ENERGY SECURITY BOARD

Post-2025 Market Design Directions Paper

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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	Synchronous Services Markets
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

In September 2020, the Energy Security Board (ESB) released a consultation paper that outlined reform options under consideration as part of the Post-2025 market design project. The ESB published over 90 submissions from a broad range of stakeholders responding to the paper.

This paper provides a high-level summary of stakeholder feedback and, having considered this feedback, sets out the consolidated reform directions the ESB proposes to pursue as part of the Post-2025 project, in the following areas:

- **Resource adequacy mechanisms and ageing thermal transmission** – ensuring the right mix of resources is available to the system through the transition to deliver reliable supply to customers
- **Essential system services and scheduling and ahead mechanisms** – ensuring those resources and services required to manage the complexity of dispatch and deliver secure supply to customers are available when needed
- **Demand side participation** – progressively unlock the potential of the demand side to compete in the wholesale market and deliver local benefits while maintaining system security
- **Transmission and access** – providing the network to meet future needs, arrangements for early implementation of renewable energy zones, and longer-term arrangements to ensure efficient use of the national network.

These four focus areas reflect stakeholders' views on interaction between some of the seven workstreams (Market Design Initiatives) set out in the consultation paper.

The intent of this paper is to set out the direction of work within the Post-2025 work program, rather than elicit stakeholder views at this time. In March 2021, the ESB will consult on potential market designs which are being developed in accordance with the direction in this paper. Various accompanying papers published with this paper are, however, open to consultation.

Resource adequacy mechanisms and ageing thermal transmission

Over the next two decades, 26-50 gigawatts (GW) of new large scale variable renewable energy (VRE) – in addition to existing, committed and anticipated projects – is forecast to come online, supported by between 6 GW and 19 GW of new flexible and dispatchable resources, as approximately 16 GW of thermal generation (61% of the current coal fleet in the NEM) retires.

Stakeholders offered mixed views on whether current resource adequacy mechanisms in the National Electricity Market (NEM) were sufficient to attract the required investment. Almost all stakeholders expressed concerns around policy uncertainty and the need to align government policies and programs – particularly those incentivising investment – with the needs of the NEM.

By implementing various schemes targeting new investment, governments have indicated a preference for strengthening and lengthening the duration of signals to bring on new investment through the transition.

Current jurisdictional investment schemes apply only to new investment and target particular types of resources. They provide longer term investment signals, which need to be complemented by effective short to medium term measures to ensure the full mix of resources includes those with flexible, dispatchable capabilities and real time incentives to ensure those resources are efficiently dispatched to meet customers' needs, and the system can continue to operate in a reliable state.

Given this landscape, the ESB will focus reform efforts in this workstream on managing the entry of new resources into the market and the orderly exit of resources throughout the energy transition in the presence of substantial government investment schemes.

Specifically, the ESB will continue to explore the following reforms:

- *Continued development of an operating reserve (through the essential system services workstream) to ensure flexible, dispatchable resources are valued in the market and have an incentive to be available when they are needed.*
- *Exploration of options to enhance the retailer reliability obligation, to ensure retailers have an incentive to maintain a portfolio of contracts, including with resources presently in the market, to reliably meet their customers' needs and to provide a longer duration price signal for investment in necessary resources that may not be part of government schemes. As part of this, the ESB will reflect on how to address concerns raised by stakeholders regarding the complexity of the Retailer Reliability Obligation (RRO), 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 a policy objective.*
- *Investigation, with governments and stakeholders, of a potential NEM-wide, common approach to integrating jurisdiction underwriting or investment schemes for new investment into the NEM – recognising such schemes are likely to be an enduring feature of the energy sector as governments seek to manage risks associated with the energy transition in their jurisdiction.*
- *Further consideration of mechanisms to ensure the orderly exit of thermal plants as they retire from the system – possibly including changes to notice of closure requirements, regulated or negotiated arrangements with thermal plants, and contingent scenario planning.*

Essential system services and scheduling and ahead markets

Stakeholders supported the direction set out by the ESB for essential system services in the September Consultation – to use co-optimised market-based procurement where possible and, where not possible, structured procurement approaches. The ESB's considerations have prioritised:

- The need 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
- The need to procure system strength in a structured manner, and
- The potential need for a new operating reserve or ramping service.

The ESB will continue to work on a spot market approach for valuing and procuring inertia as a long-term priority, in the first instance assessing the value of procuring inertia under structured procured arrangements if required in the interim, noting that many stakeholders noted that valuing and procuring missing system services is a priority that cannot wait until 2025.

The ESB intends to use the Australian Energy Market Commission (AEMC) rules change process to accelerate this agenda consistent with this direction, as follows:

- *Fast frequency response and primary frequency response – being considered via the Infigen and AEMO rule changes (further details in accompanying AEMC directions paper).*
- *Consideration of operating reserves – being considered via the Infigen Energy and Delta Electricity (Introduction of ramping services) rule changes (further details in accompanying AEMC directions paper).*

- *Network Service Provider structured procurement provision of system strength – being considered via the TransGrid rule change.*
- *Developing operational scheduling mechanisms to schedule system strength and inertia via the Delta Electricity (Capacity commitment mechanism for system security and reliability services) and Hydro Tasmania rule changes.*

Stakeholders had mixed views about ahead mechanisms. The unit commitment for security (UCS) concept was generally supported. Some stakeholders supported further consideration of ahead scheduling of services, with the priority being the procurement and dispatch of services under structured procurement for system strength and possibly inertia (collectively known as "synchronous services").

Many stakeholders did not see the value in a voluntary ahead market for energy and services. Retailers and generators were mostly opposed while some providers of demand services and large users did see value in ahead scheduling.

The ESB intends to further develop these options as follows:

- *Use the operational timeframe rule changes on synchronous services (Delta and Hydro Tasmania) to progress development of the UCS.*
- *Consider ahead scheduling of system services first through the rule changes related to synchronous services markets (Delta and Hydro Tasmania), and more generally after new system services markets (including system strength, fast frequency response, operating reserves) have been defined.*
- *Continue to develop the concept 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.*

Demand side participation

Current arrangements do not make it easy for new and innovative technologies or service providers to enter the market, and are also not set up in a way that rewards customers for their flexibility. Changes are needed so:

- Clear signals are provided for when more energy supply (or demand) is needed and can be efficiently provided to keep the system in balance
- Customers can manage the output from their solar photovoltaic (PV) systems, air conditioners, hot water units or pool pumps to help make this happen
- The impacts associated with falling system minimum demand (where over 50% of customers are likely to be using some form of distributed energy resources (DER) by the end of the decade) are reduced.

Customers should be rewarded for this flexibility where it is efficient to do so. To support this, the ESB is pursuing an integrated set of reforms, that incorporates market integration of DER, establishing a two sided market and associated scheduling, technical, regulatory, consumer protection reforms, including the following.

Reducing cost and variability

As the NEM moves towards a system of millions of distributed resources, the ESB is considering changes that are needed to improve system efficiency and lower costs. An increase in the visibility of resources to support efficient forecasting and scheduling is required, as well as measures to address network stability and enable the value to customers be recognised from the demand flexibility that DER can efficiently offer.

The ESB will:

- *Work with jurisdictions on planning and design for state-based compliance approaches to increase the technical capabilities of newly installed solar PV inverter equipment at a national level.*
- *Undertake analysis on the potential shift of passive solar PV towards active (price responsive). Examine options for accelerating this shift from passive to active resources.*
- *Examine options for new services to support 'turn-up' or 'shifting' of load where it is efficient; e.g. electric vehicle managed charging or via ahead market scheduling.*
- *Consider incentives for flexible demand and DER to participate in scheduling and options to reduce the barriers to participation in efficient dispatch. This will include design work to further develop the 'scheduled lite' model.*

Participation and choice

Under the current rules, it is difficult for small consumers to access a range of markets for delivery of energy or system services that could reward them for shifting their demand or changing the shape of the load over the course of a day, or several days to deliver overall efficiency. The ESB is progressing work with the market bodies to reduce barriers to participation in the market, and working with the Australian Renewable Energy Agency (ARENA) to commission studies to better understand the potential for flexible demand under a range of scenarios and conditions.

The ESB:

- *Notes its continued support for development of flexible trading arrangements and will work to further develop future 'participation models', including the 'trader-service' model.*
- *Will continue analysis to build a deeper understanding of the size and characteristics of the potential flexible demand market, including the study under development with ARENA.*
- *Will work with market bodies to evaluate the effectiveness of different policies to identify where changes could be made in overcoming barriers to unlock the greatest potential of flexible demand.*

Improving access

New and innovative energy products and services may be difficult for disengaged and low-income consumers in particular to access. With the continued rapid deployment of rooftop solar, and the expected growth of electric vehicles, finding ways to unlock the value of these resources to deliver value to all customers will be important. The ESB is considering new ways for customers and communities to access the benefits directly. As part of this we need to consider ways for managing the risks and costs of congestion at times of oversupply from embedded small scale (solar PV) generation.

- *The ESB and market bodies will consider options for supporting and augmenting the existing tariff reform agenda with more flexible, locational price signals.*
- *The market bodies will undertake analysis by the market bodies on: options for tariff structures that could improve efficient utilisation of the distribution network; what is needed to enable community storage business models; and associated approaches that could be taken to incorporate these changes into the regulatory frameworks and tariff reform process.*

Addressing uncertainty

Current and future markets and policy settings, and how people are motivated to respond to incentives, is uncertain. Setting a clear pathway for future changes to market design, and the accompanying roles and responsibilities to support an effective future two-sided market, is an important outcome of the Post-2025 program.

- *The ESB will begin engagement with market bodies, customers, industry and government stakeholders on a Maturity Plan. This plan is intended to provide a pathway to jointly consider and determine future roles and responsibilities needed to support an effective two sided market. This plan will include details of distribution security design, cyber security, national shift to active solar PV, and interoperability frameworks.*

Consumer protections

Customer groups have had an active interest in the development of the two-sided market policy and customer advocates are keen to work with ESB and the market bodies to develop a customer protections framework that is more fit for purpose. This recognises the emerging range of new service providers and business models to provide different offerings to customers.

- *The ESB will work with consumer groups and industry to progress development of a consumer protection framework between December 2020 and June 2021. This work will involve use of a risk based approach to consider where future protections may be necessary, focussed on identifying and prioritising areas of greatest need and potential harm.*

Transmission and access

The generation mix is moving towards large scale renewables in more decentralised and dispersed locations. The transmission grid needs to develop, and access to it needs to change to support investment and lower overall costs.

Stakeholders have concerns about efficient and effective connection to, and use of, the grid. Grid connection is difficult in many areas and technical issues, mostly associated with low system strength, affect the timeliness and cost of connection. Once connected, high levels of congestion and significant reductions in marginal loss factors are problematic.

While the current access arrangements may have been adequate in the past with only incremental investment occurring, they are not fit for the future transformational change to the system. Without resolving these issues there will be higher prices for consumers.

In the longer term, the ESB's preferred solution is the introduction of locational marginal pricing with financial transmission rights. This is the only option put forward to date which can work across the whole of the NEM and drive both more efficient investment and more efficient dispatch and use of the network.

However, the introduction of locational marginal pricing and financial transmission rights is a significant change. In submissions to the September consultation paper, generators expressed concerns about complexity, uncertainty, and increased risk associated with this solution. Customer representatives expressed mixed views about whether the substantial benefits would be realised in the current environment. Some stakeholders accepted the need for change, but argued that the arrangements should be introduced more gradually. For all these reasons, a broad range of stakeholders have indicated that their preferred focus, at least initially, is to develop arrangements for renewable energy zones (REZs).

Having considered these issues, the ESB is pursuing the following initiatives.

- Actioning the Integrated System Plan (ISP) – *the ESB has already developed comprehensive changes to the planning framework, which are now in place and supported by AER* *guidelines. The AER is undertaking further work to provide more predictability about how the AER will assess actionable ISP projects under the economic regulatory framework, and improve the AER's regulatory assessment processes.*

- *Implementing and delivering REZs:*
  - *Developing the framework for REZs is the key focus for the ESB at the current time. REZs are a key stepping stone to build towards the long-term goal of locational marginal pricing and financial transmission rights. This means there will not be a publication on the longer term access regime at this time (previously indicated for December 2020).*
  - *The ESB has already progressed planning arrangements for REZs through stage 1 of its REZ work program. The ESB is now considering connection, access and pricing frameworks for REZs leading to how a REZ will be filled and how it will be maintained. The accompanying consultation paper sets out options for interim arrangements to implement REZs.*
- *Enhancing and supplementing congestion information – the ESB is considering ways to improve information and visibility to the market about where congestion exists, and what is forecast in future. This will supplement existing information provided to generators and the market about the amount of congestion, and reduce transitional risks from uncertainty in moving to the enduring locational marginal pricing and financial transmission rights framework.*
- *Transition pathways – the ESB is developing a set of reforms that could build on the REZ model to provide a stepping-stone towards the long-term, whole of system access solution. As part of this, the ESB is considering how to move to the longer term access regime in a way that mitigates the risks in transition as well as the impact on existing contracts.*
- *Enduring locational marginal pricing and financial transmission rights solution – as stakeholders have highlighted, these are major reforms and it is therefore important that the introduction of locational marginal pricing and financial transmission rights is closely coordinated with the other Post-2025 reforms. By taking time to set out REZ frameworks and developing transition pathways, further decisions will be made across the Post-2025 program which will allow for greater coordination with transmission access reform.*

Next steps

The ESB will continue to work with the Post-2025 project advisory groups, jurisdictions and other stakeholders to develop the detailed market design for these options ahead of further public consultation in March.

A number of accompanying papers have been released seeking feedback on specific elements of the Post-2025 reform agenda. These can all be found on the ESB website[1].

[1] https://esb-post2025-market-design.aemc.gov.au/

1 INTRODUCTION

1.1 Background

In March 2019, the former COAG Energy Council requested the Energy Security Board (ESB) to advise on a long-term, fit-for-purpose market design for the National Electricity Market (NEM). The request recognised the challenges faced by the current NEM design and that a new design should comply with the National Electricity Objective ('the NEO').[2] The NEO is:

'to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to –

a. *price, quality, safety, reliability and security of supply of electricity; and*

b. *The reliability, safety and security of the national electricity system.*

Any market design option(s) should contribute to meeting the outcomes set out in the former COAG Energy Council's Strategic Energy Plan, including its central outcome – delivering more affordable energy and satisfied consumers. Finally, outcomes should be consistent with the objectives set out in the Finkel Review[3], to support an orderly transition for the NEM.

This paper presents an update on the progress made by the ESB on the Post-2025 market design project. In September 2020, the ESB published a consultation paper (September Consultation) that outlined reform options under consideration as part of the Post-2025 market design project. In this directions paper, we set out a summary of stakeholder feedback to the recent consultation and provide our thinking on issues raised. Copies of public submissions are available on the Post-2025 program website together with the September Consultation and accompanying background reports.[4]

As set out in the September Consultation, the Post-2025 market design project is seen as a pathway to a fit-for-purpose market design for the NEM. The transition happens over time through phases to ensure changes are fit for purpose. It is not envisaged that an entirely new design would be introduced at a single point in time. All reforms will be evaluated together to ensure they lead to an integrated solution, with final recommendations on all reforms made by mid-2021 and required legislation and rules then developed and introduced over time. The key deliverables program is shown in Figure 1 below.

FIGURE 1 POST-2025 PROGRAM KEY DELIVERABLES

[2] http://www.coagenergycouncil.gov.au/energy-security-board/post-2025; the NEO is set out in section 7 of the National Electricity Law

[3] Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future; June 2017

[4] http://www.coagenergycouncil.gov.au/publications/post-2025-market-design-consultation-paper-%E2%80%93-september-2020

The ESB will continue to develop potential market design elements consistent with the directions set out in this paper through to March 2021. A consultation on potential market designs will be carried out in March, followed by detailed evaluation and then recommendations to Energy Ministers mid-2021.

More detail about the Post-2025 program and its workstream activities is available on the Post-2025 program website.[5] The detail set out in this paper reflects the joint collaborative efforts of the ESB and the market bodies, the Australian Energy Market Commission (AEMC), Australian Energy Market Operator (AEMO), and Australian Energy Regulator (AER).

[5] https://esb-post2025-market-design.aemc.gov.au/

2 STAKEHOLDER FEEDBACK

2.1 Overview of submissions

The ESB received a total of 108 written submissions to the September Consultation, with 92 non-confidential submissions published on the ESB website. Over the consultation period, the ESB carried out over 30 stakeholder briefings together with the market bodies, a series of CEO roundtable discussions, and multiple generator interviews to support the Resource Adequacy Mechanism and Ageing Thermal Generation Strategy workstreams. This feedback builds on additional engagement carried out by the market bodies with stakeholders.

In parallel with the consultation process, the ESB carried out an intensive period of engagement on issues relating to DER Integration, via a series of 'design sprints'. This process was carried out over August to November 2020 and enabled insights from over 70 industry, technology, customer and government stakeholders.

The ESB would like to thank all those that took the time to contribute to these processes. The feedback has been comprehensive, providing valuable insights to inform development of the Post-2025 designs. Key themes and issues emerging via these processes are set out in this paper.

2.2 General themes

There was general support across stakeholder groups that the ESB has identified the right set of issues, and support for the issues being presented as an integrated reform program. While differing views were voiced regarding the options for reform being considered or the relative priority of each challenge, many parties voiced support for the articulation of the problems identified for each program initiative.

Many stakeholders supported taking a staged approach, with some suggesting periodic review points be identified that would allow for course adjustment over the transition. Multiple stakeholders discussed the impact of COVID-19 on the current economic environment and what this may mean for the energy transition. This feedback focused on both the customer and community impact of the recession, as well as on the potential for an even faster energy transition to emerge on the back of government stimulus initiatives.

Stakeholder support was offered for increasing opportunities that value and reward customers, and to unlock the potential value of latent flexible demand. However, a number of stakeholders, including customer groups and Energy Consumers Australia (ECA), highlighted the lack of trust between consumers and energy market participants as a challenge needing to be addressed as part of any future market design.

Gaps in reform program

Some gaps in the reform program were identified by a number of parties. These included:

- Some stakeholders calling for an explicit carbon abatement mechanism; with some respondents calling for changes to the NEO or the Australian Energy Market Agreement (AEMA) to address climate or environmental policy objectives through broader governance measures.
- Concerns were raised by stakeholders noting the lack of focus on system resilience, particularly in light of the difficult bushfire season in Australia over last summer.

- A number of stakeholders (including consumer groups and union representatives) highlighted the need for a 'just transition' and a focus on industry adjustment and development issues.

The ESB recognises these are areas of considerable community and stakeholder interest, but notes they are outside the terms of reference issued to the ESB by the former COAG Energy Council for this reform program. We note that work on future market design is being carried out with the market bodies and together with customer, industry and government stakeholder input. It is imperative that any future market design is consistent with the NEO, but the ESB is also working hard through this program so future designs can work alongside government policy targets and aspirations at state or federal level. Where work is occurring on adjacent policy initiatives (e.g. system resilience), the ESB is working closely with relevant market bodies to ensure alignment where appropriate.

2.3 Post-2025 workstreams

As set out in the September Consultation, the ESB set up seven work programs – market design initiatives (MDIs) – to evaluate and develop market design options for the Post-2025 market reform program.

Stakeholder feedback highlighted interactions across many of these workstreams. Reflecting this, in this paper we have consolidated our response to feedback as set out in Table 1.

TABLE 1 POST-2025 MARKET DESIGN INITIATIVES

Market Design Initiatives		Directions and next steps
MDI-A	Resource Adequacy Mechanisms (RAMs)	Considered together in Chapter 3
MDI-B	Ageing Thermal Generation Strategy	
MDI-C	Essential System Services (ESS)	Considered together in Chapter 4
MDI-D	Scheduling and Ahead Mechanisms	
MDI-E	Two-Sided Markets	Considered together in Chapter 5 – *Including elements of the Scheduling and Ahead Mechanisms*
MDI-F	Valuing Demand Flexibility and DER Integration	
MDI-G	Transmission Access and the Coordination of Generation and Transmission	Considered in Chapter 6

3 RESOURCE ADEQUACY MECHANISMS AND AGEING THERMAL GENERATION STRATEGY

Key points

- Over the next two decades 26-50 gigawatts (GW) of new large scale variable renewable energy (VRE) – in addition to existing, committed and anticipated projects – is forecast to come online, supported by between 6 GW and 19 GW of new flexible and dispatchable resources as approximately 16 GW of thermal generation retires. Stakeholders shared with the ESB divergent views on whether the NEM's current resource adequacy mechanisms were sufficient to attract the required new investment.
- Some stakeholders thought additional resource adequacy mechanisms would be required but provided only qualified support for the options canvassed by the ESB (enhancements to the retailer reliability obligation, a decentralised capacity market or an operating reserve). Some stakeholders offered their own suggestions on how investment signals could be strengthened, lengthened, or both.
- Almost all stakeholders expressed concerns around policy uncertainty and the need to align government policies and programs –particularly those incentivising investment – with the needs of the NEM.
- Governments have indicated a preference for longer duration signals to bring on new 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, for example, supporting community transition and jobs or delivering low emissions and renewable energy policy targets.
- Each of these schemes apply only to new investment and target particular types of resources. They provide longer term investment support and need to be complemented by more effective short to medium term measures to provide the full mix of resources including those with flexible, dispatchable capabilities. Strong real time incentives can ensure those resources are efficiently dispatched to meet customers' needs and the system can continue to operate in a reliable state.
- Given this landscape, the ESB will focus reform efforts in this workstream on managing the entry of new resources into the market and the orderly exit of resources in the presence of substantial government investment schemes. This is a slightly different perspective for resource adequacy discussions, which typically focus on ensuring there is sufficient capacity to meet peak demand.
- To achieve this, the ESB proposes a framework for a NEM wide approach to resource adequacy based on:
  a) Improving real time arrangements and sharpening price signals in the market;
  b) Considering options to enhance the retailer reliability obligation, requiring retailers and large users to maintain a portfolio of contracts to reliably meet their customers' needs
- The ESB will work with governments and stakeholders to investigate a potential NEM-wide, common approach to integrating jurisdiction underwriting or investment schemes for new investment into the market. This approach would recognise that such schemes are likely to be an enduring feature of the energy sector as governments seek to manage risks associated with the energy transition. A discussion paper outlining how this might be achieved will be released early in 2021, following further consultation with jurisdictions. Any consideration of a NEM-wide approach or to amendments to the retailer reliability obligation would need to consider the circumstances and outlook of each NEM jurisdiction.

- The ESB is also giving further consideration to residual reliability, security and affordability risks that may be addressed by further arrangements for managing thermal plant exit in an orderly way. Options under consideration include changes to notice of closure requirements, regulated or negotiated arrangements with thermal plants, and contingent scenario planning.

3.1 Feedback from stakeholder consultation

The September Consultation sought feedback from stakeholders regarding issues raised by the MDI-A covering Resource Adequacy Mechanisms and MDI-B covering the strategy for Ageing Thermal Generation.

Stakeholders responded to specific questions asked in the September Consultation and also provided a broad range of advice on matters relevant to the MDIs. The ESB also held confidential interviews with 12 NEM investors to better understand the timing risks regarding coal-fired plant exits and how confidence is formed in business cases.

The resource adequacy mechanism discussion asks whether the current NEM design will deliver an adequate mix of resources and capabilities through the energy transition. The focus was on factors that can deter investment such as the absence of long-term price signals and missing elements of energy markets. Among the uncertainties considered was the timing of ageing thermal generator exit and the mix of capabilities that will be needed for a reliable system.

In the section on ageing thermal generators, the unprecedented scale of the exit of thermal resources from the NEM was considered and the discussion focussed on the risks of the transition and the mechanisms (including resource adequacy mechanisms) available to address these.

Feedback from stakeholders varied depending on whether they consider the current market settings to be:

- Largely adequate but felt opportunities exist in the NEM to boost real time signals, or
- Inadequate in bringing on new capacity needed over the medium term.

Some stakeholders such as Engie, Flow Power and the Australian Energy Council (AEC) thought the current market settings and NEM design are adequate and the existing energy-only market is effective. Others, such as AGL and Infigen Energy noted that, while the existing energy only market has been effective, changes may be required in order to manage the risk of 'new modes of failure' and new problems associated with extreme weather events. Snowy Hydro noted that there is a capacity investment problem in the NEM, but prefers current arrangements to be used to address the problem. Bluescope Steel recommended focusing on other market design initiatives before considering new resource adequacy mechanisms.

Other stakeholders, such as EnergyAustralia, Tesla, Alinta Energy, Origin Energy and Hydro Tasmania, did not think the market settings or design are adequate to bring on the appropriate mix of resources needed over the medium to long term. They suggested the NEM lacks bankable long-term price signals to underpin the business case for new dispatchable capacity.

Most stakeholders agreed that an ageing thermal generator strategy, designed to manage thermal exits, should draw on the other MDIs, particularly the resource adequacy mechanism and essential system services (ESS) workstreams, and that the case for additional measures to manage thermal exits was not clear. For example, EnergyAustralia proposed that if measures to lengthen and strengthen the signal for investment and changes to ESS are implemented additional measures are not needed for an ageing thermal generation strategy.

Rio Tinto noted given the level of government action there was no need for additional constraints on thermal exits. Clean Energy Council, Tesla, Flow Power and Infigen Energy recommended encouraging new capacity rather than prolonging the operation of existing capacity through revenue streams for ageing thermal generators.

However, some stakeholders were supportive of further measures to manage thermal exit, canvassing an array of concerns and a range of solutions.

Bluescope noted that existing notice of closure requirements – even if complied with – would not be sufficient to invoke a market response in time to provide replacement capacity. It suggested expanding the notice of closure requirements to cover mothballing, or extending the minimum notice period.

Others, such as GE Renewables, Grattan Institute, and Infigen stated further concerns that thermal plant may breach their notices of closure for either financial reasons, or due to unforeseen mechanical failure. Proposed solutions included adding financial incentives to notice of closure requirements or improving contingency planning.

Other stakeholders, such as Alinta and Major Energy Users, recommended that contracts procured by AEMO or governments in limited circumstances could be used to mitigate timing risk.

Some stakeholders expressed concern that uncertainty of thermal exit was a barrier to new investment, and that more certainty of a plant’s exit date would rectify this. For example, ERM Power recommended employing a ‘hard’ closure date with limited ability to extend; the Australian Institute, University of New South Wales (UNSW) and Bright Sparks recommended regulating their closure.

Others such as Hydro Tasmania noted that flexibility was important to allow efficient exit decisions to be made, and suggested changes to allow exit dates to be brought forward.

Views on short-term signals

Stakeholders largely supported the adoption of mechanisms such as an operating reserve that sharpens the short-term investment signal, with many noting that it is the most direct method to support flexibility and incentivise investment in dispatchable capacity. Stakeholders were also wary as to whether the short-term signal will be sufficient on its own to bring on investment in new capacity. This is because an operating reserve (like frequency control ancillary services (FCAS) markets) is unlikely to have a forward price due to a lack of a derivative market, or the operating reserve market price may be too uncertain to build a business case around, or both.

Some stakeholders were concerned whether the benefits of an operating reserve would outweigh the cost.

Views on long-term signals

Stakeholders who commented on resource adequacy mechanism options which adjusted or expanded on the financial retailer reliability obligation model were largely unsupportive of those options. Common concerns were:

- Insufficient time has passed to understand whether current retailer reliability obligation arrangements are effective (and therefore should not be amended or extended), that retailer reliability obligation incentivises financial risk management rather than plant build, or that these options are overly complicated. Some stakeholders noted generally that more work would be required on the longer-term options (both financial and physical) before they could comment on whether they would effectively complement short-term investment signals.

A small number of stakeholders expressed explicit support for a resource adequacy mechanism option that built on the retailer reliability obligation.

Stakeholders were divided in their support for longer-term resource adequacy mechanisms options that looked to either link qualifying contracts with physical assets, or implement a decentralised capacity market.

Stakeholders supporting capacity arrangements tended to cite their ability to create greater market liquidity and provide clear investment signals. Stakeholders not supporting capacity arrangements cited its separation from the real time price, the compliance burden, the possibility for additional costs and the risk of entrenching market power.

Views on the transition and community impacts

Alongside comments provided on resource adequacy and investment dynamics within the energy market, stakeholders (including the ACTU, Electrical Trades Union and the United Workers Union) reflected on the impact that the energy transition – and indirectly the impact of decisions advanced as part of the resource adequacy mechanism workstream – may have on communities around the country where the energy sector constitutes a significant part of local economies.

Stakeholders advocated that decisions related to the transition should recognise – and be made within – the context of broader social and industrial policies. In particular, stakeholders noted the need for programs and projects to demonstrate that they have social licence, can manage their environmental and social impacts, and will deliver secure jobs with decent conditions and economic benefits for host communities while addressing challenges with transitioning workers and communities.

Consideration of these aspects of the transition are reflected in the appetite of governments for improved certainty, longer duration price signals and a more managed approach to entry and exit of key assets.

3.1 Proposed directions

The ESB is combining the resource adequacy mechanisms and ageing thermal generation strategy streams into a single workstream. This decision is in response to stakeholder feedback that the issues were closely related and that MDIs to address one issue would impact the other.

As noted above, a significant number of stakeholders considered that longer duration investment signals would be needed to drive investment through the energy transition. This view was often centred around concerns regarding uncertainty created by government policy changes and schemes designed to drive new investment. Some of these schemes can act against the mechanisms (scarcity pricing) in the market that create the signals for new investment.

