducing an integrated ahead market. Potential pre-conditions to monitor for progressing this next reform could include:

- impacts of new essential system services arrangements, their associated procurement and scheduling mechanisms.
- Demand-side participation rates and utilisation to provide flexibility. In the short term, the implementation of the Wholesale Demand Response Mechanism in October 2021 will provide insights as to the conditions required for demand-side resources to participate effectively.

- DER penetration and orchestration. In the short term, trials associated with DER orchestration and integration into the wholesale market, such as Project EDGE and Symphony will inform the necessary market augmentations to support effective integration.[42]
- Increasing penetration of storage.

3.6. Illustrative pathway



42 See: AEMO, Project EDGE, https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge; and AEMO, WA Distributed Energy Resources Program, https://aemo.com.au/en/initiatives/major-programs/wa-der-program.

4. Integration of Distributed Energy Resources and Demand Side Participation

4.1. Key points

The sheer scale in consumer-driven growth of 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 a more de-centralised energy system. A significant amount of electricity is already generated at a smaller scale. In South Australia this type of generation already provides over 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).

Historically, customers did not engage with their retailers beyond receiving energy at their home or business, paying bills and perhaps switching providers. In future, energy that customers use may also be self-generated or supplied by their neighbours. The traditional one-way power flow from large generators through transmission and distribution networks to customers has become a two-way flow with customers providing and demanding power. This shift opens up opportunities to unlock value to all customers and considerable flexibility can be added to the system.

Existing regulatory arrangements met the requirements of the traditional electricity supply model and are now evolving to support customers and unlock value for them from being flexible with their demand and DER. Where retailers and aggregators can access wholesale markets on behalf of individual customers, this flexibility can be harnessed to deliver services that support the wholesale market as well as providing services to networks. By unlocking the value of aggregated DER, this can provide a competitive alternative to large scale generation to deliver low-cost energy and system services, as well as reducing the need for investments in networks. This results in benefits to all customers (not just those with DER).

Technical integration of DER is needed to ensure that a reliable and secure system continues; arrangements need to support service providers to interact with the wider systems and wholesale market; and customers must be able to be able to switch between new retailers and aggregators without too much difficulty or cost.

The ESB considers the following is needed:

- Clarity and direction on **roles and responsibilities** for various actors in the system and how they may evolve. While core activities are likely to remain, roles need to evolve to meet more dynamic needs of both the customer and the distribution network. For example, as the penetration of DER increases, distribution networks must actively manage and procure services to keep their network operational and stable. Similarly, retailers may now offer customers many different products ranging from traditional power supply to energy saving services. These changes are all about delivering greater value to customers but need to be developed in a way that builds on a clear understanding of roles and responsibilities for all parties.
- A **transitional pathway for reform** that sets out action to take now and develop further reforms for later implementation. 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 demand-based assets into the market at all levels, safely and effectively.

Immediate reforms include a risk assessment tool that helps to assess whether customer protections may be needed with the expansion of new forms of energy services, opportunities to streamline and increase easy customer participation, appropriate technical standards, and arrangements to address minimum demand on the networks so that security and power quality is maintained.

Initial reforms focus on rewarding customers for their flexible demand and increasing value to the system from flexible resources. Customers should benefit from potential revenue streams where flexibility in their energy use can be offered (through a retailer or aggregator) to the wholesale market or through network services.

Reforms also focus on changes 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.

A maturity plan approach is proposed to identify priority issues for DER integration and deliver and inform the detailed design consistent with directions on future roles and responsibilities. The maturity plan is an iterative process through which six monthly 'releases' will identify priority issues for reform, deliver detailed analysis of, or solutions to address, needed regulatory change or capability development. Its governance will allow it to function as a vehicle for collaborative co-design and coordination of several significant DER related reforms, drawing on insights from adjacent processes such as industry or ARENA trials. Outcomes and findings from the maturity plan approach will be relevant to immediate and initial reforms and enable the **next reforms** to emerge, including regarding the future activities required from distribution networks to securely operate their networks.

4.2. Roles and responsibilities

Digitalisation, new technology and market developments are changing the way that customers interact with the electricity market and creating new opportunities for service providers to meet customer needs. The widespread adoption of rooftop solar, in particular, has brought many of these changes into focus. These changes mean the roles and responsibilities of actors across the system will also 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;
- facilitates innovation by service providers; and
- enables networks and AEMO to maintain a secure and reliable energy system; and
- delivers an efficient market that drives down costs for all consumers.

Traditional roles and responsibilities

Before rooftop solar became widespread, the roles and responsibilities of customers, retailers, generators, and networks were clearly defined and understood. In the simplest of terms:

Customers – householders and business were connected by their distribution network and supplied with energy by their retailer and billed for that service.

Retailers – bought energy in the wholesale market (or generated it themselves as gen-tailers) and on sold that energy. Customers were billed for the energy supplied. The cost of transmission and distribution network services (for transporting the power) was included in the bill.

Distribution networks – transported power from the transmission system to the customer. They operated their network securely and reliably in line with regulated standards. Charges for the service were regulated and passed on to consumers through retailer bills.

Transmission networks – transported power from the generators to the distribution networks and connected customers and operated reliably and securely in line with regulated standards. Charges and costs were regulated and passed through to consumers in retail bills.

AEMO – operates the wholesale market by dispatching power from large generators each interval at lowest overall cost and in a manner that kept the whole NEM secure and reliable. AEMO facilitates retail market processes (B2B and B2M processes to enable customer services to be delivered and markets and market participants to be settled). AEMO is also the transmission system planner. Its service is paid for through user charges.

Current roles and responsibilities

In the present situation with increasing installation of rooftop solar, household batteries, EVs, smart appliances and smart meters, these roles and responsibilities are changing.

Customers now are likely to receive marketing offers from retailers and aggregators that not only sell energy but also buy energy or reward customers for changing their energy consumption. Customers may be offered battery storage in return for the customer supplying some energy and essential system services from that battery; they may be offered cheaper bills through management of their energy use by adjusting the times when their hot water, air conditioner or pool pump operates (possibly via automation or smart appliances). Customers can expect multiple products and services to be offered to them and they may end up dealing with more than one retailer or aggregator.

Retailers or aggregators face a wholesale market where energy prices vary substantially across time and where revenue can now be made by managing their customers' demand to suit this variability. Furthermore, with the assets that customers now own, the ability to aggregate customers and manage their flexible demand and battery storage provides attractive revenue making opportunities for retailers and aggregators. A small individual customer cannot trade in the wholesale market but as part of an aggregate they can (offering services into a range of wholesale services markets and or to support networks) and share the value of doing so with the aggregator/retailer and other customers in their aggregation.

The distribution networks now need to support two-way energy flows on their system with the growing penetration of DER, and also flows that can ramp up or down quite suddenly with changes in the weather. This makes operating the network in a stable and reliable manner decidedly more complex, particularly as these networks do not traditionally have the technology for visibility of these changing flows or active control. New ways to manage and monitor these systems are needed and will require additional services to keep the system within its technical limits. In some cases, these services can be incentivized through tariffs, or provided by the aggregated customers, who through their storage and energy management (for example) can even out the load across the day and offer other essential system services at competitive prices. DNSPs need visibility of DER to manage the variability of energy production and system security within their operating limits and facilitate wholesale market integration of aggregated DER resources.

The transmission networks also have emerging issues - as energy flows on the distribution networks become more weather dependent and complicated, transmission operations also become more complex (e.g., voltage management needed to support low operational demand).

For **AEMO** the task of maintaining system stability is more challenging. When parts of the system are experiencing close to zero demand the importance of essential system services to balance the system cannot be overstated. The importance of essential system services is addressed in Chapter 3 but in the context of DER (as with other resources) it is important to recognize that a mechanism to maintain minimum levels of operational demand is necessary for power system security. AEMO will need to provide direction to other actors to manage system security and will require sufficient transparency of DER to manage and plan for these requirements.

These changes are already occurring, and they raise at least four threshold issues.

- First, what models provide customers with the greatest choice to select a retailer or aggregator (or both)?
- Second, what protection is needed for customers with all these new products being offered by often new retailers/aggregators?

- Third, how is the system to be kept in balance?
- Fourth, what tariff and other regulatory change is needed at the network level to benefit all consumers?

Selecting Retailers / Aggregators

New products and services are emerging that provide customers with more choice on how they can participate in the market. These include offers of batteries in return for some supply of energy and services from that battery, or cheaper bills for customers by adjusting the times when their hot water appliances, air conditioner or pool pump operates.

As they can now, in future customers should be able to select offers that suit their needs. Customers should be rewarded for their flexible demand and actions that contribute to a more efficient power system and be protected no matter how they choose to engage.

To achieve this, the market framework needs to allow customers to participate in as many of the services as they choose, potentially via different service providers. The ESB is considering reforms to enable new business models to emerge and to make it easier to provide new services to customers, and these are discussed in the reform pathway below.

Looking at a practical use case, under current arrangements the role of aggregating DER (e.g., solar PV) is provided by the retailer. In moving towards a new two-sided market design, new active solar PV customers could be facilitated through an aggregator, for example as a type of solar VPP service under the Trader participant category. The consumer protections model (see Immediate reforms below) would be consistent with risks and obligations for managing and operating solar energy systems on behalf of customers. In such a model, the energy generation services can be unbundled from primary energy supply.

The issues and first steps relevant to these paths are considered in an initial reform on the pathway, the 'trader-services' model. The rapid uptake of solar PV assets on the grid means these examples are relevant as initial use case priorities; however, it will be important to consider these same issues for other emerging technologies and with two-way flows (such as, batteries, electric vehicles).

Questions for consultation

27. What are stakeholder views on the issues raised on supporting market participation for active DER? Are there other paths that could also be considered for different types of consumers?
28. Is the unbundling of services delivered by active DER resources (e.g., solar PV, batteries or smart hot water appliances) from energy supplied by DER viewed as important to allow innovation and new business models? What might be the pros and cons of this approach?
29. What might be implications of a growing fleet of active batteries or electric vehicles? Are other pathways that need to be considered to reflect these needs?

Customer choice and protection in the energy transformation

As more service providers emerge there is a need to consider the types of protections that may be needed for each of the new products and services. The ESB has proposed a risk assessment tool to help assess where risks or opportunities to customers may be emerging and ensure the protections in place remain fit for purpose. For example, what are the right-sized obligations for third parties that are delivering the services, and how and where do these obligations differ from the service of essential energy supply. These obligations can evolve under the trader-services model of the two-sided market design and be informed by the Maturity Plan process where common use cases for new products and services will be considered consistent with emerging priorities.

Customer switching between new service providers

One of the key outcomes for customers in the future active DER market is increased choice. Given that providers of these products and services will be focused on creating *stickiness* by offering better price, quality and support to their customers; this needs to be balanced with the need to reduce risks associated with customers being locked-in to a single provider, or to experience high costs for switching from one provider to another with a solar PV and storage system that they own.

Acknowledging that no two products and services are the same, and transfer of all the customer's data and capabilities is not always feasible, a comparison can be drawn from the telecommunications sector. There are three mobile networks who at one stage all competed for customers on the basis that they "owned" the customers mobile phone number (they had been assigned a mobile number range). When it became apparent that losing a mobile number was becoming a barrier to switching and competition, the industry provided the platforms and processes for smooth portability of mobile numbers between carriers, and the retention of the mobile numbers.

Potential avenues that could be pursued to avoid customers being locked into single providers include:

- <u>Market to develop appropriate arrangements</u>:

  Rather than imposing barriers to innovation and extra complexity from localised regulation, one pathway is to allow the market to work out the way forward, and address risks and consumer protections as they emerge. Under this approach market solutions will emerge that will be in the best interests of customers.

  An example of this approach is the development of the Australian version of the international standard IEEE 2030.5 on communications protocol for DER. Currently, this is being developed by a number of participants for jurisdictions that have high uptake of DER, and likely to be introduced over the coming 12-24 months. Whilst an important piece, there are a number of related implementation issues such as registration, identity and switching that fall outside of the standard that will have implications for customers. As customer uptake of DER increases, there may be a need to ensure a nationally consistent standard is developed to support customers desire to switch providers, as seamlessly as possible.

- <u>National standards</u>:

  A second challenge is the need to maintain cybersecurity. Scenarios that impact the security of the entire energy system could emerge if clear and consistent standards and regulations are not put in place for active DER connected to the system. Technical interoperability and cybersecurity standards could be introduced and supported at a national level, rather than at a network or jurisdictional level, acting as enablers to allow different technology types to interact with the market on a consistent basis. Clear and consistent cybersecurity standards and operational processes will provide protection to both customers and the grid system but may not meet localized needs and timing as adequately.

- <u>Common business process to facilitate switching:</u>

  Consider similar switching capabilities for customers with DER like solar, batteries or demand response devices that are provided for switching between retailers today. This approach would allow smaller players to enter the market, and stronger competition between similar product and service offerings. However, the costs of introducing these switching capabilities and common business processes would also need to be considered.

Questions for consultation

30. Are there constraints on switching providers with DERs today? Are constraints on switching likely to occur through standards being introduced now or expected, such as IEEE 2030.5?
31. What are stakeholder views on approaches outlined? What might be the advantages and disadvantages associated with each?

32. Are there other potential approaches that could be considered?

Balancing at the system limits

With more DER being installed at households and businesses, distribution networks need to manage two-way energy flows on their system and also flows that can ramp up or down quite suddenly with changes in the weather. The ability of networks to transport and deliver electricity safely, securely, and reliably is being challenged. Distribution networks will need to have a more active role managing these operational needs as the resources on their network systems evolve, with regulatory arrangements needing to evolve to support these new realities.

To ensure the physical limits of the network can be kept in balance and manage congestion, DER will need to respond to signals from distribution networks about emerging system issues such as local congestion or low demand. Today, DNSPs manage these issues by establishing static limits for each DER connected to the network at time of installation, which are not responsive to the more dynamic nature of the system and congestion issues.

By moving to a more dynamic mechanism, DNSPs would take the additional responsibility for the creation of dynamic limits and publish these limits in way that retailers and aggregators can access and enforce them. These signals are intended to be transparent, and auditable, so that the limits reflect the physical realities, and that consumers can be assured that their DER investments are not being unnecessarily restricted by any third party. Conversely, there must be clear compliance on the retailers and aggregators to ensure these limits are observed.

While the ESB considers the distribution network operators are the obvious providers of the dynamic limits or envelopes for each active DER that reside on their networks, there are less clear scenarios where DNSPs are operating existing DER fleets such as load control of hot water, or when applying limits on behalf of AEMO. From the perspective of a customer who has just installed a new solar system, they will need clarity on who they are entrusting their asset to, under what conditions the assets might be constrained and by whom, what might be the commercial impacts, and how any disputes will be resolved. There is also an issue around transparency of these limits and how they are visible and shared between networks, consumers and a range of service providers.

