Australian Energy Market Commission

REVIEW

FINAL REPORT

ELECTRICITY NETWORK ECONOMIC REGULATORY FRAMEWORK 2020 REVIEW

1 OCTOBER 2020

INQUIRIES

Australian Energy Market Commission
GPO Box 2603
Sydney NSW 2000

E aemc@aemc.gov.au
T (02) 8296 7800

Reference: EPR0085

CITATION

AEMC, Electricity network economic regulatory framework 2020 review, Final report, 1 October 2020

ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

CONTENTS

APPENDICES

TABLES

FIGURES

1 OVERVIEW

1.1 The 2020 Review — keeping an eye on the horizon

Australia's electricity markets are undergoing a profound transformation which reflects the transition from a centralised system dominated by thermal generation to one that sees increasing diversity in generation that includes both grid scale and distributed renewable generation resources, supported by energy storage and network solutions.[1] The way consumers interact with the electricity system is also changing in response to new technology and market developments, and climate change concerns.

The purpose of this annual review is to consider whether the economic regulatory framework for electricity networks continues to support the delivery of the national electricity objective (NEO) in light of these changes in the energy market.[2]

In making this assessment, the Australian Energy Market Commission (the Commission) undertakes significant, ongoing consultation with stakeholders to understand different perspectives and identify opportunities for reform. This consultation informs the Commission's understanding of how key reforms are progressing and what it should prioritise next.

The Commission welcomes this feedback and endeavours to engage collaboratively and transparently to develop a shared vision of the future of the energy sector. This feedback is also an important input into decisions on how the Commission prioritises its reform program.

In the *2020 Economic regulatory framework review* (2020 Review), the Commission outlines its priority reform considerations for distribution and transmission network regulation over the next 18 months, and how this fits with longer term market reforms led by the Energy Security Board (ESB) *Post 2025 Market Design* for the national electricity market (NEM). In particular, this year's report explores the implications of some major developments highlighted by this consultation:

- the evolving role of distribution networks
- the implementation of the Integrated System Plan (ISP) for transmission networks
- innovative approaches to consumer engagement.

1.2 Stakeholder consultation

For this year's review, the Commission engaged an expert consultant, farrierswier, to conduct a series of independent interviews with key stakeholders to explore priorities for network regulation reform and better understand stakeholder views. Farrierswier conducted 17 interviews with a wide range of organisations, including consumer groups, network businesses, retailers, market bodies and governments. The report prepared for the Commission can be found on this project's web page.[3]

1 AEMO, *2020 Integrated System Plan*, p. 11.

2 See: https://www.aemc.gov.au/sites/default/files/2018-07/Terms%20of%20reference.PDF

3 See: https://www.aemc.gov.au/market-reviews-advice/electricity-network-economic-regulatory-framework-review-2020

The Commission also received 14 submissions, which are also available on the project's web page. Issues raised in submissions are discussed and responded to throughout this report. Issues that are not addressed in the body of this document are listed in appendix D.

Stakeholders identified a wide range of issues that may require attention or reform — some of them are emerging issues beyond DER integration. The Commission also received mixed feedback from stakeholders on how these issues should be progressed.

1.3 Distribution

The 2020 Review has highlighted a clear need for a holistic consideration of the regulatory framework for distribution networks. Stakeholders have raised a number of issues relevant to the evolving role of distribution networks. They have also highlighted the desire for a coordinated and strategic approach to manage the electricity sector's transformation, especially in relation to DER integration. These issues are discussed in further detail in chapter 2 of this report.

There is a significant program of work under way to integrate DER into the electricity system. The three market bodies are working together with the ESB to identify and address current and future challenges and opportunities associated with efficiently DER into the electricity system (see Box 1 below). The Commission will make a significant contribution to this program of work. The Commission is currently considering several related rule change requests, including distribution access and pricing reforms.

BOX 1: THE ESB'S DER INTEGRATION ROADMAP

The ESB's DER integration work program has three overlapping stages:

- Foundational stage: technical standards will be put in place, especially to support system security and distribution network operation. New governance arrangements will ensure standards can be updated and new standards created as needed, including to support DER market participation.
- Facilitating participation stage: regulatory changes will be made to support DER participation in the NEM, especially through smarter distributor systems (a combination of regulatory and technical changes)
- Full market participation stage: where DER is active and optimised to unlock value across the system and markets. Planning is underway for this stage.

Source: Energy Security Board, *DER Integration Roadmap*, September 2020.

Further, as part of the ESB's *DER Integration Roadmap*, the Commission will commence work to identify further reforms needed to clarify the role of distributors and better facilitate the integration of DER. This includes consultation on potential reforms to promote non-network options and address any barriers to the efficient deployment of community scale storage — responding to stakeholder submissions to the 2020 Review. The Commission will prioritise this work over the next 18 months.

1.4 Transmission

The way transmission planning is undertaken is changing with the introduction of the Integrated System Plan. The ISP is a whole-of-system plan to maximise net market benefits and deliver low-cost, secure and reliable energy through a complex and comprehensive range of plausible energy futures.

Significant transmission investment has been proposed over the next few years. Actionable projects under the 2020 ISP are expected to cost over $11 billion from 2022 to 2026.

A timely question is whether the existing economic regulatory framework remains fit-for-purpose when these large, discrete, non-recurrent transmission investments are required, such as the large transmission projects identified in the ISP.

Stakeholders raised concerns that the current regulatory framework may not be suitable for new actionable ISP projects. The ISP planning approach to identify necessary transmission network investments across the NEM may be inconsistent with an *ex ante* incentive-based regulatory framework. These issues are further explored in chapter 3 of this report.

The Commission will work closely with the Australian Energy Regulator (AER) to understand whether any changes are required to the economic regulatory framework for transmission networks. We are closely monitoring this transition to identify any tensions in the current framework.

1.5 Consumer engagement

Network businesses have made significant improvements to the way in which they engage with consumers in recent years. Previous consumer engagement reforms have been a success, although there is scope for further improvements and to embed this cultural change into 'business-as-usual' operations.

In chapter 4 of this report, the Commission considers new reforms to further promote consumer engagement. Leveraging process-based incentives could give consumers a greater say in the development of regulatory proposals and outcomes that ultimately impact their energy service provision — while providing a 'way around' the inherent resource imbalance between consumers and the network businesses.

Specifically, increased regulatory flexibility could allow the AER to adopt consumer 'negotiated settlements' with networks and, possibly taking these agreements into account, expedite and/or streamline its regulatory determination processes. But such changes raise fundamental questions about the intent and framing of network regulation and require careful consideration.

These policy issues can be progressed by the AER, Energy Consumers Australia (ECA) and Energy Networks Australia (ENA) as part of the 'New Reg' project.

1.6 The Commission's reform priorities

The issues identified in this year's review have differing levels of urgency. Some of the actions identified in this year's review require significant stakeholder consultation, while some require further investigation or continual monitoring. Table 1.1 below provides a high level summary of the Commission's regulatory reform priorities in the near future.

Table 1.1: Commission's priorities

PRIORITY	YEAR
• Consider DER integration rule change requests. • Consider DER Initial minimum technical rule change request. • Progress DER integration activities identified under the ESB *Post-2025 market design* project.	2020
• Consult with stakeholders on potential changes required to the regulatory framework to support DNSPs' efficient integration of DER — including issues such as community batteries, ringfencing, clarification of role for DNSPs and implications on economic regulation of networks. • In conjunction with the AER, consider whether changes are needed to the transmission investment framework in the context of implementing the ISP.	2021
• Progress rule change requests identified in the consultation on changes required to the regulatory framework. • Continue to monitor developments in consumer engagement, consider rule change requests if proposed by AER/ECA/ENA.	2022 and beyond

The Commission is cognisant of the number of reform processes that stakeholders are being asked to engage in the next 18 months, notably the ESB 2025 reform process. The Commission has proposed that it does not publish this report in 2021, focusing on supporting the ESB 2025 processes and progressing the reforms outlined in Table 1.1.

The Commission will continue to engage with stakeholders to monitor emerging issues and consider future priorities, especially in relation to DER integration, implementation of the ISP and consumer engagement.

2 DISTRIBUTION: ADAPTING THE REGULATORY FRAMEWORK

Through submissions and interviews, stakeholders have raised a wide range of other issues relating to the current regulatory frameworks for distribution networks in the context of sector transformation. This was reinforced by a significant focus in the interviews conducted by farrierswier.

Some of the issues raised include considering the role of distribution-connected batteries, the role that DER, stand-alone power systems and microgrids are to play in networks' fulfilment of obligations and provision of services to consumers, as well as how distribution network service providers (DNSPs) should manage extreme climate risks.

While these issues could potentially be addressed through discrete rule change projects, they are also interrelated. Attending to these issues individually will not address stakeholders' desire for a coordinated and strategic approach to network transformation, and clarity on the role of DNSPs in a more decentralised electricity system.

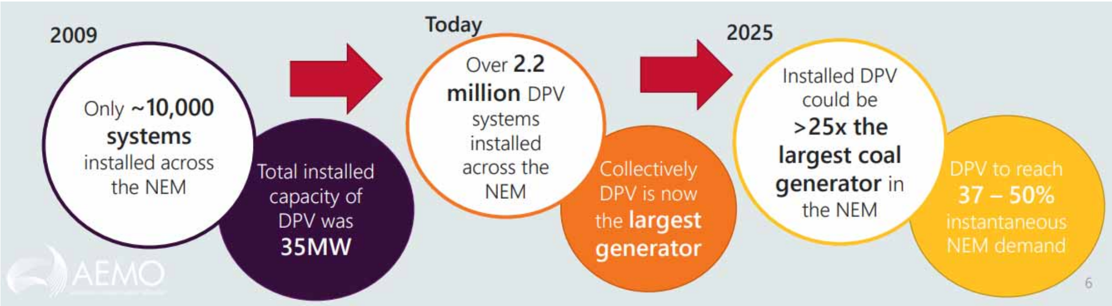
There is a clear need for a holistic consideration of the regulatory framework for the distribution network, including clarifying the role of DNSPs in the changing electricity sector, and to ensure an appropriate regulatory framework is in place to support network transformation. The Commission will prioritise this work over the next 18 months.

2.1 Context

One of the key aspects of the electricity system transformation is the increasing uptake of distributed energy resources. These resources can provide services to different parts of the electricity system, including network businesses, the wholesale market and consumers themselves.

According to AEMO's forecasts, rooftop solar installed capacity across the NEM is set to far exceed that of the largest remaining coal generator in the NEM in the near future.

Figure 2.1: DER uptake trends



Source: AEMO, *Distributed PV: An overview of the RIS Technical Appendix A*, May 2020.

This consumer-led uptake of DER is changing the way the distribution network is being used. The system that was designed for one-way flow is now providing two-way flows. It is also playing an increasing role as an interface for customers to participate in changing energy markets for both the purchase and sale of energy services.

Distribution networks have an important role to play in facilitating these services, but there remains an unresolved debate on the exact nature of this role.

The increased penetration of DER also has system-level implications. At the same time that DER has the potential to provide flexibility to the electricity system and to reduce wholesale costs for consumers, it can also create challenges.

Some immediate challenges faced by consumers include the increasing instances of distribution network constraints, preventing consumers from exporting their surplus energy into the grid.

The market bodies and the Energy Security Board have work programs to address many of the challenges and realise the benefits of DER integration. For example, the Commission's *2019 Electricity network economic regulatory framework review* (2019 Review) set out ten recommendations, and many of them are already underway — see appendix A for a summary of progress.

Distribution access and pricing reform was a key recommendation from the 2019 Review. The Commission's investigation clearly identified that the current distribution access and pricing framework is unsuitable for a high DER future.

The Commission worked extensively with a range of stakeholders through ARENA's DEIP collaboration platform to develop consensus on the understanding of issues and exploration of potential reform actions. These are significant reforms and there are now three rule change requests before us to progress this reform.

The access and pricing rule change requests address a key part of the reforms needed to enable the framework to better support the sector's transition. Box 2 below provides a high level summary of the rule change requests.[4]

4 See: https://www.aemc.gov.au/news-centre/media-releases/consultation-underway-requests-new-rules-better-integrate-distributed

BOX 2: DISTRIBUTION ACCESS AND PRICING RULE CHANGES

In July 2020, the Commission received three rule change requests from SA Power Networks, the St Vincent de Paul Society Victoria, and Total Environment Centre together with the Australian Council of Social Service.

The increased uptake of DER, especially rooftop solar, is redefining the role of distribution networks. The proponents consider the current regulatory framework is no longer fit-for-purpose.