Jurisdictional investment schemes can be viewed as an implicit recognition that jurisdictions consider additional mechanisms are necessary to drive required investment, even if they are based on the consideration of various policy priorities other than reliability. These schemes are likely to be a feature of the market for the foreseeable future.

Examples of the range of different government schemes are detailed in the text box below.

TEXT BOX 1 STATE SCHEMES, ENTRY CHALLENGES AND THE RISK OF MARKET DISTORTION

In November 2020 the NSW Government launched its Electricity Infrastructure Roadmap[6]. The Scheme aims to guide the energy transition in NSW by supporting the development of transmission and underwriting 12 GW of renewable energy across five REZs (CW Orana, New England, South West, Hunter, Illawarra) and a development pathway for 2 GW of long duration energy storage by 2030. The development of renewable generation is intended to be sized and timed to replace the progressive closure of coal-fired power stations. In addition to long duration storage the Scheme allows for further actions to deliver firming resources to meet the NSW Energy Security Target.

Underwriting of generation, long duration storage and firming is intended to be facilitated through the Infrastructure Investment Safeguard which will award Long Term Energy Services Agreements through a competitive tendering process. Long Term Energy Services Agreements are intended to be option contracts which will give the new resources optional access to a competitively set minimum price and should “adopt, to the maximum extent possible, the conventions and standards in relation to similar agreements in the national electricity market.”

Governments created the NEM to promote greater efficiency and economic incentives, and over the years they have continued to intervene to drive outcomes particularly with regard to promoting renewable developments and safeguarding consumer outcomes.

In this regard, the NSW Electricity Infrastructure Roadmap is aimed at facilitating investment in renewable resources that are timed to replace the energy lost as power stations close, while ensuring investment in new firming resources that are needed to back this up. In underwriting these projects, the government provides increased certainty to investors and in return their cost of entry is lower.

Neither the underwriting of renewable or firming resources is new to the market, nor the only intervention that is likely to impact the market over the coming years. Government interventions that aim to facilitate renewable or firming resources are:

1. Past Reverse Auctions:
    - Queensland, Victoria and the ACT are, and have, facilitated investment in renewable resources through reverse auctions that have been based on contract for difference payments.
2. Future Reverse Auctions:
    - Victoria is considering under its proposal for a second reverse auction (VRET[7] II) to include dispatchable technology (e.g. energy storage systems), potential coverage of the Victorian Government load (either virtually or directly) and scope to provide additional transmission and network support given the current and future outlook of the power system in Victoria.
3. Current Certificate Schemes:
    - The Large-scale Renewable Energy Target and Small-scale Renewable Energy Scheme operated by the Commonwealth Government also facilitates investment in renewable resources through certificate-based schemes.
4. Other Underwriting Schemes:
    - The Underwriting New Generation Investments program was established to support the entry of firm generation capacity through a range of mechanisms including contracts not dissimilar to that proposed under the Infrastructure Investment Safeguard.

[6] https://energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap

[7] Victorian Renewable Energy Target scheme, https://energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap

5. Government Ownership:
   - The Queensland Government through CleanCo has targeted the support for 1,000 MW of new renewable generation by 2025 and recently committed $500m into a Renewable Energy Fund that would allow its Government owned corporations to increase public ownership of both commercial renewable projects and supporting infrastructure.[8]
   - The QLD Government, through its ownership of Stanwell, CS Energy, and CleanCo continues to have significant influence over the future retirements of thermal generation in the context of any concerns about reliability that may emerge.[9]
   - The Commonwealth Government committed to the delivery of Snowy 2.0 and has signalled the potential for Snowy Hydro to build a gas fired generator in NSW by 2023.

While these schemes address aspects of the entry needs of the system, the NEM is transforming rapidly - and as a result - the challenges in integrating the system as it evolves are complex. Rewarding resources outside the market increases the risk of distortions and adds to the complexity. This is further exacerbated when interventions are delivered inconsistently and in uncoordinated way.

Each of these schemes apply only to new investment and target particular types of resources. They provide longer term investment support which cannot be easily replicated by market mechanisms and need to be complemented by more effective short to medium term measures to ensure the full mix of resources required are retained and real time incentives to ensure those resources are efficiently dispatched to meet customers' needs.

Given this policy and market context, the focus of the combined workstream will shift from considering mechanisms to incentivise investment in flexible, dispatchable resources to ensuring *timely entry* of resources into the market and *orderly exits* from the NEM throughout the energy transition.

Ensuring *timely entry* of resources into the market and *orderly exits* from the NEM throughout the energy transition.

Timely entry is aimed at ensuring:

- new resources are operating in the system as they are needed
- overall system costs are minimised by avoiding investment that is too early or late.

Orderly exit is concerned with ensuring that:

- reliability and security outcomes continue to meet community expectations after a generator exits
- participants maintain efficient levels of investment in capital expenditure on maintenance
- price shocks are minimised
- the exit of thermal generation is anticipated (by the market, government and community).

The ESB recognises that government investment schemes have an important role to play in delivering on broader policy objectives that go beyond the scope of the electricity market design. The refocused workstream acknowledges the role of these schemes and seeks to provide a way

[8] https://budget.qld.gov.au/files/BP2_8_Public_Non-financial_Corporations_Sector.pdf
[9] https://www.aer.gov.au/system/files/State%20of%20the%20energy%20market%202020%20-%20Full%20report%20A4.pdf page 83

to integrate them within a national market construct that maintains system reliability and security at least cost to consumers.

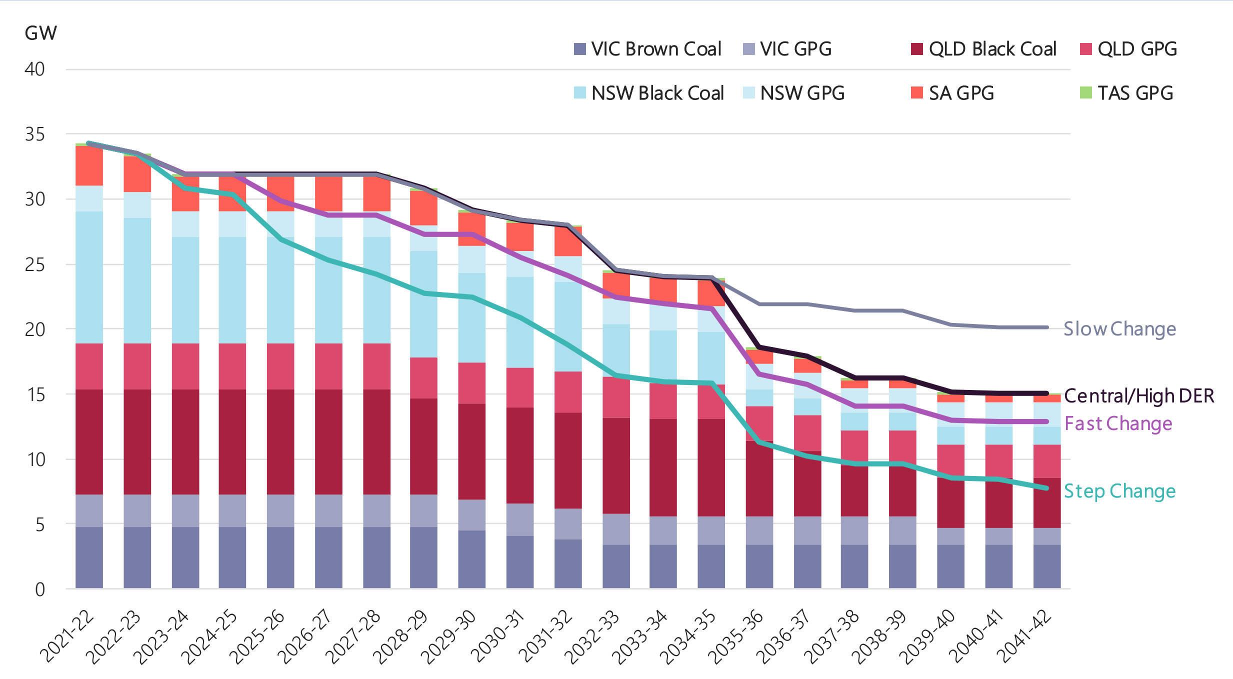
The options we propose to develop further aim to preserve the role of the real time market and financial contracting market in providing a signal for investment and providing incentives to make resources available when they are needed, which we expect to be the main, enduring resource adequacy mechanisms after the energy transition has run its course.

The box below explores the impacts government underwriting schemes can have on the national market. The scope, or extent, of these impacts will be considered when designing for resource adequacy in the NEM.

TEXT BOX 2 GOVERNMENT SCHEMES AND THEIR MARKET IMPACT

The addition of capacity from government-backed schemes places downward pressure on the energy price, and the expected future prices of energy. The faster the new investment comes in, the faster the downward pressure on prices. This puts resources not party to government backing at a competitive disadvantage meaning they are less likely to attract investment. The lowering of the future expected energy price may make it difficult for thermal plants to maintain commercial viability. It is therefore likely to lead to exits of thermal plant faster than anticipated. The speed of the transition will impact how much the energy price signal is lowered. As an example, the NSW Roadmap includes a legislated amount of 12 GW entering the system before 2030. This will put NSW on a transition pathway that is at least as fast as the Integrated System Plan (ISP) step change scenario shown in Figure 2 below.

FIGURE 2 COAL-FIRED AND GAS-POWERED GENERATION RETIREMENTS



Source: AEMO 2020 ISP

Different reliability standards:

Government schemes that seek to achieve a higher reliability standard than is being targeted by the market settings create a distortion in the market that result in government programmes undercutting and crowding out new and existing private sector projects. Consequently, where a higher standard is being targeted, this may be better delivered via out of market mechanisms rather than in-market, reducing the potential for distortion.

Delivering the right mix of capabilities:
Current market settings encourage retailers to contract with a portfolio of resources in order to hedge their price risk and maintain reliability. The table below shows the different types of market role and corresponding technologies that the system will need through and after the transition.

Market Role	Technologies
Managing excess solar energy	Demand Shifting, storage – battery, pumped hydro
Daily ramp to meet evening peak demand	Storage, gas fired generation
Maintaining resource adequacy for extreme demand	Demand management, gas fired generation, storage
Managing wind droughts in winter and over- night running	Gas fired generation, long duration storage
Providing necessary security services	Various

Out of market schemes that drive investment in specific classes of asset risk undermining incentives for participants to invest in the full range of resources required. However, it will be important that within a three or four year period market participants have the ability, flexibility and incentive to invest either as a secondary trade from the underwritten contract or using private risk to solve and respond to price signals within the real time market.

Risk allocation:
Jurisdictional underwriting schemes shift the current market design risk profile from the private sector to the public sector with ultimately consumers and/or taxpayers taking on the investor risk. The extent of this risk transfer will depend on whether the private sector is incentivised (through retailer's exposure to high spot prices, for example) to maintain a degree of private risk. If the jurisdictional underwriting scheme is implemented within a robust and well-functioning market this risk should be minimised to only the long-term risk of new investment.

To meet the objectives of the refocused workstream, the ESB proposes to explore the following key directions:

- **Ensure the spot and contract market continue to provide incentives for the efficient use of resources in the market** – the ESB will investigate an operating reserve market as part of the essential system service workstream as well as a range of other reforms to ensure all services are valued.
- **Consideration of enhancements to the retailer reliability obligation** – a number of stakeholders expressed support for longer-term signals in various different forms. Given the presence of government-backed investment schemes, the retailer reliability obligation could be used to strengthen incentives for market participants to maintain a portfolio of contracts to reliably meet the needs of consumers. Therefore, the ESB will consider whether the retailer reliability obligation's efficiency can be improved, and its complexity reduced to support the ESB's revised focus of supporting timely entry and orderly exit of resources.
- **A NEM-wide approach to jurisdictional investment schemes** – further, the ESB proposes to explore options that could be developed to integrate contracts derived from jurisdictional schemes in to the market on a voluntary basis in a way that minimises investment uncertainty. The ESB intends to publish a discussion paper for consultation on such a NEM-wide approach early in 2021, following discussion with jurisdictions.
- **Exit arrangements** – the ESB is also giving further consideration to arrangements for managing thermal plant exit in an orderly way to address residual reliability and security risks. The ESB is also giving further consideration to whether there are residual reliability, security

and affordability risks that may be addressed by further arrangements for managing thermal plant exit in an orderly way.

3.1.1 An operating reserve

A centrally procured operating reserve is being considered as part of the ESS workstream to ensure the power system has resources available to cover the variability and uncertainty in supply and demand. The ESB is working through options to ensure that system services (such as inertia, system strength and frequency control) are accurately estimated, and a mechanism is created to ensure those services are valued in the market.

The operating reserve was also raised in the September Consultation as a resource adequacy mechanism that would sharpen real time market price signals. An operating reserve is a service that could be separately procured and co-optimised in the real time market according to a carefully constructed demand curve and cost allocation method that minimises the cost to consumers. Unbundling the reserves service from the energy price, and explicitly valuing it, may place increased pressure on the energy price during times of intra-day resource scarcity. Depending on its design and the quantity procured, it may present a scarcity price signal for dispatchable capacity.

However, given the complementarity of the operating reserve and essential services to ensure all essential services are valued, further investigation of an operating reserve has been taken forward within the ESS workstream. Its impact on expectations of the future price of energy and its ability to provide an investment signal will be considered once its design in the ESS stream has been determined. The AEMC has published an accompanying paper, alongside this paper, to provide further detail on operating reserves.

3.1.2 An enhanced Retailer Reliability Obligation

Most stakeholders identified policy uncertainty as a barrier to investment. Many also agreed that governments are unlikely to tolerate the sustained high prices required to prompt a market-led investment response. This mis-match with current market design has in turn driven a number of out of market interventions and contributed to policy uncertainty.

Of those stakeholders who agreed a longer duration investment signal was needed, there was no clear preference on a mechanism to provide that signal.

One option put forward by the ESB is enhancements to the Retailer Reliability Obligation (RRO). These enhancements could provide market participants with more incentives to ensure resources with the right mix of capabilities are invested in or retained in the market, and available to the market to meet reliability needs. In doing so this may contribute to future policy stability. Hence, the ESB sees merit in further exploring mechanisms to increase the duration of the price signal for investment.

The RRO is a mechanism designed to reduce reliability risks in the NEM. As noted previously, irrespective of government-investment schemes, the market still needs dependable forward price signals to support the medium to shorter term market needs. The RRO looks to support reliability by targeting retailers' contracting behaviour and strengthening the forward price of energy.

The ESB is mindful that a number of stakeholders did not support amendments to the RRO, with many considering that:

- Insufficient time had passed to assess its effectiveness
- It incentivises financial risk management rather than plant build, or
- It can prove complicated and cumbersome.

The ESB recognises the merits of these critiques and the context in which they were made and will use the RRO framework to examine various enhancements that may improve reliability outcomes. As potential enhancements are considered, the ESB will consider how they might contribute to ameliorating these criticisms.

Further, for any change to be supported, it must be found to be consistent with the NEO and pass the evaluation process outlined in Section 7 of this paper. In this context the ESB will need to consider the circumstances and outlook for each NEM jurisdiction.

Protecting consumers from reliability risks and price shocks from thermal retirements will be a key focus of the ESB's deliberations.

Enhancements to the RRO could increase incentives on retailers to purchase contracts, including contracts offered through government underwriting schemes, firming them up in the process. This could help bring government underwriting schemes into the NEM arrangements on a nationally consistent basis. Integrating the contracts derived from these schemes within the RRO could also help ensure the take up of contracts is supported by retailer led investment, providing contract market signals that are reflective of market needs. This should help to provide for *timely entry*.

An enhanced RRO could also provide for a more *orderly exit*. The focus of the RRO is on reliability in the market. Appropriately valuing contracts that provide for that reliability supports investment in existing, as well as new plant, and helps provide an orderly exit of older and more costly generation, given it will provide a clear signal as to the value of the contracts of these plants.

The ESB will not consider a decentralised capacity market as a separate competing option but will consider the physical backing required of qualifying contracts as one possible enhancement to the RRO. This approach will ensure possible future reforms are made within the RRO, which is familiar to governments and market participants and should facilitate an easier comparison against the baseline.

Options to enhance the Retailer Reliability Obligation

Stakeholder submissions and the ESB's interviews with investors highlight the importance of real time price signals and longer-term price signals for investment.

In the NEM, resource adequacy relies on the real time energy price to reflect the short-run marginal cost of electricity and the revenues that flow from this price being sufficient over time to cover all generators' costs, including a fair return on capital. Investors make estimations of future real time energy prices and decide whether to invest in generation. Retailers and customers form views about future prices and buy contracts to reduce their exposure to high costs from high spot prices. Buying contracts supports existing generation and increasing contracts being sold provides firmer support for business cases for new investment than potential spot revenue.

Therefore, it is the real time energy price, and the contracting that references it, that provides the signal for investment. This includes investment in new plant, as well as continued investment in existing plant – such as commitments for fuel supply or maintenance capex programs – and the decisions to exit the market when a plant is no longer economic.

However, as noted above, the uncertain timing of exits and the very low marginal costs associated with renewables are presenting some unique challenges for market participants to understand the value of the future energy price. Many stakeholders noted that while the financial contract market provides useful estimations of the future price of energy up to two years out, there are no longer term signals for the value of energy. This becomes particularly problematic when there are uncertainties around the timing of exit of large lumpy capacity from coal-fired generation and uncertain outlook for energy intensive commercial and industrial demand.

This section compares a set of resource adequacy mechanism options against elements that are the focus for this workstream: *timely entry* and *orderly exit*. As the transition to cleaner energy progresses, a system that provides resource adequacy will:

- Facilitate more timely investment in new resources
- Facilitate the mix of new resources with the characteristics required to keep the system reliable
- Provide a strong signal for investment in reliability, and
- Prevent untimely exit that creates reliability challenges.

The table below describes how three different, and possibly complementary resource adequacy mechanisms, affect timely entry and orderly exit. We compare:

- The current RRO
- A 'physical RRO', which would be similar to the existing retailer reliability obligation but with qualifying contracts linked to physical resources, and
- Underwriting schemes for new resources.

TABLE 2 RESOURCE ADEQUACY MECHANISM IMPACT ON TIMELY ENTRY AND ORDERLY EXIT

Addressing the problem	Current RRO	Physical RRO	Underwriting Scheme
Entry			
Facilitate timely investment of new resources	*Partially* Relies on high penalties for non-compliance. Financial risk that participants manage rather than build capacity	*Highly likely* Relies on high penalties for non-compliance and additional compliance and regulatory burden for supply side	*Yes* Explicit contract to underpin new investment, but may crowd out non-underwritten investment from the market
Responds to the reliability needs of the system	*Partially* Qualifying contracts are financial, and therefore may or may not be physically backed.	*Highly likely* Qualifying contracts are all physically backed by dispatchable resources	*Yes* Can be specified in the contract and targeted to specific technologies.
Length of price signal for investment	1-3 year focus	1-3 year focus	Individually negotiated agreements with limited price disclosure.
Exits			
Incumbents are disincentivised from early exit	*Partially* Gentailers would need to think about their position before retiring a generator.	*Partially* Generators receive a capacity payment and high penalties discourage non-compliance	*No* Underwriting new investment below commercial rates of return will tend to bring forward retirement plans

Addressing the problem	Current RRO	Physical RRO	Underwriting Scheme
Price shocks on exit are minimised	*Partially* Retailers have an incentive to contract prior to a planned generator exit.	*Partially* Retailers have an incentive to contract prior to a planned generator exit.	*No* See above

As Table 2 highlights, underwriting schemes typically only focus on new investment and particular types of resources. As this places downward pressure on energy prices, it will make it harder for existing assets to maintain commercial viability – hence underwriting schemes may provide for timely entry, but they do not necessarily provide for orderly exit and may also impact on the responsiveness of new resource to meet the physical needs of the system.

Having a framework whereby participants are incentivised to maintain a portfolio of contracts to reliably meet consumers needs will help to balance this 'entry bias'. Therefore, while stakeholder views on the retailer reliability obligation were largely critical, the ESB considers it potentially useful to complement government investment schemes.

In considering how the current RRO could be enhanced, the ESB has analysed how the current RRO (and physical RRO and underwriting schemes) perform against the problem statement (using the elements in Table 2 above) and provides suggested directions to improve its efficacy.

The current RRO provides a muted signal for timely investment in resources. Compliance is only assessed if a number of hurdles are passed, i.e. AEMO must forecast a gap both at three years out and at one year out, and the actual demand during the reliability gap period must exceed the POE(50)[10] system demand forecast. The requirement on retailers in simple terms is to submit financial contracts to meet their combined POE(50) demand.

<u>Facilitate timely entry of new resources – partially</u>

There are a few options for strengthening the RRO so it provides a clearer and stronger signal for timely investment. An 'always on' obligation could remove the need for an identified reliability standard breach at T-3 or T-3 and T-1, as well removing the ex-ante compliance contract submission (see below). This would incentivise retailers to consistently contract at desired levels, rather than 'waiting' for a reliability gap to be identified.

There is also the potential to remove the ex-ante feature of the RRO, which requires retailers to provide to the AER their contract position one year ahead of the gap. This was a design feature of the RRO to avoid competition between retailers seeking contracts (including demand side options) and AEMO procuring Reliability and Emergency Reserve Trader (RERT) to address the reliability gap. The RRO could be changed so contracts in existence (or the closing contract position) during the actual peak period could be assessed for compliance against actual retailer demand. This would ensure retailers are contracted for their share of scaled actual demand on any day over the forecast regional POE(50) demand.

[10] The AEMO Electricity Statement of Opportunities notes that maximum and minimum demand forecasts can be presented with a 50% probability of exceedance (POE), meaning they are expected statistically to be met or exceeded one year in two, and are based on average weather conditions, or a 10% POE (for maximum demand) or 90% POE (for minimum demand), based on more extreme conditions that could be expected one year in 10 (and also called one-in-10).

Modifications to the timing of the Market Liquidity Obligation would also need to be considered to match an ‘always on’ RRO and ensure sufficient contracting from existing generators.

Removing the multiple ‘trigger’ layers of the current RRO may help reduce the complexity. However, requiring contract assessments, firmness verification and market liquidity obligations every year would increase the compliance burden for all retailers across the NEM. It also changes the objective of the RRO to encouraging contracting as opposed to filling a reliability gap.

<u>Responds to the reliability needs of the system – partially</u>

While the reliability settings of the NEM already provide an incentive for retailers to hedge their actual financial position, this could be further strengthened by linking the obligation to physical characteristics. The current RRO is built around financial contracts, so there is no direct link to the physical resources that underpin these contracts. Retailers seek the lowest cost methods of mitigating price exposure, whether it comes from physical supply or not.

Changing the RRO to focus on physical supply reduces this risk and places obligations on retailers and also on suppliers of contracts, to provide the reliability. However, obligations on contract suppliers would require an assessment of availability, to ensure the obligation to provide supply has been met. This is an additional compliance requirement.

The ESB will consider whether changing the definition of qualifying contracts from contracts used to manage exposure to spot price volatility to contracts that reflect physical resources will better meet reliability outcomes at lowest cost for consumers.

<u>Incumbents are disincentivised from early exit – partially</u>

The RRO already provides a disincentive to gentailers considering retirement of their ageing generation, provided that the retirement date is at least three years away; if a generator retires within the required 42-month notice period the RRO will not trigger. An ‘always on’ obligation would remove these timing and triggering issues.

The RRO provides a disincentive to integrated retailers to retiring their existing generating resources, however they may consider dropping large loads as an alternative way to do this.

One way of improving this would be to increase the duration over which compliance is assessed. The current RRO focuses one year at a time on an identified reliability gap which usually lasts no more than two or three months. If compliance was assessed over say three years, retailers would be incentivised to contract for longer periods. If the RRO was modified to be ‘always on’, this could be married with requirements for retailers to have a portion of contracts to be purchased to cover T+1 and T+2 in advance.

For example, in 2022, retailers would need to submit qualifying contracts for that year and demonstrate they have (as an example) up to 25 per cent of their share of historical peak demand for both T+1 (2023) and T+2 (2024). This would happen each year, so in effect retailers would need to show they have qualifying contracts to meet their share of scaled actual peak demand in that year, and also that they are preparing themselves to cover their load obligations in the next two years out.

This would lock in a longer revenue stream for a retiring generator, such that they were less likely to retire early. Such a requirement for contracting over a longer window may also give governments confidence that the market is contracting and preparing to respond to reliability needs, and thereby less likely to intervene and procure dispatchable resources themselves. When the generator does retire, retailers will know they will need to contract with new resources over the first three years following retirement and this would provide a greater incentive for them to contract or develop new resources. While a gentailer could still decide to reduce its commercial and industrial (C&I) load, a general move to longer contracting horizons would provide greater certainty to a new retailer wanting to take on this load.

Price shocks on exit are minimised – partially

The RRO requires gentailers (the main mechanism by which the RRO can influence decisions around retiring plant) to consider their net obligation position as part of any decision to retire a thermal plant. Having enduring obligations regarding contracting requirements, this may help smooth price shocks to consumers as opposed to waiting for a reliability gap to be identified.

3.1.3 Options to implement a NEM wide approach to government investment schemes

To deliver resource adequacy at least cost to consumers, the ESB will look to work with governments and industry stakeholders to investigate whether there is merit in developing a NEM-wide approach to integrate financial contracts derived from jurisdictional investment schemes into the NEM, on a consistent basis and in a way that preserves the role of the real time market and contract market in providing the primary signal for investment (and dis-investment). Such an approach would seek to provide an optimal level and mix of new investments, ensure jurisdictional schemes can enter the NEM's forward contract market, and align investment incentives with the operational needs of the system.

In the September Consultation, the ESB identified the need for long duration price signals to incentivise investment in flexible, dispatchable resources through the energy transition. To a large extent, jurisdictional investment schemes that underwrite or provide contracts for difference to support new resources can provide long duration support for new investment. This in part reduces the need for a capacity market, however the mechanism by which financial contracts derived from these schemes are integrated into the market needs to be considered.

The ESB considers the adjustments to the RRO discussed in the previous section, complemented by a NEM-wide approach to jurisdictional investment schemes, may achieve a better resource adequacy outcome over the course of the transition.

There are a variety of approaches that could be taken to establishing a NEM-wide approach to integrating investment schemes. These range from agreeing principles around scheme design and risk management that jurisdictions could embed in the design of their schemes, through to considering a centralised (NEM-wide) approach to scheme delivery with NEM-wide institutional and governance arrangements. Key to the ESB investigating these options will be identifying what options, if taken up, would provide long term benefits to energy consumers in meeting the NEO.

The ESB is at an early stage of developing how a NEM-wide approach could be implemented and does not yet have a preferred option. However, the ESB is of the view that consumers could benefit from a well-designed, consistent approach through greater policy certainty and the preservation of the benefits of a national market. Particularly given that jurisdictional investment schemes will be a significant feature of the NEM for the foreseeable future, a significant proportion (potentially the majority in some jurisdictions) of new investment in energy and firming resources will be delivered to the market through these schemes.

The ESB wants to investigate whether a well-designed, consistent approach could be superior to the counterfactual, characterised by an increasingly fragmented market with (potentially inconsistent) jurisdictional investment schemes. This scenario is compounded by a lack of certainty around market settings and a lack of a national approach to managing the impacts on resources already operating in the market or exits from the market.

The ESB will also examine the durability of such an approach, which is uncertain, and therefore the extent to which it would provide the policy certainty the market needs to invest. Any consideration of a NEM-wide approach would need to consider the circumstances and outlook of each NEM jurisdiction, as well as their policy priorities.

Some high-level principles for such a national scheme could include:

- Create terms in contracts between government and investors that continue to provide an incentive for the investor to enter into secondary contracts which offer better returns in the market (for example, the NSW put option tries to keep the contract as a backstop). The financial derivative contract is based on an option, which the generator can put at a later point in time – after the generator satisfies the buyer that the plant will be completed. This provides the generator with an incentive to enter into contracts which offer better returns in the market than the government offer.
- Contracts to ensure participants are not agnostic to wholesale price signals. This means a derivative contract that is firm and more fungible with other NEM market derivative contracts. Such a contract is consistent with the current practice in the NEM and supports generators and retailers to minimise price shocks in the real time market.
- Allow trading between NEM regions (i.e. recognise import and export from interconnectors).
- Facilitate transparency, both of the financial contracting required to address the resources and being planned for entry into the market.

The first two points above work together to ensure the investor has an incentive to respond to real time price signals, ensuring that generation is incentivised to operate to defend the contract when prices are high but also avoid running when prices are low.

Embedding principles in jurisdictional schemes

One approach to implementing these principles would be for each jurisdiction that wishes to participate to embed them in legislation, regulations or guidance that provide the heads of power and means for implementing their investment schemes. To some extent, NSW has already done this through the enabling legislation for its Energy Infrastructure Roadmap.

This would provide some level of policy certainty for participants with resources currently in the market and for investors considering future investment.

In this scenario, jurisdictions would ensure long duration underwriting schemes or reverse auctions with contracts for difference are recognised as financial derivatives and managed. The financial derivatives would then be onsold into the contract market, allowing these contracts to be available to retailers to manage price risk or potentially meet their obligations under the RRO. Jurisdictions would have an incentive to make the contracts attractive to retailers as part of their risk management approach. The success of this approach would be dependent on jurisdictions seeing value in agreeing to a common set of design principles.