One jurisdiction that has been actively considering these issues is Western Australia (WA), for application in the WA Electricity Market (WEM). Although the governance and market arrangements in WA differ to the NEM, the physical challenges to solve are the same. The ESB and market bodies have been working closely with WA counterparts and note the development of the WA DER Roadmap[43] includes thinking on these issues, including on the evolving roles and responsibilities for distribution networks.

Questions for consultation

33. Under what situations could the distribution network operator perform the role of the retailer / aggregator?
34. What are the issues surrounding connection agreements that can facilitate a retailer / aggregator for market participation and the delegation for the enforcement of limits to both DNSPs and AEMO?
35. Noting the differences in market arrangements between the WEM and the NEM, are there aspects of the WA DER Roadmap that could usefully inform how certain roles and responsibilities might evolve in the NEM?

43 https://www.wa.gov.au/sites/default/files/2020-04/DER_Roadmap.pdf

Tariff and regulatory changes

A key feature of the current regulatory framework is that it provides incentives for networks to meet their obligations and service requirements at least cost. However, the existing incentives framework may not provide balanced incentives to networks for providing export services.

There is potential for customers to be rewarded for reducing network costs, where network services can capture flexibility from demand and DER assets and reduce investment needs. As technology and service providers evolve, there will be increasing opportunity for participation in delivery of these services. But a range of basic barriers exist in the near term, regardless of which market solution is considered, such as market visibility of low voltage network performance and emerging network support opportunities.

The current RIT-D process has a diminishing fit with today's dynamic DER environment, with high transaction costs, slow time to completion, low transparency, and low uptake of non-network solutions. The supplementary Demand Management Incentive Scheme, which aims to incentivize distribution networks considering small non-network options that are outside the scope of a RIT-D was introduced in 2018 but has also had low uptake by DNSPs. To get the best outcome for customers, future procurement of localised services will need to be flexible, low cost and able to harness the value from small scale DER on Low Voltage networks.

As part of the Open Energy Networks program run by the ENA and AEMO,[44] Baringa undertook cost-benefit analysis of the various approaches that could be taken to capture these long-term cost savings for customers. The ESB has extended this work to examine the projected benefits that result from an update to the DER uptake scenarios, aligned with the 2020 ISP DER forecasts.

The report identified between $2.3 and $9.9 billion in savings from the integration of DER. The ESB consider that there is likely to be long-term value for customers to progress with both continued tariff reforms (see measures identified under immediate reforms) and more locationally based procurement options for DER services. Drawing on models proposed by industry and consumer stakeholders, and examples from similar jurisdictions, the following approaches have been identified for discussion and feedback.

Structured procurement (manual): building on the RIT-D process, a redesigned procurement process that streamlines the tender process into a regular cadence and faster timeline and accepts bids from multiple parties. It could provide some benefit at relatively low cost with little/no ICT overhead, and made more competitive, but would still retain relatively high transaction costs, making it unsuitable for small scale DER used for MV and LV network support.

Structured procurement with digital platform (flex market): Similar to the flexibility markets design operated by DNSPs in the UK market, these auction platforms are simple to use, operate alongside tariffs structures and ongoing enhancements, and lower the barriers of access for new flex providers via lowering transaction costs. Again, the costs to build and operate are non-trivial, but has the advantage of being possible to deliver via one or several common platforms.

Retailer portfolio level tariff charges: This approach would charge retailers at the portfolio level for network access and allow retailers more versatility to optimise network charges within their portfolios. This would provide a clearer signal for retailers to play a stronger role in network efficiency, however this would likely restrict non-retail licensed aggregators from participation. There are also non-trivial implementation costs associated with this solution.

Dynamic price signals per network element (real time distribution market): Analogous to locational marginal pricing solutions, this style of solution could be coupled with a capacity auction mechanism to provide congestion pricing, and an equitable mechanism for allocation of network access for new and existing DER owners. It is the most sophisticated, complex and likely highest cost to implement, which

44 See here: https://www.energynetworks.com.au/projects/open-energy-networks/

would need to be considered against the potential benefits case for all DER and non-DER customers in the long term.

It is important to note that in all the above concepts being considered, the assumption is that continued deployment of more cost-reflective tariffs through the AER reform program will aid in reducing costs for all consumers through supporting DER to contribute to overall system cost reductions. These new tariff formats are proposed and agreed by the DNSPs and AER at each regulatory reset. If tariff reform can be successfully implemented this may drive different behaviours regarding the deployment and use of DER assets and reduce the need for more sophisticated requirements for the structured procurement of network services by distribution businesses. Conversely, if tariff reform is too slow to respond to market changes, it this could have implications for infrastructure cost associated with connecting and supporting projected growth in electric vehicles by the end of the decade.

An important consideration for the future role of DNSPs will be their ring-fencing requirements, and which activities they are restricted from engaging in. These restrictions are in place to stop anti-competitive behaviour, cross subsidisation and are enforced by the AER.[45] The ESB considers that monopoly service providers should continue to provide monopoly services and should only engage in competitive market services through their non-regulated service provider entities.

Questions for consultation

36. What are stakeholder views on the approaches outlined? What are the potential advantages and disadvantages of each?
37. Are there alternative approaches that could also work to complement existing tariff reform processes that should also be considered? How might these work?

Clarifying future roles and responsibilities

Providing direction on these future roles and responsibilities will inform the reform pathway as set out in this chapter and determine priority issues for detailed design to be progressed via the Maturity Plan (discussed below).

The ESB recognise that the question of future roles and responsibilities has been an issue of long-standing discussion within the industry, and clarity and direction on these issues will be important for the sector to support efficient future investment decisions. The ESB welcomes feedback on the issues and questions raised to inform the high-level direction on future roles and responsibilities in its mid-year recommendations. The mid-year recommendations will not extend to the detail of enabling platform technology and solutions to support those directions.

4.3. The reform pathway

Immediate reforms need to be done now and implemented as soon as practical. Initial reforms are being developed but will need to be developed further in the near term for implementation. Next reforms are ones that we need to move to over time, given the trends and pace of the transition, or may need to be considered or revisited if certain necessary preconditions arise.

4.3.1. Immediate reforms

Risk based approach for assessing customer protections

As new products and services enter the market, customers face different offers from the present. Retailers may offer more than megawatts and may both sell and buy energy from a household. They may also offer

45 See here for AER ring fencing guidelines: https://www.aer.gov.au/networks-pipelines/ring-fencing

cheaper energy overall by varying time of day use (say through managing hot water or pool pumps). Customer protections are in place now, but the potential for new risks for consumers by new energy or DER products and services need to be assessed to ensure protections remain fit for purpose. This will be important to build and maintain trust and effective social licence with consumers.

The January Directions Paper proposed developing a consumer risk assessment tool for the market bodies to interrogate any new market design impacts and the products and services that will arise under a two-sided market. Changes to consumer protections or other complementary measures (such as safe measures that enable consumers to test and trial products) can then be identified as required, rather than as an add on at the end of the process.

The ESB propose an ongoing assessment of emerging risks or benefits and whether the consumer protection framework remains fit for purpose, and the maturity plan approach can then set out how any changes may be taken forward. This work has been informed by a series of design-thinking workshops with Energy Consumers Australia (ECA) and consumer advocates, with insights discussed further in Part B.

As new product offerings evolve and deliver benefits to consumers, there may be unknown risks and potential harms facing consumers that we need to consider. As highlighted in the AEMC's Retail Energy Competition Review 2019 and 2020, the current protection framework was not designed with the emerging energy services in mind. Changes may be needed in future to existing protections (such as those within the NECF).

The ESB consider that a risk-based approach that is ongoing and carried out in collaboration with market bodies, jurisdictions, consumer advocates and industry stakeholders is the best approach to supporting the transition to a more mature two-sided market. Use cases will be considered to reflect how customers are using DER, or new products and services, as they more actively engage with the market.

Following an international review, the proposed consumer risk assessment tool was developed. It emulates the Catapult Energy Systems[46] model to emphasise the benefits and risks customers experience in the future market equally. The proposed assessment tool:

- Incorporates aspects of risk assessment tools currently used by market bodies as part of their processes.
- Builds on work carried out by the AEMC on consumer protections in a changing energy market through its 2019 and 2020 Retail Energy Competition Reviews as well as work already underway to enhance protections as part of the Bill contents and billing requirements rule change[47] and the New Energy Tech Consumer Code.[48]
- Builds on the guiding principles proposed by the ESB in its January Directions paper. These principles do not replace the core principles of the existing consumer protection framework but guide the development of consumer outcomes and protections in the future market.

The draft consumer risk assessment tool and guiding principles are set out in Part B.

Important in any approach to consumer protections is transparency of consumer impacts under these of new services. The ACCC Retail Electricity Price Inquiry identified that transparency of consumer bills and impacts is currently limited and inadequate for effective price monitoring. The ESB's Data Strategy workstream has proposed reforms to provide greater transparency of consumer bills, services and impacts, across consumer segments. This transparency is fundamental to supporting a more flexible risk-based

46 https://es.catapult.org.uk/brochures/smart-consumer-protection-manual/

47 Further information on the bill contents and billing requirements rule change can be found https://www.aemc.gov.au/rule-changes/bill-contents-and-billing-requirements

48 A copy of the New Energy Tech Consumer Code can be found https://www.accc.gov.au/public-registers/authorisations-and-notifications-registers/authorisations-register/new-energy-tech-consumer-code.

approach to new services, as consumer impacts can be statistically monitored, and any concerns addressed quickly.

Question for consultation

38. Do stakeholders have views on additional steps or information that should be considered in the proposed consumer risk assessment tool?

Technical standards

To support the uptake of DER resources, it is important that clear minimum technical standards are put in place. Consistent and robust minimum standards enable assets to be connected and integrated safely and securely. This is an essential foundation for bringing new technologies into the system while protecting grid stability *inter alia*.

In February2021 the AEMC released its final determination on technical standards for DER.[49] This determination defined initial minimum technical standards within connection agreements between customers and DNSPs. It covers customer assets such as solar PV and batteries, and obligations on device manufacturers and installers to show that those standards are met. These changes will simplify the obligations for manufacturers and installers and provide higher certainty to consumers and operators. The ESB has identified reforms to the governance arrangements for DER technical standards, with a rule change currently being considered by the AEMC. The AEMC anticipates beginning this rule change by mid 2021.

Minimum demand

As noted in Chapter 1, Australians have invested in household solar at world-leading levels. Over 2.6 million[50] solar PV systems are installed. There are also increasing numbers of household and C&I customers investing in a range of other DER assets such as batteries, EV systems, and smart appliances. Customers are making these investments for a number of reasons, including the opportunity to reduce their energy bills.

Customer-owned solar PV devices have largely operated independently of what is happening in the wholesale energy market or in relation to levels of congestion on networks. Currently, most installed devices are incapable of reacting to these factors and are referred to as “passive”. When Australian residential customers first started investing in solar panels, the only types available were passive, and the relatively small numbers installed did not impact the operation of the system. However, with the rapid uptake of solar PV, the collective volume of solar PV serving customer load can see a significant and sharp drop in demand from the grid during the middle of the day. This creates difficulties for the networks and AEMO, in particular to maintain secure operation of the system.

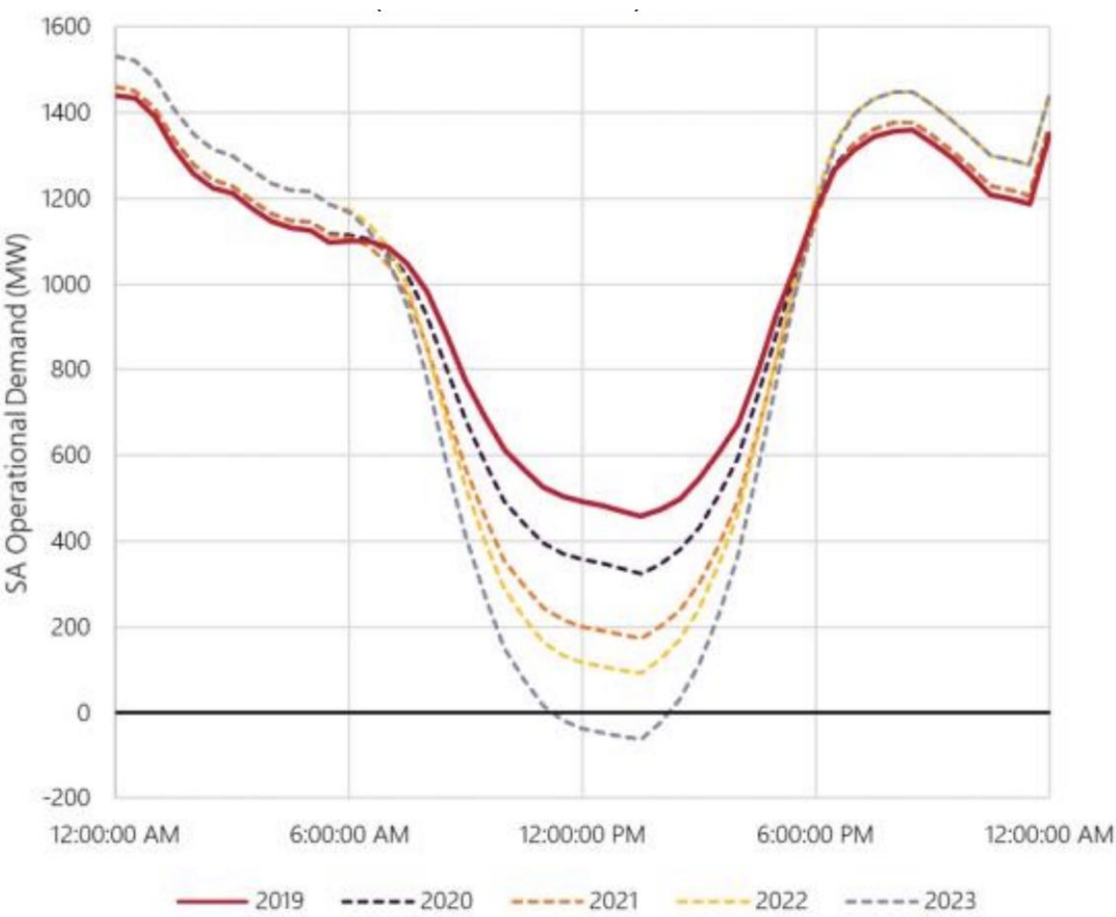
Only a few years ago, a key focus for the system operator in managing stable and secure supply to the grid was on meeting customers’ needs over evening peak periods. These maximum demand peaks are still a focus; however, the unprecedented uptake in household solar PV now means that having tools and arrangements to balance the system under falling minimum demand is now a growing challenge, particularly in states with high penetration of solar resources.

South Australia (SA) is at the forefront of this issue, with day-time demand dropping away significantly in recent years consistent with the famous ‘duck curve’, see Figure 8 below. This trend is also occurring in Queensland and Victoria, driven by a growing uptake of solar PV installations.