This package of reforms aims to unlock the benefits of DER by providing greater flexibility for the AER and distribution businesses to efficiently meet consumer preferences. The proposals focus on three key areas:

1. Updating the regulatory framework to reflect the community expectation for distributors to efficiently provide export services to support DER.
2. Promoting incentives for efficient investment in, and operation and use of, export services.
3. Enabling new pricing arrangements to:
    a. send efficient signals for future expenditure associated with export services
    b. reward customers for actions that better utilise the network or improve network operations
    c. allocate costs in a fair and efficient way.

Note: A consultation paper was published on 30 July 2020. The first round of consultation has been completed. A final rule is expected to be published by February 2021.

2.2 Community scale storage, ring-fencing and clarifying the role of DNSPs

As consumers' interactions with the electricity system evolve, so will their expectations and required standards of service. In a high DER future, the electricity system (especially at the distribution level) is increasingly likely to have multi-directional flows and become a platform to support different services that future electricity system users may value, such as access to various markets. The future electricity system and the regulatory framework need to be able to support these and potentially many other varieties of use.

2.2.1 Community scale batteries

The nature of rooftop solar system means that electricity is only generated at certain times of the day. If the electricity usage at the premises where the system is installed is lower than generation, the surplus generation is exported into the grid. In parts of the network with a high uptake of rooftop solar systems, this could lead to reverse flow — where the distribution system is transporting electricity upstream, away from a consumer.

Battery storage can play an important role in these instances. Batteries can store excess generation which can be used when the rooftop solar system is no longer generating. Battery storage units that are located at a customer's premises (behind-the-meter) are increasingly being installed. However, the costs of these batteries remain high, and for customers with a large rooftop solar system, the battery can be fully charged quite early in the day.

It is in this context that some industry participants are exploring community scale batteries as a potential alternative solution.

Community scale batteries are large capacity batteries that are connected directly to the distribution network ('in front' of the meters of individual customers), and are capable of providing a range of services such as, essential system services such as frequency control ancillary service (FCAS), arbitrage in the spot market, or network support.

Figure 2.2: Community scale battery

Source: AEMC

There are a number of potential ownership and operating models for community scale batteries. Two models that are currently being considered by industry participants are third-party owned/operated and DNSP owned/operated. Under both of these ownership models, the batteries could potentially be operated for profit, or for 'community benefit'.

A number of trials and research programs have been undertaken to examine the viability of community scale batteries. One such program was led by the Australian National University under ARENA's Advancing Renewables Program, the *'Community Models for Deploying and Operating DER'* project, aims to demonstrate how community energy models can reduce costs for consumers while increasing the amount of renewable energy generation and storage that can be installed in electricity distribution networks.

The project commenced in January 2019 and has since published three reports:[5]

1. Operating a community scale battery: electricity tariffs to maximise customer and network benefits
2. Community batteries: a cost/benefit analysis
3. Stakeholder views on the potential role of community scale storage in Australia.

ARENA has recently released the third report from the project[6] and Box 3 below highlights the key findings of the research.

BOX 3: ARENA'S REPORT ON 'STAKEHOLDER VIEWS ON THE POTENTIAL ROLE OF COMMUNITY SCALE STORAGE IN AUSTRALIA'

The report commissioned by ARENA found a consensus view from stakeholders about community scale storage (community batteries) in Australia over the opportunity presented for a wide range of economic, technical, social and environmental benefits.

However, the report noted that the appeal of such benefits differs between energy businesses, energy sector professionals and the general community. According to the findings, the design of battery models and ownership arrangements would have implications for the distribution of these benefits and must be taken into account by any proposed regulatory changes.

The report highlighted that whether the proposed storage is actually viewed as a 'community battery' will depend on a range of considerations including how householders are engaged in the design and how the benefits are distributed. As such, any proposed regulatory changes must take this into account and provide a pathway to explore different models to reveal which models are most likely to benefit all energy consumers. It also revealed the potential for some groups to resist regulatory or policy changes that enable benefits to be unlocked to new entrants.

A clear finding of this research was that a range of models are possible, all with different value propositions, and different regulatory barriers. Many participants also raised the point that regulation of community batteries needs to be adaptable and flexible.

The report emphasised that there was strong consensus among participants about the value of trials and demonstrations, indicating that demonstrations would enable the sector to understand the different financial and non-financial values storage models could bring as well as the different options for community participation. Regulatory sandboxes were recommended as a way to enable these trials.

Source: Australia National University, *Stakeholder views on the potential role of community scale storage in Australia*, August 2020.

5 See: https://arena.gov.au/projects/community-models-for-deploying-and-operating-distributed-energy-resources/

6 See: https://arena.gov.au/assets/2020/08/stakeholder-views-on-community-scale-storage-in-australia.pdf

As outlined above, some stakeholders were of the view that the current rules are a barrier to the deployment of community batteries in the NEM.

Submissions to this review have also noted the interest in community batteries and raised concerns about barriers to deployment of community scale batteries in the NEM:

- Ausgrid indicated that there is a strong community interest in unlocking the potential of community solar and storage solutions to enable more renewables, provide shared access to DER and improve the resilience of communities.[7]
- The Clean Energy Council added that the integration of batteries into local communities would improve the ability of DNSPs to balance neighbourhood load profiles and enable more homes to install solar panels.[8]
- Ausgrid also noted that another barrier to the development of community energy projects is the way energy is settled in the NEM, and suggested that changes are required to metrology or customer connection arrangements to resolve these market settlement issues.[9]

The Commission acknowledges that there is growing interest in community scale batteries, that these arrangements are a potential tool to facilitate better integration of DER into the electricity system, and that some stakeholders are concerned that the current regulatory arrangements may create barriers for the deployment of community scale storage.

Rule change requests such as the distribution access and pricing rule change package and the *'Integrating storage into the NEM'* may address some barriers. However, depending on the ownership model of the community scale battery, issues such as cost recovery and ring-fencing arrangements may need to be reviewed. A number of stakeholder submissions have raised ring-fencing as an issue. This is further discussed in section 2.2.2 below.

2.2.2 Where is the boundary between monopoly and competitive services?

Ring-fencing is the identification and separation of regulated monopoly business activities, costs and revenues from those associated with providing services in a contestable market.

Ring-fencing obligations that apply to DNSPs generally require the separation of the legal, accounting and functional aspects of regulated distribution services from other services provided by the DNSP.[10]

The objective of the ring-fencing obligations is to provide a level playing field for third-party providers in new and existing markets for contestable services, such as those for metering and energy storage services, in order to promote competition in the provision of electricity services.

Without effective ring-fencing, a distribution business could hold significant advantages in such markets.

7 Ausgrid, *submission to approach paper,* p. 3.

8 Clean Energy Council, *submission to approach paper,* p. 2.

9 Ausgrid, *submission to approach paper,* p. 2.

10 See NER Chapter 6, Part H and AER, *Ring-fencing guideline — Electricity distribution version 2*, explanatory statement, October 2017, p. 8.

Box 4 below provides a summary of the key ring-fencing obligations included in the regulatory framework.

BOX 4: RING-FENCING OBLIGATIONS

What's in the rules?

Clause 6.17.2 of the National Electricity Rules (NER) requires the AER to develop *Electricity Distribution Ring-fencing Guidelines*, which are binding on all DNSPs under clause 6.17.1 of the NER.

The rules provide the AER with principles and minimum content requirements for the guidelines. In addition, clause 6.17.2(b)(2) allows the AER to grant a DNSP a waiver from ring-fencing obligations.

What's in the AER's guideline?

The ring-fencing guideline is made up of several components. These include provisions to mitigate risk of cross-subsidies and discrimination, waivers, reporting and compliance, and transitional issues.

Measures targeted at cross-subsidisation include legal separation, separate accounting and strict cost allocation arrangements.

Measures targeted at discrimination include specific obligations around office sharing, staff sharing, branding and promotions and information access and disclosure obligations, to prevent a DNSP conferring a competitive advantage on its related electricity service providers that provide contestable electricity services and ensure a DNSP keeps information it acquires or generates confidential, and handles that information appropriately.

The guideline also includes obligations on regular reporting of compliance as well as preparation of annual compliance reports that have been assessed by appropriately qualified independent assessors.

What flexibility does the AER have?

The AER can grant a waiver that exempts a DNSP from having to satisfy one or more of the obligations in the guideline's provisions. DNSPs can apply for waivers in relation to the functional separation of accommodation or employees, co-branding obligations and in respect of legal separation.

However, not all provisions are subject to waivers. Core ring-fencing obligations for cost allocation, separate accounts, non-discrimination and information protection cannot be waived.

Source: AER, *Ring-fencing guideline — Electricity distribution*, version 2, October 2017.

The current ring-fencing arrangements was another common theme raised by stakeholders:

- Ausgrid argued that the current ring-fencing and service classification arrangements must be examined to evaluate whether they are flexible enough to allow businesses to innovate and trial new services in collaboration with their customers. In its view, ring-fencing is currently preventing Ausgrid from offering customers any sort of battery access service.[11] In addition, Ausgrid highlighted that the Energy Security Board has questioned in its *Health of the NEM* report whether ring-fencing is constraining innovation in the context of a transitioning system.[12]
- Conversely, AGL suggested a review to consider whether contestability should extend to distribution-connected 'front-of-meter' assets to enable efficient deployment as well as co-optimisation of value streams for the benefit of all consumers through orchestration.[13]
- Energy Networks Australia indicated its support for sufficiently flexible ring-fencing arrangements to ensure that distribution businesses are able to provide innovative solutions that reflect customer and community preferences.[14]

We note that, in 2019, the AER started reviewing the ring-fencing guidelines for both transmission and distribution. However, due to the COVID-19 pandemic, this project was put on hold. The Commission understands that some issues related to ring-fencing, such as community batteries, may be addressed in the AER's review.

The AER has recently released an updated timeline for the review. The next steps for each review are:

- Distribution: publish an issues paper in October 2020 (focused on possible amendments including stand-alone power systems exemptions and treatment of batteries) and a final guideline in June 2021.[15]
- Transmission: publish a draft guideline in September 2021.[16]

2.2.3 Opportunity to optimise utilisation of existing assets

As discussed earlier, the transformation and associated decentralisation of the electricity system means electricity networks — particularly at the distribution level — provide an opportunity for existing infrastructure to be utilised differently. In this context, some stakeholders suggested that a better utilisation of existing assets would minimise the risk of asset stranding and the unnecessary over-expansion of the transmission network to facilitate the connection of large-scale generation and maintain system reliability.

For example, Essential Energy noted that while additional transmission investment may be required, there should also be consideration of measures to better utilise existing distribution

11 Ausgrid, *submission to approach paper,* p. 5.

12 Ausgrid, *submission to approach paper,* p. 5.

13 AGL, *submission to approach paper,* p. 5.

14 Energy Networks Australia, *submission to approach paper,* p. 4.

15 See: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-review-august-2019

16 See: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-transmission-ring-fencing-guideline-review

network assets. It argued that this approach is likely to be lower cost than the significant investment required to upgrade transmission infrastructure.[17]

In its view, a more effective use of local resources located on the distribution network will reduce reliance on large scale generation and transmission investment and has the potential to lower overall system costs while enhancing resilience.[18]

Similarly, the Public Interest Advocacy Centre (PIAC) noted that large investments that add cost without significant overall consumer benefit should be avoided when consumer preferences and technology are changing so quickly.[19] PIAC added that smaller investments at the distribution level that can add incremental value while also allowing an easy pivot in case of changes in technology will be a more cost effective way to start delivering more effective integration of DER into the broader market.

2.2.4 The evolving role of distribution networks

Definition of DER services and participants' roles

This theme was extensively discussed during the interviews:[20]

- The Clean Energy Council emphasised that the integration of DER requires a reconsideration of existing services and clarification of the roles and responsibilities of different parties for service provision and the balance of risk, in order to optimise the services DER can provide across the supply chain.[21]
- Various interviewees (Renew, Clean Energy Council, Uniting Communities, ENA, Ausgrid, Sonnen Australia, and Redback Technologies) highlighted the need to reconsider existing services and roles in light of DER, such as the different potential roles of batteries as services selling energy or time delayed distribution.[22]

Issues such as clarification of the role of participants in the future energy system is currently being considered under the 'Two-sided market' and the 'DER integration' work streams as part of the ESB's post-2025 program. Box 5 below provides an overview of a two-sided market and some aspects of the market design this work stream is considering.