If the RRO was enduring (or had been triggered), there would be an additional incentive for jurisdictions to structure these contracts so they could qualify as qualifying contracts for the obligation. This could provide a vital link between jurisdictional investment schemes and the needs of the physical system.

Centralised approach to jurisdictional schemes

An alternative approach would entail a more formal, centralised method of facilitating underwriting through a common approach. An approach like this could see several different jurisdictional schemes feeding into the NEM, but implemented in a consistent manner.

For jurisdictions (and their consumers) – depending on the form of the national scheme adopted – a centralised approach could provide better price discovery mechanisms, i.e. better information about what financial products were valued by the market and therefore guidance on what long-term investments might be needed. It may also help governments leverage the value of interconnection in the NEM, or incentivise them to structure their schemes in a manner that is attractive to the market. This is helpful for the government to not overpay for the contracts, but also to ensure that the quantity of underwritten contracts (set by the jurisdiction) supports the physical needs of the market and minimises price shocks for consumers.

The ESB will reflect on how such a scheme could drive value for the market and consumers, while considering further flowon effects on other arrangements including those in the current over the counter (OTC) and exchange markets.

Common institutional arrangements

The institutional arrangements also need to be considered. There may be merits in exploring common bodies established within the National Electricity Law (NEL) to implement jurisdictional schemes. This could see agencies common to all NEM jurisdictions providing the functions akin to the consumer trustee, scheme administrator and regulator in the NSW electricity infrastructure scheme, for example.

Common bodies could be a significant source of efficiency and consistency in bringing jurisdictional schemes into a consistent form, providing greater certainty to the market, and further ensuring the benefits of a national market are preserved.

If this approach is pursued, it will be important that jurisdictions continued to be liable for financial exposure that arises as a result of their investment targets.

3.1.4 Role of the market

The ESB is undertaking the task of designing possible enhancements to the retailer reliability obligation or possible mechanisms to integrate jurisdictional schemes on the assumption that foundational design principles for the NEM will continue to apply, namely that:

- The private sector should continue to take on investment risk and in doing so drive investment in new resources,
- The role of retailers is to manage exposure to the spot market on behalf of their customers,
- Reliability and security can be delivered through an interconnected market, and
- Exposure to high spot market prices will incentivise efficient self-scheduling and self-dispatch of resource.

These principles are central for outcomes that are in the long-term interests of consumers and minimising the costs of the transitions. Significant departures from these principles will complicate the task of market design. The ESB will look to work with jurisdictions to confirm these principles and align our market design work accordingly.

3.1.5 Exit arrangements

As discussed in the September Consultation, over 60% of the existing thermal generating resources in the NEM is likely to exit over the next two decades. While such exits are expected, the speed and scale of the exits are unprecedented, and the nature of much of the replacement technology is different to exiting thermal generators.

Given the amount of investment that needs to occur, and the potential impact on wholesale prices as resources enter and exit, market arrangements need to be carefully considered to ensure the transition is lowest cost for consumers in the long term. Even under the best laid market designs, such transition will likely create residual risks in maintaining power system reliability, security and affordability for consumers. Residual risks include but are not limited to sudden exits and exits of large blocks of capacity that have the potential to result in reliability and security challenges for AEMO and result in high wholesale prices.

The ESB is giving further consideration to how best to address residual reliability, security and affordability risks through arrangements for managing thermal plant exit in an orderly way. Options under consideration include changes to notice of closure requirements, regulated or negotiated arrangements with thermal plants, and contingent scenario planning. These options are expanded on below.

3.1.6 Changes to information requirements

Existing notice of closure requirements require scheduled and semi-scheduled generators to notify AEMO of the year they expect a generating unit to cease supplying electricity, and to provide regular updates, with the obligation being to provide the market at least 42 months' notice.[11]

However, the ESB considers that the existing requirements may be insufficient to identify significant changes in operation (e.g. seasonal mothballing) and that this has the potential to impact reliability or security. There may be scope for strengthening the notice of closure requirements by requiring generators to:

- Provide a period of notice ahead of mothballing generator units or similar significant changes in operation, or
- Provide additional information to regulators or the market operator, for example, on changes to their contractual positions.

These changes could improve the ability for market participants, regulators and jurisdictions to plan for the exit of thermal plant, or the mothballing of thermal plant units, and minimise risks to reliability, security and affordability.

There was no further clarification from stakeholders whether economic rents exist, and publicly available information is not detailed enough for market bodies to form a view on how external factors may impact an individual thermal plant's decision to exit. This is an area where more information is needed to better understand the factors that would influence a plant's departure from notice of closure requirements. The AER is undertaking further analysis of this as part of their Wholesale Energy Market Performance Report, and its proposed approach to monitoring and analysing generator costs will provide helpful insight in the future.

However, changing the notice of closure requirements alone does not address risks arising from the sudden exit of thermal plant within the 42-month window, for example due to catastrophic technical failure. Considering that the risk of technical failure of ageing thermal plant increases with age, the ESB considers there may be scope for further policy options.

Regulated or negotiated arrangements with thermal plants

Where the exit of a plant leaves a reliability or security gap, the NEM is designed so the market responds to that gap with replacement capacity. This is done through forecasting potential shortfalls sufficiently ahead of time to allow for a market response, through the Electricity Statement of Opportunities (ESOO), Energy Adequacy Assessment Projection (EAAP) and Medium Term Projected Assessment of System Adequacy (MTPASA).

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[11] In May 2019, the ESB proposed rule revisions to give effect the the RRO which changed the minimum notice of closure period from three years to 42 months to better align with the RRO forecasting horizons. This came into effect on 1 July 2019.

If the market does not respond, AEMO has the ability to procure resources out-of-market through the RERT mechanism or to issue 'directions'. The planned thermal exit over the next 20 years is significant and the ESB will consider whether the operation of the RERT could be broadened to assist AEMO in procuring sufficient resources at least cost to consumers. The RERT, even if widened to allow for additional tools such as those discussed below, would remain a last resort mechanism.

In various jurisdictions across the US and Europe, system operators make use of regulated or negotiated arrangements such as Reliability Must Run (RMR) schemes in order to keep thermal generating units available to it when a participant is otherwise proposing to retire or mothball that unit. This can be considered similar to the existing RERT arrangements.

A market response is preferable to using the RERT, which is why the ESB is looking at potential improvements to the notice of closure requirements or other forms of improved information to support a market response. The ESB is mindful of the risks of moral hazard and wants to ensure that the RERT does not incentivise a generator to mothball or deviate from their announced closure date. Application of the RERT should follow a competitive tender process, with a RMR or similar contract with the exiting generator needing to be shown to be the least cost option. The RMR contract is discussed in more detail below.

While system operators cannot force a generator to remain operating, having completed a reliability assessment and identified a reliability gap a system operator is required to identify and consider a range of alternative options, of which an RMR contract with an incumbent generator may be one. A system operator will negotiate the terms of an RMR contract with a participant and seek regulatory approval to ensure that the contract is necessary and appropriate.

RMR contracts are intended to apply only for a limited period of time to allow the market to address degradation in system reliability that would otherwise be caused by a closure. A RMR contract will specify the services a unit is to be made available for and the basis of payment (typically verified costs that are incurred).

Individual jurisdictions have established governing market rules over their RMR schemes that reflect the functioning of their individual markets and available mechanisms. As a result, there is no single universal approach to adopting such schemes. A high-level summary of RMR process shown in the figure below.

FIGURE 3 HIGH LEVEL SUMMARY OF RELIABILITY MUST RUN PROCESS

<u>Problem identification</u>

Upon being informed of a market participant's intention to retire or mothball a generator unit, the system operator or other independent market body, in some cases working with relevant transmission owners, will perform a reliability assessment of the impact of the retirement or mothballing.[12] A method for conducting the reliability assessment will be prescribed in the market rules, and will typically require that:

- The assessment will look forward for a specified time period,
- The assessment will be conducted relative to the applicable reliability standard for the market,

[12] There is a minimum notice period specified in the market rules. For example, in markets in the US this can range from 90 days to 12 months. Upon receipt of such a notification the system operator must inform the market of the planned retirement or mothballing.

- Local issues such as voltage stability and thermal constraints, as well as broader market issues such as supply adequacy, will be assessed,
- Alternative longer-term solutions be assessed. The longer-term assessment provides a means of setting an approximate end date to the reliability issue if no other actions will address it.

The assessment identifies and explains the nature of any risks to reliability or security. While market rules will typically specify what issues can be addressed by RMR contracts these can differ between markets.

Contract negotiation

Contract negotiations regarding an RMR contract are typically between the system operator and the participant for the RMR unit.

The nature of the reliability gap is relevant, as that will determine how the RMR unit may need to be dispatched under the contract. The term of the contract is primarily informed by the reliability assessment, but the market rules typically restrict the term of the contract. Some markets limit contract terms to be between one month and one year, while others place limits on the maximum number of months that a contract can be held (e.g. 36 months) over a longer period (e.g. five years). Some market rules define processes for reviewing contracts in the timeframe leading up to the termination date and extending these contracts if required.

Contract payments vary and typically provide for base fixed payments to fund the unit staying in service, as well as compensation for the variable costs incurred when the unit is used. In certain jurisdictions, generators are required to choose between tariffs written into the market rules or prescribed by the regulator and that are negotiated with the system operator.

Contract approval

Prior to contract execution, a system operator must submit the negotiated RMR contract to the relevant regulatory authority for approval (e.g., FERC in the US, excluding Texas). The regulator will consider if the RMR contract is “just and reasonable” and not unduly discriminatory or preferential.

RMR Operations

Dispatch of an RMR contract is dependent on market design in each jurisdiction and is normally through a reliability unit commitment process conducted prior to real-time. There is a spectrum of options as to how bidding and scheduling works, including the participant bidding subject to restrictions, the system operator bidding on behalf of the participant, or the unit being directed by the system operator.

In some markets, there may be processes for adjusting market prices during periods where an RMR contract is dispatched in an attempt to reproduce the prices signals that would have occurred without dispatching the RMR unit. The aim is to avoid distorting market signals. This will reduce the risk of making other units unviable and reduce the need for further RMR contracts.

Costs are not typically recovered through energy market charges but are instead recovered through additional charges to load serving entities in the region or zone impacted by the reliability requirement.

NEM context

There are several regulatory measures already in place that help coordinate entry and exit of generation and minimise the risk of an inefficient outcome including backstop mechanisms such as the RRO, RERT and AEMO directions and instructions. While mechanisms such as RMR contracts may complement existing (or new) mechanisms and can help ensure resources are available when they are needed most, their implementation can carry several risks and would need to be carefully considered in their design and implementation.

Use of an RMR contract would be a last resort mechanism should all other planning, market or contracting arrangements fail to address the residual risk to reliability or security. If incorporated into the RERT, the contracts would only be available to plants that have already provided notice of closure and the contracts will only seek to extend the life of plants for a short period, to provide AEMO and market participants time to resolve the reliability or security issues through other means.

Key features to be considered in the design of an RMR mechanism could include:

- Minimising distortions to market dispatch and wholesale prices
- Minimising distortions to contract markets and signals for the entry of new capacity
- Reducing risks of moral hazard by generators
- Minimising the costs of the option to consumers, and
- Clearly setting out the conditions under which the RMR mechanism can be invoked including limits on the duration of the contracts.

Given the significant fixed costs associated with large thermal plant, the difficulties of securing fuel supplies and the challenges of operating plant at a low capacity factor, there needs to be careful consideration of whether this option best meets the residual system security and reliability risks at lowest cost to consumers.

Contingent scenario planning

Under this option, jurisdictions undertake some planning for unexpected events. In August 2019, the Commonwealth Government set up the Liddell Taskforce to examine the effect of the planned Liddell closure on price, reliability and security in NSW and the NEM.

The Liddell Taskforce developed a framework for assessing future coal closures which including some guiding principles for managing future coal power station closures, which could form the basis for the contingency scenario planning option:[13]

- Affordability and reliability
- Market first
- Do no harm
- Evidence-based, efficient and effective
- Test and consult.

Consideration of these options requires the identification of information that is needed to support authorities responsible for responding to a disorderly closure, and the assessment of whether structures should be put in place to ensure a coordinated approach between market bodies and relevant state and federal governments.

This option should also involve jurisdictions undertaking 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

[13] See pp. 21, Report of the Liddell Taskforce, Commonwealth of Australia and NSW Government, 2020

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. For example, this could involve obtaining planning pre-approval to shorten construction times in the event of a sudden plant exit that threatened reliability or security. This planning process would also include the consideration of locational constraints due to network congestion on identifying suitable replacement options.

Forward planning by responsible authorities for the wind-down of companies whose disorderly exit would pose risks to consumers is by no means a novel phenomenon across other sectors. For example, in the financial sector, European laws require the relevant supervisors of related banks and insurance companies to agree a plan for how they would exercise their powers if the entity's financial situation were to deteriorate and be at risk of failure.

Options no longer under consideration

The ESB is no longer considering the Grattan Institute proposal requiring plants to nominate their own closure windows with ongoing payments to AEMO which are held against compliance with the window. The ESB considers that this approach is not the best option for managing the residual risks to reliability, security and affordability from exiting thermal plant. While the proposal does provide incentives for plants to retire according to their nominated schedule, it would be difficult to completely disincentivise early closure without requiring very significant funds to be surrendered by the generators.

Additionally, in some cases, there can be benefits to flexibility in notice of closure dates, for example, if the exiting thermal plant remains the least cost option.

Stakeholder views on this option were mixed, with support from the Grattan Institute, Infigen, GE Renewables and the Electrical Trades Union, while the AEC, Intergen and Delta argued that the proposal could be counterproductive by placing further financial strain on ageing generators and could distort dispatch.

3.1.7 Analysis of the relationship between resource adequacy mechanisms and other market design initiatives

The ESB will also consider how the direction for the MDI, in a future where there is wide scale underwriting coupled with a supporting RAM, impacts other MDIs. The other MDIs that affect resource adequacy and the ESB's direction are:

1. ESS
2. Two-sided market, flexible demand and DER integration
3. Transmission access reform.

3.1.8 Impacts on essential services

There is an intersection with the identification of all the essential services provided by synchronous generators in two ways. First, establishing a value for a service separate from energy and co-optimising that service with energy creates a link with resource adequacy. For example, procuring an operating reserve or new frequency control ancillary service (FCAS) would both affect the value of resources that also contribute energy and therefore support resource adequacy to a greater or lesser degree. The split in revenues for different services can increase or decrease the respective rank of business cases for some resources over others.

If the entry of new resources is not well calibrated to the needs of the market, it may expediate the exit of thermal plants. It will therefore be extremely important for well-functioning essential system service markets to be in operation before the thermal plants exit.

3.1.9 Impacts on two-sided market, flexible demand and distributed energy resources

A future where government underwrites new capacity sufficient to dampen spot prices in the wholesale market has a few ramifications for a two-sided market and the value of flexible demand and DER. Lower average spot prices and fewer price spikes increase the amount of spot exposure a consumer is willing to take unless contract prices are equally low. They also reduce the value in responding and investing in ways to respond to high prices.

3.1.10 Impacts on access and transmission

Resource adequacy is usually considered market-wide where there is adequate interconnection between power system regions. Without a NEM-wide approach to developing government-backed investments, the value of interconnection may be lost. This may impact on the economic benefits of transmission investments. While it is prudent to also consider the supply/demand balance for regions that can be 'islanded' from time to time, the extent to which this is prudent depends on the probability of islanding and if it happens during contingent events or only during less credible events.

3.2 Next steps

The ESB will work with stakeholders, particularly consumers, governments and market participants, to develop the concepts outlined in this section in more detail so that the options can be evaluated consistent with the approach outlined in this paper (see Section 6). Key design topics and the proposed approach to progressing them are outlined in the table below.

TABLE 3 RESOURCE ADEQUACY DESIGN CONCEPTS

Design topic	Design Element	Approach
Integration of jurisdictional schemes	Develop strawman for NEM-wide approach	• Stakeholder workshop(s) on design elements • Develop a discussion paper in early 2021
Enhanced RRO	Refined proposal for enhanced RRO	• TWG workshop(s) on design elements
	Cost allocation for enhanced RRO	• TWG workshop(s) on design elements
Risk allocation of enhanced RRO and jurisdictional investment schemes	Analysis to understand the drivers of relative risk allocation between market, RRO and jurisdictional schemes	• Internal analysis
	Implications for retailer behaviour	• Internal analysis, 1-on-1 interviews, stakeholder workshop(s)
	Contract market impacts	• Modelling, TWG workshop(s)
	Implications and flow on effects to other reliability frameworks and mechanisms	• Internal analysis
Volume targets and reliability standards	Analysis to determine implications of jurisdictional targets for market arrangements	• Jurisdiction workshops to understand details of out-of-market investment targets • Reliability Panel discussion
Consumer impacts	Large consumer impacts of enhanced RRO	• Facilitated workshop(s) with large consumers and retailers
	Small business and consumer impacts of enhanced RRO and jurisdictional scheme	• Facilitated workshop(s) with consumers and retailers
Risk allocation for considered exit arrangements	Materiality assessment and understanding residual risk	• Internal analysis, modelling, TWG workshop(s)
Phase 1 evaluation		• As per the approach outlined in Section 7 of this paper.

4 ESSENTIAL SYSTEM SERVICES & SCHEDULING & AHEAD MECHANISMS

Key points

- Stakeholders supported the direction set out for ESS in the September Consultation, to use co-optimised market-based procurement where possible and, where not possible, structured procurement approaches.
- The ESB's considerations have prioritised:
  - The need 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,
  - The need to procure system strength in a structured manner, and
  - The potential need for a new operating reserve or ramping service.
- The ESB will continue to work on a spot market approach for valuing and procuring inertia as a long-term priority, in the first instance assessing the value of procuring inertia separately from system strength but still under structured procured arrangements if required in the interim.
- Many stakeholders noted that valuing and procuring missing system services is a priority that cannot wait until 2025. Accordingly, the ESB intends to use the AEMC rules change process to accelerate progression of this agenda consistent with this direction:
  - Fast frequency response and primary frequency response – being considered via the Infigen and AEMO rule changes (further details in the accompanying AEMC directions paper)
  - Consideration of operating reserves – being considered via the Infigen Energy and Delta Electricity (Introduction of ramping services) rule changes (further details in the accompanying AEMC directions paper)
  - NSP structured procurement provision of system strength – being considered via the TransGrid rule change
  - Developing operational scheduling mechanisms to schedule system strength and inertia, including the progression of the UCS and consideration of operational synchronous services markets – being considered via the Delta Electricity (capacity commitment mechanism for system security and reliability services) and Hydro Tasmania rule changes.
- Stakeholders had mixed views about ahead mechanisms.
  - The UCS concept was generally supported, and the ESB will use the operational timeframe rule changes on synchronous services (Delta and Hydro Tasmania) to progress thinking on the UCS.
  - Some stakeholders supported further consideration of ahead scheduling of services. The ESB work indicates a priority (in ahead scheduling) is the procurement and dispatch of services under structured procurement (initially system strength and possibly inertia; collectively known as 'synchronous services') as one key source of supply is slow start generators. Therefore, 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 fast frequency response and operating reserves) have been defined.

– Many stakeholders did not see the value in a voluntary ahead market for energy and services. Retailers and generators were mostly opposed while some providers of demand services and large users did see value in ahead scheduling. The ESB will continue to develop this concept, assessing the potential size of additional resources that could be brought into the market before proceeding with more detailed design work.

4.1 Feedback from stakeholder consultations

This section summarises submissions to the ESB September Consultation regarding ESS (MDI-C) and Scheduling and Ahead Markets (MDI-D). Stakeholders provided feedback in response to questions asked in the September Consultation, as well as a broad range of matters relevant to these workstreams.

4.1.1 General stakeholder feedback regarding Essential System Services

- Stakeholder responses were broadly supportive of the ESB's approach to establish markets for missing system services.
- TransGrid was of the view that some system services can be provided and priced separately to bulk energy, and that the establishment of system service markets will support operational and investment decisions. SIMEC agreed that new system service markets will provide clearer revenue streams and strengthen the business case for investors.
- There was also support to progress toward spot markets for ESS, as mapped out by the ESB in the consultation. However, a number of stakeholders expressed caution with a spot market approach. Stanwell noted that a simpler contracting approach may be better during the transition, while Hydro Tasmania and Origin Energy noted that spot markets are an appropriate framework for operational efficiency and that some form of contracting or longer-term mechanism is required for investment in new resources.
- Large users and consumer groups highlighted concerns about the rising cost of AEMO interventions and noted that these costs are generally unexpected, unbudgeted and increasing in magnitude. The allocation of costs will be an important consideration for the design of new system service markets in the next phase of analysis.

4.1.2 Operating reserve

- Stakeholder responses to the September Consultation were broadly supportive of further consideration of an operating reserve mechanism. However, some stakeholders noted that they will reserve their judgement until further detail is available and further consideration should be given to the interaction with wholesale prices, contract markets, and RERT.
- The AEC noted that an operating reserve would provide greater confidence that demand can be met on an hour-to-hour basis. Origin Energy was also of the view that an operating reserve has potential as a means of managing reliability and security of supply in operational timeframes. Tilt Renewables also thought an operating reserve would sharpen the real-time prices and highlighted that the mechanism would support demand resources being more price responsive.
- Some stakeholders were of the view that operating reserves would support investment in flexible resources. AEC stated that an operating reserve would provide an additional investment incentive in firm reserves than would be provided alone by the energy market.

- However, many stakeholders – including Origin Energy, EnergyAustralia and Snowy Hydro – were also of the view that an operating reserve spot market is unlikely to support new investment. Australian Financial Markets Association (AFMA) questioned whether an operating reserve would provide a sufficient forward signal to incentivise the generation investment necessary for future needs or allow retailers to form expectations around prices and contract accordingly.
- The AEC also questioned the use of a downward sloping demand curve for operating reserves, believing it would be inappropriate to set an effective energy price cap through the operating reserve.

4.1.3 Frequency control ancillary services

- Stakeholders were generally supportive of the road map for FCAS outlined in the September Consultation. However, Origin Energy said a more comprehensive review of the broader frequency framework is required. Similarly, CS Energy noted that the September Consultation paper did not consider whether definitions of regulation and contingency FCAS are fit for purpose.

Fast frequency response

- Stakeholder responses to the consultation were broadly supportive of further consideration of a fast frequency response (FFR) service. The Clean Energy Council (CEC), Energy Queensland, Alinta, AGL and Ausgrid said an FFR market would further incentivise investment in battery storage. AGL also noted that while new FFR markets may introduce new costs into the NEM, they should improve system resilience and the efficiency of dispatch for frequency response services.
- Stakeholders were generally of the view that co-optimisation with inertia should be the long-term goal. Some stakeholders raised caution that a spot market for FFR may be too complex and that a contracting approach may be appropriate in the near term. Origin Energy stated it would only be supportive of an FFR if it seeks to co-optimise with an inertia market.

Primary frequency response

- Several stakeholders from the generation sector believe primary frequency response (PFR) should transition from the current mandated response to a market arrangement. Snowy Hydro and Stanwell also noted they were concerned that the ESB was advocating a mandated response for PFR.

4.1.4 System strength and inertia

- Several stakeholders noted issues with the current framework and said there is a case for changing the current arrangements for system strength and inertia. CitiPower highlighted that the current framework does not recognise the challenges that distributors are facing and their role in maintaining and operating a secure power network.
- The CEC and Reach put forward the view that system strength issues are emerging across the NEM and the ‘do no harm’ requirement on new connections is leading to uncertainties, costs and delays to new projects. Origin Energy was also of the view that reform of the existing system strength framework is a priority.
- There was broad support from stakeholders for structured procurement of inertia and system strength as outlined by the ESB. AusNet said it is important for TNSPs to plan and provide a base level of system strength and not wait until there is a shortfall before acting. The AEC was of the view that focus should be on efficient provision of services through a combination of monopoly network and long-term structured contracts with competitive providers by either networks or AEMO. AFMA put forward the view that if AEMO is responsible for procurement of system strength and inertia, competition between TNSPs and generators may be possible.

- CitiPower highlighted that the current framework does not recognise the challenges that distributors are facing and their role in maintaining and operating a secure power network.
- Stakeholders generally considered that a spot market for inertia should be a long-term goal. However, AGL, UNSW and Tilt Renewables supported long-term contracting for inertia rather than a spot market.

4.1.5 Regulatory framework

- Stakeholder responses on the topic of the future design of the regulatory framework for essential system services were divided. Some favoured flexibility in the procurement of system services and others were opposed. EnergyAustralia, SA Water and UNSW supported regulatory flexibility for the trialling of system services and technologies. However, several stakeholders believed there is already sufficient regulatory flexibility for the procurement of system services. The AEC also commented that decision making power on the desired security outcomes should rest with the Reliability Panel.

4.1.6 General feedback on scheduling and ahead markets

- Stakeholder support was split across the options presented in the consultation paper. The UCS had generally strong support from the majority of stakeholder who commented. Synchronous services ahead market received mixed views from stakeholders. Most stakeholders who commented on an integrated energy ahead market were against the option; others urged the ESB to conduct analysis of the potential benefits (and costs) of an option before proceeding.
- Snowy Hydro suggested no changes to the NEM's scheduling processes are required and AEMO should rely on intentions available through the Pre-Dispatch Projected Assessment of System Adequacy (PDPASA) and Short-Term Projected Assessment of System Adequacy (STPASA) processes.
- Other stakeholders were of the view that enhancements to the existing scheduling processes should be made before progressing with an ahead market. The AEC called for greater consideration of alternatives to the current pre-dispatch engine and by the ESB. A report by Creative Energy, commissioned by the AEC in June,[14] suggested that a different pre-dispatch engine might potentially address issues of convergence and effectiveness of the pre-dispatch process. Alternatively, simpler reforms that might address these issues include more frequent pre-dispatch runs, fewer restrictions on bids and rebids, or multiple pre-dispatch scenarios.

4.1.7 Unit Commitment for Security (Option 1)

- The majority of stakeholders supported further consideration of a UCS mechanism (Option 1). However, Snowy Hydro did not support the implementation of an UCS, citing the cost of implementation and saying that AEMO should rely on information about generator intentions available through PDPASA and STPASA.
- Many stakeholders sought further information about the UCS design and how it will interface with other existing NEM processes. AEC queried whether the principles applied for directions would change from current practice with the implementation of a UCS. AGL, Origin Energy and EnergyAustralia commented that scheduling for market benefit beyond minimum security level could impact market participants and self-commitment of resources. AGL also raised a concern that committing resources through contracts for market benefit might result in the decommitment of other resources. AFMA cautioned that any implications for financial contract markets should be considered as part of the design development.

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[14] Scheduling and Ahead Markets - Design Options for Post-2025 NEM', Report prepared by Creative Energy Consulting Pty Ltd for Australian Energy Council, June 2020

4.1.8 Ahead market for system security (Option 2)

- There was a range of views from stakeholders on the merits of an ahead market for synchronous services.
- Delta Electricity supported a model where services are procured in a short term, competitive auction. Further consideration of a Power System Security Ancillary Service, as proposed by ERM Power and CS Energy, was also supported by Stanwell. In its report for the AEC, Creative Energy put forward the view that a day ahead market cannot operate without a real-time market that takes account of the physical and mandatory characteristics of the market, and this complexity cannot be incorporated into an ahead market.
- Several stakeholders noted that there is potential merit in ahead trading of services that have a real-time market, but further details are required. However, CS Energy did not believe an ahead market for system services is required, as participants are best placed to manage their portfolios and coordinate the delivery of system services. Infigen was also not able to see the benefits at this point in time and believed further consideration should be deferred until the ESS workstream is completed.

4.1.9 Integrated ahead market (Option 3)

- Most generators and retailers were opposed to the development of an integrated ahead market. Origin Energy raised concern that there is potential to over-schedule demand response ahead of time. Snowy Hydro raised a concern about the potential disruption to financial contract markets and existing operational practices. The AEC was of the view that trading in both ahead and real-time markets is unnecessarily complex.
- Support for an ahead market for energy trading was generally limited to a few demand side stakeholders (although not all). SA Water believed there is value in co-optimisation of system services and the energy markets along with the creation of an ahead market for energy. BlueScope commented that an ahead market may facilitate further demand-side participation as price uncertainty is a barrier for slower acting demand response. Enel X also thought there may be a benefit for some demand response providers if they are able to lock in a price ahead of time and schedule their operations accordingly, however the value will depend on the prices available and the notice required. Enel X noted that given volatility in prices, a day-ahead market is unlikely to provide benefit for a customer that needs an hour notice to respond.

4.1.10 Mandatory ahead market (Option 4)

- Stakeholders welcomed the ESB direction to not progress with the design of a mandatory ahead market. However, EnergyAustralia commented that to be effective an ahead market would require a high level of participation of retailers and generators.

4.2 Proposed directions

In this section we respond to issues raised in stakeholder feedback. With interactions between the ESS and Scheduling and Ahead Markets MDIs, these issues have been considered together in this chapter.

4.2.1 Essential System Services

As discussed in the September Consultation, issues being considered in the ESS workstream have significant interdependencies with issues currently being considered by AEMC as part of its workplan on system security related rule changes. In this section we have set out ESB thinking on issues raised and note how these are being considered collectively through both the ESB and AEMC work.