49 https://www.aemc.gov.au/rule-changes/technical-standards-distributed-energy-resources

50 http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations#Postcode-data-files

Figure 8 Effect on South Australian operational demand from increasing distributed PV generation (10 November 2019)



Source: AEMO, Minimum Operational Demands Thresholds in South Australia, May 2020, p18

Under these changing conditions, it is increasingly challenging for the networks and AEMO as system operator to keep the power system secure. Backstop measures have been put in place in South Australia, where AEMO can direct the full or partial reduction in output from solar PV assets (under conditions that grid demand cannot be maintained). These changes in system conditions have come about quickly, and backstop measures are needed to maintain grid demand. While these measures are important to balance the system, and manage the overall grid demand, we recognize outcomes are not great for customers, and in particular DER asset owners. Work is underway to improve outcomes for customers.

Work to address Minimum Demand

In the January Directions paper the ESB set out a proposed solution, focused on providing consumers the opportunity to maximise the value from their solar PV asset, enabling customers to choose products and services that best meet their needs and values their flexibility in future, while also providing in the short term a necessary protection function for the system.

The proposed solution involves changes as part of the 'immediate' and 'initial' reform stages; introducing a remote disconnect for distributed PV as an emergency backstop, transitioning to distributed PVs which are responsive to market signals, and turn-up services where flexible demand would be available to balance generation and demand.

The Emergency Backstop, which is a remote disconnection of the domestic PV, is a last resort response to an immediate problem. This is analogous to under frequency load shedding, where disconnection from the system occurs to prevent a more serious uncontrolled event due to the system losing stability. This would be used as a last resort, and the requirement, and magnitude for the domestic PV shedding could be determined by AEMO.

The emergency backstop functionality has been created in SA to address their current Minimum Demand risk. There is likely to be value in having a consistent approach to addressing system issues across the NEM. The ESB considers it would be valuable to consider both the SA option as well as other measures as part of this.

Initial reforms would involve development of Turn-up Services, or dynamic load services, as part of a mature two-sided market. To maintain system balance with falling demand, either generation needs to reduce, or flexible demand needs to increase. Traditionally, 'demand side response' has referred to the reduction or switching off of load. In future, where demand has flexibility to rapidly increase or shift to lower demand periods of the day (e.g., such as via pool pumps) this will provide valuable support to balancing the system. This could be delivered by out of market mechanisms like a reverse RERT, or in market via Wholesale Demand Response type mechanisms.

While the emergency backstop reduces risk, the ability for consumer's domestic PV to respond to signals creates the potential to maximise the size of installations, and to vary generation levels in response to market signals. Facilitating domestic PV to respond to market signals by varying generation levels allows consumers to access value, with third parties responding to market signals on their behalf (e.g., including price, FCAS, balancing, and network constraints). Creating the environment where third parties (retailers / aggregators) can offer products and services to customers so they can receive value for their flexible demand is key here. This enables customers to make choices of whether to participate and offer flexible response where they can access value for doing so, supporting and building social licence with customers, and making it less likely that intervention to maintain operational demand is required.

Questions for consultation

39. Do stakeholders have views on the options outlined to address issues associated with falling minimum demand and increasing access to markets?
40. What are other options to consider that might deliver better outcomes for consumers?

Tariff and pricing reform

Tariff and pricing reform is critical to DER market integration. Prices that reflect the needs on the system, signalling where more or less supply is needed to balance the grid or to signal network constraints, can help to encourage load to shift into the middle of the day when solar generation is high. In the longer term, more sophisticated tariffs may automatically optimise the use of DER across network services, wholesale and essential system services markets. Work is underway to address these needs.

Reforms to make network tariffs more cost reflective will support more efficient use of networks and demand management. Distributors are progressively making their network tariffs more cost reflective, for example. Tariff reforms reduce charges at times of low demand and raise them at times of peak demand when the networks are under strain.

Electricity distribution businesses are required to progressively move customers onto network tariffs more closely aligned to the costs of providing the services that they use.[51] Pricing reform is progressing slowly, with most networks initially adopting 'opt in' models for transferring customers to cost-reflective network tariffs. More recently, distributors are starting to require customers to 'opt out' of cost reflective network tariffs. The AER estimates this shift will result in up to half of all residential customers in NSW, Tasmania, the ACT and Northern Territory being on cost-reflective network tariffs by 2024.

The limited penetration of smart meters for residential and small business customers across the NEM (outside of Victoria) is also limiting tariff reform uptake. In December 2020, the AEMC commenced a review

51 See here: https://www.aemc.gov.au/rule-changes/distribution-network-pricing-arrangements

of the rules governing electricity meters to see what more might be needed for increased take-up of smart meters, and whether roles and responsibilities around metering under current arrangements need to be revised to drive retail innovation.

These tariff reforms focus on distribution network charges for the transport of electricity from the grid to the consumer. The AEMC is considering where other pricing reforms are relevant to the use of the network by DER owners.[52] These proposed changes aim to unlock the benefits of DER by providing greater flexibility for the AER and distribution businesses to efficiently meet consumer preferences.[53] The proposals focus on three key areas:

- updating the regulatory framework to reflect the community expectation for DNSPs to efficiently provide export services to support DER,
- promoting incentives for efficient investment in export services,
- enabling pricing tools to send efficient signals for future network costs and DER investment decisions. These tools would reward customers for actions that better utilise the network or improve network operations and allocate costs in a fair and efficient way.

The AER is also in the process of developing a DER Integration Guideline that will provide direction for DNSPs on how to value DER-driven network investment. The AER recently commissioned a study on the value of DER to help develop a framework to accurately signal networks to support DER connection and access to markets.[54]

4.3.2. Initial reforms

Streamlining participation
Trader services

Customers can currently participate in the energy or ancillary service markets in the NEM, although barriers exist that mean this is not easy. To enable opportunities for customers, both big and small, to be rewarded if they choose to participate in energy and other markets requires a new approach. So, instead of *ad hoc* and incremental changes to address new business models and technologies emerging, a framework is proposed that reflects the broader changes occurring in the NEM. The challenge for the market bodies is to ensure the arrangements keep pace, and facilitate participation in the market, to meet the needs of consumers and be cost-effective.

The trader-services model is the ESB's proposed approach for evolving the participation framework under the NER to ensure it can integrate new technologies and business models and make it easier to provide new services to customers. The trader-services model would involve creating a single, or universal, registration category for all entities who want to engage in the wholesale energy and energy services markets. This would enable "traders" to deliver a range of services to customers without having to register in multiple categories. This service-based regulation would attach obligations to the services provided rather than the assets.

For example, if a market participant wanted to trade energy and FCAS from some of its DER customers, and FCAS or energy only from others, while also having non-DER customers, it would currently have to register in three different categories of market participant. Each different category would be subject to different fees and registration requirements, and only certain services would be able to be traded from each customer connection point. Under the new model, the trader would register once as a market participant

52 See here: https://www.aemc.gov.au/rule-changes/access-pricing-and-incentive-arrangements-distributed-energy-resources
These proposals have emerged from the detailed work undertaken by a broad collaboration of stakeholders through the Distributed Energy Integration Program (DEIP).

54 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/assessing-distributed-energy-resources-integration-expenditure

and nominate the services it intends to trade from each connection point. There would be appropriate obligations tied to delivering each of those services. Customers could also choose different providers for different services, if they wish, more easily than under present arrangements. The intention is that this streamlining will improve competition between different types of service providers, leading to more diverse and better energy products and services being made available for consumers.

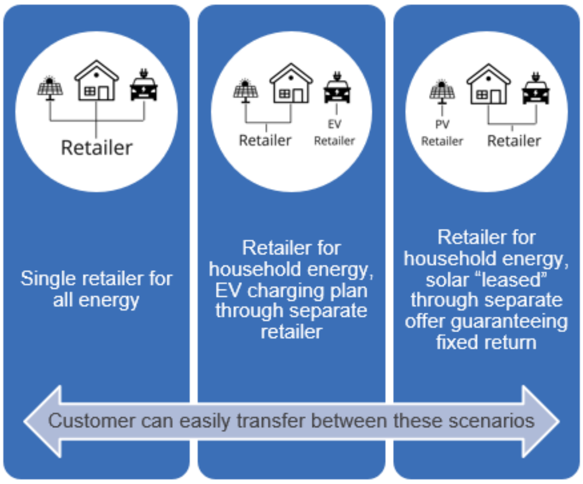
While the ESB considers that there could be benefits in implementing this model, it also acknowledges that the model represents a considerable change for the regulatory framework and industry. The design and implementation of such a model needs to be well sequenced with new service-based regulations to ensure market participants continue to meet the relevant operating standards and technical competencies. It needs to be phased in over time and may, in part, co-exist with the 'old NER' provisions before they are eventually phased out. The ESB notes these changes will also facilitate a future transition from the wholesale demand response mechanism to a more fully two-sided market, helping to address concerns raised by customers and stakeholders regarding some of the practical limitations of the wholesale demand response mechanism (to be introduced later this year as an immediate reform).

The first steps towards the trader-services model are being actively considered by the AEMC under the Integrating Energy Storage Systems into the NEM rule change.[55]

HOW THIS HELPS: CUSTOMER SCENARIO:

- Jo is a customer who rents an inner-city apartment for her young family. Jo sees an ad for a company that can reduce her electricity costs by using her electric hot water system to support the grid. On top of that she gets to stay with her current electricity retailer. This service provider would adjust the timing of the hot water system's use of electricity to support the grid, operating in the ancillary service markets and providing network support services.
- The company provides Jo with a 24/7 phone line in case there are issues with the hot water supply and gives Jo notifications prior to any activities. Jo checks with her landlord who is comfortable with the agreement given that the company has provided assurance in relation to the appliance.
- When a new opportunity arises for Jo to earn money or further reduce her electricity costs through the operation of her hot water system, such as a new market opening up, Jo's service provider can easily register and integrate into this new market and offer Jo those benefits. Jo benefits as her energy offer improves over time and she earns money while still having hot water when she needs it; and the service provider has been able to increase its flexibility to offer services to the grid.

Access to service providers



55 The AEMC will invite stakeholder feedback on this issue through the publication of its draft determination.

The ESB wants arrangements to support new entrants coming into the electricity market, while ensuring existing retailers can continue to innovate and offer new products and services. One way of encouraging more competition is to enable consumers to take up contracts with multiple service providers at their home or business.

Flexible trading arrangements

Flexible trading arrangements are a way to encourage the separation of controllable from uncontrollable resources so customers can be rewarded for their flexible demand and generation whilst not requiring a significant behavioral change for other parts of their household load. Additionally, by separating these loads a customer can choose additional energy services suppliers for their flexible demand or generation while remaining on their current retail plan for all other energy produced or consumed. This may also provide consumers the option to 'try out' new service providers without needing to find a retailer that meets all of their energy needs, especially where those needs are more diverse and complex.

Consumers are currently able to establish additional connection points to the grid, with additional meters, to achieve the benefits of engaging multiple service providers. However, this can involve considerable complexity, connection costs and multiple network tariffs. Consequently, the current regulatory framework does not support consumers easily engaging with multiple energy service providers at a single site. Through streamlining the model of participating through multiple connection points at a single premise, more flexibility can be offered to consumers. This offers customers greater opportunity to engage more specialized energy service providers and plans to suit their needs.

Part B outlines two different models to enable more flexible trading arrangements at a detailed level with consultation questions for stakeholders. Assessing appropriate customer protections to apply to these arrangements will be key consideration.

HOW THIS HELPS: CUSTOMER SCENARIO:

- Sam runs a warehousing business in the country. Sam has decided to shift his fleet of delivery vans to electric vehicles through a leasing company. Sam already has a retail electricity contract for the warehouse.
- Under the new Flexible Trading arrangements, the leasing company is able to support Sam to install charging stations to meet the fleets charging needs. To keep the costs down, the leasing company orchestrates charging in response to wholesale and ancillary market prices, as well as network tariff prices.
- This keeps all the motor vehicle costs in one place for accounting purposes and helps Sam know where the energy is going. Sam is able to obtain a preferable price for his charging stations from a specialist retailer, which is not a product offered by his current retailer.

Accommodating active participation

To maintain a stable and secure grid, the system operator needs to have sufficient certainty of the electricity resources and demand available to the grid both ahead of time and in real time.

With a growing penetration of active DER and flexible demand resources, often from traditional 'load' connection points, gaining a better understanding of how these resources behave and operate under different conditions is important. This understanding enables both the system operator and the market to meet the needs of the system as the level of flexible resources on the grid increases. This supports the efficient integration of these resources into the system in a manner that allows consumers to be rewarded for the value their assets can provide and without introducing unnecessary barriers or costs as the total size of the installed capacity of these assets grow.

Growth in non-scheduled resources raises questions about the adequacy of the current scheduling and dispatch arrangements and whether different arrangements that increase the amount of scheduled load and generation, both large and small, are needed. If these scheduling frameworks do not evolve to reflect the changing dynamics and composition of resources meeting the needs of the system, it will be more difficult to bring more VRE and DER into the NEM without adverse consequences. This creates barriers to DER owners and those that can provide flexibility through their energy use, reducing the value they receive from their assets or behaviour, and introduces extra system costs borne by all consumers.

Measures that increase visibility and forecast-ability of resources and traders' intentions in the market will likely deliver net benefits to system and market operations and outcomes, including cost savings from reduced interventions and contingency planning. However, it is important that any benefits of higher participation levels in scheduling are balanced against costs of facilitating this functionality by small participants and consumers. The ESB has been considering approaches for new scheduling arrangements that are voluntary, proportionate and have a low impact on consumers.