17 Essential Energy, *submission to approach paper,* p. 2.

18 Essential Energy, *submission to approach paper,* p. 2.

19 Public Interest Advocacy Centre, *submission to approach paper,* p. 1.

20 The Commission engaged farrierswier to conduct a series of independent focused interviews with a pre-selected group of key stakeholders to discuss priorities for network regulation reform.

21 Farrierswier, *Electricity network economic regulatory framework review 2020 — stakeholder interviews report,* p. 22.

22 Farrierswier, *Electricity network economic regulatory framework review 2020 — stakeholder interviews report,* p. 17.

BOX 5: WHAT IS A TWO-SIDED MARKET?

A two-sided market is a market model that promotes direct interaction between suppliers and customers. In simple terms, a two-sided market has all its participants responding to price based on their cost and value preferences. The parties who participate in the market are exposed to its outcomes, with buyers only supplied to the extent that they buy through the market and sellers only supplying to the extent they sell through the market.

The changing context of the electricity market and changing nature of electricity consumers are opening new opportunities for significant development of the NEM's wholesale market design. The technological barriers to greater consumer participation that existed at the inception of the NEM are continually reducing.

Benefits for distribution network operation

A two-sided market design will facilitate the active participation of end users in the wholesale energy market. Through their participation in the wholesale energy market, active end users will provide information about their intention to consume or supply. This information could be utilised by distributors to determine more accurate demand forecasts for their network. A more accurate demand forecast will be a valuable input into the optimisation of network assets with increasing levels of DER.

The two-sided market will allow for easier interaction between end users (directly or through a trader, such as a retailer) and the wholesale market. The wholesale market interface could be utilised to facilitate distribution network markets and services. There is also the potential in the future to co-optimise these distribution network markets with the wholesale energy market.

Participants in the two-sided market

In designing a two-sided market, a key design element will be determining how entities should participate in the market, through scheduling and bidding obligations.

The two-sided market design envisages two critical roles in the provision and use of energy services and the trading of those services in the market — the end user and the trader. Wholesale market interactions will be done by traders, on behalf of end users, although an end user may choose to become a trader on its own behalf.

Source: Energy Security Board, *Moving to a two-sided market*, consultation paper, April 2020.

Stakeholders also voiced their frustrations about the unresolved debate on the future respective roles of AEMO and DNSPs in managing the two-way grid:

- Energy Queensland considered that there needs to be a clear articulation of the detail and implications of changes to the roles and responsibilities of market participants.[23]

23 Energy Queensland, *submission to approach paper,* p. 9.

- Ausgrid emphasised that the development of new services means existing service classifications will be put under increasing pressure, and will require innovation and the co-design of solutions with customers to meet the changing needs of a shared network.[24]

The Commission notes that the lack of clarity on the role of distribution networks in a future system of high DER penetration was a consistent theme across stakeholder submissions.

The core roles of networks in a high DER future are likely to remain the same as today. Network service providers will continue to be responsible for transporting electricity and providing a safe, secure and reliable supply of electricity as a monopoly service provider.

However, how they undertake this role could be different in a number of key respects. In particular, how the electricity distribution network is operated and the services provided by distribution networks could change.

A high DER environment could mean that DNSPs need to alter aspects of their operation, from transporting electricity one-way to being platforms for multiple services, facilitating electricity flows in multiple directions and enabling efficient access for DER so that they can provide the greatest benefits to the system as a whole. This change is likely to have implications for some features of the current regulatory framework.

2.3 Improving grid resilience and the allocation of risk

2.3.1 Dealing with extreme weather events

For stakeholders, the increasing frequency and impact of extreme events such as bushfires requires greater recognition of the need for improved network resilience within the current regulatory framework.

Essential Energy noted that the bushfire crisis represents an opportunity to consider network resilience in a practical way and highlighted some regulatory barriers to enhancing the resilience of electricity networks in remote and regional areas.[25]

For example, Essential Energy recommended the development of agreed risk parameters for the impact of climate change to facilitate an appropriate investment making process. It also suggested that the economic regulatory framework would ideally facilitate a pragmatic approach to planning for the risk of storm and bushfire activity, taking into account societal impacts and agreeing on what is expected of networks in terms of disaster response.[26]

However, to meet these expectations, Essential Energy stated there needs to be greater flexibility in how power supply is restored, which would include proactive measures to utilise stand-alone power systems in bushfire prone areas.[27]

Ausgrid has also argued, in its recent cost pass through application, that as the risks associated with the rise in global temperatures increase, the current approach to investment may need to be re-evaluated. It suggested that, given the rise in severe weather events,

24 Ausgrid, *submission to approach paper*, pp. 2, 4.

25 Essential Energy, *submission to approach paper,* p. 1.

26 Essential Energy, *submission to approach paper*, pp. 1-2.

27 Essential Energy, *submission to approach paper,* p. 2.

further investment to improve the resilience of networks and reduce the impact of extreme weather events may be more efficient by delivering a lower total cost outcome and/or a preferable lived experience for customers and the community.[28]

Stand-alone power systems (SAPS) and microgrids

Various stakeholders (Australian Energy Regulator, Clean Energy Council, EDL Energy and Essential Energy) suggested that there is likely to be an increased role for SAPS and microgrids in how DNSPs meet their supply obligations and manage emergency and fault events.[29]

It was suggested that the current framework does not incentivise optimal investment in SAPS and microgrids, and that more needs to be done to ensure that investment is encouraged.

The Ministerial Forum of Energy Ministers (formerly COAG Energy Council) has recently consulted on changes to energy laws that would allow DNSPs to invest in SAPS. Following the making of these law changes, the detailed rules on DNSP-led SAPS developed by the Commission can be implemented.

In addition, the AER indicated that it is currently considering how SAPS and microgrids could be used to reduce bushfire risk and manage network infrastructure replacement at lower cost, which will require decisions to be made on how they should be regulated and the terms of access and pricing.[30]

Risk allocation

Energy Networks Australia (ENA) argued for a thorough evaluation on the robustness of the regulatory framework and application to extreme events and risk allocation issues. In its view, all aspects of risk allocation — including in relation to extreme events — should be taken into account when examining the risk allocation between networks and consumer.[31]

ENA indicated that the development of a clear and transparent risk allocation framework would assist all market participants by providing a common understanding of where risks sit.[32]

Overall, ENA asserted that improving network resilience will require developing a fit for purpose framework that enables the efficient distributor-led roll-out of technology such as SAPS.[33]

Extreme weather events and cost pass through

The NER allows a distribution network business to make a cost pass through application after a revenue determination has been approved by the AER.[34] The pass through approach ensures the price customers pay for network services will only incorporate the cost of

28 Ausgrid, *2019-20 Storm season pass through application,* 31 July 2020, p. 12.
29 Farrierswier, *Electricity network economic regulatory framework review 2020 — stakeholder interviews report, p*. 16.
30 Farrierswier, *Electricity network economic regulatory framework review 2020 — stakeholder interviews report,* p. 16.
31 Energy Networks Australia, *submission to approach paper,* p. 3.
32 Energy Networks Australia, *submission to approach paper,* p. 4.
33 Energy Networks Australia, *submission to approach paper,* p. 4.
34 See clause 6.6.1 of the NER.

extreme weather events after they occur and after the AER has reviewed the prudence and efficiency of the costs incurred.

The Commission is aware that some DNSPs have applied for cost pass through for the costs incurred due to extreme weather events:

- On 27 May 2020, AusNet Services submitted an application to the AER for a pass through of $14.7 million for costs associated with the 2019-20 bushfires that caused significant damage to 1,000 km of power lines in parts of AusNet Services' distribution network.[35]
- On 31 July 2020, Ausgrid submitted a cost pass through application to the AER, seeking to recover $37.6 million in additional costs incurred in responding to the 2019-20 storm season that hit Sydney and caused damage to network infrastructure.[36]

However, as there is no certainty that AER will grant these applications, Energy Networks Australia argued that this is leading to networks' concern over the need to be appropriately compensated for their responses to the increasing frequency of extreme events. It noted that this is particularly important in cases where distributors are expected to fulfil a social responsibility to restore power to affected communities.[37]

2.3.2 Recent developments in this space

The Commission and other market bodies, including AEMO, recognise that climate change and the increasing frequency and severity of extreme events is having a critical impact on the electricity network and consumers.[38]

Box 6 below provides an overview of the latest developments in network resilience and the impact of climate change.

35 AusNet Services, *2019-2020 Cost pass-through application — 2020 Summer Bushfires,* 27 May 2020.

36 Ausgrid, *2019-20 Storm season pass through application,* 31 July 2020.

37 Electricity Networks Australia, *submission to approach paper,* June 2020, p. 3.

38 See, for example, AEMO, *2019-2020 NEM Summer Operations Review Report,* June 2020, p. 3

BOX 6: RECENT DEVELOPMENTS IN NETWORK RESILIENCE AND THE IMPACT OF CLIMATE CHANGE

As part of the Integrated System Plan, AEMO is planning actions to enhance energy system resilience by 2022.

Risk analysis and evaluation will explore a range of extreme weather and energy system case studies to stress test the system beyond normal operating conditions, with the view to use this analysis to explore implications on energy system planning, optimal outcomes and system resilience.

The growing evidence base of resilience risks will then be used to develop a framework for network service providers to plan the transmission network, including a list of potential solutions that can be implemented to mitigate resilience risk.[a]

Concomitantly, the Australian Government is providing $6.1 million over three years from 2018-19 to the Electricity Sector Climate Information (ESCI) Project, with the aim of improving climate and extreme weather information for the electricity sector as part of a response to the Finkel review.[b]

Led by AEMO and partnered with the Bureau of Meteorology and CSIRO Oceans and Atmospheres, the ESCI project is designed to deliver specific information and data that electricity sector decision-makers need to manage risks to the reliability and resilience of electricity systems from extreme weather events in the context of a changing climate. One aim is to develop a risk assessment framework to support network investment.[c]

A potential outcome is a rule change that may require network service providers to take resilience and climate change into consideration in their planning, with this obligation to be applied by the AER in the process of revenue determinations. This would involve a process of collaboration between market bodies, market participants, consumers and jurisdictions to develop a proactive response to the increasing frequency and severity of extreme weather events' impact on the electricity system.

Source: [a] AEMO, *2020 ISP Appendix 8 — Resilience and climate change*, June 2020.

[b] Dr. Alan Finkel et al, *Independent Review into the Future Security of the National electricity Market*, Recommendation 2.11, June 2017, p. 26.

[c] See Department of Agriculture, Water and the Environment's website: https://www.environment.gov.au/climate-change/adaptation

3 TRANSMISSION: INTEGRATING NEM-WIDE PLANNING

The way transmission planning is undertaken is changing and significant investment in transmission infrastructure is proposed over the coming years.

Since the introduction of the Integrated System Plan (ISP) some stakeholders have raised concerns about whether the existing economic regulatory framework remains fit-for-purpose when large, discrete, non-recurrent transmission investments are required, such as the large transmission projects identified in the ISP.

Stakeholder feedback provided to this review indicate that the current regulatory framework, which was designed for 'business as usual' or recurring investment projects, may not be suitable for new actionable ISP projects.

3.1 The Integrated System Plan

3.1.1 What is the ISP?

The ISP is a whole of system plan that provides an integrated road map for the efficient development of the NEM over the next 20 years and beyond. It identifies the optimal development path for the NEM, consisting of ISP projects[39] and development opportunities,[40] as well as necessary regulatory and market reforms. The ISP is updated by AEMO every two years.[41]

AEMO developed the ISP using cost benefit analysis, least-regret scenario modelling and detailed engineering analysis to carefully select the recommended projects from a large range of possible options to achieve power system needs through a complex, energy sector transition.[42]

3.1.2 Rules to make the ISP actionable

In March 2020, ministers agreed to a set of rule changes to the NER to convert the ISP into action. The ISP 'actions' key projects by triggering RIT-T applications. These rules commenced on 1 July 2020.[43]

The ISP rules intend to streamline the regulatory processes for key projects identified in the ISP whilst retaining a rigorous cost benefit assessment.

39 The ISP considers how to best develop future Renewable Energy Zones (REZs) in a way that is optimised with necessary transmission developments, identifying indicative timing and staging that will best coordinate REZ developments with identified transmission developments to reduce the overall costs.

40 ISP development opportunities are projects that do not involve a transmission asset or non-network option and include distribution assets, generation, storage projects, or demand side developments that are consistent with the efficient development of the power system.