4.2.2 Operating reserve

The ESB has identified options for an operating reserve product to address increasing variability and uncertainty in the NEM. These options are outlined in detail in an AEMC Directions Paper that accompanies this paper. The AEMC consultation forms part of its consideration of two rule change requests that relate to operating reserves.[15]

The AEMC Paper outlines in further detail, and invites feedback on:

- The power system need for operating reserves and the materiality of the need for a new operating reserve product as the power system transforms
- The ability of a new product to support investment in flexible capacity
- High-level design parameters of four possible reserve service product alternatives.

The proposed principal aim of a possible new reserve product is to address *unexpected* changes in net demand due primarily to the variability of VRE generation over the 5-30 minute time frame. Such products may also help to address the increasing risk of security events that may have impacts beyond the timeframes currently addressed through FCAS including fast ramps of net demand.

The mix of resources expected in the future will increase operating complexity, and the market will need enough resources to maintain power system reliability and security, accounting for uncertainty and variability. To achieve this, sufficient energy reserves must be available.

Energy reserves ('reserves') are capacity in supply or demand resources, that are currently unused, available and capable of changing the supply/demand balance within the specified time. Reserves must be capable of meeting dispatch targets within that time, accounting for the operational capability including ramp rates, state of charge and firmness of resources.

Currently the NEM has both in-market and out-of-market reserves:

- In-market being generation that has bid itself available but has not yet been dispatched, and
- Out-of-market being reserves procured through the RERT (and so are an interim reliability measure).

The quantity and required response of any reserve product requires a cost/benefit trade-off. The need for a new product may be assessed by considering the requirement for reserves above and beyond what market participants may provide under current arrangements, and the costs and benefits to consumers of procuring those reserves as a service. This assessment would consider uncertainties in both operational and investment timeframes; for example, market participants may not have hedged against "unknown unknowns" or new modes of failure that are emerging.

Any product should support the provision of flexible reserves, even when the energy price is low or negative and recognise dynamic changes to the reserve needed according to system conditions. The product should provide transparent value with both short- and long-term incentives for flexibility and dispatchability, allowing 'as needed' capacity to be explicitly valued separately from 'as available' capacity. In essence, any product should aim to bring co-optimised in-market reserve response to unexpected changes, avoiding the need for AEMO intervention (including RERT procurement).

Considerations between existing arrangements for reserves, as well as the broader wholesale contract market also need to be considered.

The AEMC paper[16] invites feedback on the above characterisation, on the materiality of need of a possible product, and on the alternative product options. This feedback will be used to inform the

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[15] One rule change received from Infigen Energy (Rule change ERC0295) and the other from Delta Electricity (ERC0307) .

[16] See details in accompanying AEMC paper, which can be found at www.aemc.gov.au

ESB's development of a preferred option to address uncertainty and variability in net demand, as well as the AEMC's draft determination on the Infigen and Delta rule change proposals, which are currently due by June 2021.

4.2.3 Frequency control

The AEMC and AEMO have undertaken a substantial amount of work over recent years in relation to the frequency control frameworks in the NEM. This work is continuing with the current focus for regulatory reform on:

- the development of spot-market arrangements for FFR to help efficiently manage system frequency following contingency events during low inertia operation.
- the development of enduring arrangements to support the provision of PFR to help manage system frequency during normal operation and provide consistent active power response to support AEMO's ability to accurately predict how the power system will respond to disturbances

The consultation on changes to the National Electricity Rules (NER) for each of these work areas is being led by the AEMC, supported by technical advice provided by AEMO, as part of its frequency control work plan. Further information can be found in the accompanying AEMC paper on Frequency control rule changes.[17] Feedback will inform the progression of the AEMC's rule changes as set out below.

Fast frequency response market ancillary service

In response to a rule change request from Infigen, the AEMC is investigating the costs and benefits of establishing new market arrangements for contingency FFR services. The key elements of Infigen's proposed FFR services include that they would:

- Operate in a similar way to existing contingency FCAS, with service provision being based on enablement through the NEM dispatch on a five-minute basis
- Have service specification based on full active power response within 2 seconds, as opposed to the 6 seconds specification for the existing "fast raise" and "fast lower" services.

The AEMC will publish a draft determination for the FFR rule by 22 April 2021, following technical advice being received from AEMO on these matters in February 2021.

Primary frequency response

In March 2020, the AEMC made a rule introducing an obligation on all scheduled and semi-scheduled generators in the NEM to support the secure operation of the power system by responding automatically to small changes in power system frequency. It addressed an immediate need identified by AEMO to improve frequency control in the NEM during normal operation and following contingency events.[18]

The AEMC noted that a mandatory requirement for PFR on its own is not a complete solution and that further work needed to be done to understand the power system requirements for maintaining good frequency control. The AEMC noted that it would be preferable to introduce alternative or complementary arrangements that incentivise and reward the provision of PFR, with the rule established as an interim arrangement through till 4 June 2023.

[17] See details in accompanying AEMC paper, which can be found at www.aemc.gov.au
[18] National Electricity Amendment (*Mandatory primary frequency response*) Rule 2020, 26 March 2020

In developing enduring arrangements,[19] the AEMC will consider the following high-level issues:

- Whether a mandatory PFR requirement should continue beyond the sunset date or be revised as part of an enduring PFR arrangement
- Whether it would be beneficial to develop new market ancillary service arrangements to procure PFR for small frequency deviations
- Changes to the existing arrangements for the allocation of costs associated with regulations services through the Causer pays process, and
- How the required frequency performance during normal operation is specified in the frequency operating standard and the potential scope for a future review of the frequency operating standard by the Reliability Panel.

AEMO is currently in the process of assisting with changes to generator control systems in accordance with the Mandatory PFR rule. The monitoring of plant and power system impacts due to the roll out of the Mandatory PFR requirement will help inform the AEMC's determination of the enduring PFR arrangements.

The AEMC will publish a draft determination for the PFR rule by 16 September 2021, with this being informed by technical advice due to be provided by AEMO in June 2021.

4.2.4 System strength and inertia

The September Consultation set out the ESB's preferred direction for managing system strength and inertia. In the context of ESS, the paper outlined three options for the acquisition of these services:

- Mandatory requirements.
- "Structured procurement", to procure them through a combination of medium to longer term contracts and / or short-term auctions from synchronous service providers, as well as through the provision of network services.
- Real-time spot market.

The ESB considers that it is in the consumers' interest to complete the missing market for scarce system strength and inertia and that there is a need for:

- Proactive provision of system strength in *investment timeframes*, through either network investment of regulated network services (synchronous condensers) or contracting with existing synchronous generators, based on expected connections of new generators, particularly in those areas that currently have limited system strength; and
- Mechanisms to procure and schedule system strength and inertia in *operational timeframes* including existing and new synchronous generators.

It is important to recognise that the provision of these services may vary between these timeframes – operational levels will potentially be more or less than what is efficient in an investment timeframe, to take account of the dynamic nature of the power system.

The ESB considers that system strength is complex, and a real-time spot market is ill-suited at the current time. The structured procurement approach is preferable compared to mandatory requirement, as it is able to value the service and promote long term investment.

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[19] The AEMC intends to develop enduring arrangements for PFR through its ongoing assessment of AEMO's related rule change request, *Primary frequency response incentive arrangements*.

In October 2020, the AEMC completed its Investigation into System Strength Review,[20] which recommended a TNSP-led procurement process at the investment timeframe. Under this approach, the TNSP would be obliged to meet a ‘network standard’ for system strength. The network standard is expected to identify an efficient volume of system strength beyond power system security. The TNSP must meet the full amount of this standard by investing in network infrastructure (including synchronous condensers) or procuring non-network options (such as long-term contracts with synchronous generators and potentially in future with other technologies e.g., batteries with grid-forming inverters, if they prove to be useful sources of system strength). The TNSP-led procurement approach for system strength is expected to be implemented by the AEMC through the rule change request[21] from TransGrid. This will give effect to a structured procurement arrangement for system strength.

With respect to inertia, as per the September Consultation, the ESB’s preferred long-term approach is to develop a real-time spot market. Before such a time, inertia could be acquired under structured procurement if there is a need for an explicit procurement of the service. However, further consideration needs to be given to the potential interim arrangement, including the interaction with the provision of the other system services.

For the purposes of this paper, the ESB refers to system strength and inertia under the collective term “synchronous services”. In particular, in the operational timeframe, the term “synchronous services” is used to discuss the scheduling of resources that may be providing system strength and inertia, which in turn may have been procured through structured procurement arrangements. Such scheduling mechanisms may also extend to other services that are also not explicitly scheduled via the real-time market, such as the provision of voltage control. “Synchronous services” in this context is a placeholder to refer to these collectively, and, for clarity, is not meant to imply a bundled procurement of those services. The relevant scheduling mechanisms for these services and the ESB’s direction for their progression are discussed in the following section.

4.2.5 Scheduling and Ahead Markets

In this section we provide further clarification of how we propose to consider the development of scheduling and ahead markets options in response to issues raised by stakeholders. This section outlines work to further develop these options and highlights linkages with the AEMC’s rule change process through 2021.

In the September Consultation, the ESB highlighted four options under consideration for Scheduling and Ahead markets, and provided the following direction:

- The UCS was supported for implementation,
- Ahead markets under Option 2 (system service ahead scheduling) and Option 3 (integrated ahead market) were supported for further development, and
- Option 4 (compulsory ahead market) would not be progressed any further.

These options have linkages to the missing markets for services being established through the ESS workstream. Establishing the missing markets should reduce the current rate of interventions, such that they once more become a backstop measure used rarely.

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[20] Final Report: Investigation into System Strength Frameworks in the NEM, AEMC 15 October 2020

21 Efficient Management of System Strength on the Power System, Transgrid rule change. 'More detail on the TransGrid rule change is available at: https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system

4.2.6 Clarification of SAM options

The UCS mechanism performs different functions under the different options. In the UCS-Only option (Option 1), the UCS will complement any structured procurement of system strength, and potentially inertia, by operationalising contracts and potentially scheduling them for market benefit. In all options, the UCS will also assist with the backstop intervention process to maintain system security.

In the September paper, the UCS was proposed as a mechanism to commit additional resources to operationalise contracted system services and to assist AEMO to undertake intervention. While the ESB agrees that the UCS mechanism will be useful to coordinate and provide more transparency around the intervention process, this is not the primary reason for introducing a UCS.

The market design is intended to introduce additional services and improve the scheduling mechanisms to ensure their provision without reliance on intervention. The ESB's support for the implementation of the UCS is to ensure a mechanism is in place to schedule services acquired under structured procurement, and to improve transparency for the market in the commitment timeframe. Since the September Consultation, the ESB has clarified its thinking around the purpose of the UCS and this is described in Text Box 3.

TEXT BOX 3 PURPOSE OF THE UCS

The UCS is a proposed mechanism that allows AEMO to commit additional resources to address shortfall of system security and reliability requirements at operational time frame. Shortfalls could be:

- For a breach of a minimum system requirement for energy and FCAS (services traded in the real-time market)
- For system services not traded in the real-time market - either meeting minimum levels of security or achieving an efficient level for these services. For example, while the system could stay secure by curtailing some non-synchronous output, this could be inefficient if the total system cost is lower by committing some additional resources to mitigate the curtailment (while keeping the system secure). The UCS could be designed to schedule contracts up to some efficient level to provide market benefits in this case, and the mechanics associated with this are further described in Text Box 4.

The potential purpose of the UCS is outlined below.

- **Additional monitoring of system requirements in commitment timeframe** – in recent years the changing mix of generation has seen increasing uncertainty and volatility in scheduling, making it increasingly difficult for AEMO to maintain system security and for participants to manage scheduling risk. Through leveraging and improving existing AEMO system monitoring processes such as PASA and PD, the UCS could help to address these issues by regularly assessing the self-committed schedule of the fleet and identifying potential shortfalls of security and reliability requirements.
- **Activating and scheduling system service contracts** – the UCS could be used to schedule contracted resources to provide system services under structured procurement, using the scheduling mechanism described below.
- **If required, provide support for interventions to maintain system security and reliability** – if, after the activation of contracts, a shortfall remains, interventions would be used as a last resort mechanism to maintain system security, while minimising costs,
- **Improve transparency** – the scheduling of contracts would communicate to the market that additional units have been committed and allow other participants to respond. It would improve transparency and predictability for the market.

Consistent with the ESB's intention to consider a scheduling mechanism for services under structured procurement, which includes the UCS and other potential market processes, the ESB considers that it would be best to progress the consideration of Option 2 (System Service Ahead Market) under two sub-categories:

- The first, called Synchronous Service Market (SSM)[22], looks at the procurement and scheduling of services acquired under structured procurement,
- The other subcategory also includes ahead trading and scheduling of services that do have a real-time market.

Regarding the former, similar to the UCS, the ESB has been working to further develop the potential design of a Synchronous Service Market, and this is described in the following section. The ESB is considering both the UCS and the SSM, noting that a preference was expressed in the September Consultation to implement the UCS. In progressing the design of these options together, the ESB is considering whether there is the need for an operational procurement option such as the SSM; a brief description of some of the relevant trade-offs is provided below in Text Box 4.

With regards to the design of ahead trading and scheduling of services that do have a real-time market, the ESB agrees with many stakeholders that this first requires the design of the intended suite of the services themselves and their integration into the real-time market to be further progressed. This work will be progressed following design of the operating reserve market as discussed earlier , and also take into consideration the applicability of ahead markets for frequency control services.

Option 3, an integrated ahead market, includes the potential to trade energy ahead of real-time and is being considered together with the work being progressed focused on demand side participation (see Chapter 5). An integrated ahead market would also feature a mechanism to schedule system services under structured procurement and include trading and procurement of system services with a real-time market. Work is underway across the joint workstreams to develop ahead market designs for the trading and scheduling of flexible demand and DER. Work is also underway to develop a clearer understanding of the potential size of additional flexible demand side resources that could be brought to the market via an ahead market for energy or system services. The ESB continues to support continued development of such ahead markets for evaluation and will work with stakeholders to develop this detail in early 2021. See the September Consultation and accompanying documents for more detail on how ahead markets could work in the NEM.

4.2.7 Scheduling of system strength and inertia

As indicated in the September Consultation, the ESB is of the view that system strength and inertia, with the latter included before the development of a real-time spot market in the long term, could be acquired under a structured procurement mechanism. Structured procurement could include TNSPs signing long-term system service contracts with generators under non-network options.

As system services procured through structured procurement do not have a real-time market, there is a need to develop a scheduling mechanism for them at the operational timeframe. This section sets out some further detail regarding such a mechanism to establish a common understanding ahead of further progressing the design and evaluation in the next phase.

[22] As noted, the term "synchronous services" has been used in this paper as a placeholder term to collectively refer to system strength and inertia. As such, the operational market for these services which could be acquired under structured procurement arrangements has been names "Synchronous Services Market" as a placeholder to allow for further consideration and evaluation of this option.

Such a scheduling mechanism could schedule and activate contracted resources and would link long-term contracts with dynamic system requirements in the commitment timeframe leading up to real-time dispatch. How such a mechanism could potentially work is described in Text Box 4 below. The intention of the scheduling mechanism design would be to ensure that the relevant services are delivered, and resources can be remunerated for their services, aiming to reduce reliance on out-of-market interventions.

TEXT BOX 4 AN OPERATIONAL SCHEDULING MECHANISM FOR SYNCHRONOUS SERVICES

Objective of the scheduling mechanism

There is often a positive relationship between the level of system strength and inertia and the level of non-synchronous generation (e.g., variable renewable energy) that can be supported at the same time. For example, often more system strength means that the system can support more non-synchronous generation, which will lead to a net market benefit if the reduction in dispatch cost due to higher non-synchronous generation outweighs the cost of providing the additional system strength.

The scheduling mechanism could therefore be configured to deliver either:

- The **minimum level of system services** to keep the system secure, where some non-synchronous output might also be curtailed. In this case, the objective function of the mechanism would be *to minimise the total* ***resources costs incurred due to the additional commitment*** *over the relevant scheduling window*, or
- The **efficient level of system service** to not only keep the system secure, but also to minimise the total system-wide dispatch cost by explicitly recognising the trade-off between the cost of more system service and the benefit of additional low-cost VRE generation enabled. In this case the objective function would be to *minimise the total* ***system-wide dispatch cost incurred*** *over the relevant schedule window*, as indicated through pre-dispatch bids.

The level could also be configured differently depending on which type of service it is looking to schedule. As a preliminary assessment where the scheduling mechanism is being used to schedule services procured under structured procurement, the ESB considers that it would be appropriate to adopt the efficient level, whereas when it is being used to support interventions, it should only do so to the minimum required level. The relevant level will be further consulted on through the next phase of design and implementation. The ESB recognises the concerns that some stakeholders have raised with regards to scheduling for an efficient level ahead of the real-time market, and will engage further on this issue.

The high-level process of the scheduling mechanism

During the September Consultation process, ERM and CS Energy proposed a Power System Security Ancillary Service Model (PSSAS Model), which is very similar to synchronous service scheduling mechanism considered in this MDI. The UCS, in conjunction with an SSM, could be used to implement this. The high-level process is similar between the two and can be summarised as follows:

- The mechanism would run at fixed regular intervals (e.g., daily or every few hours).
- Participating resources can make offers consisting of the following components, either of which could be offered at $0:
  - A $/online/hour start-up cost, plus
  - A $/MW/hour contract-for-difference payment for running at minimum generation.

  While offers from contracted resources could be affected by contract terms, it is expected that the relevant terms should facilitate participation in the mechanism. The corresponding technical details would also be required to be provided to the scheduling process (e.g., minimum generation levels).

- Depending on the design choice, the mechanism will clear to deliver either the minimum or efficient level of the system services, as based on the pre-dispatch schedule at the time. It will produce a schedule for resources cleared to provide the services under structured procurement.
- For contracted resources, it is expected that the contracts could specify their obligation for following the activation schedule and the penalty for deviation. The obligation for uncontracted resources scheduled through the mechanism will be considered further in progressing the design for an operational procurement mechanism.
- The resulting schedule only applies to resources participating in the mechanism. All self-committed resources could be free to change their PDS bids before real-time as usual.

4.2.8 Clarification of the options for scheduling system services

The September Consultation supported the implementation of a UCS mechanism to schedule these services. In addition, the ESB is also considering whether an operational procurement mechanism (i.e., an SSM), that allows resources without long-term contracts with TNSPs or AEMO to provide these services at the operational timeframe would also have benefits. In terms of the options for the SAM MDI, this could either lead to the adoption of option 1 (UCS-only), or option 2 (UCS plus an SSM).

The 'UCS-only' option and 'UCS+SSM option' are similar in that both mechanisms:

- Could schedule system services under structured procurement to realise market benefit, with the underlying scheduling mechanism of a similar design, as outlined in Text Box 4 above.
- Only commit units to meet a breach of minimum system requirements for energy and FCAS, and any other in-market ancillary services to be introduced, eg. operating reserve.
- When interventions are utilised under either option, intervention payments will be made as per the current framework (i.e., for RERT and directions compensation).

The UCS-only and UCS+SSM are different in that:

- The UCS-only schedules contracted resources, while an SSM could schedule contracted and uncontracted resources, possibly through an auction process.
- The UCS-only is a scheduling mechanism and may not require a new payment mechanism, noting that the payment mechanism will need to be dealt with through the contracts it would be is scheduling (and who pays for these contracts to start with still needs to be considered). On the other hand, the SSM would have a payment mechanism which will be investigated further.

The mechanics of each option are described further in Text Box 5 below.

TEXT BOX 5 UCS-ONLY

The UCS is a common component in all options considered in the Scheduling and Ahead Markets workstream. However, its scope and design could vary in each. The process of the UCS-only option is described below and summarised in Figure 4.

The UCS-only process has two key modes – a system services scheduling mode and intervention mode.

In the "**system service scheduling mode**" the UCS would, to the extent possible, schedule system service contracts to provide system services under structured procurement. This would be done through running the synchronous service scheduling mechanism described in section 5 at fixed regular intervals. The scheduling outcome and the associated commitment decision would be communicated to the market at the earliest instance possible and the commitment outcomes would be reflected in pre-dispatch by the relevant resource providers. The “system service scheduling mode” is limited to the following:

- Only resources under system services contracts can participate in the mechanism.
- It will only schedule system services under structured procurement and not other energy and system services[23].

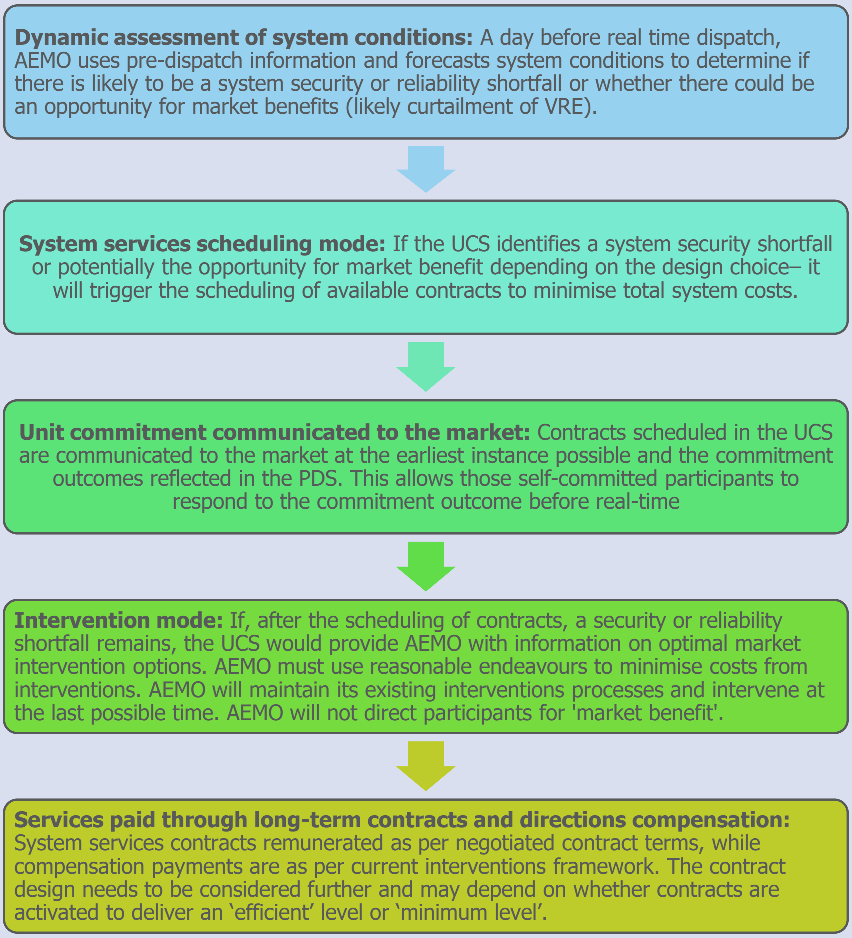
In all options (including the UCS-only option) under the Scheduling and Ahead Markets MDI, the UCS also has an **“intervention mode”** in which it would help AEMO undertake last resort out-of-market intervention (including RERT, direction and instruction) to keep the system secure and reliable. When in such “intervention mode”, the UCS would advise to commit additional resources *at lowest cost*, including contracted or uncontracted resources, *only if* a breach of *minimum* reliability and security requirement is identified. The general design framework for UCS “intervention mode” could continue to be based on the following principles and allow AEMO to retain sufficient flexibility to use best endeavours to keep the system secure and reliable:

- There would be no specification of the list of services AEMO can use the UCS for as a support for interventions, in order to enable flexibility for intervention as new services emerge
- AEMO must use reasonable endeavours to minimise its impact on the self-commitment decisions by market participants,
- AEMO must use reasonable endeavours to minimise total cost incurred from its intervention but be allowed the flexibility to determine the “lowest cost” option as the situation requires.

Between two “system service scheduling mode” runs, the UCS could advise to commit additional resources only through “intervention mode”, which would be run regularly to continue to monitor any shortfall in reliability and security. It is expected that with system services acquired under structured procurement and scheduled operationally, the reliance on AEMO out-of-market intervention to provide these services could be reduced and direction should revert to rare and last-resort events.

[23] However, the result of scheduling could have a flow on impact on energy and other system service prices.

Figure 4 Overview of the USC-only Process



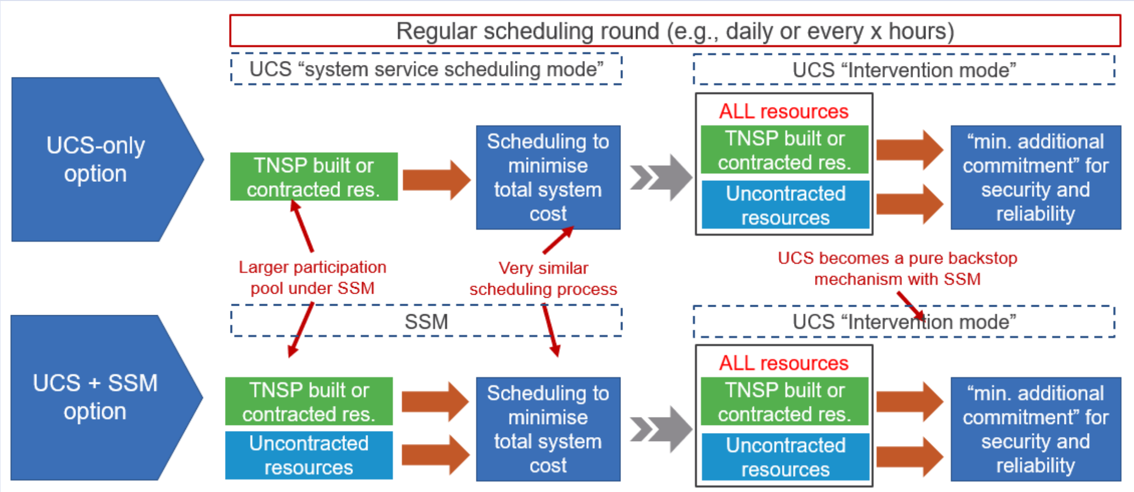
Synchronous Services Market

The SSM is an ancillary service market in which AEMO could hold a regular auction to schedule and activate resources to provide system services under structured procurement. At its core the SSM uses the same scheduling algorithm as the UCS in "system service scheduling mode", as outlined above. There are, however, two key differences:

- First, the SSM would allow uncontracted resources to participate on a voluntary basis, alongside contracted resources at the same time, and be paid based on their cleared offers.[24] In contrast, in the UCS-only option, uncontracted resources would only be called on to provide system strength and inertia only under an intervention and are only compensated as directed participants.
- Second, uncontracted resources failing to adhere to their schedule might face different consequences compared to contracted resources, as the penalty for the latter might be specified in the contracts. For uncontracted resources, the SSM schedule would be expected to be "financially binding". That is, resources that deviate from their SSM schedule (i.e., are not online for the scheduled intervals) would not receive payment for the hours they deviate from the schedule. There could also be additional financial penalties applied, especially if it leads to AEMO needing to intervene to keep the system secure.

Figure 5 below provides a comparison of scheduling system services under structured procurement in the UCS+SSM or UCS-only option.

FIGURE 5 COMPARISON OF THE SCHEDULING PROCESS BETWEEN UCS+SSM AND UCS-ONLY OPTIONS



Note: for ease of comparison, this figure assumes that the scheduling mode of the UCS will adopt an efficient level and schedule to minimize total system cost; this design choice is yet to be made.

The operational procurement mechanism, the SSM, could potentially complement TNSP-led procurement by utilising existing uncontracted synchronous resources to meet operational system conditions not included in the investment planning and procurement stage. This could lead to a higher operational cost of providing these services if available and cheaper uncontracted resources are unable to be utilised.

The ESB is considering whether there is a need for such a procurement mechanism to therefore also include uncontracted resources for system services when realising market benefits. Further consideration also needs to be given to other design details, particularly as we transition to these arrangements. To the extent that some services are localised and provided by a relatively limited number of resources, it results in a risk for transient market power to be exercised, which creates a risk that this could cause increased costs for customers. Various measures may act to ameliorate these risks, such as a cap on payments to generators. These issues will be further considered as this workstream progresses.

It will also be important to consider *who pays* for these services when they are procured. This is the process of determining which parties should bear the cost of providing the service. This includes the consideration of the efficient allocation of costs and risks with the parties best placed to manage them. Whether it is consumers, or generators, or a combination therefore may differ for each service depending on the other market design characteristics and will require further consideration.

4.3 ESB Directions and next steps

4.3.1 Essential system services

The ESB intends to use the AEMC rule change process to accelerate progression of this agenda consistent with the approach set out in September Consultation and ESB Directions provided in this chapter.

- FFR and PFR – being considered via the Infigen and AEMO rule changes (further detail is in the accompanying AEMC directions paper).
- Consideration of operating reserves – being considered via the Infigen Energy and Delta Electricity (Introduction of ramping services) rule changes (further detail is in the the

[24] This could be similar to the PSSAS model.

accompanying AEMC directions paper). Options will be narrowed down for the ESB March Consultation Paper and AEMC invites detailed stakeholder feedback to inform the ESB recommendations in June 2021. A draft determination for the two relevant rule changes is due in June 2021.

- NSP structured procurement provision of system strength – being considered via the TransGrid rule change.
- Developing operational scheduling mechanisms to schedule system strength and inertia, including the progression of the UCS and consideration of synchronous services markets – via the Delta Electricity[25] and Hydro Tasmania[26] rule changes, as discussed below.