Scheduled Lite

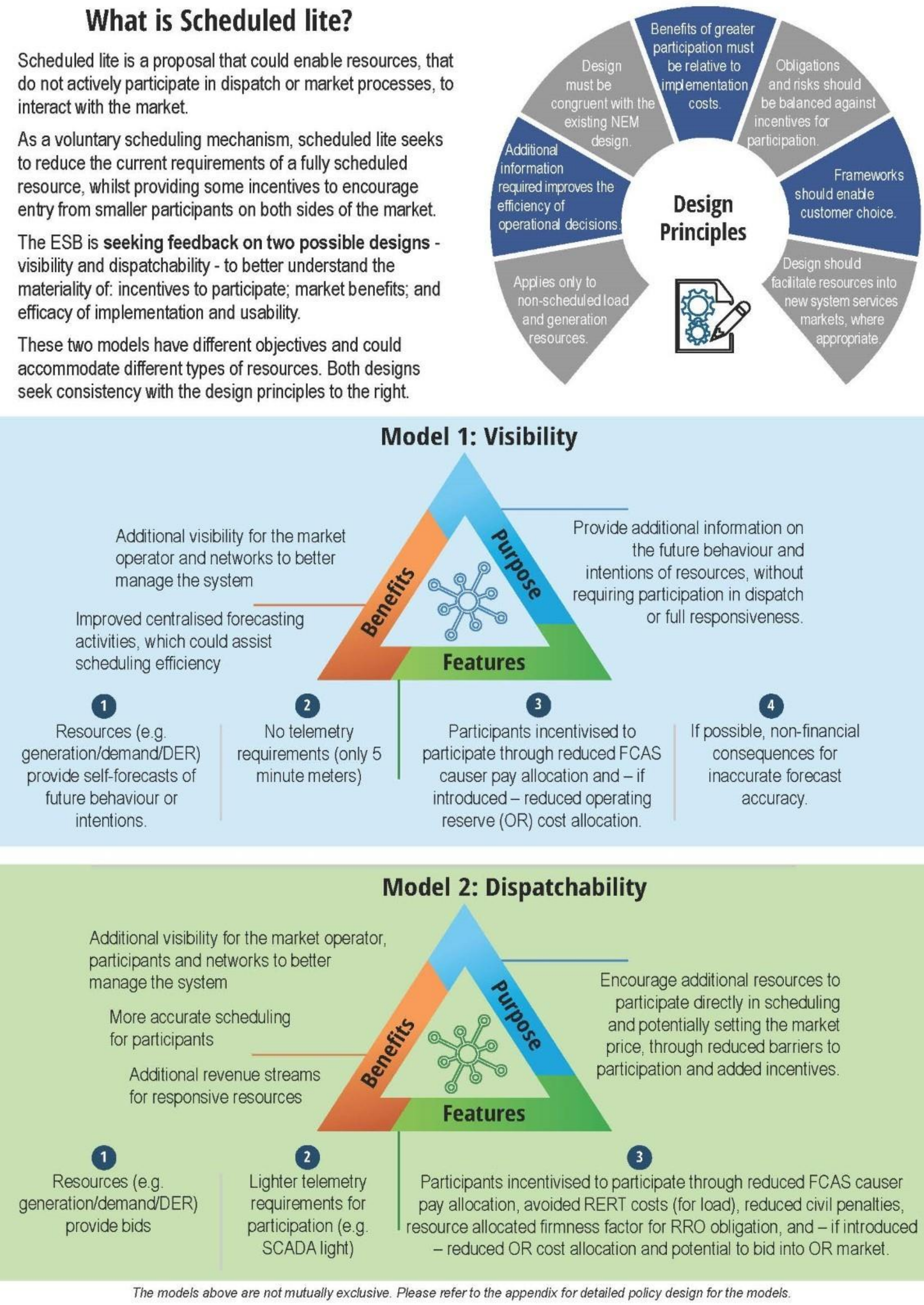
The January Directions Paper identified the concept of 'scheduled lite'. This is a participation classification that could be used to schedule these additional resources into the market and facilitate participation in the market. The ESB has set out two potential models for 'scheduled lite' with different levels of obligations and incentives. Both models adopt a voluntary approach, allowing assets and use cases most suitable to participating in a 'lite' manner to do so, noting that the arrangements will likely evolve as insights are gained from trials, participation and as technology matures. The ESB is seeking feedback on the materiality of incentives to participate, market benefits, and efficacy of implementation of the two potential models.

The ESB notes that greater use of mandatory approaches may be needed in the future if:

- a voluntary system was not able to achieve a balance of obligations and incentives that could deliver value in the long-term interests of consumers
- operational inefficiencies caused by a lack of visibility accelerated faster than voluntary measures could adequately address.

Figure 9 below provides an overview of the scheduled lite concept for stakeholder feedback. Further detail about possible designs, including consultation questions regarding these concepts, is set out in Part B.

Figure 9 What is scheduled lite



The models above are not mutually exclusive. Please refer to the appendix for detailed policy design for the models.

Ease of transfer and switching

Energy customers change their retail providers in response to attractively priced deals, or offers that suit their choices (e.g., where retailers may offer renewable based tariffs). To support this switching, there are regulatory protections and processes in place to ensure that switching providers is not too difficult or costly, and that artificial barriers are not in place to prevent or unreasonably limit the ability of customers to access alternative suppliers.

In future, customers with DER assets may want to engage in offers with different service providers in the market. For example, customers may enter contracts that need their DER assets or smart home devices to communicate with third parties such as retailers, aggregators, or DNSPs.

Technical standards – interoperability and communications

For customers to have access to a wide range of energy providers and plans to enable choice in how they use their assets, these providers will require the ability to communicate with and operate these devices. This refers to the 'interoperability' of devices. Without a minimum level of 'open' interoperability functionality within the device, customers may have their DER assets locked-in to certain providers or offerings. This would limit future choices for customers as well as limiting the ability for contracted service providers to use those assets to maximise the benefits for the customer under an energy plan. It will also limit the ability of new aggregators or retailers to enter the market and stimulate competition and innovation as they will not be able to communicate and compete for the existing fleet of customers, without additional cost and installation of extra equipment at the premises.

The ESB is seeking feedback on principles relating to the interoperability of DER devices. It is intended that these principles can be used to guide efforts on the creation of standards, and structures that incorporate active DER efficiently into the larger system. These include:

- *Consumers should be able to share data with service providers* - Interoperability should be standardised to allow data portability and sharing between consumer, aggregator, network and market
- *Consumers' DER assets should have a level of portability between providers* - These standardised communications should enable consumers to move between providers (and technology) and promote competition between providers. These standards should be *minimum* levels of capability while allowing providers to layer additional functionality over the top so they can offer their own innovative products and services
- *Control of and access to consumer devices should be limited to clear use cases* - Control of any consumer device by a network or system operator should be limited to a set of well documented use cases that can be updated from time to time as agreed by industry
- *Consumers need to receive clear information about the compatibility of their DER assets* - Device manufacturers, installers, and service providers must be transparent about any proprietary technology resulting in closed eco-systems and the consequences or limits of those closed eco-systems.

Question for consultation

41. Do stakeholders have views on the proposed principles? Are there other principles that should be considered to deliver benefits for consumers?

4.4. Next reforms

While the reform pathway itself does not identify specific 'next reforms' at this time, it is anticipated that the ESB's directions of future roles and responsibilities will be included as part of the final recommendations mid-year. The Maturity plan approach will also continue to identify reforms relevant to the pathway. As different reforms are implemented, and the scale and complexity of customer device installation increases there will be a need for greater co-ordination between Aggregators and Retailers, Distribution Networks and AEMO to ensure customers can easily access multiple markets, that data can be easily exchanged, and that network access and congestion problems are addressed. The Maturity Plan approach will identify relevant reforms and identify their priority, including any reform required to encourage more co-ordination between roles.

4.5. Approaching the work – the Maturity Plan

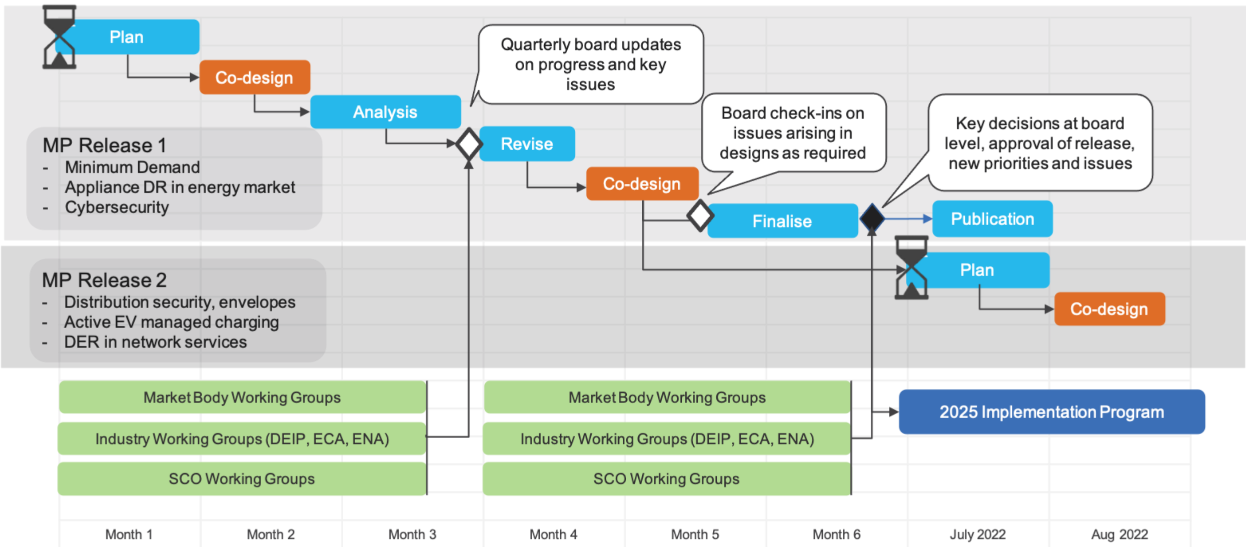
The proposed reform pathway for DER integration will need to continually evolve and be added to, given the profound nature of what is involved in effective DER integration. The changes occurring across the sector will continue at pace, with new technologies, products and services continuing to emerge and raising issues that must be looked at holistically and urgently to ensure that regulatory reform keeps up and ahead of this pace.

Recognizing that further consideration of the pathway will be required as DER continues to integrate into the market, the January Directions paper proposed a Maturity Plan approach to support this work. It is intended that the Maturity Plan will provide a vehicle for:

- examining and prioritizing strategic issues associated with the integration of DER; and
- the detailed design of several significant DER related reforms identified as a priority issue, and
- ongoing oversight of the Board's direction on roles and responsibilities

It is a process for 'co-design', which will involve relevant stakeholders, customer representatives and market bodies. Outputs will include effective DER integration.
Each six-monthly Maturity Plan release over the upcoming three years, will focus on priority issues that can provide the highest near-term benefits to customers through an accelerated design and implementation. To assess priority customer issues a series of Use Cases will be used as part of the process. An example of this approach is set out in Figure 10 below.

Figure 10 Maturity Plan approach



Priority issues for the first release of the Maturity Plan will be determined by the ESB. The Board's direction on paths for role and responsibilities will inform priorities for detailed design work to be undertaken as part of the first release. Consideration of customer protections will be a core component of assessing emerging risks and opportunities emerging with each issue.

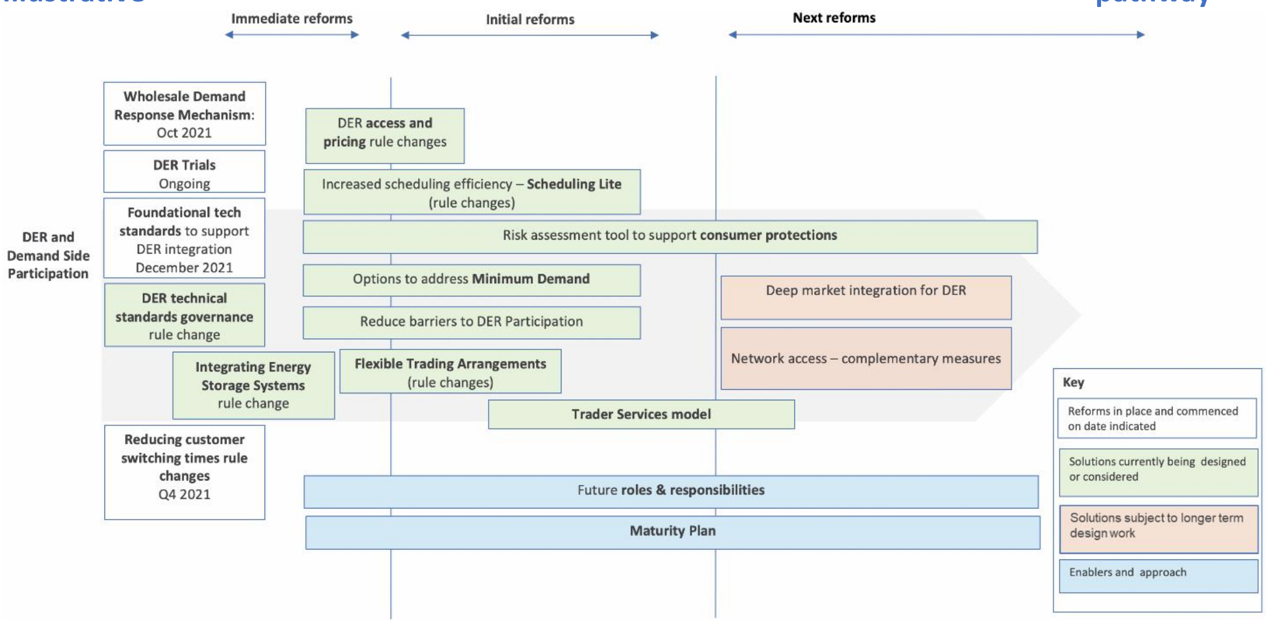
Priority issues to be considered as part of the first release of the Maturity Plan will include:

- **Minimum Demand** – Assessing options to support balancing the grid with rapidly changing demand and supply sources and patterns. How different measures impact on consumer outcomes and how these can be improved to unlock greatest value to customers and the grid.
- **DER Participation –** Alongside the development of the new participation models for the two-sided market, the use cases of appliance-based demand response or curtailment, such as electric hot water,

and split cycle air conditioners, is being tested to better understand the consumer experience for the design of these services.

As priority measures, work on these issues has commenced and are immediate reforms on the pathway that are being developed and will be implemented as soon as possible. Further details on the Maturity Plan framework, its proposed scope, priorities and governance, are set out in Part B.

4.6. Illustrative pathway



5. Transmission and Access

5.1. Key points

- The current transmission network was designed to transport energy from coal fuelled and hydro generation to load centres. 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 than a scatter-gun approach. However, the current open access regime results in investment signals that do not align with underlying power system conditions.
- Transmission hosting capacity over the next decade is expected to fall short of the levels of renewable generation expected, which means congestion needs management. 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 would be 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 objective of access reform is to drive coordination between transmission, generation and storage.
    - In longer term investment timeframes, there is a need for stronger locational signals and improvements in the ability to connect, and
    - in the shorter-term operational timeframes, there is a need for congestion management.

  A more coordinated process for bringing new generation online improves the ability to connect.
- The ESB has developed the 'actionable Integrated System Plan (ISP)' changes to help implement the priority network investments identified in the ISP and deliver additional network capacity where needed. Further changes are proposed which would provide a development plan for Renewable Energy Zones (REZ).
- Substantial transmission investment will be needed to accommodate the forecast 26-50 GW of new large-scale variable renewable energy expected by 2040. Challenges are emerging in getting the new network built in a timely manner and at least cost. The ISP assesses the costs and benefits of actionable ISP projects. The costs of an actionable ISP project are then further refined through the Contingent Project Application (CPA) approval process. If there is a significant change to costs at CPA stage, then AEMO also undertakes a "feedback" loop through the ISP model to ensure the benefits of the project still exceed the costs. As the Regulatory Investment Test for Transmission is principally a net economic benefit test that relies on the inputs, assumptions and scenarios of the ISP and uses less developed costs than the CPA, it is unclear what additional benefits the RIT-T delivers for actionable ISP projects however it does significantly add to the time taken to get these projects approved.
- Governments also may value a range of benefits that are not currently captured by either the ISP or the RIT-T. These benefits may include boosting local economies or delivering additional employment opportunities in rural communities. These wider economic benefits could be captured in a broader cost-benefit test for actionable ISP projects to guide the respective contributions of tax payers and electricity consumers. Recent actionable ISP Projects have seen a significant increase in costs (QNI, Project EnergyConnect) and additional funding options such as contestability may also need to be considered to deliver these projects at least-cost.
- The methodology used to allocate transmission costs between jurisdictions and between loads is coming under greater scrutiny. For instance, the actionable ISP project to develop Marinus Link is subject to a decision rule whereby the project will only proceed if agreement is reached on how the cost of the project will be recovered. There is also a debate underway about whether generators should share in the cost of transmission investment. The ESB has already provided advice to Energy

Ministers on transmission cost allocation and governments are currently conducting further analysis and considering next steps.