41 AEMO, *2020 Integrated System Plan*, p. 9.

42 AEMO, *2020 Integrated System Plan*, pp. 9, 14.

43 See: http://www.coagenergycouncil.gov.au/publications/actionable-isp-final-rule-recommendation

3.1.3 AER's Guidelines to make the ISP actionable

Following extensive stakeholder consultation, on 25 August 2020, the AER published a set of three final guidelines to clarify how AEMO will develop the next ISP and how transmission businesses will apply the RIT-T to actionable ISP projects:[44]

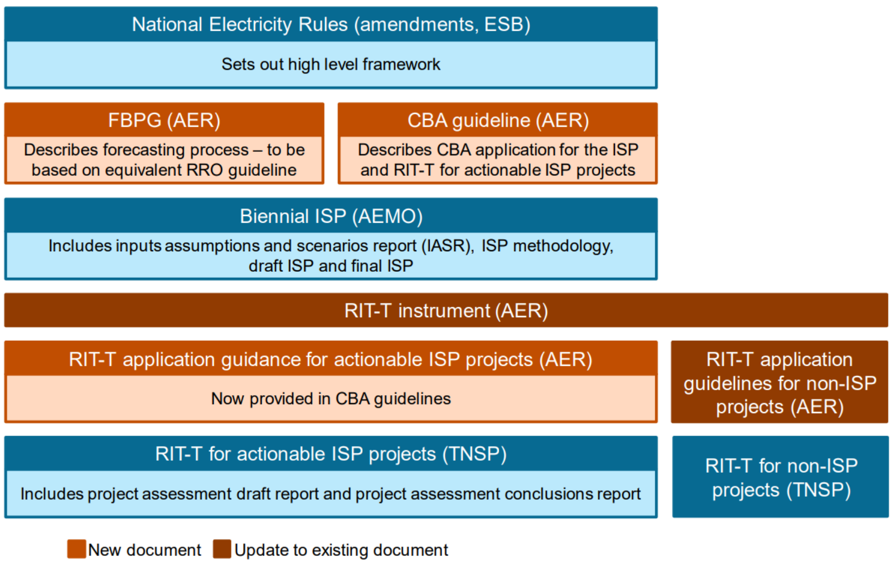
1. Cost benefit analysis guidelines
2. Forecasting best practice guidelines
3. RIT-T application guidelines for non-ISP projects

Together these guidelines govern the analysis and consultation that underpin the ISP and related regulatory investment tests. While AEMO has flexibility around how it identifies optimal investments, its decisions must be fully transparent and informed by stakeholder engagement.

The cost-benefit analysis guidelines promote rigorous cost-benefit analysis while minimising duplicated effort between the ISP and RIT-T by requiring RIT-T applications to use ISP inputs, assumptions, scenarios and analysis as much as possible. In addition, by encouraging AEMO to explore a broad range of projects (including non-network projects) at the ISP stage, the guidelines aim to reduce the need for extensive analysis at the RIT-T stage. The new guidelines will apply to the 2022 ISP and to some current and all future RIT-T applications.

Figure 3.1 below shows the regulatory governance framework for the transmission planning process under the new framework, for ISP and non-ISP projects.

Figure 3.1: ISP regulatory governance framework



Source: AER, *Guidelines to make the Integrated System Plan actionable*, explanatory statement, 25 August 2020.

44 See: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable

This distinction between ISP and non-ISP projects is important because not all RIT–T applications will flow from actionable ISP projects under the new framework.

There will remain RIT–T applications that will be initiated by transmission network service providers (TNSPs) separately, such as RIT–T applications for asset replacement projects.

The current transmission planning framework will apply largely unchanged to these projects.[45]

3.1.4 Transmission projects identified in the 2020 ISP

The 2020 ISP has identified four categories of transmission projects:

1. **Committed ISP projects:** these are network projects identified by the 2018 ISP which have now completed their regulatory approval processes.[46]
2. **Actionable ISP projects:** these are network projects which are underway or which should commence the regulatory approval process soon. For projects not yet underway, a date for which a Project Assessment Draft Report (PADR) must be completed is provided.[47]
3. **Actionable ISP projects with decision rules:** the decision rules for these projects can be assessed during the RIT-T process and will be confirmed by AEMO during an ISP feedback loop process with the TNSP once the decision rules eventuate.[48]
4. **Future ISP projects:** these are potential transmission investments which in some scenarios would enable efficient development of variable renewable energy and storage systems required in the longer term but are not required yet or may not be optimal in some scenarios. In some cases, this ISP recommends preparatory activities now — in other cases, no action is needed until the next scheduled ISP (in 2022).

A significant level of transmission investment is identified over the next few years. Between 2022 and 2026, the modelled cost of actionable ISP projects under the 2020 ISP is around $4.8 billion, with an additional $6.73 billion worth of projects under the category of actionable ISP projects with decision rules. For comparison, the current combined regulatory asset base of transmission networks amounts to $21.4 billion.

---

45 AER, *Guidelines to make the Integrated System Plan actionable*, 25 August 2020, p. 5.

46 See: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2018-integrated-system-plan-isp.

47 The PADR is a stage in the regulatory approval process in which the TNSP determines a draft outcome to meet the identified need.

48 A 'decision rule' refers to action or decision to take at one time, but also an action or decision to take at another time in the future if the appropriate market conditions arise. It is the set of conditions or triggers that, if they occurred, may justify a subsequent stage of a project proceeding.

Table 3.1 below provides an overview of the Actionable ISP projects included in the 2020 ISP:

Table 3.1: **2020 Actionable ISP projects**

PROJECT	TIMING	APPROVAL STATUS	COST RANGE [ISP MODELLED COST]
Actionable ISP projects			
VNI Minor (upgrade of existing VIC-NSW interconnector)	2022-2023	RIT-T complete NSW: pending Transgrid CPA VIC: committed	\$74m to \$137m [\$105 million]
Project Energy Connect (new interconnector between NSW-SA)	2024-2025 (with staging from late 2022)	RIT-T complete Pending CPA	\$1,393m to \$2,587m [\$1,990 million]
HumeLink (upgrade to reinforce NSW southern shared network)	2025-2026	PADR complete Pending PACR (late 2020)	\$1,470m to \$2,730m [\$2,100 million]
Central-West Orana REZ Transmission Link	2024-2025	RIT-T not yet initiated	\$450m to \$850m [\$650 million]
Actionable ISP projects with decision rules			
VNI West (new interconnector between VIC-NSW)	2027-28	PSCR Complete Pending PADR (~ late 2020)	\$1,211m to \$2,249m [\$1,730 million]
Marinus Link (new interconnector between TAS-VIC)	Stage 1: 2028-2029 Stage 2: 2031-2032	PADR complete Pending PACR	Stage 1: \$1,292m to \$2,399m [\$1,845 million] Stage 2: \$2,209m to \$4,102m [\$3,155 million]

Source: AEMO, *2020 Integrated System Plan*, Appendix 3 — Network investments, 30 July 2020.

3.2 Current arrangements

Currently, TNSPs are regulated under an ex-ante incentive-based framework. This framework incentivises TNSPs to provide regulated services as efficiently as possible by locking in revenue allowances before the beginning of each regulatory control period.

With revenue locked in, TNSPs are incentivised to provide services at the lowest possible cost because their returns are determined by their actual costs of providing services. If TNSPs reduce their costs to below the estimate of efficient costs, the savings are shared with consumers in future regulatory periods.

The regulatory framework also provides for a number of incentive schemes such as the efficiency benefit sharing scheme, capital expenditure sharing scheme, service target performance incentive scheme as well as the demand management innovation allowance mechanism.

These schemes are designed to support the underlying incentive regulation framework by providing TNSPs with continuous incentives to pursue efficiency gains and sharing them with consumers without compromising on service quality, and to provide funding for research and development in demand management projects that have the potential to reduce long term network cost.

The NER also contain provisions for two key elements that relate to the planning and revenue determination for TNSPs: the regulatory investment test for transmission and contingent projects. These provisions have increasing importance as the forecast level of transmission investment under the ISP increases in the near future. The remaining part of this section discusses the current operation of these key instruments.

3.2.1 Regulatory investment test for transmission (RIT-T)

The RIT-T is a key element of a wider planning framework established under the National Electricity Law (NEL) and the NER to promote efficient investment in transmission infrastructure in the NEM.

The RIT-T is an individual project cost-benefit analysis that is applied to all new transmission network investments that have an estimated cost of $6 million or more.[49]

The purpose of this test is to identify the credible option that maximises the present value of net economic benefits to all those who produce, consume and transport electricity in the NEM.

The RIT-T only applies to investments that include a regulated component; that is, investment that is at least, in part, funded by regulated revenues recovered from electricity consumers. It does not apply to investments that are fully funded from other sources, for example augmentations paid for by generators, merchant interconnectors, or investments funded by governments.

---

49 Clause 5.16.3(a)(2) of the NER states a figure of $5 million, but the AER's latest cost threshold determination, conducted in accordance with clause 5.15.3 of the NER, has specified that a RIT-T applies where the capital cost exceeds $6 million.

The RIT-T is designed to be a consultative and transparent process for transmission planning. The test allows for public consultation and comment within a transparent framework. This transparent and consultative process is important for considering non-network options, and is important for market participants to be able to provide feedback on the 'network effects' of the investment — that is, the impacts the investment will have on other market participants on the meshed network. These actions ensure that TNSPs are accountable in how they apply the cost-benefit analysis and that they consider non-network options in a way that they genuinely select the most efficient investment.

Following a rule change in 2017, the RIT-T now also applies to large replacement projects, rather than just augmentation projects.[50]

In 2017, the Ministerial Forum of Energy Ministers (formerly COAG Energy Council) published the findings of its review of the regulatory investment test for transmission, which found that the RIT-T remained the appropriate mechanism to ensure that new transmission infrastructure in the NEM is built in the long term interests of consumers.[51]

3.2.2 Contingent projects

A contingent project is a project assessed by the AER as reasonably required to be undertaken, but which is excluded from the ex-ante capital expenditure allowance in a revenue determination because of uncertainty about its requirement, timing or costs.

This mechanism is often used for projects where it is not clear at the start of the regulatory period whether the project will be required, for example projects that will only be needed if demand reaches a certain level.

Contingent projects are only permitted to be identified in the revenue determination if the proposed capital expenditure exceeds the threshold amount of either $30 million or 5 per cent of the maximum allowed revenue.[52] They are approved subject to certain triggers being met, one of which is the completion of a RIT-T.

A revenue determination also identifies associated trigger events. Should the trigger event occur, a TNSP may apply to the AER during the regulatory period to amend the revenue determination to include forecast capital expenditure and incremental operating expenditure for the project.

The AER is required by the NER to assess applications by transmission networks to amend their revenue determination and the RAB to include the revenue and capital costs required for a contingent project.[53]

The NER set out the requirements on networks in lodging applications and the obligations on the AER in assessing applications.

50 AEMC, *Replacement expenditure planning arrangements, final determination*, 18 July 2017.

51 Ministerial Forum of Energy Ministers (formerly COAG Energy Council), *Review of the regulatory investment test for transmission*, 6 February 2017.

52 Clause 6A.8.1(b)(2)(iii) of the NER.

53 Clause 6A.8.2 of the NER.

These requirements include information that TNSPs must provide when they make an application, the factors that the AER must consider in assessing that information, and the timeframe in which the AER must make its decision.[54]

3.3 Stakeholder views

This section provides a summary of the issues raised by stakeholders, either through submissions or interviews, that relate to the transmission regulatory framework.

3.3.1 Issues raised in submissions

Increased risks and uncertainties

Various stakeholders believe that risk has increased and is greater for large transmission projects:

- Energy Networks Australia argued that the current framework causes the transmission business to take significant risk in relation to capital expenditure forecasts.[55]
- Spark Infrastructure was of the view that there is a potential disconnect between the optimal 'development path' identified by AEMO and the lowest cost outcome for consumers and for that reason AEMO should be required to present the expected savings to electricity customers for each ISP development path, and where possible, for each actionable ISP project.[56]
- AusNet Services suggested the AEMC should focus on the potential for approaches to ensure that committed major project costs are included in a contingent project revenue determination in a way that mitigates the cost uncertainty risk for network users and transmission networks.[57]
- Transgrid noted that there are a number of unknowns when estimating the costs for large and complex projects and that the current framework does not provide certainty for actual cost recovery.[58] Transgrid argued that a bespoke approval process for large and nationally significant projects is a potential solution to the issues relating to the existing contingent project framework.[59]

Harder to obtain finance

Due to the large scale of the ISP projects, some stakeholders also highlighted difficulties in securing finance for such projects:

- Spark Infrastructure noted that it is increasingly difficult to maintain benchmark credit rating and attract efficient capital, especially for large greenfield projects.[60]

54 Rule 6A.8 of the NER.
55 Energy Networks Australia, *submission to approach paper*, p. 3.
56 Spark Infrastructure, *submission to approach paper*, p. 4.
57 AusNet Services, *submission to approach paper*, p. 2.
58 Transgrid, *submission to approach paper*, p. 1.
59 Transgrid, *submission to approach paper*, p. 2.
60 Spark Infrastructure, *submission to approach paper*, p. 2.