4.3.2 Consideration of operational procurement of system strength and inertia

The AEMC is coordinating with the ESB on its consideration of the two rule changes that relate to operational considerations of system strength and inertia markets. These rule change requests propose new arrangements to procure system services, including reserves, and synchronous services such as inertia, and system strength.

As both the UCS and SSM involve changes to the scheduling for system services, it may be useful to consider the coordinated progression and so potential coordinated implementation of the UCS and SSM.

The ESB will continue to explore the merits and possible design elements of the SSM for the March 2021 paper. This assessment and design will build on work being considered in the rule change proposed by TransGrid currently being considered by the AEMC.

The ESB's thinking and assessment on operational considerations for system strength and inertia – as detailed above – will inform the approach to each of these rule changes. The draft determinations for the two relevant rule changes by Delta Electricity and Hydro Tasmania are due in March and April 2021, respectively, with final determinations due in mid 2021.[27]

There will also need to be further consideration on the interactions between the different methods to procure system services, as has been highlighted.

4.3.3 Timeline for development

Figure 6 below provides an indicative timeline of the proposed progression of the system services and scheduling mechanisms through the AEMC rule change processes. The time to implementation of rule changes indicated in the figure is driven in part by the requirement to make system changes to the dispatch process or for procurement. The indicated time to implementation is indicative only.

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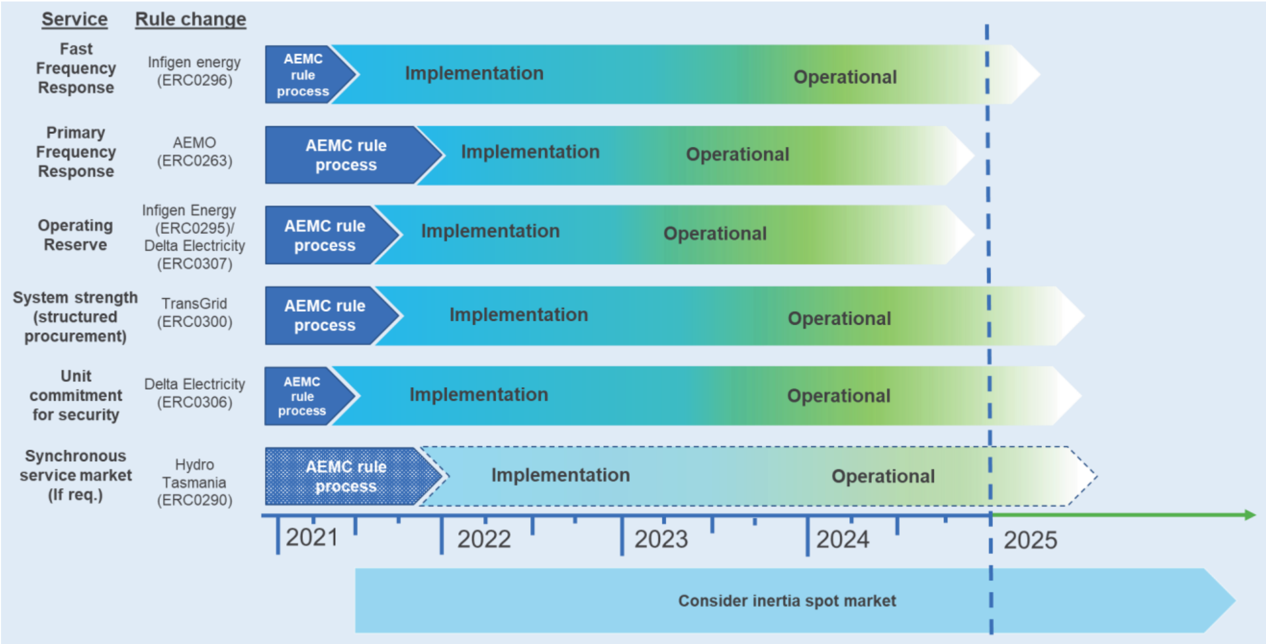
[25] 'Capacity commitment mechanism for system security and reliability services', Delta Electricity
[26] 'Synchronous Services Market', Hydro Tasmania
[27] For further information, refer to the AEMC website: https://www.aemc.gov.au/rule-changes/capacity-commitment-mechanism-system-security-and-reliability-services

FIGURE 6 DEVELOPMENT OF ESSENTIAL SYSTEM SERVICES



5 DEMAND SIDE PARTICIPATION

Key points

- How demand side participation is treated and valued across the Post-2025 program requires holistic consideration. This section sets out our considerations (across the program) about how participants can get value for their flexible demand, both efficiently and effectively.
- **Reducing cost and variability**: Energy costs should be minimised for all customers – both household and business – while allowing demand to be efficiently met. This is particularly true for customers experiencing hardship.
  - Over the past decade, many customers have sought to reduce their energy costs, and support renewable energy, by installing small scale solar PV at their household or business. The growth in these intermittent sources of supply is both decreasing wholesale market demand for energy and making that demand more variable. The costs of managing the increased variability become significant as the proportion of small-scale solar PV penetration increases. AEMO and distribution networks have had to intervene in the market to maintain system stability and such interventions increase costs for all customers. These changes have occurred faster than market and regulatory frameworks have been able to keep up and backstop measures have been put in place to meet current needs.
  - As we move towards a system of millions of distributed resources, the ESB is considering changes that are needed to improve system efficiency and lower costs. An increase in the visibility of resources to support efficient forecasting and scheduling is required, as well as measures to address network stability. It is also important to enable customers to optimise the value from their DER assets and flexible demand, particularly at times when the energy system most values this flexibility.
- **Participation and choice**: Under the current rules it is difficult for small consumers to access the range of markets for delivery of energy or system services that could reward them for shifting their demand, or changing the shape of the load over the course of a day or several days. For example, it is difficult for small consumers who own batteries to be rewarded for offering supply at different times. This would not only benefit the owner of the battery but can also help to reduce energy costs on the system at peak times, which would lower costs to consumers more generally.
  - Market arrangements, along with those for metering and connection, do not support consumer preferences to access the products and services that could be offered (and which consumers may want from the providers they choose) and can also be complex for consumers to navigate. Today, people can contract with one retailer only, and not with other intermediaries (such as aggregators) in the energy market. Furthermore, retailers are limited in what they are permitted to offer to customers.
  - While supportive of the concept of a two-sided market, many stakeholders agreed further work is needed to understand the barriers to participation, to reduce complexity and develop a clearer understanding of the potential value and flexibility of flexible demand. The ESB is progressing work to reduce barriers to participation in the market, so consumer benefits can be unlocked without the need for consumers to engage in the market more than they do currently. The ESB and market bodies have been carrying out research on this and are also working with ARENA to commission studies to better understand the potential for flexible demand under a range of scenarios and conditions.

- **Improving access**: New and innovative energy products and services may be difficult to access for disengaged and low-income consumers. With the continued rapid deployment of rooftop solar, and the expected growth of electric vehicles, finding ways to unlock the value of these resources to deliver value to all customers will be important. The ESB is considering new ways for customers and communities to access the benefits of rooftop solar and other DER directly. As part of this we need to consider ways for managing the risks and costs of congestion at times of oversupply from embedded small scale (solar PV) generation.
- **Addressing uncertainty**: Current and future markets and policy settings, and how people are motivated to respond to incentives, is uncertain. As an industry, the rate of DER uptake has been consistently underestimated, as has the speed of related changes that have impacted the networks and markets. With the system now seeing widespread uptake of variable renewable energy, and associated network investment, greater certainty regarding the path forward is increasingly important. This is required to reduce inefficient and uncoordinated investment, and increased costs and risks for customers. Setting a clear pathway for future changes to market design, and the accompanying roles and responsibilities to support an effective future two-sided market, is an important outcome of the Post-2025 program.
- **Consumer protections**: Customer groups have had an active interest in the development of proposals for a two-sided market. While supportive of the overall direction, customer advocates are keen to work with ESB and the market bodies to develop a customer protections framework that is more fit for purpose. This recognises the emerging range of new service providers and business models to provide different offerings to customers, and that new or evolved protections may be extended to these services or business models where needed. The ESB will work with customer groups to develop a risk-based approach to the future framework for customer protections, focused on identifying and prioritising areas of greatest need and potential harm.

5.1 Stakeholder feedback

5.1.1 The case for a two-sided market

Stakeholders provided feedback in response to questions asked in the September Consultation and on related matters. Insights have also been gathered via the DER Integration engagement processes.[28]

While a majority of stakeholders welcomed a move to a more fully developed two-sided market, some questioned whether the case had really been made. Some stakeholders were concerned about the pace of reform and suggested that current initiatives (such as the wholesale demand response mechanism) should be implemented and evaluated before moving to additional measures.

Stakeholders suggested the ESB carry out a more detailed assessment of the benefits and analyse the potential for the demand side to actively participate. This was linked to concerns about the feasibility of a large numbers of consumers engaging in a two-sided market. The barriers may be difficult and costly to address – these include the lack of cost-reflective price signals for small retail customers and perceived low levels of consumer engagement,

[28] Insights were gathered from those involved in processes such as OPEN and the WA DER Roadmap plus a range of local and international examples. The unique co-design program that was run in September and October 2020 brought together more than 70 stakeholders from across Consumer groups, Technology providers, Retailers, Networks, Market Bodies and Agencies provided a vehicle to understand the varying barriers and opportunities in the market.

understanding and trust. Some stakeholders are concerned that the move to a two-sided market may not deliver equitable outcomes, suggesting the majority of benefits would be delivered to those customers who could afford to invest in rooftop solar, and DER more generally, partially at the expense of other customers.

5.1.2 Removing barriers to participation

There was overall support for the ESB's approach to the participation reforms that try to make it easier for customers to enter the market and obtain value from their demand flexibility. The main themes were positive, although stakeholders are keen to understand and have visibility of the detail of any changes.

Many stakeholders supported changes to the participation framework to enable more types of service providers to have direct engagement with end-users (including large and small customers and generators) and offer innovative demand flexibility services (Enel X, ARENA, AEC, Bright Sparks, Alinta Energy, Austela, Bluescope, ERM Power, Flow Power, Infigen, Origin Energy, Stanwell, Tesla). Ausgrid also noted that participation reforms should also unlock value from community resources, echoing support from consumer groups for community-based energy trading and storage.

Stakeholders noted that DER can play an important role in broad market participation over time (AGL) by shifting passive DER into active DER.[29] Connection and market access were identified as key barriers to this shift (CEC, EEC).

Some stakeholders noted that participation requirements should be adjusted to accommodate the different capabilities of new technology. Others commented that any changes should be underpinned by a technology-neutral approach when traders are delivering like-for-like services.

However, some stakeholders expressed caution. Themes included:

- Existing barriers to greater market participation from end consumers should be addressed first, including a lack of cost-reflective price signals for small consumers, complexity, cost and consumer apathy (Grattan Institute).
- There should be more emphasis on removing barriers to existing retailers offering more innovative products (barriers to retailers were taken to include a lack of consumer understanding, trust, willingness to engage, retail price caps and availability of enabling technologies).
- New services being provided via third party aggregators will increase complexity for the customer and this may be a significant barrier.

With regards to implementation of the participation reforms, there was general support for a process that systematically removes barriers and reduces risks to consumers. Many stakeholders stressed that the removal of barriers that prevent aggregators from offering new services to small consumers is a priority in this process. Stakeholders noted that the DER Integration and Two-Sided Markets workstreams should work closely to remove barriers to aggregators providing services to customers. Retailers generally highlighted the need for voluntary participation as a first step and would not support moving to mandatory participation.

[29] Passive DER refers to where resources such as solar PV are exporting excess energy to the grid without any moderation to output in response to price signals. Active DER is where these resources have their output moderated up or down in response to whether the market is signalling a need for more energy via market prices.

5.1.3 Dispatch and scheduling

Many stakeholders agreed with the principle of increased participation in central wholesale market dispatch and the removal of barriers. However, there was divergence about the importance, urgency and method for achieving this.

For example, the AEC, CEC and EUAA had different long-term visions for how dispatch frameworks could evolve. The CEC proposed a long-term vision where all demand and supply-side participants are scheduled under similar obligations. However, the AEC and EUAA disagreed, stressing that any approach to scheduling load needs to be flexible and focus on resolving actual market barriers, which are impeding increased demand response.

Consumer groups noted that scheduling arrangements for small consumers should not be identical to those for generators. The Aluminium Council also proposed that any new dispatch arrangements be voluntary.

Gentailers were cautious about the changes to the proposed scheduling and dispatch frameworks. EnergyAustralia noted the importance of the magnitude of price-responsive demand on operational forecasting, requesting the ESB estimate the size of these impacts and should identify what level of price responsiveness becomes unmanageable. AGL stressed that customer preferences are a key barrier to demand-side participation in central dispatch, suggesting it should be considered closely in the development of any new arrangements.

Other generators were supportive of changes to the dispatch and scheduling framework which would increase the visibility of demand resources in the wholesale market. Stanwell explicitly supported reviewing and removing scheduling and dispatch barriers and considering incentives to put demand resources on equal footing with generators. However, Stanwell did not support the long-term vision for the full participation of load in the scheduling and dispatch framework. Snowy Hydro stressed the need for any new central dispatch frameworks that included demand resources to penalise non-conformance to encourage efficient reliability outcomes.

Enel X and Flow Power provided conditional, in-principle support for the ‘scheduling-lite’ concept raised in the consultation paper[30]. However, they stressed they require more information about these arrangements before progressing and its development will likely be iterative.

Some stakeholders had concerns about what a future scheduling and dispatch policy would look like, with Enel X raising concerns about the possibility that it would require load to be scheduled, in order to access the spot price. Similarly, consumer advocate, Energetic Communities, raised concerns that a future policy would require small consumers to be scheduled, as opposed to the obligations being placed on the third parties who would be coordinating participation in the spot market on behalf of small customers.

5.1.4 Improving access

Most NSPs are supportive of a two-sided market but are generally opposed to integrating the two-sided and DER workstreams due to the limited solar PV (and other forms of DER) capable of active management.

The move from passive to active solar is a key focus of the DER Integration workstream. AusNet Services suggested it would be useful to quantify the current level of elasticity of demand for household energy to enable the benefits of more active DER to be modelled, but Ausnet also notes equity considerations may dampen customers’ exposure to true network costs.

While some NSPs (including SA Power Networks (SAPN) and AusGrid) considered customers are responding to tariff reform price signals, many raised the potential for network tariffs to distort demand response price signals. For example, non-cost reflective network tariffs may discourage

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[30] http://www.coagenergycouncil.gov.au/publications/post-2025-market-design-consultation-paper-%E2%80%93-september-2020

consumers from load shifting, even if they have price signals from the wholesale market encouraging them to do so.

Other NSPs considered that network tariffs should not unnecessarily hinder wholesale energy market outcomes, however, network tariffs should not be used to signal wholesale market issues (instead they should reflect network costs). This is because wholesale market spot price signals are generally more volatile and driven by different external factors. As a result, there will be times when these wholesale spot price signals do not align with network price signals.

CitiPower considered the regulatory framework needs to address cross-subsidies (such as inefficient feed-in tariffs, restriction on export tariffs and a lack of cost reflectivity in micro-generation connection charges) which distort network service providers ability to provide cost-reflective tariffs.

Some network service providers and DER technology companies are interested in establishing arrangements to support customers to offer in and receive value for their demand flexibility, not only in terms of responding to high prices but also to enable them to better plan and coordinate their operations when bidding in demand flexibility from load or storage. For example, Ausgrid supported the ESB approach of creating regulatory frameworks that unlock value from community resources; stating its work investigating community batteries is a potential case study for ESB consideration. The ENA noted ring-fencing arrangements limit NSPs from utilising battery solutions to offer additional services, beyond use for network services. They noted the importance of the ringfencing guideline and upcoming review to consider the ability of distribution NSPs (DNSPs) to provide such services. It also notes the importance of visibility at the Low Voltage (LV) network level to identify and communicate export constraints.

5.1.5 Roles and responsibilities

Need for greater clarity

Stakeholders agreed that a more dynamic demand-side involves a range of new functions to ensure reliable, efficient, and equitable outcomes. Stakeholders generally agreed that there is a need for greater clarity about future roles and responsibilities and that the traditional change mechanisms for the sector are not working.

Process for managing change

Stakeholders expressed a preference for an inclusive, objective and time-efficient process for determining future roles and responsibilities. This should involve an appropriate sense of urgency while avoiding sweeping ‘big bang’ changes that presume precise knowledge about the emerging future. Some consumer groups also noted the need to consider the consumers’ perspective when designing future roles and responsibilities.

Relationship to existing initiatives

Multiple stakeholders emphasised the need for any process aimed at evolving roles and responsibilities to fully comprehend existing initiatives that are either directly related or immediately adjacent. Some placed very significant emphasis on the need, for example, to ensure future roles and responsibilities include a clear rationale of how they relate to cost-reflective network tariff reform already underway. Others raised issues about the interrelation between technical standards versus more market-based approaches and their associated trade-offs. Clearer direction was sought on how these trade-offs may be managed going forward, and how that may impact long term customer value.

Terminology

Many stakeholders found the market design and technology architecture very complex, particularly around the issue of future roles and responsibilities. The lack of a shared set of technical and architecture models, and no common terminology to navigate future options, emerged as a challenge.

Some stakeholders expressed concerns around the likely costs and that steps should be taken to minimise costs to consumers where a benefit may be intangible (ECA).

5.1.6 Customer protections

The need for a fit-for-purpose protection for consumers was noted by a wide range of stakeholders. All agreed with the ESB that the development of a strong consumer protections framework is vital. Consumer protections were a key theme in consumer advocate submissions, and a phased approach to participation was supported to assess and deliver consumer protections during the transition. This was also raised by Energy Queensland, AGL and SAPN.

The ECA's submission listed seven specific actions required from the Post-2025 work, including that the ESB and market bodies work with the ECA and consumer groups to embed the values and expectations of consumers in the detail of the market design initiatives.

Market participants such as Alinta Energy, CS Energy, EnergyAustralia, Engie, Flow Power, Intelligent Automation, Rheem, Snowy and Stanwell all noted the importance of consumer protections being fit for purpose. More generally, retailers were concerned that new services provided via third party aggregators would increase complexity for the customer. They suggested this could be a significant barrier to participation and, as a result, there should be more emphasis on removing barriers for existing retailers so they are able to offer more innovative products. Retailers noted that these barriers include:

- A lack of consumer understanding, trust, and willingness to engage
- Retail price caps, and
- The availability of enabling technologies.

Of the limited number of stakeholders who did not support the move to a two-sided market, the main concern raised was that the two-sided market was too complex (including responses from Snowy Hydro and Dr M Gill) and that it would result in more complexity for consumers (Energy Queensland).

5.2 Summary of issues

The current NEM manages supply offers at dispatch to meet forecast demand. The wholesale market at present does not dispatch the majority of demand at its willingness to pay. This means consumers are not able to realise the value of their flexible demand. Supply from small units (for example household solar PV) all contribute to meeting supply, but it is not dispatched or managed in the same way as large generating units. The growing uptake of DER[31] means it is increasingly important to improve how the NEM integrates both supply and demand resources. Stakeholder feedback highlighted a number of challenges in making the shift to a two-sided market. These challenges are described in some detail in the summary box at the start of this chapter, but in summary include:

[31] https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en

- Reducing cost and variability
- Participation and choice
- Improving access
- Addressing uncertainty
- Consumer protections.

The ESB intends to progressively introduce reforms and controls which support a move to a two-sided market that addresses these challenges and unlocks value for all customers. While a two-sided market already exists for some large customers, a range of technical and process specifications limit the potential for many large loads to bid directly into the wholesale market, and smaller customers are further restricted from participating at all under the current framework. Our intention is to continue to work together with customer groups and industry stakeholders to develop these reforms, with a focus on improving outcomes for all customers.

5.3 Current situation and next steps

A range of factors are combining to create challenges in the system at the moment, with the impact of falling demand creating particular challenges in some states already. Poor visibility of all resources on the system for scheduling and dispatch is also leading to inefficiencies in forecasting, and overall increased costs to customers. Together with barriers in the current arrangements, that make it hard for new parties with innovative technologies and business offerings to enter the market, overall outcomes for customers need to improve.

This section sets out work underway to better understand and address these issues.

Reducing Cost and Variability

Energy affordability is an important consideration in developing the future market design. Many customers have sought to reduce their energy costs by installing solar PV at their household or business. However, the absence of market signals to incentivise efficient investment in and use of these decentralised resources has created other costs in operating the system, increasing energy prices for consumers overall. We need arrangements that encourage and support resources to more efficiently to deliver the greatest benefits to all customers – for example, encouraging flexible demand or DER to flex at times when these are appropriately valued by the wholesale market.

Changes are needed to address some of the key issues driving up cost and risk in the system - minimum demand appearing in the system is one example. While the effects of widespread solar PV are being felt in some specific jurisdictions at present, emerging trends across the NEM suggest there is value in a clear and coordinated national approach to mitigate these outcomes for customers.

Some areas of increased costs associated with the participation of flexible demand emanate from a lack of operational visibility of DER assets which reduces the efficiency of economic scheduling. Similarly, the continued connection of DER assets with no capability to support moderation of output, such as passive solar PV and unmanaged electric vehicle charging, is also increasing future costs of system operation for all non-DER users. Moreover, increasing the effective utilisation and harnessing the flexibility of DER assets, will unlock value and reduce costs for all consumers.

5.3.1 Falling system minimum demand

Current situation

Work is underway across the market bodies and state governments to mitigate the security risks associated with falling minimum demand, including updates to standards, power system studies, changes to operational processes and systems.[32] In South Australia, there has already been a pragmatic response with compliance and consumer incentives implemented quickly to arrest the onset of minimum demand.[33] For the longer term across the NEM, there is value in developing enduring solutions for managing minimum demand that can be implemented in a nationally consistent framework.

There is a strong rationale to address the root cause of the problem, redirecting the trend of passive, non-price responsive solar PV exports towards price-responsive load and the uptake of active solar PV by rewarding the efficient use of PV assets. If this root cause is not addressed then the use of backstop measures is likely to become prevalent, and in turn, could cause them to become less efficient.

Outlook for minimum operational demand

Minimum operational demand is forecast to decline rapidly as the strong uptake of PV is projected to continue. The scenario being tracked at present is close to AEMO's Step Change scenario that shows negative operational demand in both South Australia and Victoria by mid-decade.

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[32] https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/standards-and-connections

[33] https://www.sapowernetworks.com.au/data/308586/installing-generation-after-28-september-2020-/

FIGURE 7 OUTLOOK FOR MINIMUM OPERATIONAL DEMAND

Source: AEMO, ESOO 2020

While minimum operational demands are falling across the NEM, South Australia is already experiencing very low operational demand levels. Around 330MW of distributed PV was installed in South Australia in the last financial year which contributed to a new record low minimum demand of 300MW in Spring 2020.

Victoria is expected to experience the largest annual falls in minimum operational demand as the installation of distributed PV increases through the Solar Homes program.[34,35] AEMO is also reporting increasing risks associated with minimum operational demand emerging in Queensland.[36]

Falling minimum demand levels, if not effectively managed, will lead to issues with managing voltage, system strength, and inertia. This will drive up costs and risk through increases in directions by AEMO and interventions in economic dispatch, and additional provision of services for system restart, increased ramping capacity, voltage management and system strength and inertia services.

Lack of response to price signals

Although there are several drivers of negative prices in the real time energy market, the occurrence of low operational demands largely coincides with frequent low prices in the middle of the day. As observed in South Australia, the incidence of negative prices is increasing as operational demands fall, with record instances of negative prices in South Australia and Queensland in Spring 2020.[37] However, many resources are not responding to these low-price signals.

Stakeholder feedback suggests the following factors may contribute to the current lack of response to price signals:

- Lack of market mechanisms – for example in wholesale demand response to market prices – to support a change in demand or the shifting of load, alongside complexity barriers for loads to enrol in such programs.

[34] More information on Victoria's Solar homes program is at https://www.solar.vic.gov.au/

[35] The central scenario presented in the 2020 ESOO projects a fall in minimum operational demand in Victoria from 2,745 MW in 2020-21 to 1,145 MW in 2024-25 with distributed PV capacity uptake of 2.3 GW over the same period.

[36] 2020 Electricity Statement of Opportunities, AEMO

[37] AEMO Quarterly Energy Dynamics Q3 2020

- Market floor price may not be low enough to incentivise loads to increase or load shift, where customers are able to do so.[38]
- Existing power purchase agreement (PPA) contracts in the market reward solar operators simply for supply at any price, making them not price responsive at all.
- A vast majority of existing rooftop solar PV inverters are not capable of being price responsive, and require equipment upgrades or replacement to be able to respond to wholesale price signals.
- There is a lag for the price signal to have an effect. Existing equipment, operational processes, contracts, and market awareness is slow in response to the opportunity cost.

Feed in tariffs and active solar PV

The NEM now hosts upwards of 10 GW[39] of small-scale solar PV. The majority of this is being incentivised through Feed-In Tariffs, a payment from retailers to consumers who export their surplus solar PV energy.[40] AEMO's modelling shows that the growing fleet of PV resources is the root cause of falling minimum demand in the system, driving the need for backstop measures that can bring more load on to balance the system or alternatively cease feed-in supply from solar PV where this is possible.

Feed-In Tariffs were initially created by state governments to increase the uptake of solar, and have been extremely successful in delivering that goal. Some first movers continue to receive more than 60c/kWh for export.[41] The policy sought to provide consumers with revenue certainty in order to grow the market, when the cost of installing solar PV was relatively more expensive, and the volume of solar PV exports was not at a sufficient level to affect the stability of the grid.

Today, Feed-In Tariffs are unregulated in most jurisdictions (except Victoria), and are generally shifting to better reflect the underlying average wholesale market price, albeit some retailers are using higher Feed-In Tariffs as an acquisition tool. Regardless of the price, consumers are favourable to the structure of feed-in-tariffs, as they offer clarity and certainty for the customer's investment, and a relatively simple method of comparison between retail offers.

The challenge is to find pathways by which the solar PV systems can become responsive to the wholesale price, yet offer simple and certain consumer price signals at the discretion of the retailer or aggregator to compete for customers on. This is particularly relevant for periods of negative prices, where more load is required on the system, if solar PV owners continue to export at times of negative prices. Instead of focusing on ways and means of changing the solar feed in tariffs, there may be more value in focusing on the methods that retailers and aggregators can use to enable price responsive, active PV systems in their portfolios.

The ESB will consider approaches to shifting towards active PV, noting that this shift has other system benefits. It allows higher export levels during off-peak times, and can help dynamic limits during congestion periods to maintain the network within safe operating limits. The ESB will evaluate options for NEM wide approaches that will:

- Accelerate the switch from passive to active solar PV technologies, and
- Recruit flexible loads into schemes that will add more headroom to regions that are worst affected. These options are discussed below.

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[38] Note that the setting of the market floor takes many things into account, aside from load shifting.
[39] CSIRO, 'Projections for small-scale embedded technologies
[40] Feed-In Tariffs are minimum payments per KWh of exported solar PV energy.
[41] https://www.energy.vic.gov.au/renewable-energy/victorian-feed-in-tariff/premium-feed-in-tariff/maintaining-eligibility-for-the-premium-feed-in-tariff

Directions and next steps

Directions for active solar PV

There are several approaches being considered to accelerate the shift from passive to active solar PV. Such approaches could reduce the volume and frequency of emergency backstop measures (and associated costs) that would otherwise be needed to meet the minimum demand challenges.

Modelling will be undertaken to compare the various measures, and look at trade-offs between costs and risks, with the analysis presented in March 2021. This would consider the following scenarios:

1. Do nothing: what will be the likely cost of backstop measures without any further intervention from governments or market bodies, which can act as a baseline for other measures.
2. Introducing compliance mandates on new PV installations. Consider the impacts of measures (such as those in South Australia) coordinated at a national level but implemented by states, which will mitigate minimum demand issues becoming worse and accelerate the opportunity for networks to support a framework for dynamic export limits during midday congestion. Modelling would need to consider the rate at which compliance would come into force, and the costs of additional backstop measures needed in the meantime.
3. In addition to compliance mandates on new installations, additional incentives for upgrading existing PV inverters offered in the form of market signals, or off-market incentives. Modelling would need to consider uptake of new schemes, and additional backstop measures needed.

Given the immediacy of this issue, the ESB will begin work with all states (including WA) on specific approaches early in 2021, with the objective of harmonising compliance approaches nationally where sensible to streamline costs and processes nationwide.

Directions on market-based approaches

Several of the initiatives discussed in this chapter will work to enhance the responsiveness of DER to price signals. These new market mechanisms could deliver improved price signals to flexible demand resources to respond to minimum demand events. In addition to the market mechanisms outlined in other sections of this paper, the ESB intends to further consider the following options:

- Inclusion of "turn-up" loads or load shifts in the Wholesale Demand Response Mechanism, which will allow customers without direct exposure to wholesale pricing to participate during low to negative price events.
- Establishment of an emergency reserve, similar to RERT, that incentivises off-market resources to become price responsive to negative prices.

To better understand the potential efficacy of these services, further work will be undertaken to evaluate how much capacity will likely participate at various price points, and likely timeliness for bringing such capacity online.