- Ahead of its final recommendations mid-year the ESB will consider issues relevant to the role of the RIT-T, the nature of the test and issues regarding the allocation of costs between jurisdictions.
- Some congestion on the system is efficient, because the cost of transmission to alleviate all congestion is prohibitive. Overall costs of transmission and generation are both minimised with some congestion in place.
- However, without reforming access arrangements, new generation will locate and operate in ways that exacerbate congestion which means electricity cannot be dispatched to meet demand at the lowest possible cost. Congestion management is already a critical and growing issue, making connecting to the grid complex. Transmission hosting capacity over the next decade means congestion needs management given the levels of renewable penetration. More coordination between transmission and generation will also reduce the risk of low marginal loss factors and facilitate grid connection.
- A REZ framework is a key first step in reforming access. It promotes efficient location decisions by making it more attractive for generators to invest in certain parts of the network. As a planning-based solution though, it does not provide a real time solution for congestion management.
- REZs provide a partial solution that applies to specific geographic locations within the power system. Outside the REZs, the problems associated with open access would remain. Due to the way electricity flows across the grid, issues outside the REZ are felt inside the REZ. This can only be addressed through solutions which apply across the whole system, of which REZs are part.
- Other changes are also needed if we hope to stay ahead of the dramatic increase in large-scale battery deployment – currently 327 MWh and estimated to be 900MW by 2024 and emerging technologies such as hydrogen and also large flexible load/source of demand response on the horizon. By adding more local granularity to price signals, for batteries and these loads would charge or use energy and discharge or not use energy at the times that are most valuable. That way these technologies work within, and not against, a high variable renewable energy power system.
- Given these issues, the ESB is exploring whole of system access options that can form a stepping-stone towards a long-term solution for transmission access. Given stakeholder feedback to date, the ESB has sought to design the medium-term access options in a way that mitigates the important negative impacts of access reform identified by stakeholders. The five options are:
  - A congestion management model
  - Congestion management model with REZ adaptions
  - Connection fees
  - Generator transmission use of system charges (G-TUOS)
  - A hybrid model of connection fees and the congestion management model.
- The ESB's initial analysis suggests that the congestion management model with REZ adaptions and the hybrid connection fee/congestion management model may best meet the objectives. Unlike the other options, these options both provide locational signals to incentivise efficient investment and enable the efficient management of congestion in operational timeframes. We are seeking stakeholder views on each of the models and how they meet the objectives.
- The chapter also provides an update on reforms to date under transmission access reform, including development of REZs and additional analysis on changes that could be made to provide more useful congestion information over time than is currently available.

Building on the January Directions paper, this section sets out the proposed transition pathway to deliver transmission and access reforms. Immediate reforms need to be done now and implemented as soon as practical. Initial reforms need to be developed further in the near term for implementation. Next reforms are ones that we need to move to over time, given the trends and pace of the transition, or may need to be considered if certain conditions arise.

5.2. Immediate reforms

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

- New transmission investment
- Actionable ISP rules
- Interim REZ framework - including access within a REZ
- AEMC's Dedicated Connections Assets Rule change
- AEMC's system strength investigation, and
- Initiatives to enhance the information available on congestion.

The ESB also notes the substantial work programs being undertaken in parallel by State governments. The reforms described below are intended to complement and support the work of State governments.

New transmission investment

Substantial transmission investment is needed to accommodate the forecast 26-50 GW of new large-scale variable renewable energy expected by 2040. These relatively smaller and geographically dispersed renewable generators need to connect in windy or sunny parts of the grid. Historically the transmission network was built to transport energy from coal fuelled and hydro generation to load centres. The current networks have not required large amounts of transmission capacity in the areas where this new generation needs it.

AEMO has prepared two ISPs which describe 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 that are underway. 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 committed projects underway and three future ISP projects that need to deliver additional REZs (Figure 11).

Figure 11 Current and planned new transmission projects

Classification		Project	Indicative timing
Committed	**Committed ISP projects.** These are critical to address cost, security and reliability issues, and are underway and have already received their regulatory approval.	SA System Strength Remediation	2021-22
		QNI Minor	2021-22
		Western Victoria Transmission Network Project	2025-26
Actionable[1]	**Actionable ISP projects.** These are also critical to address cost, security and reliability issues, and are either already progressing or are to commence immediately after the publication of the 2020 ISP10. These projects have not yet completed their regulatory approval process.	VNI Minor	2022-23
		Project EnergyConnect	2024-25
		HumeLink	2025-26
		Central-West Orana REZ Transmission Link	Mid-2020s
		VNI West[2]	2027-28
		Marinus Link[2] - Cable 1 - Cable 2	 2028-29 to 2031-32 2031-32 to 2035-36
Preparatory Activities Required	**Actionable ISP projects with decision rules.** These projects are also critical to address cost, security and reliability issues. The decision rules for these projects can be assessed during the RIT-T process and will be confirmed by AEMO during an ISP feedback loop process with the TNSP once the decision rules eventuate.	QNI Medium & Large	2030s
		Central to Southern QLD	Early-2030s
		Reinforcing Sydney, Newcastle and Wollongong Supply	2026-27 to 2032-33
		Gladstone Grid Reinforcement	2030s
		New England REZ Network Expansion[3]	2030s
		North West NSW Network Expansion[4]	2030s
Future ISP Projects	**Future ISP projects.** These projects would reduce costs and enhance system resilience and optionality. They are not yet 'actionable' but are expected to be so in the future and are part of this ISP's optimal development path.	Far North QLD REZ	2030s
		South East SA REZ	2030s
		Mid North SA REZ	2030s

2020

2040

1 Estimated practical completion including any subsequent testing - projects may be delivered earlier
2 Decision rules may affect timing
3 May be accelerated by government initiatives
4 Not shown on map. AEMO requires that preliminary engineering designs be completed by 30 June 2021

Source: AEMO, 2020 ISP Overview, p7

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, biodiversity, indigenous heritage, 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.

The regulatory investment test for transmission (RIT-T) and transmission cost allocation

Substantial transmission investment will be needed to accommodate the forecast 26-50 GW of new large-scale variable renewable energy expected by 2040. Challenges are emerging in getting the new network built in a timely manner and at least cost. The ISP assesses the costs and benefits of actionable ISP projects. The costs of an actionable ISP project are then further refined through the Contingent Project Application (CPA) approval process. If there is a significant change to costs at CPA stage, then AEMO also undertakes a "feedback" loop through the ISP model to ensure the benefits of the project still exceed the costs. As the Regulatory Investment Test for Transmission is principally a net economic benefit test that relies on the inputs, assumptions and scenarios of the ISP and uses less developed costs than the CPA, it is unclear what additional benefits the RIT-T delivers for actionable ISP projects however it does significantly add to the time taken to get these projects approved.

Governments also may value a range of benefits that are not currently captured by either the ISP or the RIT-T. These benefits may include boosting local economies or delivering additional employment opportunities in rural communities. These wider economic benefits could be captured in a broader cost-benefit test for actionable ISP projects to guide the respective contributions of tax-payers and electricity consumers. Recent actionable ISP Projects have seen a significant increase in costs (QNI, Project EnergyConnect) and additional funding options such as contestability may also need to be considered to deliver these projects at least-cost.

The methodology used to allocate transmission costs between jurisdictions and between loads is coming under greater scrutiny. For instance, the actionable ISP project to develop Marinus Link is subject to a decision rule whereby the project will only proceed if agreement is reached on how the cost of the project will be recovered.[56] As discussed elsewhere in this chapter there is also a debate underway about whether generators should share in the cost of transmission investment. The ESB has provided advice to Energy Ministers on transmission cost allocation[57] and governments are currently conducting further analysis and considering next step.

Given the importance of efficient and timely investment in networks, the ESB will consider issues relevant to the role of the RIT-T, the nature of the test and issues regarding the allocation of costs between jurisdictions ahead of its final recommendations mid-year. The ESB welcomes feedback on these issues to inform the direction on them.

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 associated with the previous incremental planning approach.

Under the previous 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.

Under the actionable ISP framework, the scale of AEMO's modelling exercise has increased to an extent that the Rules requirements can now be met before generation projects become committed. 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 if a transmission investment associated with a REZ is classified as an actionable ISP project and it passes the RIT-T, it is able to proceed on a regulated basis – that is, the assets would be built, owned and operated by the local TNSP and funded by consumers.

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. For instance:

- NSW is implementing its legislated Electricity Infrastructure Roadmap, which involves the development of five REZs;

56 AEMO, *2020 Integrated System Plan*, July 2020, p.83

57 http://www.coagenergycouncil.gov.au/publications/23rd-energy-council-meeting-communiqu%C3%A9

- 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.[58]

The ESB is working closely with governments on these matters. The transition pathway for access reform, 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 associated with unanticipated constraints and variable marginal loss factors 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.

In the January Directions paper, the ESB committed to develop a set of reforms that could build on the interim REZ framework to provide a stepping-stone towards a long-term, whole of system access solution. These reforms are designed to address the concerns of stakeholders about the proposed transmission access model including the risks in transition and the impact on existing contracts.

In parallel, the ESB is working with State governments to develop a framework for the efficient planning, development and maintenance of REZs. The ESB is conducting this project in accordance with a two-step process:

1. Rule changes that require the jurisdictional planner to develop a detailed and staged development plan for each priority REZ identified in the ISP. These changes would 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 has recently completed Step 1 of this process. The ESB's REZ Planning 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. This is an incremental refinement of the recently finalised actionable ISP Rules and the ESB considers that these changes should form a permanent part of the actionable ISP framework.

In light of the potential for significant local community impacts associated with REZs, the ESB has recommended that REZs are subject to a special planning regime that includes measures to take into account evidence supplied by 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 Stage 1 recommendations increase the deliverability of transmission projects by ensuring that social licence issues are understood and taken into account at an earlier stage in the planning process.

The ESB has published a consultation paper and draft REZ planning Rules[59] and has submitted its recommendations to Ministers. Ministers are currently considering the ESB's recommendations and draft Rules.

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58 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

59 See http://www.coagenergycouncil.gov.au/publications/energy-security-board-renewable-energy-zones-planning-consultation

Step 2 – REZ implementation

The ESB has also published a consultation paper[60] that considers how REZs could be implemented in the near term, addressing the questions of how to establish a REZ, and how to maintain a REZ once it is established. The ESB's work is intended to provide the fundamental principles for REZ implementation which may be complemented by the work of State governments.

The REZ consultation paper proposes to use a coordinated process overseen by a "REZ coordinator" to establish a REZ. A cap would need to be established specifying the hosting capacity of a REZ or stage of a REZ. Generators could then participate in an auction or tender process to compete for the right to connect to a REZ as part of that capped capacity. In return, they receive benefits in terms of cheaper connections due to scale economies, and increased certainty during the connections and approvals process. The cap on capacity could then need to be maintained through some form of physical or financial access right to the REZ's transmission network. This would provide REZ investors with improved investment certainty.

The REZ consultation paper envisages a framework where the REZ coordinator is nominated by the relevant State government Minister. Governments can play an important role in the development of REZs by integrating new infrastructure build into broader community, economic and industrial policy. For instance, the NSW Electricity Infrastructure Roadmap[61] and the Victorian REZ development plan[62] include measures to engage with communities and develop strategies to encourage investment, employment, and skills development.

Successful participants in the REZ tender process acquire a package of access rights. These rights limit the extent to which REZ generators may be constrained over time due to subsequent generation entry within the REZ causing worsening congestion or loss factors. Although constraints may still arise outside the REZ boundary, the REZ consultation paper describes four options for access within a REZ:

- Connection access protection model
- Financial access protection model
- REZ as a region; and
- Early allocation of financial transmission rights.

The ESB notes that only the first two of these options received any support in submissions, and a number of respondents preferred the status quo (no access rights).

These access options are designed to protect the access of REZ generators between their connection point and the point where the REZ connects to the main transmission network (the REZ reference node). It does not resolve issues arising between the REZ reference node and the regional reference node. The ESB's medium term access options (described in section 5.3) complement and strengthen initiatives to develop REZs by introducing reforms to prevent the access of REZ generators being degraded by inefficient developments outside the REZ.

The interim REZ framework is discussed in a separate paper that is due to be submitted to Energy Ministers shortly.

Dedicated connections assets Rule change

60 ESB, Renewable Energy Zones Consultation Paper, January 2021. Available at: https://energyministers.gov.au/publications/stage-2-rez-consultation-energy-security-board

61 https://energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap#-what-is-the-electricity-infrastructure-roadmap-

62 Victorian Government, Victorian Renewable Energy Zones Development Plan Directions Paper, February 2021 pg 5. Available at: https://www.energy.vic.gov.au/__data/assets/pdf_file/0016/512422/DELWP_REZ-Development-Plan-Directions-Paper_Feb23-updated.pdf

The AEMC is currently consulting on changes to the Rules which would enable a generator, or a group of generators, to fund designated network assets and have these assets subject to a special access regime. The current Rules provide a framework for coordinating and sharing connections between generators as dedicated connection assets (DCAs).[63] To date sharing of these assets has been restricted by the existing framework. The AEMC published a draft rule in November 2020[64] establishing a framework promotes sharing and efficient investment in transmission infrastructure by providing an incentive for a generator, or a group of generators to fund a shared asset. This new framework offers an opportunity to commercially develop a limited but similar scheme to a REZ. In practice, DNAs could form the radial parts of REZs or could be stand-alone small REZs.

System strength investigation

The AEMC has recently published the results of investigation into system strength frameworks. This review addresses problems that overlap with the problems addressed by the interim REZ framework; namely, uncertainty, delay and high costs during the generator connection process.

The AEMC's proposed reforms are designed to proactively provide the volumes of system strength needed to maintain system security, and to support more timely connection of new generation so consumers can benefit from having cheaper and lower emissions generation. As such, the two reforms are complementary.