- Transgrid shared a similar view, adding that the current approach to RAB indexation is likely to significantly impair its ability to finance large, non-business as usual investments. Transgrid considered this time lag between costs incurred and revenue recovered to be a significant potential unintended consequence faced by those looking to build and own the major ISP projects.[61]

Risk allocation and cost overruns

Transgrid noted that for standard regulated capital projects (for example a $50 million project), unexpected cost overruns can be absorbed into a TNSP's existing revenue allowance over a five-year period by re-prioritising other projects, as well as through the smoothing effect of other projects coming in under their expected cost.[62]

Transgrid then added that, by contrast, a 10 percent cost overrun on large transmission investment required by the ISP (for example a $1.5 billion project) cannot be absorbed within a TNSP's five-year revenue allowance. In this scenario, a TNSP (and as a result, its debt and equity investors) would bear the risk of the overrun given the potential for the AER to prevent a TNSP from recovering this expenditure as part of an ex-post review of capital expenditure under the NER.[63]

Transgrid argued that while it uses best endeavours to accurately forecast the prudent and efficient costs of ISP projects at the required time and take project-level uncertainties into account in developing its cost forecasts, it does not consider it appropriate or reasonable that TNSPs bear the risk of unexpected costs for these projects, particularly given that the delivery and timing of these projects are being driven by the broader ISP process.[64]

Multiple regulatory bodies is adding to the complexity of the approval process for large transmission projects

Transgrid noted that the number of regulatory bodies and stakeholders involved in multiple stages of assessment is creating long time periods for approval and adding unnecessary costs to projects.

It also argued that the long approval process is also creating a misalignment between when the project construction would commence (based on the existing regulatory approval processes and stages) and when the construction is required to commence in order to meet governments' expectation of completion dates.[65]

Ensure the RIT-T process remains suitably rigorous

AGL, on the other hand, noted that the flexibilities afforded by the ISP Rules may offer an attractive approach for TNSPs to access contingent project revenues for expanded transmission projects that may have been otherwise more difficult to access under the existing economic regulatory framework.

61 Transgrid, *submission to approach paper*, p. 4.
62 Transgrid, *submission to approach paper*, p. 3.
63 Transgrid, *submission to approach paper*, pp. 3-4.
64 Transgrid, *submission to approach paper*, p. 3.
65 Transgrid, *submission to approach paper*, p. 2.

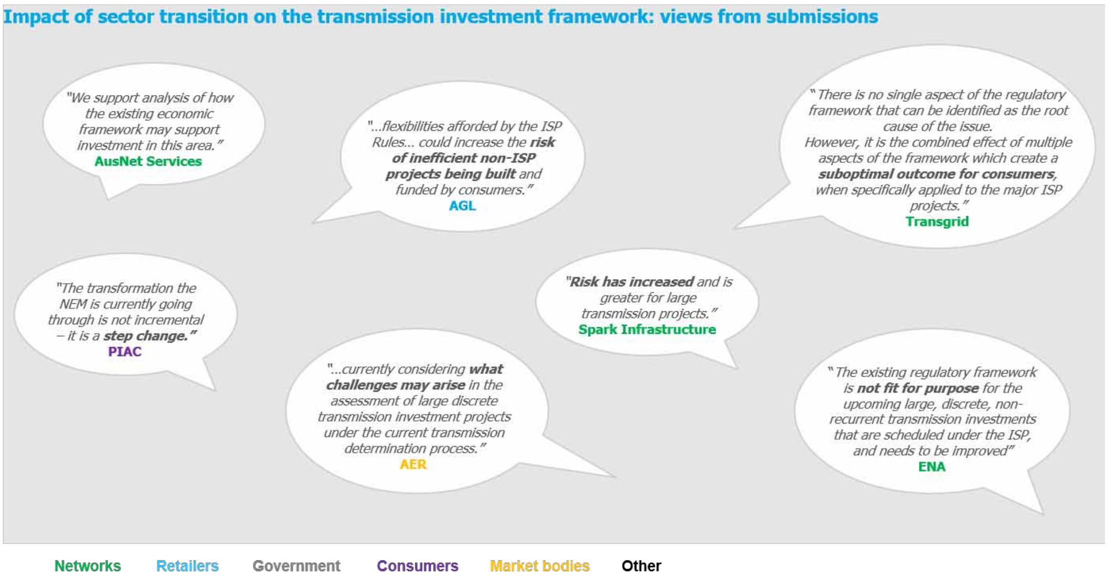
This could increase the risk of inefficient non-ISP projects being built and funded by consumers, especially where their investment case is dependent on (or strengthened by) an ISP-priority project. AGL welcomes the rigours of the existing RIT-T process, which tests projects on their own merits, to limit consumer risks of over investment and cost inefficiency.[66]

Ring-fencing

AGL raised concerns about the cross subsidisation of new unregulated activities by TNSPs using their regulated asset base and monopoly status, specifically to procure, own, operate or provide energy storage, demand management and new network services. AGL acknowledged that regulatory projects are currently pending or underway to assess these risks.[67]

AGL encouraged the AEMC and other market bodies to closely coordinate their work streams to ensure a considered approach is taken to avoid unintended market consequences.[68]

Figure 3.2: Views from submissions



Source: Submissions to approach paper.

66 AGL, *submission to approach paper*, p. 3.

67 AGL, *submission to approach paper*, p. 3.

68 AGL, *submission to approach paper*, p. 3.

3.3.2 Issues raised in interviews

As noted earlier, farrierswier conducted focused interviews with a wide range of stakeholders, including two TNSPs.

Even though there was limited focus in the interviews on NEM transmission issues, there were some common themes related to the large ISP projects and the current RIT-T process, which are reflected below.

How best to promote optimal aggregate transmission outcomes

Closely related to the question of the regulatory framework, interviewees noted that there is considerable pressure from governments and others to build large transmission projects which are seen as a solution to address various jurisdictional issues (e.g. closure of brown coal generation in Victoria).

This feedback came through not long after the Victorian government changed the transmission rules applicable in its jurisdiction.

These solutions are considered largely in isolation of each other and may in fact be inconsistent. Given this, the aggregate NEM-wide outcomes may not be optimal. A common question from stakeholders was:

"How does the AER ensure that the right aggregate outcome is achieved?"

Renewable Energy Zones (REZ)

The AEC and Powerlink raised concerns that the political narrative driving the creation of REZs is not correct, arguing that building REZs shifts the location rather than the opportunity for generation.

They argued that it encourages REZs to locate remotely rather than locally (which may or may not be socially optimal) rather than not be built at all.[69]

The AEC considered that the basis of decision on REZs should be on least cost option across the supply chain. There was a concern that government policy attention on REZs may lead to proper analysis not being undertaken leading to inefficient decisions.[70]

Powerlink suggested that there needs to be clarity on the problem(s) that the REZs are looking to solve, and how different REZs are from other transmission related reform initiatives.[71]

AEMO as a central planner

Several stakeholders questioned whether AEMO as a non-profit transmission planner has the right incentives to undertake robust unbiased analysis.

69 Farrierswier, *Electricity network economic regulatory framework review 2020 — stakeholder interviews report*, p. 11.
70 Farrierswier, *Electricity network economic regulatory framework review 2020 — stakeholder interviews report*, pp. 11-12.
71 Farrierswier, *Electricity network economic regulatory framework review 2020 — stakeholder interviews report*, p. 12.

It was suggested that an independent transmission planner could potentially better manage the risk of planning bias, and provide a more robust policy and commercial basis for managing transmission stranding risk.[72]

Existing RIT-T rules should continue to be applied

Some interviewees raised concerns about how the ISP has developed and whether it will bypass the RIT-T process in the future.[73]

To date, the rules that have actioned the ISP have largely supported continuing the rigorous cost-benefit analysis of RIT-T, and the ability to challenge by industry was considered positive.

This discussion highlighted that in this case the emerging issue was not about changing the regulatory framework, but rather ensuring the existing RIT-T rules and process continued to be properly applied, and that any government funding was also to be included in the analysis.[74]

Risk of asset stranding and/or under utilisation of assets

It was also suggested that transmission businesses may become more risk averse about long term asset stranding risk due to concerns about increased competition, and/or government involvement in transmission projects which may lead to over building.[75]

3.4 Maintaining a watching brief

As noted earlier, since the introduction of the ISP, some stakeholders have raised concerns about whether the existing economic regulatory framework remains fit-for-purpose when large, discrete, non-recurrent transmission investments are required, such as the large transmission projects arising from the ISP.

We understand that there will be a number of contingent projects that come from the actionable ISP. These projects are expected to be large discrete projects which may present challenges for the AER in its assessment given the lumpy and unique nature of the contingent projects.

In addition, stakeholders raised a number of issues (e.g. increased risks, financeability, cost overruns, AEMO as a central planner, etc.), which have the common thread of relating to the impact that the large ISP projects are having on the investment framework.

All these issues raised by stakeholders were manageable by TNSPs when working with 'business-as-usual' or recurrent investment projects. However, it is important to recognise the significant changes in the NEM since the introduction of the existing economic regulatory framework, and the dynamic market environment in which it can be expected to be applied going forward.

72 Farrierswier, *Electricity network economic regulatory framework review 2020 — stakeholder interviews report*, p. 14.
73 Farrierswier, *Electricity network economic regulatory framework review 2020 — stakeholder interviews report*, p. 11.
74 Farrierswier, *Electricity network economic regulatory framework review 2020 — stakeholder interviews report*, p. 7.
75 Farrierswier, *Electricity network economic regulatory framework review 2020 — stakeholder interviews report*, p. 14.

The Commission acknowledges the step change in the way transmission investment is planned and executed. However, it is hard at this stage to fully understand the impacts of this transition.

In addition, the AER also noted in its submission that it is currently considering two key issues:[76]

- whether the existing tools and assessment approaches are fit-for-purpose in supporting prudent and efficient investment decisions for large transmission projects, and how risks can be effectively managed and efficiently allocated to ensure efficient network investment
- whether, in light of the above considerations, there are opportunities to streamline the transmission planning and regulatory processes for actionable ISP projects (for example, by removing duplication in assessments).

Some options the AER has advised it is considering is how it can provide greater guidance to stakeholders on how these projects will be assessed under the framework, to reduce uncertainty and provide greater clarity and predictability, particularly on the contingent project application process as well as any ex-post review. It is also considering other reforms to the framework that could be put to stakeholders, including governments, industry and consumer representatives, for consideration that may promote better consumer outcomes and that may strengthen competitive tension.

Following the conclusion of this review, the Commission will work closely with the AER to assess whether any changes are required to the economic regulatory framework for TNSPs in light of the significant transmission investment that is forecast to take place in the near future. Both the AER and the AEMC will look to engage with stakeholders on any changes considered.

76 AER, *submission to approach paper*, p. 2.

4 GIVING CONSUMERS A GREATER SAY

The Australian community should have trust and confidence in the regulatory framework. Network proposals and AER regulatory decisions impact a wide range of individuals, businesses and organisations.

Effective and meaningful engagement is essential to provide stakeholders with an opportunity to inform and influence these outcomes. Robust customer representation allows for more constructive, positive engagement between all parties — with increased focus on issues most important to consumers, such as affordability, reliability and provision of DER-related services. This is harder to achieve than it may sound.

Submissions to this review have identified possible opportunities to incentivise enhanced consumer engagement by the network businesses. This includes consideration of whether the AER should have greater regulatory flexibility to adopt consumer 'negotiated settlements' with networks and, possibly taking these agreements into account, expedite and/or streamline its regulatory determination processes.

These issues raise fundamental questions about the intent and framing of network regulation and require careful consideration. The Commission is open to working collaboratively with stakeholders to progress thinking on the policy considerations. However, the current focus of our work program is on reforms to better integrate DER into the energy system (as discussed in chapter 1).

4.1 On the right track

As reported in the *2019 Review*, network businesses have made significant improvements to the way in which they engage with consumers in recent years.[77] The Commission observes the networks and the AER are making continual improvements and innovating to push the boundaries of consumer engagement.