Nationally consistent emergency backstop approach

An effective nationally consistent framework for an emergency backstop arrangement should be pursued to manage system security issues associated with minimum demand conditions, reducing the risk of uncoordinated mandates or arrangements that sit outside of the market rules, including potential roles for NSPs, retailers or Metering Coordinators.

Any emergency backstop needs to be compatible with market-based arrangements which enable end users to participate in the wholesale market and directly respond to price, and in doing so mitigate minimum demand conditions.

The ESB will undertake work with industry and government stakeholders over 2021 to develop potential arrangements to facilitate a nationally consistent approach.

5.3.2 Participation in scheduling and dispatch

Current situation

A second driver of increased cost and risk to the system is the lack of forward visibility in overall system behaviour. To increase the amount of price responsive flexible supply and demand (including from DER) participating in market scheduling and dispatch processes, changes are required to remove barriers and provide incentives for traders to participate.

This would not impose scheduling requirements on end users themselves. It is intended that 'traders' (service providers), acting on behalf of end users, would be incentivised to participate, either through passive aggregation of their customers' load profiles, or through a more active approach where traders provide products to their customers that incentivise customers to commit to more predictable energy use.

An active approach would need to recognise the differences between smaller consumers and generators in their ability to commit to different types of energy use. Increasing participation of active resources and behaviours in-market will deliver benefits:

- To end users (where changes in demand reflect real willingness to pay or supply)
- To the system (enhanced visibility, efficient resource coordination, reduced interventions), and
- To overall market efficiency through the economic dispatch of active, flexible supply and demand.

Table 4 below highlights a range of existing market, regulatory and technical barriers preventing more active participation.

TABLE 4 BARRIERS TO THE INTEGRATION OF ACTIVE, PRICE RESPONSIVE BEHAVIOURS AND DER

Market barriers	Technical and regulatory barriers
• End users' level of market engagement (opportunity, ability, motivation) • Ability to engage and directly access and respond to market conditions and participate in dispatch (i.e. >5 min) • Existing arrangements accommodating non-scheduled resources • Minimum capability and operational overhead to interface with market systems • Costs for compliance and penalties for deviations	• Capacity to participate (AGC/SCADA/communications/smart metering) • Minimum integer bidding thresholds • Forecasting capability • Framework for consumer protections for electricity as an essential service • Network access and pricing arrangements • Regulatory and procedural uncertainty in current and future DER participation models

Opportunities to encourage greater participation in 'scheduled load' classification

The existing framework provides for load being classified as 'scheduled load' to participate in central dispatch. While a number of bi-directional connection points do participate like this, this framework is designed for large consumers, not residential or small businesses. There are limited incentives for more load to participate in this way, and there are a range of technical and compliance requirements that apply. In light of this, the ESB is considering increasing opportunities more controllable and predictable end user loads to participate in this manner.

Directions and next steps

Concept design of a 'scheduled lite' dispatch arrangement

Recognising the barriers for demand side participation in central dispatch, the ESB is exploring alternative scheduling and dispatch arrangements ('scheduled lite'). A scheduled lite model would seek to improve information provision from currently non-scheduled, price responsive behaviours which currently occur out of the market. Expected use cases may be service providers (i.e. VPP operators), traders who aggregate across multiple connection points, or providers of demand response.

Options for alternative scheduling and dispatch arrangements are being explored through the AEMC's generator connections rule change (currently out for consultation).[42]

Incentives for demand and DER to take part in scheduling

The ESB is continuing to investigate the use of incentives that could encourage price-responsive flexible sources of supply and demand to take part in scheduling and dispatch processes.

Arrangements to lock in a financial position and trade energy ahead of time, such as a voluntary energy ahead market, may encourage flexible demand currently hindered by the requirement to operate using real-time price signals. This could facilitate greater scheduling of flexible demand or aggregated DER resources for participation in a range of markets.

Opportunities to unlock the value of flexible demand resources, such as storage, may also be realised through existing or new resource adequacy mechanisms or through provision and co-optimisation of new essential systems services (such as operating reserves). With high forecasts penetrations of flexible demand and DER, linking capacity and participation of these resources from the investment timeframe through to real time can improve market efficiency.

The ESB considers that, while it is appropriate to keep the scheduling and central dispatch framework voluntary, the transition to a more active two-sided market should continue to be monitored. This is to understand the ongoing price-responsive supply and demand occurring in a non-visible way to the market and system operator, and whether additional disincentives may be needed for resources or traders above certain thresholds or scales to ensure the system is operated in an efficient and secure manner.

[42] See here for more info: https://www.aemc.gov.au/rule-changes/improving-connection-process-embedded-generators

Participation and Choice

To support a broader range of service providers and technologies entering the market, we need to remove barriers that make it difficult for them to participate in markets. Such barriers limit opportunities for innovative new business models that can support consumers to unlock the value of their DER assets or demand flexibility. Where energy storage (for example via batteries) can be used to shift timing of when supply is consumed or delivered to the grid, such resources can be used to reduce energy needs on the system at peak times, which would lower costs to consumers. The ESB is keen to support consumers having access to competitive products from a range of service providers to help them unlock this value.

Making it easier for parties (such as aggregators or battery service providers) to enter the market will increase opportunities for parties to offer new services to customers, and for customers to choose products and services that meet their diverse needs. We expect these offerings will evolve over time in response to customer choices and behaviours. What we need to do first is to create an environment where parties can enter and offer services, which customers may take up from the providers they choose. Appropriate protections will need to be in place for customers that take up these offers and products.

As part of removing barriers to participate, we also need to better understand what customers may need to support their increased participation in the market. Some customers may have limitations on their flexibility due barriers such as production processes, but others may be able to take advantage of greater digitalisation to increase their potential flexibility. For smaller residential customers, complexity can be a barrier, as well as the ability to opt out of restrictions on their energy use in order to be confident about taking on an energy product or contract that requires any active behaviour changes or constraints on their autonomy. Where barriers can be removed this can increase the potential flexible demand that could then participate in a range of energy or emerging essential system service markets. Specific barriers and steps being taken to address these are discussed below.

5.3.3 Removing barriers to participation

Current situation

There are growing numbers of new business models and new technologies in the NEM, including large and small-scale energy storage systems, aggregated response and virtual power plants. In response, AEMO's NEM registration categories have grown incrementally, with new categories added to the market rules. This generally adds complexity for market participants and new entrants. There is also increasing overlap of formerly distinct categories (e.g. Market Customers representing 'load' connection points can be net exporters of energy in some intervals due to solar and other DER uptake).

An increasing number of regulatory workarounds and frequent rule changes have been used to accommodate these developments. This "band-aid" approach is inefficient and may distort incentives to participate efficiently in the market. Additionally, the NEM arrangements, particularly for wholesale market participation, use 'asset focused' regulation, i.e. participant categories (and the associated regulatory obligations) are based on the assets present at the connection point, as opposed to the services bought or sold. This approach becomes more complex as the number of services and service providers increase and new asset combinations emerge (e.g. hybrid facilities with load, generation and storage).

There are several existing barriers to greater market participation from the demand side and by newer, smaller participants, e.g. those with new technologies. These include cost and complexity of market entry and participation in bidding, which is particularly burdensome to smaller participants. This is due to high fixed operational and financial costs, minimum thresholds and integer-based requirements for bidding and participation, bespoke or manual arrangements for some services; and low access to information on how newer technologies and participation models can operate within markets.

The ESB is developing solutions to address these barriers, and these are discussed below.

Directions and next steps

The 'trader-services model'

The ESB is considering changes to simplify the wholesale market participation framework – the "trader-services model" would:

- Simplify existing AEMO registration process in the NEM by accommodating existing categories in a single "trader" category. This would be one universal registration category covering all commercial parties participating in the NEM (e.g. retailers, aggregators, generators, scheduled loads, ancillary service providers). Technical and capability-based specifications would differ based on the services the trader has elected to provide.
- Provide for greater regulatory flexibility that supports innovation by attaching obligations to services at connection points as opposed to attaching them to registration categories and assets.
- Enabling new participation models that allow end users to obtain services from more than one trader at a site. For example, an end user such as a residential customer may have a contract with a trader providing standard retail services for their uncontrolled load, and a separate arrangement with another trader that trades their DER output or controlled load and sells services on their behalf in the wholesale market.

The key entities and elements in the trader-services model are set out in the earlier Two-sided market consultation paper.[43]

How would aggregators participate as traders?

As participation frameworks evolve, aggregators would continue to be able to register as traders and would be able to provide any service on an aggregated basis (i.e., aggregating energy flows/services from multiple connection points on behalf of end users), where they can meet service specifications set for that service.

Principles regarding the way in which traders aggregating multiple connection points, including those with DER, participate in the market are described below.

TEXT BOX 6 PRINCIPLES FOR AGGREGATOR PARTICIPATION UNDER THE TRADER-SERVICES MODEL

- End user access to markets and competitive service providers:
  - An end user (consumer or aggregator) may enter into a contract with one or more traders, including aggregators, for premises, and may switch between traders as desired (subject to the terms of the relevant contracts).
  - One trader (aggregator) should not be able to prevent other traders (aggregators) contracting with an end user to offer other services to the wholesale market or other energy markets.
  - Technical standards should not impose unreasonable requirements that act as barriers to participation in the services traded in the wholesale market.

[43] https://prod-energycouncil.energy.slicedtech.com.au/sites/prod.energycouncil/files/Two-sided%20markets%20-%20ESB%20COAG%20Paper-%20Consultation.pdf

- Contracts between end users and aggregators will be subject to appropriate consumer protections, which would be comprised of general (e.g., Australian Consumer Law) and energy-specific (e.g., in relation to the sale of energy for residential consumption).

- Having registered as a trader and entered into contracts with end users, an aggregator obtains access to the system, and the relevant energy market, via a connection point. Obligations on the aggregator are service-based, not asset based.

- An aggregator may aggregate services from any number of end users located across an area where the same price is payable for that service (currently, a region; later this may be further limited if locational marginal pricing is introduced), subject to any requirements from AEMO in relation to system security.

- Rules relating to access to markets will be based on system and market needs, and access rights and obligations should be equivalent as between aggregators and other types of traders (e.g., in relation to scheduling and metering). Except to the extent necessary to recognise technical differences, there are no special categories or special rules. In the interests of efficiency and lowering costs for end users, the aim is to achieve a level playing field for all types of traders.

- An end user's arrangements with traders should allow the end user to receive payment reflecting the value the end user's activity or response provides across the relevant markets, to incentivise provision of an efficient amount of that service. However, to limit the total costs of energy system services, and thereby contain costs borne by all end users, a payment should avoid double counting an activity or response.

- Aggregators, and other traders, should face network costs and non-energy costs that are proportional to the costs caused by their use of the system in respect of the relevant services, and which allow for efficient recovery of fixed costs.

How do we get there?

Moving to the trader-services model is a relatively large change for energy sector participants and will not be done all at once. The implementation of the model requires careful sequencing with new service-based rules being phased in and co-existing with the current arrangements. This phasing approach would be informed by necessary changes to systems and processes and consideration of how to best minimise the direct costs for participants in order to avoid affordability impacts for customers. A first step on the path to a trader-services model is being investigated through the Integrating Storage Systems in to the NEM (Integrating Storage) rule change process. Through this rule change, the AEMC is seeking feedback on various options to reform the registration categories so that they better accommodate storage and new business models as set out in the AEMC's consultation paper.[44]

Another aspect being considered as part of the participation framework is to provide end users flexibility so they can choose what offering to take up at their house or business. For example, customers may wish to engage multiple service providers ('traders') to take advantage of specialised service offerings for certain types of energy use or for exporting energy to the grid.

The ESB is investigating new participation models that provide opportunities for traders to engage consumers with flexible demand, and value the contribution of services provided by all end users. It is intended that the models developed will support customer choice, evolve over

[44] https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem

time in response to the needs of the market and be underpinned by fit-for-purpose consumer protections.

Flexible trading models

Initially, the ESB is considering two new participation models, termed “flexible trading models”:

- The first model involves evolving the Small Generation Aggregator framework to explicitly enable the classification of storage units, (for example battery storage, electric vehicles) and allowing participation in the provision of ancillary services. This model would also support the ability to have enabled different end users for each connection point (for example a landlord and tenant, or long-term lease arrangement for provision of generation plus storage, etc.).[45]
- The ESB is also considering a further extension of the Small Generation Aggregator framework to allow additional traders to provide services from a single site by establishing a connection point within the boundaries of an end user’s electrical installation (i.e., behind the existing meter). Technical requirements and additional safeguards could be set out in subordinate procedures. This flexible trading model requires further design work and stakeholder engagement. For both models, the aim would be to introduce participation options which benefit end users but avoid end users needing to engage with any retailers, DNSPs or other parties who did not want to opt into this arrangement for their customers.

Further changes are expected to be required to implement the trader-services model. This may include the ESB considering the Multiple Trading Relationship reforms, or elements of, previously considered by the AEMC.[46]

How can the costs and benefits of new participation models be assessed?

To identify barriers for these and other models, the ESB sought advice from Energeia on the costs of establishing a second connection point. Energeia investigated the barriers and opportunities to improve network service provider connection processes, with a specific focus on the costs and barriers involved for households and larger users obtaining a second connection point. This work is detailed in an accompanying paper that can be found on the ESB website.

Key barriers identified include distribution network connection policies, timeliness and potential for delay, and network tariffs for second connection points. Energeia recommended that addressing these issues would provide a clearer path for customers to undertake the works required to engage with multiple financially responsible market participants and achieve a two-sided market.

The ESB is developing an indicative cost benefit analysis method to assess new participation models on the path to a full two-sided market trader model. This includes an assessment of the costs and benefits of introducing new participation models at the consumer level and system wide. The ESB intends for this analysis to be applied initially to the flexible trading models outlined above and presented to stakeholders in March 2021.

5.3.4 Understanding the size and characteristics of the demand side

Current situation

The ESB agrees that it is a priority to gain a deeper understanding of how flexible demand might participate in delivery of a range of services and markets. To build this understanding, a number

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[45] This flexible trading model is currently being considered through the Integrating Energy Storage Systems into the NEM rule change.

[46] https://www.aemc.gov.au/rule-changes/multiple-trading-relationships

of activities are underway across the Post-2025 program. Unlocking this potential flexibility will require a range of economic and practical barriers to be addressed.

Current challenges and opportunities for demand-side participation

For a vast majority of unscheduled loads today, it is inherently challenging to accurately understand the size and price thresholds should they wish to bid into the spot market. AEMC has commissioned work from Energy Synapse to build further understanding about the availability and key features of current forms of flexible demand in the NEM.[47]

Based on data in the AEMO Demand Side Participation Information (DSPI) portal, Energy Synapse estimates that there is currently a large amount of potential demand flexibility in the NEM; approximately 4.3 GW.[48] [49] This has the potential to grow, but is likely to be surpassed by growth in other DER resources that will also provide flexibility in future.

TABLE 5 POTENTIAL FLEXIBILITY FROM DER AND DEMAND RESOURCES

	2020	2022	2025	2030	2035
Residential Solar PV (GW)	8	9-12	12-18	13-23	15-26
Residential Battery Storage (GW)	0.5	1	1-3.5	2-10	3-14
Residential Demand Response (GW)*	2.3	2.9	3.7	5.2	6.6
C&I Solar PV (GW)	2	2-3	3-6	3-9	4-12
C&I Storage (GW)	0	0	0-0.1	0-1	0-1.8
C&I Demand Response (GW)*	2.0	2.0	2.0	2.0	2.0
Electric Vehicles (GW)**	0	0	0-5	0-10	7-25
Total (GW)	**14.8**	**16.9-20.9**	**21.7-38.3**	**25.2-60.2**	**37.6-87.4**

** Energy Synapse analysis of AEMO DSPI portal for 2020 capacity, assuming no increase in future capacity*
*** nameplate capacity assuming 30% of vehicles are plugged into an average charger of 10kW*

There are a range of DER and flexible demand use cases reflected in this analysis. These include pool pumps, hot water and heating and cooling devices. Forecasts in the uptake of stationary storage are varied. Due to its greater ability to operate within markets, there is high value in ensuring storage can be price responsive both through enabling hardware and innovative retail plans. The uptake of electric vehicles is expected to grow into the 2030s and be a large source of flexible load. Forecasts are currently less clear regarding the amount of full market participation relative to stationary storage. Work is beginning on exploring this through both technical and customer lenses, considering how users can and receive and respond to price signals to charge and discharge their vehicle battery.[50]

It is not only the volumes of demand response but also its characteristics that show promising potential for it play a stronger role in the future NEM. Influential characteristics include the extent to which the delivery of demand response is automated or requires manual activation; revenue

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[47] https://esb-post2025-market-design.aemc.gov.au/

[48] Energy Synapse report defines the term “demand response” quite broadly, to refer to all forms of demand flexibility. This includes controllable embedded generation and storage, in addition to load curtailment. This approach is supported as it enables understanding of the full spectrum of demand flexibility and how it could be used to support the future grid.

[49] The approach taken to produce Table 5 is to estimate the addressable market size, based on sectorial projections for rates of adoption of key technologies (solar, storage and EVs), and extrapolation of historical data where appropriate. Residential Demand Response numbers are taken from the Energy Synapse report, using an assumption of an additional 20% active participation of residential hot water and cooling loads by 2035. Table 5 draws on inputs from the report commissioned by Energy Synapse; the AEMO Integrated System Plan, 2020; CSIRO ‘Projections for small-scale embedded technologies’ report, 2020; Energia Distributed Energy Resources and Electric Vehicle Forecasts, 2020.

50 https://arena.gov.au/projects/realising-electric-vehicle-to-grid-services/

certainty; frequency of activation; and preferences for notice period including when making production planning decisions. Respondents to a recent survey by Energy Synapse expressed that where demand response is automated, it can respond within five minutes, whereas manual processes preferred at least one hour.

Directions and next steps

The ESB will continue analysis to build a deeper understanding of the size and characteristics of the potential flexible demand markets. This includes developing a study with ARENA to consider the contribution flexible demand and DER could make under a range of future conditions and longer-term planning scenarios.

The ESB recognises that a range of complementary measures may be needed to improve outcomes especially for those consumers who do not have the means, ability or motivation to engage in new energy market offerings. Such measures could include, for example, a focus on information, advice and non-financial support services or financial support.

The use of such measures (by governments and/or other bodies) could assist in increasing the numbers of customers wishing to participate in a two-sided market, thereby increasing the availability of potentially flexible demand. This would increase the reliability, security and affordability benefits delivered to all customers. The ESB is working with the ECA and consumer groups to help identify how different segments of consumers would engage in a two-sided market.

5.4 Addressing longer term issues

As well as needing to remove barriers being experienced currently, we also need to develop arrangements that better meet the needs beyond the transition. This means we need to rethink how we approach issues relating to access and evolve customer protections, so they are fit for purpose for how customers are likely to start using energy products and services. Setting a clear path forward to address ongoing issues regarding policy uncertainty is a key part of moving forward with the transition.

This section sets out work underway to consider and address these issues.

Improving Access

The rapid increase in DER has seen many customers engaging in the market as both producers and consumers of electricity. Many customers do not have the means or access to the potential benefits of DER (e.g. due to access to capital or rental property restrictions), leading to a potentially growing ‘energy divide’ for those customers with and without access to DER. Potential exists for new business models to provide opportunities to customers and communities (e.g. via community storage) and these options are being explored.

With the continued rapid deployment of rooftop solar, and the latent potential for emerging battery storage and electric vehicles to be harnessed at a distribution level, as well as existing lower tech storage opportunities such as smart hot water units, there is an accelerating need to manage the risks of congestion and oversupply from embedded generation, while at the same time, leveraging the benefits of increased competition and flexibility these resources bring to the system.

5.4.1 Network access and pricing

Longer term issues to be addressed

With recent forecasts in DER uptake exceeding earlier expectations, there is greater value in coordinating use of these assets. The Baringa report,[51] delivered for the Open Energy Networks program, forecasts significant net benefits after costs (up to $8bn by 2039) in orchestration of DERs, specifically in the areas of driving network efficiencies and avoiding infrastructure augmentation.

The pace of change means that it is more important for network businesses to be active in harnessing the value of DER to drive improved network efficiency. This will require networks to develop new price structures that support the adoption and connection of price responsive, active technologies, in the right locations.

For the more strategic design of the two-sided market, there are a number of issues that must be considered as part of assessing the roles networks should play; e.g. should we expect tariffs to line up with wholesale price signals, should we rely on their impacts to address security issues such as minimum demand, and are they nimble enough to deal with the pace of change? Should we look to distribution networks for the delivery of firming capacity in the distribution network to soak up the excess solar, and what role might community batteries play to this end?

The ESB will continue to work closely with the market bodies to leverage existing processes where possible as part of the Post-2025 program to consider these issues.[52] Given the pace of change occurring on the system, the ESB has set out reflections on where existing processes may need to be complemented to deliver more expedient results.

Directions and next steps

Directions for DER network access and distribution security

Managing access to networks has come into recent focus. Some networks are moving towards technical solutions that implement elements of a distribution security layer that can constrain the operation of DER within the operational limits of the network.

Trials carried out with distribution networks over the past three years testing innovate new strategies and technologies are nearing completion (e.g. TasNetworks, SAPN, EVO, EQ[53]). There is emerging consensus across the industry around the technical capabilities and high-level approach for constraining DER at the security limits of the network through Dynamic Operating Envelopes.

The ESB is supportive of the technical direction for distribution security, which offers a long-term solution for the Post-2025 market design as more networks encounter high penetration of DER. However, there are some immediate areas that require clear governance and direction to ensure that scope and responsibilities are clear, that emerging technical designs are consistent at a national level, are coherent with other elements of the market design, and represent the lowest cost and risk pathway. These include:

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[51] https://www.baringa.com/en/insights-news/points-of-view/assessment-of-open-energy-networks-frameworks/
[52] https://www.aemc.gov.au/rule-changes/access-pricing-and-incentive-arrangements-distributed-energy-resources
[53] http://brunybatterytrial.org/
https://www.sapowernetworks.com.au/data/308666/trial-aims-to-help-support-more-solar/
https://arena.gov.au/news/act-distributed-energy-trial-to-help-optimise-network-integration/
https://arena.gov.au/assets/2020/08/state-of-der-technical-integration-project-summaries.pdf

- The scope of use of dynamic operating envelopes by both networks and the system operator and making clear distinctions between how limits are imposed due to congestion or system stability, and that of economic network and/or system optimisation and co-optimisation.
- The rules by which DER are constrained, how envelopes are assigned to consumers, how this is governed and what data is shared to ensure compliance.
- The approach by which they are enforced under different architectural models. For example, under a decentralised architectural model, where aggregators are given the responsibility to enforce the limits set by the Dynamic Operating Envelopes, how is compliance managed, and how is the risk of non-compliance allocated contractually amongst the parties.
- The manner in which Dynamic Connection Agreements are struck with consumers, consumer rights and obligations, achieving national standardisation, and the manner which data on the limits is shared with aggregators responsible for enforcement.
- Evaluating whether all networks should develop the technology capabilities independently, or whether it may be faster, cheaper and lower risk to streamline a NEM wide rollout.
- Consideration of how these relate to tariffs and price signals received by customers.

The ESB will set out further consideration and analysis on these issues in March 2021.

Supporting directions for tariff reform

The ongoing implementation of tariff reform being carried out by the AEMC and AER to move towards more cost reflective and time of use structures are important reforms.[54] These processes will allow a gradual transition to cost reflective prices that act as a long-term signal for investment, and a stable reflection of the long-term system need.

A range of tariff trials are currently under way and more are planned, principally in relation to distribution-level storage and dynamic pricing. While these trials are enabling new ways of working now, the AER expects to see in the next round of Tariff Structure Statement proposals the current and emerging tariff trials transition into mainstream tariffs. Offered more broadly, these will support improved network utilisation and new customer services as well as helping to avoid the need for more expensive poles and wires investment.

Part of the challenge for tariff reform is the speed of the process for addressing short term and specific locational issues. These temporal issues will be considered further by the ESB with market bodies, particularly to identify any additional incentives that can complement the current tariffs and the ongoing reform process. Any additional incentives should drive more efficiency in network expenditure and put downward pressure on consumer costs.

In addition, the AEMC is currently considering rule change requests to reform distribution network access and pricing arrangements. The changes proposed include updating the regulatory framework to reflect the changing role of distribution networks provide both consumption and export services, clarify access and export arrangements for DER and the removal of current prohibition on distribution businesses to include export tariffs. The AEMC is conducting significant consultation on the changes, and a draft determination will be published by March 2021.

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[54] For more info see: https://www.aemc.gov.au/rule-changes/access-pricing-and-incentive-arrangements-distributed-energy-resources

Directions for locational price signals

Stakeholder feedback suggests there is consistent and widespread support that DER should be used to improve network efficiency where possible, and that benefits should be returned to owners through some type of price signal.

Consistent with this, and recognising the continued rapid uptake of DER, the ESB with the market bodies are exploring opportunities for pricing signals to encourage uptake of DER in the right locations, and during the most useful time periods. Specific use cases here could be to manage thermal capacity limits in the network during summer peaks, or to manage voltage limits on LV/MV feeders. The two overarching directions that will be examined in more depth are:

- Locational and dynamic time of use tariffs, which can be more targeted than standard tariffs. While these tariffs can offer some benefit to the DER owner, they can also propagate broader benefits back to all users of the distribution network through lower overall long run costs.
- Structured procurement of location specific network services contracts. This is the approach being trialled in WA and VIC as part of DER market trials and has been deployed widely across the UK networks. These are typically multi-year capacity contract style market signals and are intended to maximise the direction of value back to DER owners and their agents. Contracts such as these with aggregators or owners of DER can help avoid potentially more expensive network capex investment to manage localised network issues, saving costs for all consumers, including DER owners.

Detailed analysis of the two options will be undertaken. This will consider the strengths and weaknesses of these approaches and develop a framework for evaluating the costs and risks of a do-nothing scenario to baseline how quickly these options for more locational price signals could be soundly justified.

Options for community level access

Building on growing stakeholder interest in local and community energy concepts, the ESB and market bodies are exploring options for alternative network pricing arrangements that can support access to DER in providing services to others in localised parts of the distribution network. These local tariff structures have the potential to:

- Encourage community level flexibility and network efficiency (e.g., community storage) that drives improved efficiency of the system, and consequently lower costs for consumers
- Be more cost reflective than the flat, postage stamp tariff pricing, and reflect the benefits that DER are bringing to the local system to increase headroom, stability etc. can reflect
- Open opportunities to improve social equity and increased consumer participation and can offer communities additional non-financial benefits that supports the case for their introduction (e.g. zero carbon communities)
- Encourage innovation, new business models, and new services that can improve network efficiency, and in the long term drive down network costs for all consumers.

These options will be considered further, including developing some first use cases and business models that these tariffs could support, their implications and interactions with ringfencing and competition issues already under consideration by the AER,[55] and a methodology and process for evaluating the benefits for their introduction.

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[55] https://www.aer.gov.au/communication/aer-publishes-electricity-distribution-ring-fencing-issues-paper

Addressing Uncertainty

The Post-2025 program will set out a pathway for development of a future two-sided market as part of a progressive phased approach to provide greater clarity to the market, stakeholders and customers. The ESB intends to continue to work with customer advocates and stakeholders to ensure the arrangements developed are fit for purpose and meet the needs for each stage of the transition. As part of this, there is a need to address uncertainty regarding future roles and responsibilities in a two-sided market – the ongoing lack of clarity is leading to further uncertainty, uncoordinated and inefficient investment decisions. The ESB intends to establish a process with industry and customer stakeholders to resolve these issues, to support effective decision making on the form of future market arrangements.

5.4.2 Clarity on roles and responsibilities

Longer term issues to be addressed

Over the past decade, forecasts of DER uptake have consistently underestimated how much DER is being driven by consumer choice, and how quickly these changes would impact across the system and markets.

Consumers are continuing to drive these changes through their choices. Even in the current economic environment, uptake of DER is presenting at the high end of previous estimates.[56] At the same time, where policies being driven at state level to drive uptake in renewable or low emission technologies, these are further increasing uptake of DER. This means that these issues are moving forward at a faster pace than ever before. To drive efficient outcomes for customers, greater collective coordination and certainty regarding how these resources will be integrated into markets is needed. Without this clarity, we will see customers receiving reduced value and increased costs associated with inefficient investment.

Establishing a clear architecture, and accompanying roles and responsibilities to support the new two-sided market will be a major step forward in reducing this uncertainty, building consumer trust and providing long term clarity of direction for the DER community.

Over the last four or more years, there have been some important initiatives around Australia that have laid much of the groundwork for dealing with these future uncertainties, including the CSIRO/ENA Electricity Network[57] Transformation Roadmap, Open Energy Networks from the ENA and AEMO[58] and the DER Roadmap and reform process run by the Western Australian Government.[59]

The ESB sees value in taking a pragmatic approach where clarity is progressively developed around the customer choices that will change, and several operational areas regarding the future roles for participants, and the responsibilities and risks they will be required to take on. Some examples of functionality that will impact the DNSPs, AEMO, aggregators and retailers include distribution security to ensure the safe and secure dispatch of DER, value stacking and co-optimisation of DER, the implementation of operational cybersecurity frameworks, as well as data sharing platforms, and interoperability standards.

In this section we set out the ESB's thinking on how these issues can be considered together with customers and industry stakeholders.