The reformed system strength regime could apply to REZs – i.e., AEMO could identify a system strength node within the REZ– and planning for system strength could occur as part of the REZ design process. While system strength is a key driver of uncertainty and delay associated with the connections regime, it is not the only challenge. The ESB proposes to design a REZ framework that integrates the new system strength regime to deliver a coordinated process for generator connections.

Enhanced congestion information

As outlined in the Directions Paper, enhanced information about existing and forecast congestion has the potential to improve the coordination of transmission and generation investment.

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 planning to consult on the Congestion Information Resource Guidelines later this year, which will provide a timely opportunity for stakeholders to provide input on the information that they would find useful for AEMO to provide.

The Directions paper outlined a range of ways in which congestion information could be enhanced. The Congestion Information Resource mainly provides information across operational timeframes. The Congestion Information Resource pertains to the following options from the January Directions Paper:

1. Publish local pricing offsets more prominently; and
2. improve the congestion information available to participants.

The third and fourth options are not in scope of the forthcoming information guideline consultation because they are relevant to longer timeframes:

3. Establish a near term (~2 year) congestion forecasting framework; and
4. Establish a long-term (~10-20 year) congestion forecasting framework.

63 DCAs are privately owned and operated power lines that facilitate the connection of a generator/large load customer to the Primary TNSP's transmission network. Under the existing Rules, DCAs of a considerable length, i.e., large DCAs – power lines with a length of 30km or more – are subject to a special 3rd party access regime.

64 AEMC, *Connection to dedicated connection assets, Draft determination*, November 2020. See https://www.aemc.gov.au/rule-changes/connection-dedicated-connection-assets

The longer the timeframe, the more uncertainty is introduced and the less reliable the forecasts are. Long-term plans such as the Integrated System Plan (ISP) approach uncertainty through a scenario-based planning approach, where scenarios are defined to explore the risks of over and under-investment in the transmission network. Local investment decisions require different scenarios that explore local risks. Given its whole of system outlook and its focus on least cost outcomes, the ISP is not designed to perform this function.

In considering feedback to options 3 and 4, stakeholders are pointed towards the REZ scorecard appendix to the ISP, which provides local information on expected system strength, loss factors, resource availability and climate risks. Stakeholder feedback on the content of the scorecards occurs as part of the broader ISP engagement process.[65]

Due to the uncertainty in long-term forecasts and the comprehensive information already published in the ISP, the ESB suggests that requests for additional information to inform investments be directed to AEMO's rigorous ISP consultation.

The ESB welcomes feedback on the desire to explore options 3 and 4.

5.3. Initial reforms

As foreshadowed in the January Directions paper, there is a need for medium-term models to bridge the gap between the interim REZ arrangements and long-term access reform. Work is also underway to support efficient and timely delivery of transmission investment.

Medium term access reform options

REZs are only a partial solution to the broader challenges that access reform seeks to address. This is because REZs provide an access solution that applies to specific locations within the power system. Outside the REZs, the problems associated with the access regime remain. In an interconnected power system, investment decisions elsewhere on the power system resonate across the grid – including within REZs – affecting power flows and the supply and demand balance faced by other market participants. A comprehensive solution needs to apply on a market-wide basis, not in isolated pockets. In essence, REZs need some form of system wide access regime to work well.

Looking further ahead, the medium-term access options are also designed to be a stepping-stone towards a longer-term solution locational marginal pricing (LMP) and financial transmission rights (FTR). The January Directions paper noted that long term access reform is a substantial change to the market design – so substantial that a gradual approach to implementation is required. The ESB is therefore looking to develop transitional arrangements to reduce the risk of the change and the impact on contractual arrangements, minimise implementation costs and provide a learning period for the market.

The ESB's objective for transmission access reform is to design a forward-looking market framework that addresses each of the issues arising from the current market settings. These issues are set out in Table 2 below (access reform objective). Part B includes further evidence and analysis of the nature of each issue.

Table 2 Transmission access reform – Issues to be addressed

No.	Issue	Description
1	Locational signals	There are inaccurate locational signals for generation and storage, ultimately driving a larger, costlier set of generation and transmission investments than would be required if investment was more accurately targeted.
2	Congestion management	Congestion is a permanent feature of a high VRE power system, however, the current regional pricing model creates a divergence between what

65 https://aemo.com.au/-/media/files/major-publications/isp/2020/appendix--5.pdf?la=en

		happens on the power system and what happens in the wholesale market in operational timeframes. In the event of congestion, the current market design applies simplified rules that reward market participants for acting in ways that are inconsistent with economic efficiency.
3	Enabling new technologies	The market design does not reward emerging technologies for providing services that enable the efficient integration of renewables. In particular, measures to promote the efficient location and operation/use of network for storage and new large flexible loads (e.g., hydrogen) is critical given the potential for these technologies to both alleviate and worsen transmission congestion. Better price signals are needed to support new business models so these technologies work within, and not against a high variable renewable energy power system.
4	Risk management tools	Market participants may benefit from additional risk management tools to manage risks of congestion, falling marginal loss factors and technical issues due to others' locational decisions, which make grid connection difficult. These risks add to the cost of becoming a generator in the NEM.

The ESB has developed three models (and two further variations) which attempt to mitigate the shortcomings of a partial access solution and also address stakeholder concerns that have been raised with the long-term solution of LMPs and FTRs. A brief description of each model and a summary of how they meet the access reform objectives is provided below. The full models and analysis are set out in Part B.

Given the issues with the stand-alone REZ model, the transition from the interim REZ models to a whole of system solution should occur as soon as the medium-term models can be fully designed and an appropriate implementation schedule occur. Alternatively, and depending on the model selected and its compatibility with the non-access elements of the REZ models, there may also be the chance to use such a model as part of the interim REZ framework. The ESB plans to provide further advice on this in its Interim REZ recommendations to government.

Congestion management model

This model introduces two changes to the existing arrangements which work in tandem. It builds on work undertaken during earlier reviews, notably Optional Firm Access (Stage 1).

First, all scheduled and semi-scheduled generators would face a congestion management 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. This removes incentives to 'disorderly bid' in the presence of congestion and so promotes dispatch efficiency and congestion management.

Second, all scheduled and semi-scheduled generators would receive a rebate, calculated each dispatch interval, funded from the collective revenue received from the congestion management charges. The size of the rebate is a function of generator availability, not dispatch quantity, meaning that generators do not have an incentive to bid in a disorderly fashion, as they do now. 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 more fulsome access reform, such as the introduction of locational marginal pricing and financial transmission rights.

This model is expected to be less complicated to implement then the long-term solution of LMPs and FTRs as it makes use of existing systems and does not involve changes to the dispatch engine).[66] However, implementation costs will be explored further as part of the evaluation approach (see Section 6).

66 Previous detailed work on implementation was undertaken as part of previous reviews, notably Optional Firm Access (Stage 1)

Congestion management model mechanism modified for new investment and renewable energy zones

Under a 'plain vanilla' congestion management model, rebates are provided to *all* scheduled and semi-scheduled generators. While the congestion management charge addresses incentives for *dispatch* efficiency and limits market disruption, receipt of the rebate by new entrant generators undermines *investment* efficiency. The additional rebate distorts signals in investment timescales (although no more so than the current arrangements).

A modified version of the congestion management model is to charge all scheduled and semi-scheduled generators the congestion management charge (as per the model described above) but limit receipt of the rebate to incumbent generators and new entrant generators that connect as part of a REZ tender process. New entrant scheduled and semi-scheduled generators that are either not foundational to a REZ, or do not connect inside a REZ, would not receive a rebate. This would improve incentives to locate efficiently.

Another way of implementing an adapted congestion management model could be to differentiate between existing and new transmission assets, specifically interconnectors, for the purpose of determining eligibility for congestion rebates. Rebates that apply to new transmission assets, including REZs and interconnectors built under the actionable ISP framework, could be allocated via a tender or auction process. This approach would enable the costs of transmission investment to be shared between customers and the generators that wish to use the assets. At a conceptual level, this approach would be similar to grandfathering the current transmission network and applying LMPs/FTRs to any new transmission infrastructure. The obligation to purchase rights to congestion rebates (essentially FTRs) could be extended to all new intra-regional investments as well as interconnectors.

Locational connection fee

This model would charge new generators connecting to the grid a connection fee. The connection fee can be calculated based on one of two options:

1. The net present value of the expected marginal cost of congestion caused by a generator connecting to the grid at a particular location, over a defined period.
2. The net present value of the efficient cost of transmission infrastructure required as a consequence of a generator connecting to a particular point on the transmission network.

The connection fee would be calculated before generation is built. This would be done to ensure that the estimated future cost of congestion will be reflected in the total cost of the project in the planning stage, therefore providing an incentive to build at locations to minimise the connection fee. The fee would be calculated administratively according to a guideline or formulation developed by AEMO. While the fee would be set and fixed at the time of connection, it could be recovered from the connecting party over time.

The fee would vary depending on the generator location because some areas of the network will have more capacity to host new generation capacity than others, and different expectations of other subsequent generation connections affecting flows on the network. This option could be designed to complement a REZ framework by exempting generators that participate in a REZ tender from the need to pay a connection fee.

The fee would vary over time, for a given location, depending on the network topology at the time of the fee calculation. By exposing new connecting generators to an estimate of the marginal cost of their decision on grid congestion, generators would face an incentive to locate in areas that will minimise their impact on congestion, in conjunction with other important factors influencing their location. Incumbent generators would not be subject to a connection fee, given that they are already connected to the grid.

Generator transmission use of system charges

Customer representatives have argued that this different treatment is at the heart of the lack of coordination between transmission and generation.[67]

A generator transmission use of system (Generator -TUOS) model would charge generators an ongoing charge that reflects the relative cost of providing transmission infrastructure at a given point on the network. This model is in the early phase of development. The charge would be designed to provide a locational signal for generators such that they internalise the network costs associated with maintaining the standard at their chosen location. In return for paying TUOS charges, generators could receive a defined level of access standard. This approach is consistent with the charges that apply to load. A G-TUOS approach has applied in Great Britain for decades.

Consideration would need to be given to what proportion of TNSP revenue would be recovered from generators. Both generators and load benefit from the transmission network and so it is difficult to precisely assign costs between them. The most straightforward method of allocating costs may therefore be a fixed proportion of TUOS revenue, such as a 50/50 division.

Once the split between load and generators is determined, a Generator -TUOS approach typically uses an administrative process to calculate a locational factor that is used to apportion transmission costs between generators. It would also be necessary to establish a charging methodology to define the metrics used to calculate generators' charges – for instance, whether generator bills are calculated by reference to the capacity or output-based factors, and whether there is a fixed portion. Charges would be recalculated annually as part of the transmission charging process.

Consideration may also need to be given to the appropriateness and form of any transitional provisions to apply to existing generators.

Hybrid congestion management and connection fee model

Each of the models outlined above have different strengths and weaknesses. On this basis, it is worth considering if the models could be combined into a hybrid approach to utilise the strengths of multiple models.

The congestion management model and the connection fee models would be likely to complement each other particularly well. As described above, the connection fee model would provide locational signals in investment timeframes, while the congestion management model would provide efficient congestion management signals in operational timeframes.

Importantly, the combination of these models would be internally consistent because the fixed up-front nature of connection fees (targeted at investment decisions) will not crossover or 'double up' with the dispatch by dispatch interval price signals (targeted at operational decisions) provided through the congestion management model.

Assessment of models
Table 3 summarises how each of the models set out above meets the access reform objectives.

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67 For example: Major Energy Users stated that: *If generators were required to pay for all of the costs that are incurred by transmission networks to enable delivery of their product to market then this would provide much better coordination between transmission networks and generators. Until this basic issue is addressed, there will continue to be excessively complex arrangements and delays in building needed transmission*. See Major Energy Users, Submission to ESB's consultation on REZ Planning Rules, September 2020. Available at: http://coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/MEU%20Response%20to%20Consultation%20Paper%20and%20Draft%20Rules%20%E2%80%93%20Interim%20REZ%20framework%20.pdf

Table 3 Assessment of medium-term access options

	Option	Locational signals	Congestion management	Efficient signals for storage	Ability of generators to hedge risk
1	Congestion management model	Does not provide locational signals because the refunds mitigate the impact of the congestion prices.	Generators receive a market signal to bid their short run marginal costs	Storage is paid to invest and operate in a way that alleviates transmission congestion as they receive the LMP to charge and discharge.	Removes volume risk but adds basis risk and introduces congestion management refunds to manage this risk. While refunds are useful price risk mitigation tools, they are not perfect.
2	Congestion management model modified for new generation and REZs	Provides efficient locational investment signals through exposure to LMPs for new generators outside of REZs and incentives to participate in REZ auctions within REZ.	Generators are incentivised to bid their short run marginal costs.	Storage is paid to invest and operate in a way that alleviates transmission congestion as they receive the LMP to charge and discharge.	Foundational REZ generators face reduced risk, but other new entrants face LMPs with no risk mitigation tools (as the intent is to channel investment into REZs).
3	Connection fee	Generators are provided locational signals at the point of connection. Relies on administratively process to accurately forecast the forward cost of congestion.	No change to market design in operational timeframes.	Difficult to create locational signals because storage can either alleviate or worsen congestion depending on charging or discharging. No change to market design in operational timeframes.	Generators continue to bear volume risk and have no direct congestion risk mitigation tools for operational timeframes. Connection fee is fixed up front and reduces subsequent entry risk.
4	Generator TUOS	Provides some locational price signals to generators. Relies on administratively process to accurately forecast the forward cost of congestion, and generators being able to predict the administratively determined charges.	No change to market design in operational timeframes.	Difficult to create locational signals because storage can either alleviate or worsen congestion depending on whether it is charging or discharging. No change to market design in operational timeframes.	Generators continue to bear volume risk and have no direct congestion risk mitigation tools for operational timeframes. The resetting of Generator -TUOS charges on an administrative basis represents a risk to generators (similar to MLFs).
5	Hybrid connection fee and congestion management model	Generators are provided locational signals at the point of connection. Relies on administratively process to accurately forecast the forward cost of congestion.	Generators are incentivised to bid their short run marginal costs.	Storage is paid to invest and operate in a way that alleviates transmission congestion as they receive the LMP to charge and discharge.	Removes volume risk but adds basis risk and introduces congestion management refunds to manage this risk. While refunds are useful price risk mitigation tools, they are not perfect.

Our initial analysis highlights that the congestion management model with REZ adaptions and the hybrid connection fee/congestion management model may best meet the ESB's access reform objectives. In particular, these two models both provide price signals to incentivise efficient investment and more effectively manage congestion in operational timeframes.

In developing these models, the ESB has sought to address the main concerns[68] raised by market participants in relation to the LMP/FTR model:

- the regulatory risk relating to changing the financial outcomes of incumbent market participants under the enduring access reforms is less problematic because the model broadly replicates existing financial outcomes,
- contractual renegotiations are less likely to be required or could be more modest, given that, for example, the existing regional pricing arrangements would be retained,
- the complexity of the market would appear to reduce compared to the status quo, given that market participants would no longer be incentivised to engage in disorderly bidding, and inter-regional settlement residues would be more predictable,
- market participants would gain experience of FTR value streams without needing to buy them.