For example, the AER is exploring and applying, to an extent, negotiated-settlement approaches between consumer representatives and the network businesses. The AER and AusNet Services are trialing the New Reg process — giving a Customer Forum a substantial say in the development of AusNet Services' recent regulatory proposal (see section 4.3).[78] Network businesses like Jemena have taken up the challenge of significant direct engagement with their end customers. Ausgrid submitted that innovation and co-designing solutions with its customers is key to evolving the shared distribution network to efficiently meet the changing needs of customers.[79]

The increasing effort put into consumer engagement is recognised by consumer representatives. PIAC agrees the environment of network revenue determination processes

77 AEMC, *Electricity network economic regulatory framework review*, September 2019, pp. 54–63.

78 AusNet Services, *submission to approach paper*, p. 3.

79 Ausgrid, *submission to approach paper*, p. 3.

has changed markedly in recent years — with increasingly positive and constructive engagement by the AER, networks and consumers on regulatory processes.[80]

4.1.1 Culture is King

The AER stated that meaningful consumer engagement involves at its core a cultural change.[81]

There has been a major cultural shift in the sector. Consumer engagement is becoming embedded into business-as-usual operations. Network businesses are now broadly demonstrating a commitment to ongoing and genuine consumer engagement — improving trust between consumers and the networks.[82] Essential Energy highlighted the importance of this cultural change:[83]

> Another key learning for Essential Energy has been the importance of maintaining ongoing consumer and stakeholder engagement so that it becomes embedded as business as usual and not a one-off exercise to be undertaken as part of the regulatory proposal process. This will ensure that network businesses can continuously adapt in line with customer expectations in a rapidly changing energy environment.

The Energy Charter is an important initiative to embed a customer-centric culture and conduct in energy businesses. It seeks to align the whole energy supply chain behind a common purpose: putting customers at the forefront and fostering collective accountability for better customer outcomes.[84] Signatories — including some network service providers, retailers, and generators — are publicly accountable for delivering improved outcomes for customers.

Based on similar values, ARENA's Distributed Energy Integration Program (DEIP) is driven by the premise that exchanging information and collaborating on DER issues will more efficiently identify knowledge gaps and priorities, as well as accelerate reforms in the interest of consumers. DEIP is a collaboration of government agencies, market authorities, industry and consumer associations aimed at maximising the value of customers' DER for all energy users.[85]

The joint Energy Networks Australia (ENA) and Energy Consumers Australia (ECA) industry awards for consumer engagement and innovation also play an important role — creating strong incentives for network businesses to innovate and in building knowledge of successful engagement approaches.[86]

80 PIAC, *submission to approach paper*, pp. 2-3.

81 AER, *submission to approach paper*, p. 3.

82 AEMC, *Electricity network economic regulatory framework review 2019,* September 2019, p. 55.

83 Essential Energy, *submission to approach paper*, p. 3.

84 The Energy Charter, January 2019, p. 7. See: www.theenergycharter.com.au/

85 See: https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/

86 See: www.energynetworks.com.au/event_type/annual-awards/

4.2 But structural barriers remain

It is widely acknowledged that there are significant barriers to effective consumer engagement in regulatory processes, which are not easily overcome.[87] The inherent complexity of the regulatory framework and resource imbalances between consumers and the network businesses create challenges for the consumer voice to be adequately heard, considered and ultimately reflected in regulatory outcomes.[88] The AER is the only match for the experience and expertise of the network businesses' regulation teams and their consultancy budgets.

Ausgrid's submission highlighted the challenge of how to ensure customer consultative groups are representative of a network's customer base and have the capability and time to advocate for the right customer outcomes.[89]

In its interview with farrierswier, Uniting Communities said its main concern was its ability to participate with limited resources. Further, Uniting Communities considered improvements should be made to link and collaborate consumer groups to build trust and confidence in energy markets and energy businesses.[90]

Rather than addressing these structural barriers, AGL suggested there are diminishing returns to consumer engagement and that technical considerations should just be left to the AER:[91]

> … AGL has appreciated this level of consumer engagement but has doubts whether any further benefits can be derived from any additional engagement and whether such activities can replace the industry knowledge and balance of the Regulator. We recognise the AER has been exploring negotiated-settlement approaches between consumer representatives and the network businesses but believe the added complexity and high cost of these approaches raise doubts on their effectiveness as a central part of the regulated framework.

4.2.1 The role of the AER

The AER must be unbiased and objective as an administrator of the rules. The AER must be impartial when considering the arguments put to it in a regulatory process, regardless of who they are from. But, as recognised by a former AER Chair:[92]

> … the submissions we have received to date have been heavily weighted towards the network businesses' arguments. There is an obvious 'gap' in the information submitted to us. If we have few submissions from consumers or consumer groups, how can we be sure that we are making decisions that reflect the long term interests of consumers?

87 AEMC, *Electricity network economic regulatory framework review*, September 2019, pp. 54–63.

88 AER, *submission to Ministerial Forum of Energy Ministers (formerly COAG Energy Council) consultation paper on consumer engagement*, November 2017, p. 9.

89 Ausgrid, *submission to approach paper*, p. 5.

90 Farrierswier, *Electricity network economic regulatory framework review 2020 — stakeholder interviews report,* p. 12.

91 AGL, *submission to approach paper*, pp. 4–5.

92 See: www.aer.gov.au/news/giving-consumers-a-say-on-energy-network-prices

Despite being well-resourced and highly sophisticated, energy retailers have had limited involvement in AER network regulation processes to date. For example, AGL only made a five-page submission total on the five Victorian network distribution businesses' 2021–2026 regulatory proposals.[93] Further, the retailers have provided very limited input on AER guideline consultation processes to date, including on issues as impactful to customers' bills as the rate of return guideline.

This absence of strong customer representation under the current market structure has meant consumer groups have been left as the main advocate on behalf of small customers to improve energy affordability. That's not ideal. Jurisdictional consumer groups generally have a wide remit covering a range of essential services, with competing priorities and sometimes very limited resources.

Albeit limited, institutional arrangements have been put in place to help to balance the information, arguments and evidence presented to the AER as part of its regulatory processes. For example:

- The AER instituted the Consumer Challenge Panel to provide input into AER network regulation decisions on issues of importance to consumers, and establishes Consumer Reference Groups to represent consumer perspectives and interests on guideline review processes.[94]
- ECA provides an independent, national voice for residential and small business energy consumers. ECA has built capacity and expertise to engage in network revenue decision and guideline processes — especially on 'high payoff' issues common across jurisdictions, such as rate of return.
- Further, ECA supports consumer advocacy through its Grants Program.[95] This allows consumer bodies to apply for a grant to engage with the networks in the development of their regulatory proposals, and with the AER in network revenue decision and guideline processes (among other things). However, ECA's overall grants budget is limited, and it needs to support a diverse range of advocacy and research work across Australia. Only a small proportion of ECA grant applications seek funding for consumer advocacy on AER network regulatory processes.

4.3 Finding a way around

Increasing the resources available to consumer groups and ECA would allow them to contribute more effectively to the AER's regulatory processes and improve the balance of the institutional arrangements. But calls for additional government funding, including as part of the *2017 Energy Minister consultation process on consumer resourcing*[96] and more recently

93 See: www.aer.gov.au/networks-pipelines/determinations-access-arrangements

94 AER, *submission to approach paper*, p. 3.

95 See: https://energyconsumersaustralia.com.au/grants

96 See: www.coagenergycouncil.gov.au/publications/consumer-participation-revenue-determinations-and-associated-regulatory-processes

by Uniting Communities, have not been actioned.[97] This is unlikely to change in the current economic environment.

The New Reg project, a joint initiative of the AER, ECA and ENA, is an alternative approach to network regulation. The process seeks to understand consumer views and preferences (through research), empower customers and draw out the 'other side' to an argument, and internalises the funding requirements — with costs passed on to consumers through network charges.

The main idea of the New Reg Process is that consumers, through a Customer Forum, and the network business can come to an agreement that the revenue proposal reflects consumer perspectives and preferences.

The Customer Forum is created to become the 'counterparty' to the business in reaching these agreements. It is resourced to understand consumer views, and to reflect these in a process of 'mutually advantageous discovery' to find better outcomes for consumers.[98] The New Reg process supplements, rather than replaces, other forms of engagement the AER and networks undertake with consumers and consumer groups.

AusNet Services has undertaken a trial of the New Reg model:[99]

> The Customer Forum was established to represent the perspectives of our customers, drive cultural change across the business and to negotiate and agree key parts of our Revenue Proposal. It was supported by a substantial amount of customer research and engagement, including with end use customers (residential and business), consumer advocates and our Customer Consultative Committee. Material developed for the Customer Forum was published on our website for transparency, and we published a Draft Electricity Distribution Regulatory Proposal in February 2019 containing our initial agreed positions for stakeholder feedback.

4.4 Leveraging process incentives

The idea of negotiated-settlements is not new. This form of regulation is more consistent with the National Access Regime under Part IIIA of the Competition and Consumer Act, and is applied in other jurisdictions — especially North America. The Monash Business Policy Forum previously advocated an approach to public utilities regulation that relies less on upfront regulator decision-making, and more on stakeholders to determine access terms for essential network infrastructure, with regulatory backup as necessary:[100]

> In contrast to an upfront regulatory determination, giving primacy to a negotiated settlement sees the regulated parties negotiate the terms of the access arrangement

97 Report for Uniting Communities, *Resourcing Consumer Engagement*, Seed Advisory, July 2019.

98 The joint ECA, ENA and AER submission notes 'the Customer Forum's representatives are selected to credibly represent perspectives of all end users, be they residential, small business or commercial and industrial. These persons are also required to have relevant skills and experience to ensure they function as an effective and robust counterparty to the network business.' (p. 2)

99 AusNet Services, *submission to approach paper*, p. 3.

100 Monash Business Policy Forum, R*ethinking utility regulation in Australia*, December 2015, pp. 6–7.

> they want. Further, it allows the parties to make trade-offs that reflect their preferences. In the absence of an agreement, the regulator can still be called upon to impose an arbitrated decision. ...
>
> The underlying economic benefits are, in some sense, obvious — negotiations are voluntary and allow parties to trade across price and non-price terms freely. When a unanimous agreement is reached, it is implicitly of higher benefit than the expected litigated outcome. In the absence of an agreement, parties are no worse off.

Under the New Reg model, if the network business and its Customer Forum can reach agreement on some or all aspects of the regulatory proposal, there is an expectation that the AER's decision-making process would put significant weight on these outcomes. This expectation creates an important incentive for the parties to reach agreements and gives the Customer Forum 'leverage' in negotiations — a key insight from the *Scottish Water case study*, which the New Reg model is based on.[101]

Further, if a network business successfully undertakes the New Reg process, and reflects the outcomes of negotiations in its regulatory proposal, the AER may expedite and/or streamline the revenue determination process.[102] This is consistent with the AER's ongoing efforts to encourage networks to submit proposals that are underpinned by effective engagement and capable of being readily accepted — as highlighted in the *2019 Review*. Again, this creates incentives for networks to find common ground with consumers in developing their proposals.

Leveraging these process-based incentives would not diminish the role of the AER as the economic regulator, or take away from its responsibility to make statutory decisions that promote the NEO. The idea is not to make the Customer Forum a substitute for the experience and expertise of the AER. Rather, the New Reg process relies on the AER to support negotiations by providing clear guidance on how it would assess the various aspects of a regulatory proposal:[103]

> Central to the Early Engagement Process is the idea of creating a 'dynamic conversation' between the network business and Consumer Forum, supported by the AER, to achieve outcomes in the long term interests of consumers. These discussions should be structured with the aim of reaching agreements in a timely way. The AER needs to be assured that it has sufficient visibility during the Early Engagement Process that it can indicate that something will not be acceptable before it is submitted.
>
> Throughout the engagement process, the AER will contribute to the process of reaching agreement by providing information and explaining issues through 'advice notes' and/or presentations that communicate the 'boundaries' of the rules, and what

101 For more information on the Scottish Water example, see the AER, ECA, ENA 2018 *New Reg Approach Paper*, available here: www.aer.gov.au/networks-pipelines/new-reg

102 AER, ECA, ENA, *New Reg directions paper*, March 2018, p. 7.

103 AER, ECA, ENA, *New Reg directions paper*, March 2018, pp. 5–6.

> it may consider as an acceptable regulatory outcome — consistent with AER guideline approaches. The AER may also identify aspects of a proposal that in its view would most benefit from consumer perspectives, including through customer research and wider stakeholder consultation.