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[56] https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en
[57] https://www.csiro.au/en/Research/EF/Areas/Modelling-and-forecasting/Roadmaps/NTR
[58] https://www.energynetworks.com.au/projects/open-energy-networks/
[59] https://www.wa.gov.au/government/publications/der-roadmap

Directions and next steps

The essential architecture of the future two-sided market can be explained as a platform that is capable of integrating customer owned energy technology systems and applications. In future, a new genre of products and services may be available to consumers, which could include bundles of technology, energy and other services, built for simplicity for customers, while providers participate in markets behind the scenes on behalf of the customers.

These platform models and architectures are not unique to energy; examination of the banking and telco sectors show a similar path down a digital transition where products and services have transformed completely within a decade. Sharing of platforms and infrastructure has been a significant part of that success, including examples such as the SWIFT banking system for messaging and transactions, sharing and interoperability of the ATM networks, and the agreed processes and technical standards for switching mobile phone providers.

The architecture for DER needs to take a similar path, to allow the sharing and interoperability of these assets into a range of local and wholesale market services and returning value to customers (via their intermediaries) to reciprocate the transfer.

Roles and responsibilities in the two-sided market

The process for identifying roles and responsibilities for the new capabilities is an important component to supporting development of an effective two-sided market. Previous processes, such as the Network Transformation Roadmap and the Open Energy process, have outlined high level design concepts such as the hybrid model but stopped short of moving into sufficient functional detail needed to make meaningful decisions on detailed responsibilities. Decisions on these questions will be important to support the effective integration of DER into future two-sided market arrangements.

A design exercise has been undertaken to map out possible technically feasible combinations of where the various functional capabilities could be performed. These combinations hinged around how and where key functions could sit and what data would be communicated, such as signalling and enforcement of dynamic operating envelopes, and DER asset level operational visibility, forecasting and cybersecurity capabilities. These combinations were loosely described around four main vectors of function and responsibility.

- **The No Platform Model**: this is baselined from our systems and processes today - i.e., essentially a point-to-point architecture between all actors with no shared capabilities beyond what are in use today (e.g., the Market Settlement and Transfer Solutions system, 'MSATS')
- **DSO weighted model**: this model weighs more functions and responsibilities towards the DNSPs acting as a DSO, which would involve some but relatively minor shared capabilities.
- **DMO weighted model**: this model weighs more functions and responsibilities towards AEMO, which would involve a greater proportion of shared capabilities.
- **Aggregator weighted model**: this model weighs most functions towards the retailer / aggregator, and with some minor shared capabilities.

Work has not been carried out to further develop any of these options, and the ESB recognises that other variants could also evolve in discussions with stakeholders. There is a wide spectrum of views on the best way forward. However, it is also clear that progress in moving discussions forward has stalled via existing processes. To support a fully effective two-sided market design, decisions will need to be made on these issues. The following matters are considered priority areas for consideration to enable benefits:

- Starting from the No Platform model today, delivery on the high priority areas will move the architecture towards an expanded role for Aggregators, where innovators and new market entrants will be likely to rapidly evolve capabilities to value stack and optimise across markets, alongside data sharing and compliance obligations.

- Consider where there is a positive architectural and economic rationale for evolving some shared capabilities and services over time, which are likely to bring cost reductions, simplicity and faster upskilling in information, communication and technology capabilities across the sector.
- Where DER penetrations increase sufficiently, consider how the future two-sided market may see a tighter coupling between the distribution network and transmission level energy, capacity and security services, and in the need for an expanded approach to co-optimisation.

Development of a Maturity Plan

To balance the need for some immediate clarity and direction alongside the host of changes in the market and uncertainties in growth of DER, the ESB proposes to work with industry and customers to develop a Maturity Plan. This plan sets out a process to work through a technology uplift out to 2030. A paper outlining the scope and approach to the Maturity Plan, the priorities for first Release deliverables, including the ESB's proposed process for engagement with stakeholders, will be released early in 2021, and will solicit feedback on its overall direction, structure and priorities.

The rationale for moving to a Maturity Plan is to put a clear structure in place for governance, decision making and delegation. Specifically, this would cover system-wide architecture and design, roles and responsibilities, and technical progression and implementation of capabilities for the two-sided market. To enable the initial development, supporting governance arrangements will remain with the ESB and the market bodies for the immediate future. While further details will be developed together with stakeholders, it is anticipated the plan would in principle:

- Be iterative, use the latest information in decision making, and lower the risks of building out capabilities in a highly uncertain environment.
- Key technical decisions, delivery and evaluation of the priorities set out in the plan via the regular governance and decision-making process.
- Include scope of all aspects of long-term deep integration of DER across the system, including technical standards, regulatory issues, network access and market participation and articulate a clear transition path to the future state two-sided market.
- Leverage and coordinate work underway across adjacent processes, as laid out in the ESB DER integration roadmap[60] (for example, network tariff reform, linkages with DEIP and ARENA programs etc.), the Commonwealth Government's Technology Roadmap,[61] and other state and federal programs and working groups.
- Implement a governance and decision structure on a regular cadence (say six monthly), approving content and priorities of future releases of the Maturity Plan. The plan will also clarify the relationship with other DER technical standards governance processes.
- The plan will set out the clear priority areas to proceed with for the first release of the Plan (see below for current indicative priorities), to be complete by June 2021, and will recommend priorities for the second release by March 2021.
- The Maturity Plan will baseline its activities from systems and markets as of June 2021, develop a do-nothing baseline scenario for business cases for future releases.

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[60] http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/ESB DER Integration Workplan Oct 2019.pdf

[61] https://www.industry.gov.au/data-and-publications/technology-investment-roadmap-first-low-emissions-technology-statement-2020

Priorities for the Maturity Plan

Priority issues for consideration relating to matters regarding an expanded Aggregator role, shared infrastructure and future co-optimisation are highlighted above. The ESB notes the following priority areas below that it intends to consider together with industry stakeholders:

Near term priorities:

- **Stakeholder buy-in**: As the first step, the future vision of the two-sided market must be articulated and communicated with all stakeholders; both industry stakeholders and consumers to build trust, collaboration and support for the future role of DER, the maturity plan and collective success.
- **Active solar and participation**: Addressing growing passive rooftop solar as the root cause of the increasing minimum demand issues is an urgent issue. This would likely involve working with the states on a national multi-step approach to coordinate and streamline state-based compliance approaches on technology installations in early 2021 and offer a pathway towards a market-based approach in the medium term.
- **Distribution Security**: Bringing security constrained dispatch to the distribution level will require the communication of dynamic envelopes, dynamic connection agreements (DCA) with customers, and the enforcement and compliance roles identified and agreed as the first implementations move to production in 2021/2022.
- **DER Interoperability and Cybersecurity standards**: At points of interconnection between DER vendors and aggregators, network, market and system operators, the exchange of data and control signals should be standardised as a priority, initially through industry consensus, and in the longer term through formal standards if and when required. The design of cybersecurity frameworks, selection of high priority use cases, and draft communication APIs (application programming interface) will be prioritised at the working group level for initial release by June 2021.

Medium term priorities are:

- **Market Services Access**: To maximise the efficiency of our energy system, the system should be maximising the utilisation of DERs through value stacking. Ensuring that all market services are designed and launched for participation for DER, and value stacking capable.
- **Operational Data**: Data for asset and aggregation levels of granularity, availability forecasts and distribution security compliance, platforms, protocols, privacy / rights for its sharing between parties.

Customer Protections

Underpinning any future market design customers will need to be adequately protected. New market models, products and services may raise new risks for consumers in the existing wholesale and emerging service markets, in particular disengaged consumers, those with limited digital or energy literacy or those experiencing hardship. As the types of energy service and product offerings starts to evolve, and the role of the consumer also changes in the market by unlocking the value of their flexible demand, we need to evolve our protections frameworks to keep up with these changes.

It will be important that future arrangements are designed to reduce and remove unnecessary complexity, which poses risks to all consumers. Consumer protections are required to build trust and provide an adequate safety net for these changing needs where customers may receive energy products and services through a broader range of service providers (i.e., not just retailers). They will also support consumers to have the confidence to engage more actively in the market if they choose to do so.

5.4.3 Fit-for-purpose protections

Longer term issues to be addressed

The National Energy Customer Framework (NECF) was created to protect consumers in a market where energy flowed to the consumer and retail offerings were largely homogeneous. This is no longer the case.

In a two-sided market, the role of the consumer (end-user) changes. While an end-user will not need to participate in a two-sided market any more than they would today, the ability for a trader (such as a retailer or an aggregator) to shift a customer's load or import or export their energy will become a fundamental part of the market. For example, a consumer may decide to hand management of their smart hot water load to a third party that rewards the consumers who participate. The third party may adjust the energy consumption of the hot water based on market prices while making sure the consumers access to hot water isn't adversely impacted, consistent with terms agreed between the customer and service provider. Some sharing of the value between the customer and the third-party aggregator/organiser would occur.

New business models and services will bring opportunities for customers to receive explicit value for their flexible demand. Digitalisation provides richer and more regular data, and a broader range of communication opportunities to allow customers to interact with their retailer, their data, and the market. Digitalisation is also leading to new ways for consumers to control, use and store energy.

The new opportunities that will come from a two-sided market bring potential new risks for consumers. Given this, and the low base of consumer trust,[62] a strong consumer protection framework is an integral part of the move to a two-sided market as well as a focus on reducing or removing complexity where possible. We need a fit-for-purpose framework able to accommodate new products and services that also protect the interests of consumers, so consumers can have confidence to engage in the market if they choose to do so and receive protection where appropriate.

For consumer protections, the ESB will build on the work already carried out by the AEMC on consumer protections in a changing energy market through its 2019 and 2020 retail energy competition reviews. This work will also build on work already underway to enhance protections as part of the billing contents rule change and the New Energy Tech Consumer Code.[63]

The NECF and Australian Competition Law (ACL) are the two current frameworks that offer consumer protections to energy customers in the NEM. The ACL protects energy consumers in relation to the supply of goods and services, while the NECF includes energy-specific provisions relating to the sale of energy. In its 2019 retail energy competition review, the AEMC found that the NECF and ACL largely complement each other to maintain a strong consumer protection framework for energy consumers.

However, the model originally contemplated by the NECF is no longer the only one available for consumers to access energy. This is testing the boundaries of application of the NECF. A two-sided market with two-way flows and digitalisation may blur the lines between the NECF and ACL. An example of this would be a bundled electric vehicle and charging service where the scope of what is covered by the ACL and the NECF may not be immediately clear. The ESB will need to address these challenges in developing a fit-for-purpose consumer protection framework for a two-sided market.

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62 https://energyconsumersaustralia.com.au/projects/consumer-sentiment-survey

63 https://www.accc.gov.au/public-registers/authorisations-and-notifications-registers/authorisations-register/new-energy-tech-consumer-code

In its 2020 retail energy competition review,[64] the AEMC recommended that a variety of regulatory approaches should be used to develop a fit-for-purpose consumer protection framework. The ESB agrees with recommendations from the AEMC 2020 retail energy competition review, that a variety of regulatory approaches should be used to develop a fit-for-purpose consumer protection framework. Protection frameworks should consider:

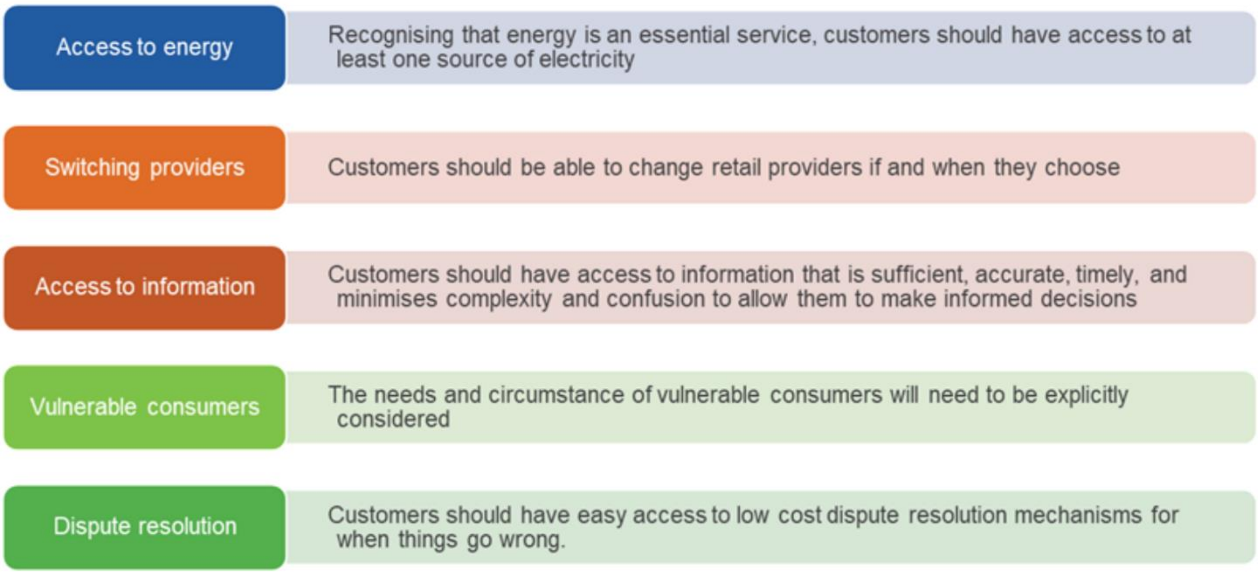
- Principles-based and prescriptive regulation depending on the level of flexibility needed or the potential harm to consumers
- Mandatory and voluntary regulation, with the possibility of considering the use of industry codes of conduct.

As is the case today, not all aspects of the two-sided market will need to be governed by the NECF, and complementary consumer protections for energy products and services will be required.

Directions and next steps

To support development of the future framework, ESB sees value in using a shared set of principles to drive consumer outcomes and protect consumers dealing with new services that they have not dealt with before. Figure 8 below outlines draft principles the ESB intends to use to start work together with consumer groups and industry to underpin the development of the future framework.[65]

FIGURE 8 DRAFT PRINCIPLES TO SUPPORT DEVELOPMENT OF CONSUMER PROTECTION FRAMEWORK



The ESB intends to use a risk-assessment approach to inform the development of the framework. In doing this, we will be able to identify and prioritise for consideration those products and services that are likely to have higher risks for consumers or result in higher levels of harm. The right level of protection can then be assessed, including if any new protections should be developed beyond what exists today.

Services that will be prominent in a more developed two-sided market exist today. Understanding the possible harms and risks associated with existing services will help to identify what consumer protection changes may be needed in the short term. Not only is this important for protecting

[64] https://www.aemc.gov.au/market-reviews-advice/2020-retail-energy-competition-review
[65] These draft Principles draw on the work done by the AEMC in its competition reviews, including work commissioned from Dr Chris Decker: https://www.aemc.gov.au/sites/default/files/content/AEMC-submission-on-consumer-protections-behind-the-meter-consultation.pdf

existing customers but it also helps to deter activities that could reduce the community's trust in those services that will play an important role in a future two-sided market.

6 TRANSMISSION AND ACCESS

Key points

- The generation mix is moving towards large scale renewables in more decentralized and dispersed locations. The transmission grid needs to develop; and access to it needs to change to support investment and lower overall costs.
- Stakeholders have concerns about efficient and effective connection to, and use of, the grid. Grid connection is difficult in many areas and technical issues, mostly associated with low system strength, affect the timeliness and cost of connection. Once connected, high levels of congestion and significant reductions in marginal loss factors are problematic.
- These issues have arisen as many new generators seek access to the grid. Under the current regime, generator's access to the grid is determined by individual decisions, with no coordination and limited transparency regarding the impact these decisions on other parties and the broader development of the network.
- While the current access arrangements may have been adequate in the past with only incremental investment occurring, they are not fit for the future transformational change to the system.
- Without resolving these issues there will be higher prices for consumers and the grid will be more difficult to operate:
  - There are limited signals for generation and storage to locate in the right location
  - Generators and storage will not operate or use the network efficiently, due to congestion, and the fact that they all receive the same regional price
  - Efficient location and use of storage is critical given its ability the potential for it to have major impacts on congestion
  - Market participants have limited tools to manage risks of congestion, falling marginal loss factors and technical issues due to others' locational decisions.
- In the longer term, the ESB considers that the introduction of locational marginal pricing with financial transmission rights is necessary. This is the only alternative put forward to date which can work across the whole of the NEM and drive both more efficient investment and more efficient dispatch and use of the network.
- However, the introduction of locational marginal pricing and financial transmission rights is a significant change. In submissions to the September Consultation, generators expressed concerns about complexity, uncertainty, and increased risk associated with this solution. Customer representatives expressed mixed views about whether the substantial benefits would be realised in the current environment. Some stakeholders accepted the need for change but argued that the arrangements should be introduced more gradually. For all these reasons, a broad range of stakeholders have indicated that their preferred focus, at least initially, is to develop arrangements for REZs.
- In recognition of these concerns, the ESB is prioritising the development of REZ arrangements as a first step in improving transmission access. Rules are already in place to expedite the approval of the transmission enhancements identified in the ISP and for the detailed planning within a REZ. The immediate focus of the ESB's work is now on developing arrangements to implement REZs.
- The work on REZ development will be prioritised ahead of work to progress the detailed technical specification of locational pricing and financial transmission rights set out in the AEMC's September paper and an approach to manage the transition .

- This means there will not be a publication on the longer term access regime at this time (previously indicated for December 2020). This allows the transmission frameworks reform pathway to be better aligned with other market reform changes being considered under the Post-2025 work program.
- However, under the current access regime, generators have no direct incentive to invest in line with the ISP or to locate new generation in identified 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.
- The ESB has released a Consultation paper alongside this Directions paper that sets out options for REZs, and how these can provide a pathway towards the long-term goal of access reform.

The pathway for reform of transmission frameworks could also include improving information provision about congestion in the NEM, as well as investigating alternative paths for change which mitigate the risks in transition and the impact on existing contracts.

6.1 Stakeholder feedback

This section summarises submissions to both the ESB September Consultation and the accompanying AEMC interim report addressing transmission access reform issues. Stakeholders provided feedback in response to questions asked in the September Consultation, as well as a broad range of matters relevant to the Transmission and Access workstream.

6.1.1 Integrated System Plan (ISP)

Stakeholders were generally supportive of the implementation of the ISP. However, some stakeholders raised concerns over the allocation and magnitude of costs of the investment in comparison to their likely benefits.

In addition to supporting implementation of the ISP, a number of generators considered that the ISP will address the issue of congestion in the grid and improve locational signalling. For example, the CEC considered that the ISP and actioning the ISP rule change will address congestion and improve locational signalling, however it did not present further explanation as to how this would occur.

Some consumer groups noted that they were concerned about the cost related to the implementation of the ISP. For example, the Energy Users Association of Australia (EUAA) stated that: "*consumers cannot support a model that has them bearing an inefficient and inequitable share of the risk,"* and urged the ESB to *"ensure consumers are not the risk backstop for the investments of others*."

The Australian Aluminium Council (AAC) also raised concerns over ISP projects locking in extensive costs to consumers over the long-term.

Some stakeholders suggested that it was necessary to have an access framework in place that would ensure the efficiency of ISP investments. For example, ENGIE considered that providing the correct locational signals to new generation investments will be critical to the efficiency of the NEM through the 2030s and 2040s. The AER considered that locational marginal pricing is important to realising the least-cost outcomes arising from the ISP. Monash University went further, arguing for the use of locational marginal pricing to resolve congestion before the build-out of transmission infrastructure.

6.1.2 Locational Marginal Pricing and Financial Transmission Rights

Views regarding the introduction of locational marginal pricing and financial transmission rights

Generators and investors were generally opposed to the introduction of locational marginal pricing and financial transmission rights. Views from consumer groups and network businesses were mixed.

Some generators and investors doubted the effectiveness of locational marginal pricing to deliver benefits to the market. For example, NEOEN suggested that the introduction of locational marginal pricing could create barriers to entry in the market. Others suggested that the introduction of locational marginal pricing and financial transmission rights will have adverse effect on the ability of investors and generators to forecast revenues and the CEC suggested that the transmission access reform design in its current state would increase the weighted average cost of capital. Additionally, the CEC, as well as the CEIG, suggested that the access reform proposal in its current state will necessitate the reopening of PPAs in the market, and that this will come at a high cost to the parties to these contracts.

There were some exceptions to the opposition from generators to the implementation of locational marginal pricing and financial transmission rights. For example, ENGIE considered that locational marginal pricing should be implemented if there is clear evidence that such measures are warranted, and ENEL Green Power was supportive of the introduction of locational marginal pricing and financial transmission rights.

Alinta noted that if locational marginal pricing and financial transmission rights were to be introduced, implementation should be delayed to better align with the modelled benefits of access reform, and to allow the implementation of other key Post-2025 initiatives.

Networks were mixed in their support for the implementation of locational marginal pricing and financial transmission rights, dependent on ongoing development of the detailed specifications of the reform. For example, Energy Networks Australia (ENA) noted that it was supportive of improving congestion arrangements and locational signals for generator investment given the approach chosen had demonstrable benefits, and that any reform was in the long-term interests of consumers.

Views from consumer representatives were mixed. The EUAA opposed the introduction of locational marginal pricing and financial transmission rights and argued that a more equitable approach to funding REZs should be developed. Some consumer groups and other stakeholders were supportive of the introduction of locational marginal pricing and financial transmission rights. The Public Interest Advocacy Centre (PIAC) supported the introduction of locational marginal pricing, stating that the introduction of locational marginal pricing is likely to improve locational signals for connecting generators.

Energy Consumers Australia (ECA) noted that: “*The NERA modelling commissioned by the AEMC indicates that the changes could reduce costs for consumers by more than $3 billion by 2040*”. ECA further stated that it is “*incumbent on stakeholders who challenge both the use of locational price signals and the analysis to offer detailed alternative plans to unlock the savings and deliver the planning benefits for consumers*”.

The AER suggested that locational marginal pricing is important to realising the least-cost outcomes arising from the ISP, and that while full locational marginal pricing (i.e. nodal pricing) is the most efficient option, the AEMC suggestion is a “*pragmatic step forward*”.

Views regarding alternatives to locational marginal pricing and financial transmission rights

Stakeholders suggested a number of alternative solutions to the transmission access reform proposal. These proposals can be broadly grouped into three categories:

- The first and most common category of alternative solution suggested by stakeholders was actioning the ISP and the development of REZs, which, in their view, would address congestion and provide locational signals for generators.
- The second category of alternative suggestion presented by stakeholders was the provision of better wholesale market information for participants, but that the current market design be kept largely intact. The information suggested for clearer publication included the shadow locational marginal prices currently solved by the NEM Dispatch Engine (NEMDE), network congestion information in the form of congestion maps, and indicative do no harm congestion requirements across the network.
- The final category of alternative solution proposed by stakeholders was a 'causer pays' approach to connections, either through generator-funded transmission augmentation as suggested in the Optional Firm Access Review in 2014 or a deep connection charge.

6.1.3 Renewable Energy Zones

Stakeholders were generally supportive of the development of REZs. Some stakeholders expressed a desire for more detail about the development of REZs, and how issues such as access and funding would be addressed. Some stakeholders offered explicit suggestions for how to address issues of access within REZs.

Some stakeholders were supportive of REZ development as a way to address concerns associated with congestion and locational signals for connecting generators. For example, Canadian Solar stated that the development of REZs will assist to address congestion.

Some stakeholders were supportive of the continued development of REZs and noted that more detail surrounding the operating framework of REZs was needed. For example, the CEC argued for the further investigation of the applicability of either physical or financial rights for REZs in preference to the continued development of the AEMC's whole of system transmission access reform proposal.

Consumer groups such as the Australian Council of Social Services (ACOSS), The South Australian Council of Social Services (SACOSS) and the St. Vincent de Paul Society were supportive of REZ development. However, they also supported sharing costs and risks of REZ investment between generators, investors and consumers, rather than just between consumers. Similarly, the EUAA, referring to REZ development, noted that all parties who benefit from investments in new transmission should pay their fair share.

Networks expressed similar views to consumer groups. For example, the ENA stated that it is supportive of the REZ planning framework, but also considered that a number of safeguards are required to prevent consumers bearing excessive costs.

Finally, some stakeholders suggested methods which would ensure that REZs are developed efficiently. The AER stated that locational marginal pricing would facilitate REZs. Furthermore, Delta Electricity stated that in order for REZs to be developed efficiently, generators inside the REZ must be exposed to the costs of network enhancement directly attributable to a locational decision.

6.2 Proposed general directions

In this section we respond to key issues raised in stakeholder submissions.

6.2.1 Who pays for transmission?

A wide range of consumer representatives considered that consumers should not be forced to continue to bear the risk and fully fund transmission infrastructure. This issue was raised by consumer representatives in relation to all transmission infrastructure i.e. REZ expenditure, ISP build and transmission infrastructure more broadly.

The Post-2025 focus on transmission, access and REZs is focussed on providing the mechanisms to transform the national network to meet future needs, to change the access regime to coordinate generation and transmission build, to lower the cost of connecting to new generators and to ensure that the augmented transmission system is efficiently used to maximise the benefits to customers. Shifting some of the cost of transmission to generators can assist in this, but only to the extent that generators face efficient costs which provide incentives for them to invest or operate differently.

The introduction of locational marginal pricing and sale of financial transmission rights would provide a mechanism whereby generators share the cost of transmission infrastructure with consumers and effectively bear the cost of their congestion. These costs are dynamic, reflecting the actual costs in each dispatch interval.

Under the current arrangements, customer pay transmission use of system (TUOS) charges in two components, one of which is the locational charge. This aims to reflect the cost of the infrastructure required to support the load at each transmission connection point. A locational TUOS charge could also be applied to generators and determined by the TNSP each year under a TUOS charging methodology. Some stakeholders suggested using generator TUOS as an alternative approach to locational marginal pricing.

TEXT BOX 7 GENERATOR TRANSMISSION USE OF SYSTEM CHARGES

Under this model, generators would pay an administratively calculated TUOS charge, with this attempting to reflect the incremental cost of using the network at various locations. The charges would vary by location because the cost of using the transmission system varies by location. These charges could be updated on an annual basis.

The two main options for determining generator TUOS include:

- Using administratively determined estimates of the long run marginal cost of transmission at each connection point, which is similar to the locational charges that loads currently face.
- Using administratively determined estimates of the short run marginal cost of congestion over the course of a year, which is similar to the current process used for marginal loss factors.

Where generator TUOS frameworks are used internationally they are often accompanied by a generator reliability access standard. Typically, this applies on an averaged basis throughout a generator reliability region, similar to the reliability standard that already exists for load. While this does not provide a specific access right to individual generators it would deliver some assurance as to the average level of congestion.

Assessment of the model

Generator TUOS models involve setting a price signal that is calculated administratively in advance and which seeks to provide effective locational signals for investment. That is very difficult, especially in a more complex power system with a mix of variable renewable energy, conventional generation and storage using the transmission system in different ways and at different times. In particular, a generator TUOS charge would not reflect the dynamic, short run marginal cost of the transmission network. This means that in operational timescales, generators and storage would not be sent the appropriate price signals and is likely to result in inefficient dispatch.

For any generator TUOS model that would include a generator reliability standard:

- This standard would lack flexibility by mandating a uniform level of access for generators – generators would have to pay the administrative set price and receive the administratively set level of access in return. There would be no flexibility or optionality for generators in this.
- Consumers would bear the risk that the regulated standard is inappropriate. This may result in an inefficiently high amount of transmission (high TUOS charges for load without commensurate reductions in wholesale prices), or an inefficiently low amount of transmission (high wholesale prices without a commensurate reduction in TUOS charges for load), or a combination of the two in differing locations.
- Generators would also need to bear the risk that the regulated standard is inappropriate. For generators, an inefficiently high amount of transmission could lead to high TUOS charges without providing substantial reductions to their volume risks because the increased transmission leads to increased access for their broader area rather than for an individual generator specifically.

The ESB recognises the complexity of transmission access reform and considers that there may be merit in keeping a generator TUOS option under review, as it could have the potential to provide stronger locational signals to generators than the status quo arrangements. It may also improve the efficient allocation of risk because generators are better placed than customers to manage the risk of generator location decisions.

Some stakeholders also suggested applying deep connection charges to generators seeking to connect to the grid in the future. Deep connection charges could be applied to maintain a given level of congestion in the grid and recover the cost of doing so from new generators. Those charges would provide an incentive for generators to connect in efficient locations where the cost of connection balanced the value of the resources. Deep connection charges are explored further below.

TEXT BOX 8 DEEP CONNECTION CHARGES FOR GENERATORS

Under this model, a new generator pays for both cost of the physical connection to the grid (its shallow connection costs, which it already pays for) along with the costs of any transmission network reinforcement, over that already committed, required to maintain access for all existing network users. These costs are often referred to as a “deep connection charge.”

The need for reinforcements is assessed by reference to the impact of the new generator connection on the ability of the TNSP to meet the transmission reliability standard. Under a deep connection charging model, the transmission reliability standard typically includes standards that relate to the ability of the network to export generator output as well as standards that relate to load.

This new charge calculated at the time of their connection based on the estimated cost of the network reinforcement required to accommodate them. The payment can be set as a one-off upfront payment, or it can be converted into $/MWh over a long period of time (e.g. 20 – 30 years), or it could be paid based on some other arrangement that could be negotiated between the generator and their TNSP. If converted into a $/MWh charge, the forecast of the output of the generator in question is needed over the same period in order for the calculation to be made and the potential impacts on the efficient dispatch of the plant needs to be considered.