Implementation costs are expected to be comparatively lower than that associated with the LMP/FTR model as major changes to the dispatch engine are not required. However, implementation costs will be explored further as part of the evaluation approach.

The ESB is also considering the extent to which the various models provide a stepping-stone towards long term access reform. While it would be possible to design a process to transition from a connection fee and/or generator TUOS to an LMP/FTR model, it would be necessary to unwind elements of the medium-term arrangements in order to move to the long-term arrangements.

Given the complexity of designing a G-TUOS regime in the first place, this option would be likely to become an enduring feature in its own right rather than a stepping-stone to long term reform. Under a connection fee model, the fee is fixed up front, which means there is a risk of overcharging if the market design subsequently moves to an LMP/FTR model. To avoid this, it would be necessary to design the fee in a way that can transition to a long-term access model at a fixed point in the future. For instance, if full access reform was scheduled to be introduced in 2030, then the connection fee would be designed to reflect the net present value of the network impact of the connecting generator between the time of connection and 2030. In contrast, it is expected that the congestion management model could better transition to the longer-term solution of LMPs/FTRs.

We are seeking stakeholder views on each of the models and how they meet the objectives. A more detailed description and assessment of the models is provided in Part B.

Measures to support timely and efficient transmission investment

Regulation and financing of large transmission projects

The AEMC is currently considering the request for rule changes relating to the financing of ISP projects.[69] The Commission intends to commence a broader review, in cooperation with the other market bodies, to consider options to support the timely and efficient delivery of large transmission projects that are in the long-term interests of consumers, recognising that the nature of transmission investment is invariably changing. While the scope of the review is yet to be confirmed, it is likely that it will include matters such as financing, regulatory and governance issues.

68 Other than the concern that reform is not needed, which the ESB does not agree with.

69 AEMC, *Draft Rule Determination - National Electricity Amendment (Participant Derogation – Financeability Of ISP Projects (Electranet)) Rule 2021* 4 February 2021, p33

The AER is also undertaking a work program that is focused on the efficient and timely delivery of actionable ISP projects. As part of this work, the AER is preparing guidance notes governing its assessment of contingent project applications (as well as project staging and ex post reviews) in relation to large actionable ISP projects. These guidance notes should provide additional certainty and clarity to TNSPs governing how the AER will approach these assessments and should help to drive more efficient delivery of actionable ISP projects in the medium to longer term.[70]

Both of these bodies of work will seek to promote cost efficiency in projects identified as part of the ISP least cost generation and transmission pathway.

Transmission cost allocation

The methodology used to allocate transmission costs between jurisdictions and between loads is coming under greater scrutiny. For instance, the actionable ISP project to develop Marinus Link is subject to a decision rule whereby the project will only proceed if agreement is reached on how the cost of the project will be recovered.[71] (As discussed elsewhere in this chapter there is also a debate underway about whether generators should share in the cost of transmission investment.) The ESB has provided advice to Energy Ministers on transmission cost allocation[72] and governments are currently conducting further analysis and considering next steps and governments are currently conducting further analysis and considering next steps.

5.4. Next reforms

In the long term, the ESB's preferred solution for access reform is to shift to locational marginal pricing and financial transmission rights. It is a more comprehensive access solution to the issues raised. It is a well-established model that has been successfully applied in numerous overseas markets for decades.[73] The ESB notes that many stakeholders are opposed to such reform but there are issues that must be addressed.

As highlighted in Part B, there are fundamental issues with the current access framework leading to poorly coordinated generation and transmission infrastructure investment and material problems with congestion and losses. The materiality of these problems is only going to grow with the significant new build planned to go ahead as the existing coal fleet retires. Given these problems it is critical to implement incentives to support congestion management in the short term, as well as a comprehensive and transparent transition to the long-term solution.

While the immediate reforms and medium-term access options will assist congestion management in some ways, by their very nature they are a sub-optimal long-term solution. They are cheaper, quicker and less disruptive to implement, but do not fully resolve the problems that we are trying to address. These short to medium term solutions are better thought of as interim, or grandfathering, solutions

70 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulation-of-large-transmission-projects

71 AEMO, *2020 Integrated System Plan*, July 2020, p83.

72 http://www.coagenergycouncil.gov.au/publications/23rd-energy-council-meeting-communiqu%C3%A9

73 Locational marginal prices are consistent with the fundamental principle of good market design that prices should reflect marginal costs. Locational marginal prices and financial transmission rights are common and well-established overseas in a variety of different settings, and widely considered to be beneficial. They have been progressively implemented in all seven US-organised electricity markets starting with PJM in 1998 and ending in the 2010s. The successive role out of the design is evidence of its success. Closer to home, New Zealand's market commenced with LMPs in 1996. Similar reforms are currently being undertaken in Ontario, Canada as part of Market Renewal reforms in that country. These reforms are designed to transition that market towards a renewable future. No market has reversed its decision and reverted to a regional pricing regime.

on the way to fully implementing a future access framework to drive better outcomes for the NEM and consumers.

When considering an appropriate timeline to make the transition from medium term/interim arrangements to the arrangements that will support the grid of the future, the impact on the market, the cost, and the risk of delaying implementation need to be taken into account. Understanding the success and learnings of any medium-term access solutions implemented will also be important.

Analysis has shown that ensuring the right locational investment signals are in place in the very early 2030s is critical to ensure efficient build of the more than 50GW of new generation foreshadowed to be built in the NEM by 2040. This timeline is also optimal for minimising market disruption, as it aligns with the end of the existing suite of Power Purchase Agreements, which have been cited as one of the largest potential problems with an earlier implementation date. This timeframe also gives the market ample time to consider the changes and be fully prepared from when the changes are implemented to when they come into effect.

Questions for consultation

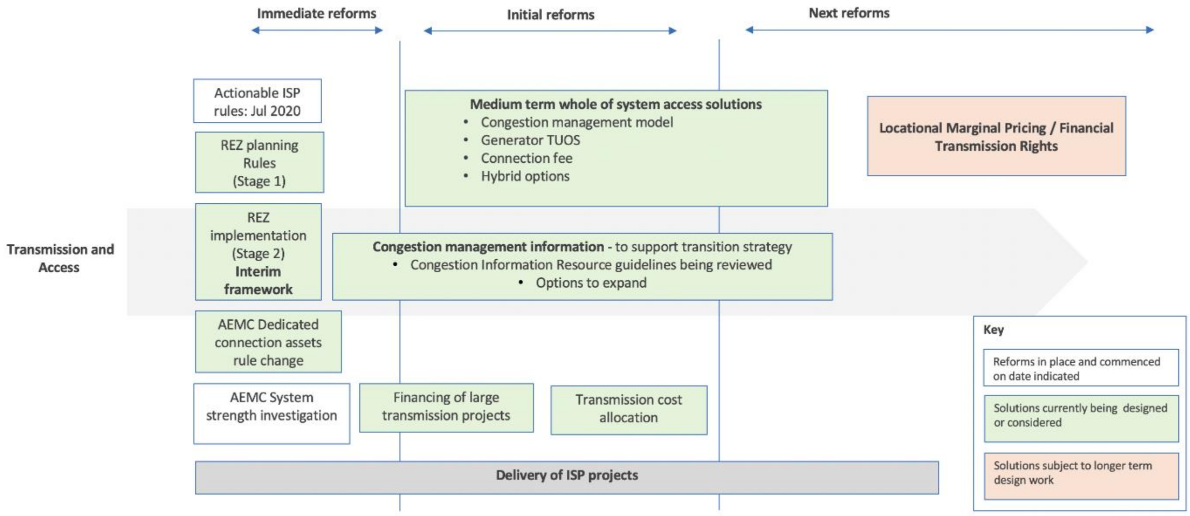
42. Does the proposed reform pathway for transmission and access meet the needs of the transition?
43. For each medium-term access option presented in the attachment:

- Do you think that the model satisfactorily addresses the access reform objectives set out above?
- If any, what is your main criticism of the model?
- What additional detail do you require to understand the option?

44. Which medium term access option is preferable?
45. Are there alternative options that the ESB should consider?
46. Are there potential improvements to the options that the ESB should consider?
47. Would enhanced congestion information help to improve the coordination of transmission and generation investment? If so, what additional information would add value?
48. What are stakeholder views on when these arrangements should be implemented by / when? What should be taken into account when determining implementation timeframes?

5.5. Illustrative pathway

The Transmission and Access reform pathway can be summarised as follows:



6. An Evaluation Approach and Interdependencies

In developing a fit-for-purpose market design, some changes are needed, immediately, others are needed over time so they meet the needs and pace of the transition, while allowing for flexibility to adapt to its pace and evolving market conditions.

In its January Direction paper, the ESB noted that in providing final recommendations on market design, its final advice would not present an entirely new design to be introduced at a single point in time. Rather its advice would recommend reforms in many areas that can be implemented over time as the market develops. This allows reforms to be coordinated to minimise implementation costs and manage temporal and related interdependencies between reforms and changes in the market.

As the paper makes obvious the reforms are aligned along proposed transition pathways to address the issues raised in each of the workstreams in the 2025 project. These workstreams were established and subsequently consolidated to four to evaluate and develop market design options that tackle the strategic challenges identified by the ESB in its September Consultation paper as being critical to address the transition.[74]

As discussed in this paper, the reform pathways have been set out to reflect their urgency and fall into three categories:

- **Immediate reforms** – these are proposed measures for immediate implementation to address imminent problems in the NEM. As such they are reforms that are either underway or are being developed now for implementation as soon as possible.
- **Initial reforms** – these are reforms that we need to develop further in the near term for implementation. Many of these reforms will need to be implemented pre-emptively to solve emerging challenges, that have a clear solution.
- **Next reforms** – these are reforms that we may need to move to over time, given the trends and pace of the transition, or may need to be considered or revisited if certain preconditions arise.

Some reforms included in the proposed transition pathways are still under development, others have options for them included for consultation in this paper. The ESB acknowledges that decisions between options or recommending a direction for development for a reform may impact on how the reform should be categorised on the pathway. Decision on options will be made taking stakeholder feedback into account and completion of the further work foreshadowed ahead of final recommendations.

Quantitative analysis

In its September Consultation paper, the ESB outlined a two-phase evaluation process that would be used to inform and support the ESB's final recommendations in its P2025 work. In response to stakeholder request for more information on the ESB's evaluation approach, the January Directions paper set out more information around the form of the final recommendations and how the evaluation process will support development of the final recommendations.

Part of the evaluation process will include quantitative analysis to inform individual reform pathways and all of the reforms considered together to consider relevant interdependencies. The ESB considered that it would be useful to share more information with stakeholders on our approach to this analysis.

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74 https://energyministers.gov.au/publications/post-2025-market-design-consultation-paper-%E2%80%93-september-2020

Objectives for quantitative analysis

The objectives for the quantitative analysis that will be undertaken include the following:

- Evaluation of the benefits and the costs of the proposed pathway to assist with evaluating whether it is likely to promote the national electricity objective.
- Providing evidence to inform specific design decisions where multiple options for reform have been identified on a pathway.
- Providing stakeholders with a more detailed explanation of the ESB's final recommendations.

Modelling is an important tool that will assist with understanding how outcomes of the proposed reform pathways might vary in different states of the world and give insights into their potential impacts. However, many of these reforms are subtle and so complex to model. Given the complexity and limitations of the modelling tasks that will be undertaken, modelling outcomes will need to be supported by qualitative assessment. The September Consultation paper also outlined the qualitative assessment that will be undertaken in evaluating proposed reforms, which assessment has informed development of reforms on the proposed pathways.

Costs of the reform

Identifying the costs of the reform will be an important input into the quantitative analysis that will be done. Ahead of mid-year the Board will also consider how implementation costs, in particular, are recovered.

The costs of the reform will include the:

- implementation costs for industry and the market bodies
- ongoing costs for participants and market bodies, including transaction costs.

Given the scale and nature of the reforms, these implementation costs will be difficult to estimate with any degree of certainty. However, we will seek to quantify likely costs as follows:

- First, use the proposed reform pathways set out in this paper as they include immediate and initial reforms - as a basis to develop an estimate of relevant costs. Where options still exist in a pathway, some assumptions may need to be made and the assumptions will be reflected in the estimates determined.
- Second, work with AEMO to determine the costs to the market operator of implementing these options. These costs will be planning level estimates in the form of a wide range.
- Third, where possible undertake separate assessments of the likely costs to other parties from specific reforms. We will also consider how best to estimate likely costs to participants

Overview of modelling tasks

There are two key modelling tasks that will be completed to meet the objectives of the quantitative analysis.

<u>Benefits of reform</u>

Costs of reform are easier to quantify than the benefits. This is because the reform aims to change the incentives and behaviours of market participants, the benefits of which may accrue many years in the future, and so are inherently uncertain. While the ESB will not be undertaking a detailed cost benefit assessment, we consider that it is possible to indicate the relative 'size of the prize' of the outcomes that each reform pathway is seeking to achieve.

In approaching benefits, a two-phase process will be used.

Phase 1 - Assessment of individual workstreams in isolation

Phase 1 will involve a number of key steps. To test the relative impact of a proposed pathway, we first need to define the reference case – i.e., the 'no reform scenario – against which a proposed pathway or 'reform scenario' can then be tested. This involves developing a common baseline model of the NEM, using the current Rules framework and the current Integrated Systems Plan (ISP)

In using the current ISP, the intent is for there to be uniformity between the assumptions used for the ISP and the assumptions used for as part of the modelling competed in support of the Post 2025 work. Given the rapid evolution of the system it is our initial view that the assumptions informing the Step Change scenario are appropriate to inform the 'no reform scenario'.

An additional consideration that will be determined is how we account for the recent announcement by the NSW Government about the NSW Roadmap, which included 14 GW of new capacity for the system over the next decade. While the current ISP did not account for this in its assumptions, given the impact of this scheme we think its exclusion will likely drive very different outcomes over the course of the modelling horizon. Accordingly, it will be included as part of the reference case.

The ESB is mindful that AEMO is currently developing the next ISP. We will be working closely with AEMO on this work to ensure uniformity of the assumptions by the ESB as much as possible.

The 'reform scenario' that will be tested against the base case will be same pathway used for the purpose of developing estimates of implementation costs.

A common modelling framework will be developed to assess the two scenarios. For some workstreams this may involve using a long-term least cost planning approach, like that used for the ISP, with a set of agreed input assumptions (e.g., about fuel costs, demand, technology costs etc). The expected output of this modelling will be a total cost of operating the system, accompanied by an implementation cost for the reform scenario.