4.5 Reform options

Reforms put forward in submissions could, if adopted, enhance process-based incentives to create greater leverage for the consumer voice in regulatory determination processes.

The AER submitted there are potential benefits in moving away from a prescriptive, input-based, 'one-size fits all' revenue determination process to a more flexible framework that better incentivises regulatory proposals that reflect consumers' needs and preferences:[104]

> While enhanced early engagement and the AusNet Services New Reg Trial have occurred under the current rules, these processes have highlighted the limitations on the AER to fully take account of the specific consumer engagement and consumer preferences of individual businesses. For example, irrespective of the quality of early consumer engagement and support of consumers for a regulatory proposal, the rules include a prescribed process and set of discrete constituent decisions that applies to all businesses. This arguably blunts the incentive for networks to invest in enhancing their current consumer engagement processes. Furthermore, even if a network business and its customers agree to an incentive scheme or arrangement that reflects the specific outputs that customers value, there may not be scope to implement it under the current rules.

ENA noted the regulatory framework should be sufficiently flexible to ensure that consumer preferences drive regulatory outcomes, and that the New Reg project has identified potential reforms to provide sufficiently flexible to accommodate the delivery of outcomes that consumers want.[105] For example, AusNet Services submitted there may be an opportunity to shorten the formal process for assessing regulatory proposals post-lodgement with the AER.[106]

The joint ECA, ENA and AER submission highlighted early learnings from the New Reg trial and proposed the following potential reform options:[107]

- Rewarding effective engagement in regulatory timing and assessment of proposals: the regulatory process needs to deliver clear value to customers and networks when proposals are well-founded on, and follow from, effective engagement, and a standardised 'cookie cutter' process does not reflect the diversity of relevant circumstances and review priorities.

104 AER, *submission to approach paper*, p. 3.

105 Energy Networks Australia, *submission to approach paper*, p. 4.

106 AusNet Services, *submission to approach paper*, p. 3.

107 Joint ECA, ENA and AER, *submission to approach paper*, pp. 2–4.

- AER decisions should be made on a more holistic basis: the 'siloed' rules framework of individual building block decisions can work against the flexibility that may be required to better reflect consumer–network agreed price and service combinations.
- Move towards performance-based regulation: network revenue determinations (and hence engagement) are dominated by an input focus, rather than consumer valued outputs, which heavily directs limited resources towards contested debates on the precise inputs to be used to achieve the desired outcome.
- More flexible incentive framework to meet consumer preferences: established incentive schemes do not fully target the service outcomes customers value and take time to introduce or adjust, which means that the current incentive scheme may not promote the delivery of the full range of service outcomes consumers truly value.
- Addressing issues outside of the building block model: the current framework needs a mechanism to give stakeholders confidence that 'whole of chain' issues they raise in network determination processes will be treated satisfactorily, while not compromising quality and resourcing of core determination decisions.

4.5.1 Policy considerations

Facilitating negotiated-settlements

The regulatory framework requires the AER to take account of network businesses' consultation with their end-customers. When determining capital and operating expenditure allowances, the AER must have regard to the extent to which the forecast includes expenditure to address the concerns of consumers, as identified by the network business in the course of its engagement in developing its regulatory proposal.[108]

Giving the AER discretion to put greater weight on consumer engagement outcomes raises significant policy questions. For example:

- What 'rewards' would be used to incentivise networks to undertake significant engagement in developing their regulatory proposals — such as less regulator scrutiny of the proposal to streamline the process, and/or financial payments?
- What circumstances would be appropriate for the AER to adopt a 'negotiated-settlement' (for example, what criteria)?
- Are there some aspects of a regulatory proposal that are more amenable to negotiated-settlements than others, or should it be about the proposal as a whole?

The AER engaged independent consultants, farrierswier and CEPA, to provide ongoing monitoring and evaluation respectively of AusNet Services' trial of the New Reg process. The consultants' reports indicate the outcomes of the New Reg process so far are promising.[109] However, the 'lessons learnt' are still being understood. AusNet Services noted the effectiveness and efficiency of the New Reg process, compared to other forms of regulatory

108 Clauses 6.5.6(e)(5A) and 6.5.7(e)(5A) of the NER.

109 See: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/consultation-on-the-new-reg-process/updates

engagement, could only be fully assessed following the AER's final decision on the negotiated outcomes.[110]

Relatedly, Spark Infrastructure said the extent to which increased consumer engagement undertaken by the networks will influence and be reflected in AER decisions is not clear yet.[111] Ausgrid questioned what weight the AER should put on consultation outcomes in reset decisions.[112] PIAC submitted trust in engagement processes may be undermined if it is unclear or opaque how the regulator considers consumer engagement in making its decision:[113]

> The outcomes of deliberative forums and engagement must be transparently and honestly considered by the AER in making its decision, and clear reasons provided for why and how it has chosen to use or not use the outcomes.
>
> Therefore, PIAC considers more formal consideration of how differences between the AER and consumer engagement in revenue determinations are identified and resolved would be beneficial.

Fast-track processes

Under the NER, the AER's ability to expedite a revenue determination process is somewhat limited. The NER prescribe a process for consultation on network revenue determination processes and publication of information that will inform those decisions.

The AER has some discretion on the timing of submissions and revised proposal due dates, although the rules prescribe minimum lengths of time for each step in the consultation process.[114]

There is scope to give the AER some additional flexibility to design its consultation processes. But there are important policy considerations, including the appropriate level of detail in the rules. For example:

- Should an option to expedite regulatory determination processes be prescribed in the rules (at a principle-level) for more certainty or left to the AER to outline in a guideline?
- If a fast-track option is made available, what are the risks of the AER taking a more light-handed approach to regulation by streamlining its process?
- What safeguards would be required to ensure stakeholders always have an opportunity to raise concerns about a regulatory proposal, including any agreed outcomes between a network business and consumers?

110 AusNet Services, *submission to approach paper*, p. 3.
111 Spark Infrastructure, *submission to approach paper*, p. 2.
112 Ausgrid, *submission to approach paper*, p. 5.
113 PIAC, *submission to approach paper*, p. 3.
114 See Chapter 6, Part E of the NER.

Constituent decisions

The rules require the AER to make many 'constituent decisions' on each of the building block components and other matters that are used to calculate the maximum revenue allowance.[115] The AER considers the interrelationships of the constituent components in coming to a decision that contributes to the achievement of the NEO.

But separately assessing and deciding on each component of the building block model is contrary to the concept of the AER approving a single maximum revenue amount, and may limit the AER's ability to exercise discretion and judgement on trade-offs between different aspects of a regulatory proposal.

These trade-off considerations could be increasingly part of any negotiations between consumers and the businesses — especially for how risks are allocated. The complexity of the rules can reduce the ability of consumers to understand the interrelationships and engage on the issues.

On the other hand, the current level of prescription may provide network businesses greater regulatory certainty and assurance that they will have a reasonable opportunity to recover at least their efficient costs of meeting their regulatory obligations. This is particularly important given that state and territory governments can impose new regulatory obligations on network businesses, and the networks may be expected to recover these costs through AER revenue allowances.

Output or performance-based regulation

The Commission accepts the AER, ECA and ENA view that the rules relating to constituent components may focus the AER's decisions more on detailed and legalistic cost assessments — rather than on the networks' overall outputs and performance and 'value proposition' to consumers.

Overseas regulators have included performance-based targets as part of a suite of tools to promote efficient investment and achievement of certain outcomes.[116] These 'output agreements' could be specific to a jurisdiction's circumstances and stakeholder preferences.

As indicated in the *2018 and 2019 Reviews*, the Commission is open to exploring the potential to shift the overall regulatory framework to a more performance-based form of regulation. This is our longer term vision of the evolution of network regulation in Australia. A first step in this direction may be to combine and simplify the expenditure assessment-related rules.

115 Clause 6.12.1 of the NER.

116 AEMC, *Electricity network economic regulatory framework review*, July 2018, p. 105.

4.6 Opportunity to further promote consumer-led outcomes

Promoting effective and meaningful engagement builds the Australian community's trust and confidence in network regulation and the AER's regulatory determinations.

There is an opportunity for reforms to help to balance current institutional arrangements — 'working around' the inherent resource imbalance between consumers and the network businesses.

The regulatory framework could enable alternative paths for network businesses to take in developing their regulatory proposals, and for the AER in assessing those proposals. The AER could be provided with greater flexibility to both take into account any agreements between consumer representatives and the networks, and use processes and assessment approaches that are better aligned with the quality of a network's regulatory proposals as a reward. Importantly, these process-based incentives can create greater leverage for the consumer voice, giving consumers a greater say and influence over regulatory outcomes.

Such reform options put forward in submissions raise important policy questions that require careful consideration. The AER, ECA and ENA can continue to develop this package of reforms as part of the New Reg project and trials. The Commission will continue to be involved through the New Reg program board.

As outlined in chapter 1, the Commission's current policy focus is on the role of distribution networks and reforms to better integrate DER into the energy system. This is consistent with stakeholder expectations expressed in submissions and interviews, and reflected in the Commission's strategic priorities and current work plan.[117] The Commission is currently considering several rule change requests relating to DER integration.

117 See: www.aemc.gov.au/our-work/our-forward-looking-work-program.

5 CONCLUSION

Australia's electricity sector transformation needs to be supported by evolution in both market and regulatory frameworks. While the ESB's Post-2025 Market Design review addresses issues in relation to market frameworks, the Commission will continue to monitor developments and ensure the economic regulatory framework remains robust and flexible to support continual sector transformation.

In this year's review, the Commission examined emerging issues in transmission and distribution and developments in consumer engagement. The issues identified in this year's review have differing levels of urgency. Some actions require significant stakeholder consultation, while others require further investigation or continued monitoring.

Table 5.1 below provides a high level summary of the Commission's regulatory reform priorities in the near future. Over the next 18 months, the Commission will focus on clarifying the role of DNSPs in the changing electricity sector and to ensure an appropriate regulatory framework is in place to support networks.

The Commission will also continue to engage with stakeholders to monitor emerging issues and consider future priorities, especially in relation to DER integration, implementation of the ISP and consumer engagement.

Table 5.1: Commission's priorities

PRIORITY	YEAR
• Consider DER integration rule change requests. • Consider DER Initial minimum technical rule change request. • Progress DER integration activities identified under the ESB *Post-2025 market design* project.	2020
• Consult with stakeholders on potential changes required to the regulatory framework to support DNSPs' efficient integration of DER — including issues such as community batteries, ringfencing, clarification of role for DNSPs and implications on economic regulation of networks. • In conjunction with the AER, consider whether changes are needed to the transmission investment framework in the context of implementing the ISP.	2021
• Progress rule change requests identified in the consultation on changes required to the regulatory framework. • Continue to monitor developments in consumer engagement, consider rule change requests if proposed by AER/ECA/ENA.	2022 and beyond

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
Capex	Capital expenditures
Commission	See AEMC
DEIP	Distributed Energy Integration Program
DER	Distributed energy resources
DMIA	Demand management innovation allowance
DMIS	Demand management incentive scheme
DNSP	Distribution Network Service Provider
ECA	Energy Consumers Australia
ENA	Energy Networks Australia
2020 Review	Electricity Network Economic Regulatory Framework 2020 Review
ESB	Energy Security Board
EV	Electric vehicle
FCAS	Frequency control and ancillary services
ISP	Integrated System Plan
NEL	National Electricity Law
NEM	National electricity market
NEO	National electricity objective
Opex	Operational expenditures
PADR	Project assessment draft report
PIAC	Public Interest Advocacy Centre
RAB	Regulatory asset base
RIT	Regulatory Investment Test
SAPS	Stand-alone power systems
TNSP	Transmission Network Service Provider
TSS	Tariff structure statement
VPP	Virtual power plant

A UPDATE ON 2019 REVIEW'S RECOMMENDATIONS

In addition to identifying emerging issues, the 2020 Review provides an update on the implementation of reforms recommendation in the Commission's 2019 Review. The 2019 Review set out ten actions key to the efficient integration of DER into the electricity grid.[118]

The recommendations are listed in Table A.1. A brief update is provided in the following pages.