A variant option of this model would be to determine an estimate of the long run marginal cost when a generator first connects to the transmission network and leave it unchanged afterwards. In this case, the estimate of long run marginal cost would be calculated by reference to the forward-looking plan for transmission investment as set out in the ISP. If a generators' location decision aligns with the ISP, they would face a lower connection charge that a generator whose location decision does not align with ISP.

Under an LRMC deep connection charging model, the charge is calculated on a case by case basis as part of each generators' connection process, and the cost is known up front. This is contrasted to generator TUOS described above, where the LRMC is recalculated on an annual basis.

Assessment of the model

The application of deep connection charges is complex when considering:

- The definition of the access of existing plant that needs to be maintained by any augmentation funded through deep access charging including which generators and storage providers, to where, under what conditions and at what times
- A baseline transmission plan needs to be adopted to calculate the incremental deep connection charge
- The lumpy nature of transmission investment meaning that deep connection charges could move over a wide range and can induce strategic queuing behaviour.

In maintaining a level of access to all existing network users, deep connection charging risks inefficient investment. It also does not provide a solution to inefficiencies in dispatch because the price they face in operational timescales would not reflect the marginal cost of congestion.

Despite these issues, deep connection charges would provide locational signals to potential investors and deliver a level of certainty. For example, by setting the charges prior to connection, generators would be able to include these in their investment decisions with no risk of change, which may decrease their overall risks.

The deep connection charging model does not give rise to the grandfathering issues that arise in relation to generator TUOS, since legacy generators have already connected to the network. However, the introduction of deep connection charges would put new entrants at a disadvantage relative to incumbents since they need to bear additional costs.

The REZ consultation paper discusses challenges arising as a result of the localised nature of REZs. As the power system evolves and more REZs are implemented, congestion outside the REZ can be expected to become more common and impact on dispatch outcomes of generators within the REZ. Deep connection charges could apply in combination with a REZ model to provide an access solution that applies to the whole power system. In this case, generators that connect outside a REZ would be required to pay deep connection charges. Alternatively, generators could participate in a tender in order to connect within a REZ.

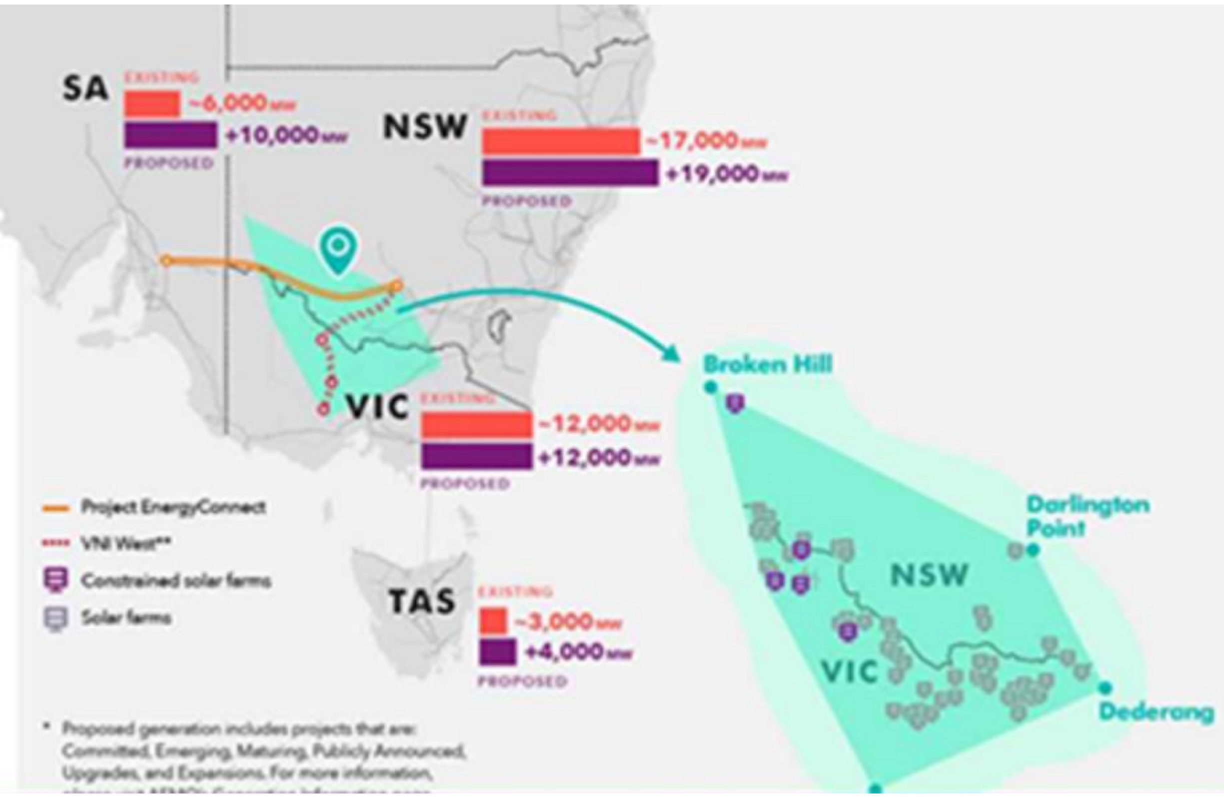
The ESB will continue to consider the longer term access regime and the approach to transition. The approach taken to the development of REZs should be consistent with, or able to coexist with, with the longer term directions.

6.2.2 Interactions between the reforms

Some stakeholders considered that actioning the ISP and implementing REZs would be a substitute to long-term access reform. However, the ESB considers that rather than being substitute access solutions, the ISP and REZs are complements to transmission access reform. To work effectively in the long term the reforms need to work together.

Congestion is likely to be a normal, everyday feature of efficiently sized transmission infrastructure to accommodate variable renewable generation – not an anomaly. Figure 9 below shows the amount of existing and proposed generation in the southern regions of the NEM. The actionable ISP projects intended to alleviate congestion in these locations are much smaller than the proposed new generation capacity. For instance, EnergyConnect has a rated transfer capacity of 800 MW, which is dwarfed by the 10 GW of proposed new generation capacity in South Australia, as well as a number of proposed projects in Southern NSW.

FIGURE 9 FUTURE DEVELOPMENTS IN THE NEM



Source: AEMO

Congestion is likely to increase because the cost of building the incremental transmission infrastructure to allow for the dispatch of variable renewable generation for the sunniest or windiest of times exceeds the benefits to reducing the cost of dispatch or reducing emissions at those times. It is more cost effective, and reduces emissions by a greater extent, to build more variable renewable generation than can always be accommodated by the transmission infrastructure, even if that variable generation cannot be always used.

The ISP does not, and should not, seek to remove all congestion from the system, meaning that issues relating to access will be common despite the transmission infrastructure expansions foreshadowed by the ISP.

Other key interactions between the ISP, REZs, and the access regime are:

- REZs are reliant on both actioning the ISP to provide direction for where they should be built and arrangements to resolve access issues within REZs. As highlighted in the accompanying Stage 2 REZ consultation paper, over time, REZs suffer from the same access problems as the wider transmission network. Consistent with this analysis the REZ paper sets out the intractable issues associated with development of REZ frameworks across meshed networks in the absence of access reform. REZs are not a substitute for an access regime, they need an access regime to work. To address the challenges of unanticipated constraints and deteriorating loss factors without access reform, it would be necessary to have a far greater degree of centralised control regarding the timing and location of generation and storage projects than is currently the case.

- The ISP needs access reform to be ultimately effective. For example, while actioning the ISP can lead to transmission investment directly, the current regional pricing regime does not provide financial incentives for generators and storage to locate consistent with the least cost forecast generator and storage development path in the ISP. In turn, the transmission investment facilitated by the ISP to accommodate the optimal location of generation and storage will itself be misplaced and mistimed.
- Transmission access reform is designed to provide efficient price signals and risk management tools to generators. However, it needs the actionable ISP to direct transmission investment. As a major reform, this will take time to implement and interim REZ solutions are needed on the pathway to it.

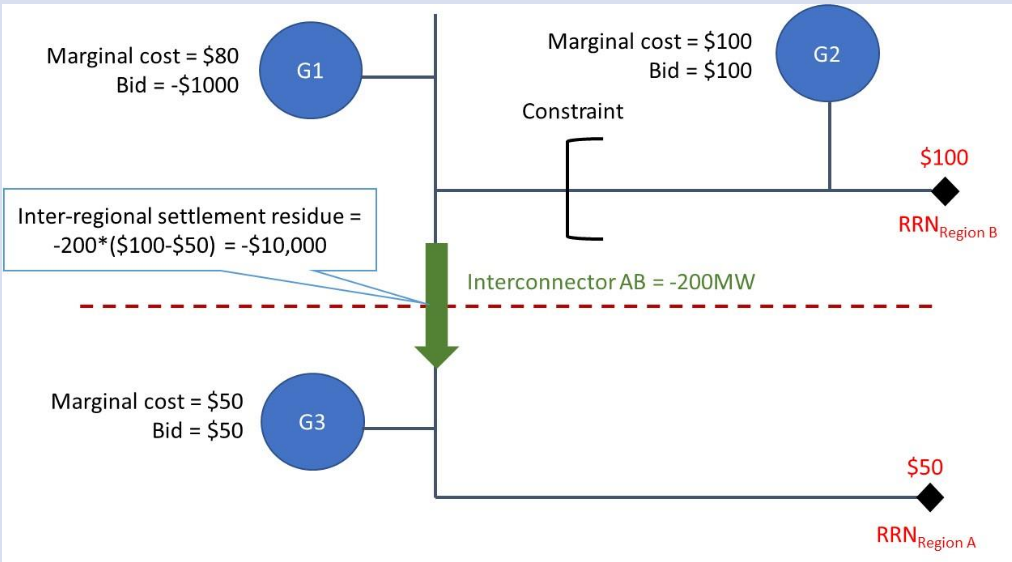
This analysis highlights the generic issues across the NEM that are likely to arise without all of the ISP, REZs and transmission access reform being implemented. There are also specific instances where these issues are likely to be particularly problematic, these are highlighted in the box below.

TEXT BOX 9 COUNTER-PRICE FLOWS ON INTERCONNECTORS

In the normal course of events, electricity will flow from low priced regions across interconnectors into higher price regions. Counter-price flows occur when electricity is exported from a high price region into a lower priced region as a result of the incentives in the current regime when there is congestion within a region. This occurs when parties faced with congestion in their region bid to the price floor and NEMDE determines that the optimal outcome to manage congestion in that region is to force the flow of electricity into an adjoining region. This possibility is enhanced by the fact that interconnectors have no ramp rates, which allows for the flow of electricity over interconnectors to be changed very quickly.

An example of counter-price flows on an interconnector is set out in Figure 10 below. For simplicity, the numbers calculated assume an hourly trading interval. While there can be many causes of counter-price flows, in this simplified example there is a constraint between the RRN in region A and the RRN in region B. This constraint causes the two RRPs to diverge. The actual constraint though is within region B.

FIGURE 10 CONGESTION AND COUNTER-PRICE FLOWS ON AN INTERCONNECTOR



Generator G1 is constrained off from its regional reference node and cannot dispatch its output despite the fact its costs are lower than its regional price. In such a case, Generator G1 could bid -$1,000 to maximise its dispatch, knowing it is constrained off from the node and therefore cannot set price. Having the lowest offer price, Generator G1 will be dispatched by NEMDE, even though the power generated by G1 cannot reach the demand centre in region B, and is instead consumed in region A. In order to ensure that demand is met in region B, it is necessary to dispatch generator G2, and this sets the RRP in that region of $100/MWh. As G1 is located in region B, it is then also paid $100/MWh. However, consumers in region A will pay only the RRP in region A of $50/MWh, including for the 200MW of G1's output consumed in that region. This results in negative inter-regional settlement residues (IRSR) of $10,000 per hour.

The negative IRSR can be greater when transfers are higher and price differentials are greater and can quickly mount up. Under the current Rules and operating procedures, AEMO would clamp flows on the interconnector as the costs accumulate. This then leads to inefficient dispatch of generators and use of the network.

There have been notable instances of counter price flows in the past, including an incident between Vic-NSW in April 2010, where $19 million of negative interregional settlement residues were accumulated in one day. The direct costs of counter-price flows are borne by customers via their transmission charges, and there are further indirect costs associated with increased wholesale market volatility and risk. These events in the past have often been complicated by the 5-minute dispatch/30 minute pricing anomaly which is now being removed.

The problems with the current regime are likely to become increasing common and significant in the future as a result of the more tidal power system flows associated with high penetrations of variable renewable energy, which results in more frequent congestion. Many of the proposed REZs are along inter-connectors and electrically close to regional boundaries which would exacerbate the potential issues.

6.3 Next steps

Based on the analysis presented above and stakeholder feedback, the ESB proposes five sets of actions. These actions form part of an implementation pathway for changes in transmission frameworks.

Step 1: Actioning the integrated system plan

The ESB developed a comprehensive set of changes to the planning frameworks, with these now in place, supported by AER guidelines. These rules are designed to streamline regulatory processes to support the implementation of key transmission projects identified in the ISP, while maintaining checks and balances on investment decisions through cost-benefit analysis and consultation.

The AER is undertaking a further work program to provide more predictability about how the AER will assess actionable ISP projects under the economic regulatory framework and improve the AER's regulatory assessment tools/processes to ensure they remain fit-for-purpose for large actionable ISP projects.[66]

The AER is also exploring whether there are opportunities to amend the regulatory framework to further improve the assessment or delivery of actionable ISP projects in the medium to longer term, such as improving the assessment process for actionable ISP projects and increasing competitive tension in the procurement and delivery of actionable ISP projects.

Step 2: Implementing and delivering renewable energy zones

Developing the framework for REZs is the key focus for the ESB at the current time. REZs are a key stepping-stone to build towards the long-term goal of locational marginal pricing and financial transmission rights.

The ESB has already progressed planning arrangements for REZs through stage 1 of its REZ work program, and is now considering connection, access and pricing frameworks for REZs. Stakeholders sought further detail about how REZs would work and the accompanying consultation paper sets out issues associated with REZs.

The Stage 2 REZ Consultation paper will also provide an opportunity for coordination and collaboration with jurisdictional governments' proposed REZ plans. New South Wales, Queensland and Victoria have all announced substantial REZ plans and the ESB is working to provide a national REZ framework which can facilitate these plans. Of particular importance is the need for the ESB to develop a REZ access framework to allow the effective operation of jurisdictional REZ proposals on meshed transmission infrastructure. Further discussion of this issue is included in the Stage 2 REZ Consultation paper.

The ESB considers that REZs need some form of access solution to function effectively. This makes them very valuable test cases for wider access reforms.

Step 3: Enhancing and supplementing congestion information

Some stakeholders suggested that information about congestion could be improved. ESB is considering ways to improve information and visibility to the market about where congestion exists, and what is forecast in future. Some options for enhanced information frameworks are set out below. This will supplement existing information provided to generators and the market about the amount of congestion and reduce transitional risks from uncertainty in moving to the long term transmission access regime. The ESB will continue to develop this option for further consideration in the March Consultation Paper.

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

TEXT BOX 10 ENHANCED CONGESTION INFORMATION OPTIONS

Under the current regulatory framework, AEMO is required to develop and publish a Congestion Information Resource (CIR).[59] The objective of the congestion information resource 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.

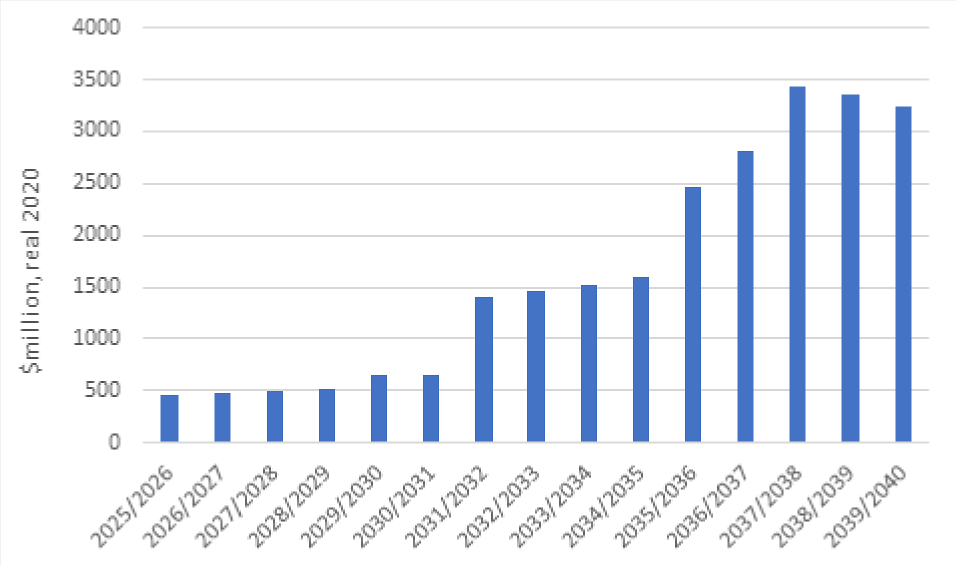
Information regarding congestion is also provided through AEMO's Market Management System database (MMS). The MMS database sets out the local pricing offsets (shadow locational marginal prices) associated with each generator connection point.

Options to improve the information and visibility about where congestion exists, and what is forecast in the future are:

1. Publish local pricing offsets more prominently.
   - Parties already have access to historical looking shadow prices through the MMS database. However, this information could be made to be more easily accessible on AEMO's website to better show the impact of congestion in the NEM.
   - While this option would be very low cost and easy to implement it has substantial limitations. Firstly, the prices are backwards looking, and don't offer an indication of future congestion. Secondly, the prices are influenced by bids made by generators under the regional pricing regime, which provides incentives to participate in race to the floor bidding, which inflates the reported costs of congestion.[60]
2. Improve the congestion information available to participants.
   - Given the issues associated with the current congestion information, the information could be provided in an improved "cleaned" state to remove the impact of distorted bidding incentives that are present in the NEM under regional pricing.
   - Similar work has been completed in the past by administratively determining estimates in place of unreliable datapoints that are influenced by race to the floor bidding or constraint violation penalties.
   - As is the case with option 1, this information would only be backwards looking, and would not offer a forecast of future congestion.
3. Establish a near term congestion forecasting framework:
   - This type of forecast would largely be designed to help participants. It could align with the ASX forward pricing curve, as well as reasonable expectations of the generation connection pipeline.
   - This method could be updated on a rolling annual basis to provide useful information that broadly aligns with investment and policy timeframes. The relatively short timeframe of this forecast could produce more meaningful and accurate results.
   - However, the timeframe for forecast might not align with transmission investment cycles or generation asset lives.
4. Establish a long-term congestion forecasting framework.
   - This forecast would align with long term forecasts such as those in the ISP and the ESOO, as well as the typical generation asset life.

- This would be a significant modelling exercise that would likely have material costs associated. The long-term nature would also likely reduce the accuracy of the results for specific projects and therefore reduce its benefits for participants.
- The task would likely be similar to that modelled under the no reform case by NERA in the AEMC's recent cost-benefit analysis in the September interim report (as set out below).

FIGURE 11 TOTAL CONGESTION RENT, BY FINANCIAL YEAR (NO REFORM CASE)



For any additional role conferred on AEMO to produce a congestion resource, consideration would need to be given to AEMO's resources and funding as this would be an additional role to what it currently does.

Step 4: Transition pathways

The ESB recognises that the introduction of locational marginal pricing and financial transmission rights is a large change for participants. We are therefore considering alternative paths for moving towards a long term solution that mitigate the risks (for example, contract market liquidity) in transition as well as the impact on existing contracts, which are key concerns for stakeholders.

In addition to the arrangements set out in the REZ consultation paper, this includes considering appropriate transition and implementation dates and transitional arrangements (grandfathering). For example, a number of participants considered that the proposed date of four years after the completion of the relevant Rule change is too soon.

Developing the REZ models in more detail will enable stakeholders to get a more granular understanding of the strengths and weakness of the alternatives to locational marginal pricing and financial transmission rights.

The transmission network recommended by the ISP is an efficient grid, not an uncongested grid. As the power system evolves and more REZs are implemented, congestion outside the REZ can be expected to become more common and impact on dispatch outcomes of generators within the REZ. The ESB considers that a stand-alone REZ model, without additional reform, will not be fit for the future.

The ESB is developing a set of reforms that could build on the REZ model to provide a stepping-stone towards the long-term, whole of system access solution. These reforms will be designed to mitigate the concerns raised by stakeholders in relation to the proposed transmission access model including the risks in transition and the impact on existing contracts.

The ESB will consider the transition to a whole of system access solution in early 2021. Ideally, the transitional solution could be implemented on a timetable that is designed to be compatible with the other Post-2025 market design reforms. Alignment with the longer-term direction would also be important in choosing the preferred option for REZ implementation. However, the interim REZ option chosen would be designed to be able to be implemented in the near future on a stand-alone basis.

Step 5: Enduring transmission access solution

The final step in this implementation pathway is the introduction of a long term transmission access regime. Locational marginal pricing and financial transmission rights would improve the locational signals faced by participants and efficiently manage congestion. The design of this framework is well progressed, and the latest information was set out in the AEMC's September Updated technical design specification and cost-benefit analysis report.

As stakeholders have highlighted, this is a major reform and it is therefore important that the introduction of transmission access reform is closely coordinated with the other Post-2025 reforms. By taking time to set out REZ frameworks and developing transition pathways, further decisions will be made across the Post-2025 program which will allow for greater coordination with transmission access reform.

In recognition of these concerns, the immediate focus of the ESB's work is now on developing arrangements to implement REZs. The work on REZ development will occur ahead of further work to progress the long term transmission access regime.

The transition to a whole of system solution could be implemented on a timetable that is compatible with the other Post-2025 market design initiatives.

7 EVALUATION AND INTERDEPENDENCIES

In the ESB's September Consultation, a two-phase evaluation process was outlined. A number of stakeholders requested more information on the evaluation process. In particular around the form of the final recommendations and how the evaluation process will support their development.

In this section we outline our current thinking on:

- The form of the final recommendations and arrangements,
- What form of options to be evaluated, how these will be evaluated and when in the process the evaluation will occur,
- Governance and implementation arrangements,
- How stakeholders may be involved in the evaluation process.

7.1 Form of final recommendations

The recommendations made by the Post-2025 project will likely indicate a market development program. That is, recommendations will set out a series of reforms that can be implemented over time as the market develops and that can be coordinated to minimise system implementation costs on participants and the market operator. This is opposed to a 'big bang' reform that commences on 1 January 2025.

The proposed reforms will be at varying levels of maturity. For example, some reforms may relate to urgent system security matters and be progressed through AEMC or ESB rule change processes, as is proposed to occur with fast frequency response for example.

The ESB will work with jurisdictions to develop governance arrangements to guide the implementation of the Post-2025 reforms. We anticipate that many proposals will need to go through an AEMC rule change process to be implemented. However, governance arrangements will be needed to coordinate decision making between the market bodies, jurisdictions and others responsible for implementation. This will be critical to maintaining a coherent market development path.

7.2 Options to be evaluated

Phase 1 evaluation – evaluation of individual market solutions

This phase will include an evaluation of the proposed solutions *within* each workstream against criteria set out in Table 6 below. The purpose of this evaluation is to ensure individual design components are based on principles of sound market design, individually meet the NEO, and will be suitable to be combined into an overall market design.

The evaluation will likely be an iterative process, with criteria applied considered several times to assist with the development of detailed market design options. To assist with this process the ESB will seek input and advice from industry participants, consumer advocates, investors and other experts through the Post-2025 technical working group and expert advisory group.

The ESB intends to complete this evaluation by the end of March 2021, after which an overall market design will be proposed for more intense evaluation in Phase 2.

At the end of Phase 1, we will propose a preferred overall package of reforms and implementation path to be evaluated and refined. The overall package may include variants of options (e.g. more than one design of an operating reserve) but will not present competing overall market designs.

TABLE 6 PHASE ONE – WORKSTREAM LEVEL ASSESSMENT CRITERIA

Assessment criteria	Description
1.Facilitate effective outcomes for all consumers - via competition where efficient and complemented by effective consumer protections and regulation where appropriate.	Rivalry in competitive markets should promote efficiencies and innovation, but should be complemented by effective consumer protection regulations to mitigate against poor or misleading conduct, and to protect those who are vulnerable or unable to safeguard their interests. Frameworks should also ensure that regulated entities such as network monopolies are subject to effective economic regulation that promotes efficiency, reliability, system security and safety.
2. Promote signals for efficient investment and operations	Efficient arrangements maximise the provision of price signals that reflect the marginal cost of the provision of a particular product or service, as well as any positive or negative externalities, in order to encourage timely and efficient decision-making in both investment, demand and operational time-scales. Efficient outcomes will be enabled across productive, allocative, technical and dynamic dimensions, supporting more efficient and effective use of capital and energy. While price signals are preferred, there may be other signals that can also be provided such as the greater provision of market information to participants.
3. Appropriate cost and risk allocation	Risk and cost allocation, and the accountability for investment and operational decisions should rest with those parties best placed to manage them.
4. Technology neutrality	Regulatory arrangements must be flexible to changing market conditions and take into account the full range of potential market and network solutions and support innovation and dynamic efficiency. They should support the right mix of resources over time, reflecting supply and demand side participants and solutions, technological developments and changes in behaviour, rather than be designed solely for the prevailing technology or business model of the day.
5. Cross-market integration	Costs to consumers will be minimised when markets complementary to energy, such as ancillary services and emissions, are designed in a way that is consistent with the price discovery mechanism in the electricity market.
6. Regulatory and administrative costs	Practical, operational and compliance impacts result in minimal unintended consequences. Changes to regulatory frameworks come with associated costs. These costs include both those imposed to implement change and the ongoing costs associated with making the change.
7. Ability to deliver a reliable system and support system security	Security and reliability challenges need to be considered as supply and demand become more variable and uncertain, and the industry transitions away from generation that traditionally delivered security services.

Evaluation Phase 2 - program level evaluation

The Phase 2 evaluation will be focused on evaluating the proposed reform package against the Phase 2 criteria (see Table 7 below), reflecting the best combinations of viable solutions brought together from across the MDI workstreams to meet the NEO.

TABLE 7 PHASE TWO – PROGRAM LEVEL ASSESSMENT CRITERIA

Principles	Description
A. Proportionate	The scale of change delivered by the design is relative to the scale of the risk and problem being mitigated and/or the potential opportunity to be gained. Design solutions may need to evolve over time in response to growing risks / opportunities; but should target the proportionate degree of change in response to the needs of the transition.
B. Credible	Capacity to evolve from current policy settings and achieve broad support. Design provides a clear and objective basis for where amendments may be warranted to phase in certain elements of the framework.
C. Affordable and equitable	Costs associated with market design are affordable and fair. Design works to optimise use of resources for the benefit of all consumers, providing enhanced opportunities for consumers to engage in and receive value from new service models.
D. Community support	Public and consumers can understand the rationale and general direction of market design. Alignment with social license expectations of community (i.e. energy as an essential service, applies appropriate degree of customer protections, supports and enables future pathways for jobs, growth, and environmental concerns).
E. Viable and coherent	Elements of the design are congruent, with interdependencies considered and highlighted. The design presents a viable and effective option that clearly addresses the problems identified. Design provides clarity and confidence regarding scope and timing of changes and a pathway for future transition needs.
F. Resilient and flexible	Ability for the design to withstand and be flexible to changes in policy targets, political developments and technological change in the broader policy landscape. The design should be resilient and flexible to such changes but enable new technology developments and business models to emerge and meet the needs of energy consumers.
G. Supports lower emissions	Ability for the design to align with decarbonization objectives and deliver reduction in carbon emissions.

7.3 Quantitative evaluation

The ESB intends to conduct a quantitative evaluation to understand the impacts of key elements of the proposed overall reform package. The purpose of the quantitative evaluation is to understand economic, market, contract and consumer impacts (particularly how price signals are seen by consumers).

The ESB intends to develop a common baseline model of the NEM (using the current Rules framework) against which key elements of the proposed reform package can be evaluated as deviations.

The ESB will start working with the Post-2025 Interdependencies and Evaluation Working Group and expert modellers to develop the approach from the beginning of 2021.

Development of governance arrangements and an IT road map for implementation

We expect that the final set of recommendations will support a reform road map with some reforms more advanced than others. This means that there will need to be an ongoing mechanism to oversee implementation and the required further development of less mature options. Some aspects of this mechanism should be considered by Ministers as they settle governance arrangements to apply after the ESB has finished its work. In addition, the ESB will provide advice on appropriate review and trigger points that should form part of the implementation path, reflecting the changing mix of market and system conditions that will shape what changes to systems, tools and market arrangements are needed over the transition period.

The ESB will develop a joint program plan, reflecting the directions set out in this paper, for consideration of the first quarter of 2021. With the narrowing of options between the September Consultation and now, this process will support a more detailed consideration of interdependencies and any issues of congruency exist across potential solutions.

As part of this, we intend to consider where opportunities may exist to leverage existing reviews or rule change processes to further develop or implement changes, or where potential exists to package reforms in a way that can minimise costs associated with systems and IT implementation.

Work has been undertaken across the market bodies this year to support efficient sequencing and prioritisation of implementation of rule change and review activities. The ESB will work with the market bodies to further align consideration of proposals across the Post-2025 program with this work.

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