The modelling undertaken will not be the same for each reform pathway. Some pathways, such as for Resource Adequacy and Aging Thermal Retirement (RAMS), will demand price modelling because this is the mechanism by which the reform scenario takes effect. But for others such as the Essential System Services, Scheduling and Ahead Mechanisms pathway, least-cost/whole-of-system modelling may be more relevant to assess the effect of the reforms on the total cost of running the system. Other approaches, such as just modelling the change in a specific variable (e.g., curtailment of generation, number of interventions, hours of the system being insecure) may also be used, particularly for very challenging modelling tasks such as the assessment of the effect of obtaining essential system services.

Phase 2 - Holistic assessment

Phase 2 will then assess holistic benefits of the pathways considered collectively, i.e., a preferred overall package of reforms coupled with an implementation path. Phase 2 modelling will consider:

- the interlinkages and complementary features of different workstreams; and
- the potential reductions in implementation costs associated with the combined, overall reform

Broadly, phase 2 assessment will incorporate the results of each of the phase 1 assessments, but then take these analyses further, either by:

- adjusting the cost assessments underpinning the modelling, depending on the data revealed in estimating implementation costs; or
- where practicable, reapplying the modelling frameworks used to complete the phase 1 assessments in combination, rerunning a least cost planning model to incorporate one or more of the pathways, for example:
    - the DER and demand response reforms; and
    - the essential services and scheduling reforms.

It is anticipated that this will produce a set of costs and benefits (whatever form those benefits take) to implement each pathway in isolation, and a set of costs and benefits to implement *all four* pathways in combination.

In this phase the interdependencies between the pathways will be considered. For example, what the reforms in each of the pathways that could be expected to lead to more efficient investment in new resources, would mean for possible exit decisions or how existing capacity may alter its operation of existing capacity.

In addition, specific modelling of some key interdependencies between pathways will also be undertaken. For example:

- assessing the resource adequacy benefits of an operating reserve mechanism when the design of that reform is further advanced; or
- determining how obtaining essential system services addresses resource adequacy, by providing additional cash flows to resources.

Other key interdependencies will be identified as part of this process.

<u>Policy design</u>

A variety of modelling and detailed analysis has already been completed in relation to the development of reforms of the various pathways. For example, in relation to the Integration of Distributed Energy Resources and Demand Side Participation pathway, the following pieces of modelling are being undertaken or have already been completed:

- An assessment of the network benefits of active DER – Baringa will be tasked with updating the assessment they completed for the Open Energy Networks program with updated DER trajectories from the ISP to see benefits of more active DER on the network (through tariffs and structured procurement of non-network options).
- 'Scheduled lite 'analysis – the AEMC will complete analysis on the uptake and benefits of scheduled light to inform the draft determination in the Generator registrations and connections rule change.
- ARENA Load Flex Study – ARENA has commenced a study into how much flexible capacity we could have on the demand side out to 2040, and which sources it would come from

Other relevant modelling, such as these examples, will also be used by the ESB to inform the evaluation of reform pathway.

As reforms are developed further, additional modelling that could assist in making key design choices will also be undertaken, where feasible.

7. Next Steps

7.1. Consultation process and submissions

The ESB invites comments from interested parties on this consultation paper by 9 June 2021. Please respond to the 'questions for consultation' in this paper in your submission.

Submission close date	9 June 2021
Lodgement details	Email to: info@esb.org.au
Document type	Must be in Word for publication
Naming of submission document	[Company Name] Response to P2025 Market Design Consultation Paper
Form of submission	Clearly indicate any confidentiality claims by noting "Confidential" in document name and in the body of the email.
Late submissions	Late submissions will not be accepted
Publications	Submissions will be published on the COAG Energy Council's website, following a review for claims of confidentiality.

The ESB will carry out a series of stakeholder briefings over the consultation period to enable further engagement on these issues.

Details will be available on the ESB webpage: https://esb-post2025-market-design.aemc.gov.au/

8. Summary of questions for consultation

Questions for consultation paper

#	Questions
Part A	
Chapter 2 - Resource Adequacy Mechanisms	
1	What types of information provision regarding jurisdictional investment schemes would benefit participants the most?
2	Which financial principles are most important in establishing means to integrate jurisdictional investment schemes with market arrangements as smoothly as possible?
3	Are there financial principles missing, or that have been included but shouldn't be?
4	What are some of the market-based signal challenges, if any, with mothballing/seasonal shutdown?
5	What additional costs or process burden may the disclosure of such information place on stakeholders?
6	What concerns do stakeholders have around the commercial sensitivities associated with disclosing information?
7	Do stakeholders perceive the disclosure of mothballing / seasonal shutdown information as limiting a participant's flexibility in operating their plant?
8	Do stakeholders agree the notice of closure exemption process should be extended to include mothballed generation? If so, should it apply to all generators or just to large designated thermal generators?
9	What suggestion do stakeholders have for defining mothballing?
10	How can governments, market bodies and market participants better work together to be prepared for exits?
11	Do stakeholders agree governments are best placed to enter into a contract with a respective participant in the event of early exit?
12	Do stakeholders agree that any future contract arrangements should be kept separate to existing RERT mechanism?
13	Do stakeholders agree with the proposed principles and measures of success? Are there others that should be considered?
14	Are there any obvious priorities given current and plausible likely future market scenarios?
15	What options are there to encourage contractual compliance among retailers without adopting higher punitive penalties?
16	Would one RRO option over another better suit particular types of market conditions anticipated over the course of the transition?
17	*[Financial RRO option]* How could you strengthen the signal? Could minimising the triggers do this? What are the unforeseen consequences or implications with this?
18	*[Financial RRO option]* What are options to make the RRO simpler, while still advancing some measures of success?
19	*[Financial RRO option]* What other impacts on small retailers and C&I customers need to be considered? How can they be best mitigated?
20	*[Physical RRO option]* Should it be a triggered mechanism, or be developed as a rolling one?
21	*[Physical RRO option]* How should the physical certificates be regulated?
22	*[Physical RRO option]* How would a physical RRO impact contract market liquidity?
23	*[Physical RRO option]* What other impacts on small retailers and C&I customers need to be considered? How can they be best mitigated?

Chapter 3 - Essential System Services, Scheduling and Ahead Mechanisms	
24	What are stakeholder views on what specific design issues should be considered for an operational system security mechanism (SSM) to support the objectives of providing secure operations through the transition of the power system and to support efficient dispatch outcomes?
25	What additional information should be considered to assess the complementarity and materiality of an operational SSM in the context of a TNSP-led solution in the investment timeframe?
26	How do stakeholders view a ramping or operating reserve as fitting within the overall framework for essential system services?
Chapter 4 – Integration of Distributed Energy Resources and Demand Side Participation	
27	What are stakeholder views on the issues raised on supporting market participation for active DER? Are there other paths that could also be considered for different types of consumers?
28	Is the unbundling of services delivered by active DER resources (e.g., solar PV, batteries or smart hot water appliances) from energy supplied by DER viewed as important to allow innovation and new business models? What might be the pros and cons of this approach?
29	What might be implications of a growing fleet of active batteries or electric vehicles? Are other pathways that need to be considered to reflect these needs?
30	Are there constraints on switching providers with DERs today? Are constraints on switching likely to occur through standards being introduced now or expected, such as IEEE 2030.5?
31	What are stakeholder views on approaches outlined? What might be the advantages and disadvantages associated with each?
32	Are there other potential approaches that could be considered?
33	Under what situations could the distribution network operator perform the role of the retailer / aggregator?
34	How might DER assets be managed in a situation where no retailer / aggregator is nominated?
35	What are the issues surrounding connection agreements that can facilitate a retailer / aggregator for market participation and the delegation for the enforcement of limits to both DNSPs and AEMO?
36	Noting the differences in market arrangements between the WEM and the NEM, are there aspects of the WA DER Roadmap that could usefully inform how certain roles and responsibilities might evolve in the NEM?
37	What are stakeholder views on the approaches outlined? What are the potential advantages and disadvantages of each?
38	Are there alternative approaches that could also work to complement existing tariff reform processes that should also be considered? How might these work?
39	Do stakeholders have views on additional steps or information that should be considered in the proposed consumer risk assessment tool?
40	Do stakeholders have views on the options outlined to address issues associated with falling minimum demand and increasing access to markets?
41	What are other options to consider that might deliver better outcomes for consumers?
42	Do stakeholders have views on the proposed principles? Are there other principles that should be considered to deliver benefits for consumers?
Chapter 5 – Transmission and Access	
43	Does the proposed reform pathway for transmission and access meet the needs of the transition?
44	For each medium-term access option presented in Part B:

	• Do you think that the model satisfactorily addresses the access reform objectives set out above? • If any, what is your main criticism of the model? • What additional detail do you require to understand the option?
45	Which medium term access option is preferable?
46	Are there alternative options that the ESB should consider?
47	Are there potential improvements to the options that the ESB should consider?
48	Would enhanced congestion information help to improve the coordination of transmission and generation investment? If so, what additional information would add value?
49	What are stakeholder views on when these arrangements should be implemented by? What should be taken into account when determining implementation timeframes?
Part B	
Resource Adequacy Mechanisms	
No further consultation questions in Part B	
Essential System Services, Scheduling and Ahead Mechanisms	
1	What are stakeholder views on the interactions between the proposed investment and operational procurement mechanisms for structured procurement? • In what other circumstances to the ones listed in the paper would having both mechanisms be complementary to one another? How should they be designed to support this complementarity? • In what circumstances might having both a long-term and short-term procurement mechanism potentially cause unintended consequences? What should be done in the design to mitigate these risks? • What are the potential impacts, in either or both mechanisms, for the different segments of industry, for efficient investment in transmission and generation, and efficient operation of the system?
2	How do stakeholders envisage contracting arrangements will work under the long-term procurement mechanism, and how may this interact with the design of the SSM or vice versa?
3	Do stakeholders agree that the UCS should schedule for an efficient level of the service which has been structurally procured, with the efficient level being with regards to meeting a dispatch cost minimisation objective, as defined by the terms of contract activation and pre-dispatch bids. • If so, why? If not, why not?
4	Do stakeholders consider the potential for the UCS to centrally-commit contracted resources to be of material concern? • If so, are the proposals put forward by the ESB sufficient to address this concern? • If not, what should be done to mitigate this concern?
5	If the UCS commits units ahead of time, how would this interact with the existing wholesale spot and frequency markets that are real-time?
6	What are stakeholder views on how the UCS schedule should be reflected in pre-dispatch and dispatch (i.e., contracted resources being required to bid into dispatch to be scheduled and/or constraints applied)? Are there any possible unintended consequences of these approaches?
7	Do stakeholders consider the potential interactions between pre-dispatch, dispatch and the UCS to be material? I.e., that participants may change their self-commitment status following the UCS run.

8	What are stakeholders' views on the best way to address the potential decommitment?
9	How do stakeholders think that the uncertainty associated with scheduling units ahead of time in the UCS should be managed? Are there any considerations that should be taken into account in addition to those outlined above?
10	Do stakeholders agree with the ESB's proposal that TNSPs would be responsible for providing AEMO with the required contract information for the system service contracts, where these have been agreed between the TNSP and the relevant resource?
11	How do stakeholders envisage the contracts for system services would be designed where these are to be scheduled by the UCS, and what information would be required to be provided to AEMO to support the scheduling mechanism?
12	Do stakeholders consider that all system service contracts (e.g., system strength) should be required to be scheduled through the UCS? I.e., must offer? • If so, why? If not, why not?
13	Do stakeholders agree with the transparency measures proposed for the UCS implementation, or suggest other considerations exist that should contribute to transparency with regards to the UCS?
14	How do generators and demand response providers position themselves under current frameworks ahead of periods of high ramping or periods of uncertainty?
15	What challenges are envisaged in a future with higher variability and uncertainty in net demand?
16	How would a reserve service influence commitment and other operational decisions made by generators and demand response providers?
17	Who should pay for reserves and why?
18	How would the fleet described in the case study have positioned itself under current frameworks in a future with higher net demand uncertainty? Would it have provided more ramping reserve?
19	In what circumstances would a reserve service be beneficial for consumers?
Integration of Distributed Energy Resources and Demand Side Participation	
20	What are stakeholder views on the proposed maturity plan approach and priorities identified for the first release?
21	Do stakeholders have any feedback on the approach for developing the trader-services model pathway?
22	What technical and regulatory barriers, challenges and opportunities may Model 2 present to Traders, end-users and distributors? What challenges would be present for metering services in either model?
23	How might the designs be improved to accommodate and facilitate greater trading of non-energy services from either model?
24	What are the benefits and risks of enabling arbitrage between separate connection points? If there are risks, including for retailer and network tariffs, how should they be mitigated?
25	Do stakeholders consider there to be high implementation costs for any of these options? If so, would these costs be borne by all system users or predominantly by the party choosing to enter the flexible arrangement?
26	Are there other options the ESB could consider on the path to support more flexible trading for end-users?
27	Are the stated objectives appropriate? Should additional objectives be considered in the design of a 'scheduled lite' arrangement?
28	Are there any additional or alternate principles that should be considered?
29	Are there any additional scheduled lite models or design elements that should be considered through this process? If so, what are the purpose, key features and benefits?

30	Are the forecasting requirements proposed for the visibility model appropriate? Are there alternate options for granularity, frequency and use?
31	Are the bid requirements appropriate for the dispatchability model?
32	What are the barriers, if any, to self-forecasting? How far ahead of time would a resource be able to provide meaningful forecasts of their likely behaviour?
33	How appropriate is the use of threshold accuracy and non-financial penalties for inaccuracy? What are the trade-offs of using this approach?
34	How appropriate is the proposed approach for the dispatchability model? Will the use of the threshold meaningfully reduce barriers to participation? What are the trade-offs associated with the use of a threshold? How should that threshold be determined (e.g., MW accuracy, or proportion of dispatch targets etc.)?
35	Should an opt-out approach prior to dispatch, like that used in New Zealand, be adopted? Would that meaningfully reduce any barriers to participation?
36	How appropriate are the proposed additional participation elements for the visibility and dispatch models?
37	For the dispatchability model, will the use of lighter SCADA arrangements meaningfully reduce barriers to participation? What other types of solutions could be considered?
38	Aside from those listed above, should the ESB consider any other elements of the scheduling framework when designing additional participation requirements for scheduled lite arrangements?
39	How appropriate are the proposed incentives for the visibility model, including: • avoided FCAS costs • reduced operating reserve costs (if introduced)? • Are these incentives material enough to incentivise participation under this model? What other incentives should be considered for this model?
40	How appropriate are the proposed incentives for the dispatchability model, including: • avoided FCAS costs • reduced civil penalties • avoided RERT costs • avoided RRO costs and the ability to underwrite qualifying contracts (subject to firmness rating) • reduced operating reserve costs and ability to bid into operating reserve market (if introduced)?
41	Are these incentives material enough to incentivise participation under this model? What other incentives should be considered for this model?
42	Are there benefits of making a distinction between active (or controllable) and passive (not controllable) behaviours behind a connection point?
43	How might a market participant (retailer; aggregator) provide information across their portfolio (many connection points)?
Transmission and Access	
No further consultation questions in Part B	

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