Table A.1: 2019 Review recommendations

1	Reforms to distribution access and pricing framework
2	Continual implementation of tariff reforms
3	AER to develop guidelines for how it will assess proposals from distribution businesses to integrate DER
4	Develop a common value of export methodology
5	AEMC to conduct a review into competition in metering arrangements and continue to monitor the roll out of smart meters
6	Working with consumer groups to understand consumer information needs
7	DNSPs to continue to develop business cases for improvement of low voltage networks visibility
8	Identify additional meter data that should be collected and made available to support better visibility of network constraints
9	Develop technical standards to support the technical integration of DER and improve resilience of the grid
10	Consider mechanisms to assess and improve compliance of distributed energy resources with technical standards

Source: AEMC, *Electricity Network Economic Regulatory Framework 2020 Review,* approach paper, June 2020, p. 4-5.

Recommendation 1: Reforms to distribution access and pricing framework

The Distributed Energy Integration Program (DEIP) Access and Pricing working group was established in August 2019.[119]

The working group is composed of a collaboration of government agencies, market authorities, industry and consumer associations that engaged in an industry consultation process to examine how network regulations could evolve so that consumers get the best value from innovations in distributed energy.

118 AEMC, *Electricity network economic regulatory framework review,* 2019, final report, p. xviii-xix.

119 ARENA, https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/, 2020.

The working group published a “Work Package Outcomes Report” in June 2020 summarising the views expressed throughout this consultation.[120]

A key outcome of this 12-month collaboration was three rule change requests lodged by St Vincent de Paul Society Victoria[121] Total Environment Centre and Australian Council of Social Service[122], and SA Power Networks[123], submitted in July 2020.

The Commission initiated the rule change requests with the publication of a consultation paper on 30 July 2020.[124] The final determination is expected by February 2021.

Recommendation 2: Continual implementation of tariff reforms

Each network distributor is required to provide retailers, aggregators and other third party providers with clear signals for the cost of their consumers' use of the distribution network.[125]

The NER require distributors to propose strategies to progress network tariff reform each regulatory period to the AER for approval in a tariff structure statement (TSS). Distributors have to consider the networks' circumstances, the expected impact on consumers within their network, and their ability to respond, when outlining the strategy for each regulatory period. They are also expected to outline how they will approach trialing more complex, innovative trials in their TSS and explain how the learning from previous trials was used to inform their strategy.

Despite progress at the network level, full cost reflective and socially accepted tariff reform at the consumer level has proven to be difficult to implement effectively. Lack of analysis of the impact on various consumer groups, lack of clarity as to how network tariffs could play out through retailers, how retailers will translate tariffs to customers and what protections and supports will be put in place for vulnerable consumers, are all contributing to delays and concerns.[126]

The most recent TSS decisions by the AER for South Australia and Queensland distributors will result in retailers facing a cost reflective price signal for all customers with smart meters, after a short transition period. These decisions will significantly step up the progress of tariff reform in those states. But the question remains of whether retailers will actually pass through these price signals to consumers.

The Commission strongly supports the AER's continued efforts to progress tariff reforms through the TSS process and ongoing roundtables with key stakeholders. There should be a strong focus on the relationship between the networks and retailers in developing and implementing cost reflective pricing structures.

120 ARENA, *DEIP Access & Pricing Reform Package Outcomes Report*, June 2020.
121 St Vincent de Paul Society Victoria, *Allowing DNSPs to charge for exports to the network*, rule change request, July 2020.
122 TEC and ACOSS, *Network planning and access for distributed energy resources*, rule change request, July 2020.
123 SA Power Networks, *Access, pricing and incentive arrangements for distributed energy resources,* rule change request, July 2020.
124 AEMC, *Distributed Energy Resources Integration — Updating Regulatory Arrangements,* consultation paper, July 2020.
125 AEMC, *Distribution network pricing arrangements,* final determination, November 2014.
126 ARENA, *DEIP Access and Pricing Package Reform Package Outcomes Report*, June 2020, pp. 36-37.

Network tariff reform will evolve from the Access and Pricing rule changes as well as the review into the uptake of smart meters in the NEM to be initiated by the AEMC in December 2020.[127]

Recommendation 3: AER to develop guidelines for how it will assess proposals from distribution businesses to integrate DER.

On 19 November 2019, the AER released a consultation paper on *'Assessing Distributed Energy Resources (DER) Integration Expenditure'* with the aim of developing guidance for distribution network to manage the increasing challenge of accommodating DER on their networks.[128]

Stakeholders were provided the opportunity to express their views through a process of consultation considering the effects DER is having on networks, the current approach to assessing DER integration expenditure, and whether the current set of expenditure assessment tools are fit for purpose both now and into the future.

The AER received 26 submissions. In response to these submissions, the AER commissioned the CSIRO and Cutler Merz to conduct a study into potential methodologies for valuing DER. This study is nearing completion, with the draft report due to be released in early September 2020 for stakeholder consideration. (see recommendation 4 below).

Recommendation 4: Develop a common value of export methodology

ARENA and the AER engaged CutlerMerz and CSIRO in a *Value of Distributed Energy Resources study* to:[129]

- Identify gaps and issues associated with current approaches and level of guidance on quantifying DER benefits.
- Develop a methodology and approach for valuing DER benefits which reflect stakeholder feedback.
- Provide a methodology or calculation tool for DNSPs to apply in valuing DER benefits which is practical, proportionate, repeatable, and flexible.
- Recommend the level of guidance that should be provided to DNSPs in quantifying DER benefits.[130]

The methodology and approach proposed will inform the AER's assessment of DER expenditure in DNSP regulatory proposals.

CutlerMerz and CSIRO released an interim report as Stage 1 of the Study in June 2020.[131] Findings from Stage 2 plus stakeholder feedback will be incorporated into the final report due for publication in September 2020.

127 AEMC, *Keeping our eye on smart meters roll out,* news update, 23 May 2019.
128 AER, *Assessing Distributed Energy Resources Integration Expenditure,* consultation paper, November 2019.
129 ARENA and AER, *Value of Distributed Energy Resources,* June 2020.
130 CutlerMerz, *DER, What is it worth to you?,* July 2020.
131 AER, ARENA, CSIRO, CutlerMerz, *Value of Distributed Energy Resources: Methodology Study — Interim Report,* June 2020.

Recommendation 5: AEMC to conduct a review into competition in metering arrangements and continue to monitor the roll out of smart meters

The Commission will review the current competition in metering arrangements in the *Review of the regulatory framework for metering services,* commencing in December 2020. The review will consider the roll out of advanced meters to small customers in the three years since the introduction of competition in metering in December 2017, as well as look at the future services required from metering.

Recommendation 6: Working with consumer groups to understand consumer information needs

The Commission will not progress with this recommendation as initiatives such as Energy Consumer Australia's Supporting Household Framework which has developed customer archetypes and the ESB's data strategy workstream are addressing similar issues.

Recommendation 7: DNSPs to continue to develop business cases for improvement of low voltage networks visibility

DNSPs are increasingly cognisant of the need for greater visibility in low voltage networks to manage DER integration.

In its 2020-25 Revised Regulatory Proposal, SA Power Networks emphasised the necessity of its Low Voltage Transformer Monitoring Program to improve the monitoring of grid loads and voltages critical for system security and reliability.[132]

In its January proposal for 2022-26, AusNet Services outlined plans for a 'voltage compliance' program of augmentations targeted at customers experiencing voltage issues. The program, entailing capex of $20.6 million, aims to benefit importers and exporters by reducing export constraints by 13 per cent.[133]

Jemena considered further investments to improve network visibility, and Powercor, CitiPower and United Energy have also proposed expenditure to improve export capacity.[134]

The AER is expected to publish draft decisions on the Victorian DNSPs' proposals in September 2020, determining the extent to which DNSPs' proposed DER integration expenditure will be allowed.

Recommendation 8: Identify additional meter data that should be collected and made available to support better visibility of network constraints.

As part of the *Review of the regulatory framework for metering services,* the Commission will identify the current use of advanced meter data, the data capabilities of advanced meters (both currently and in the future), and the meter data requirements of industry participants in the future.

132 SA Power Networks, *Revised Regulatory proposal — Overview,* December 2019, p. 8.

133 AusNet Services, *2022-26 Regulatory Proposal Part I & II,* 31 January 2020, p. 14.

134 CEPA, *Feasibility of export capacity obligations and incentives,* final report, July 2020, p. 11.

Recommendation 9: Develop technical standards to support the technical integration of DER and improve resilience of the grid.

On 5 May 2020, the Australian Energy Market Operator (AEMO) submitted a rule change request seeking to establish a framework to enable it to set initial minimum technical standards for DER. If made, this rule change will oblige AEMO to create a subordinate instrument under the National Electricity Rules that sets minimum technical standards for DER. On 2 September 2020 the Commission extended the period to make a draft determination until 3 December 2020. It considered that this extension was necessary due to the complexity of issues arising from stakeholder submissions which require further analysis.

Assessing this rule change request does not require the AEMC to consider the detailed content of the minimum technical standards. Instead, the request is concerned with the proposed creation of a subordinate instrument that specifies minimum technical standards (as initially determined by AEMO) and what the standards will apply to.

While the rule change request seeks to address some imminent system security issues caused by DER connections, the ESB has been tasked by the Ministerial Forum of Energy Ministers (formerly COAG Energy Council) to develop an ongoing governance framework for DER technical standards.

The ESB commissioned a review into the *Governance of DER Technical Standards* in December 2019.[135] The review highlighted that to date the governance of DER technical standards has been fragmented and lacked resourcing, adequate pace, clarity of roles and coordination.

In July 2020, the ESB released the *Governance of DER Technical Standards'* consultation paper proposing the establishment of a new Governance Committee, to be convened under the AEMC, to oversee the development of DER technical standards.[136] The Committee would be responsible for:

- setting a vision for DER technical standards
- developing a technical standards work program
- monitoring, reviewing and setting DER technical standards
- considering issues related to compliance and enforcement of standards in their development
- providing advice on standards and undertaking reviews.

AEMO also released a consultation paper on the initial DER minimum technical standard in August 2020.[137] If AEMO's proposed rule is made, this will be the initial DER minimum technical standard.

The ESB will provide a draft proposal with recommendations for the governance of DER technical standards to the Energy Ministers in October 2020.

135 Energy Security Board, *Review of governance of Distributed Energy Resource (DER) technical standards,* December 2019.
136 Energy Security Board, *Governance of Distributed Energy Resources Technical Standards,* consultation paper, July 2020.
137 AEMO, *Initial Distributed Energy Resource Minimum Technical Standards — for consultation,* issues paper, August 2020.

Recommendation 10: Consider mechanisms to assess and improve compliance of distributed energy resources with technical standards.

Compliance with technical standards is currently dealt with through instruments that vary with state-based legislation and Australian Standards requirements.

As noted in Recommendation 9, the ESB commissioned a review into the *Governance of DER Technical Standards* in December 2019 which identified weaknesses in the Standards Australia process, as well as under-resourcing of compliance and enforcement activities. The Review further emphasised the importance of standards to be nationally consistent.[138]

As a consequence, the ESB's consultation paper proposes creation of a DER Standards Governance Committee that would be supported by a new performance monitoring framework to allow earlier detection and remedies for non-compliance and be provided as advice to Ministers.[139]

The proposed Committee would work with bodies currently charged with training, certification and enforcement of DER standards, including state electrical licensing and regulatory bodies; the Clean Energy Council product approvals, training and accreditation processes, and the Clean Energy Regulator's compliance and enforcement process.

138 Energy Security Board, *Review of governance of Distributed Energy Resource (DER) technical standards,* December 2019.

139 Energy Security Board, *Governance of Distributed Energy Resources Technical Standards,* consultation paper, July 2020.

B NETWORKS' KEY PERFORMANCE INDICATORS

As part of the annual *Electricity network economic regulatory framework review*, the Commission monitors key performance indicators for network service providers.

The Commission acknowledges the thorough analysis of key trends in the industry undertaken by the Australian Energy Regulator (AER) in the annual *State of the Energy Market* report.[140]

The AER's report provides a highly accessible and insightful overview of the evolution of networks in the preceding decade. Therefore, for this year's review, the Commission is only reporting on the following key data sets to give a moment-in-time snapshot of energy networks in 2020:

- The key drivers of regulated revenue:
  - Capital expenditure (capex)
  - Operational expenditure (opex)
  - Regulatory Asset Base (RAB)
  - Rate of return
- Funding of demand management solutions as indicative of investment in non-network solutions to network challenges
- Distribution network utilisation levels

B.1 Regulated revenue and key drivers

How is the regulated revenue calculated?

The AER uses a 'building block' approach to assess a network business's revenue needs. Each block comprises one part of the regulator's calculation of total allowed revenue. These blocks therefore equate to the key drivers of a network business's revenue.

Specifically, it forecasts how much revenue the business will need to cover:

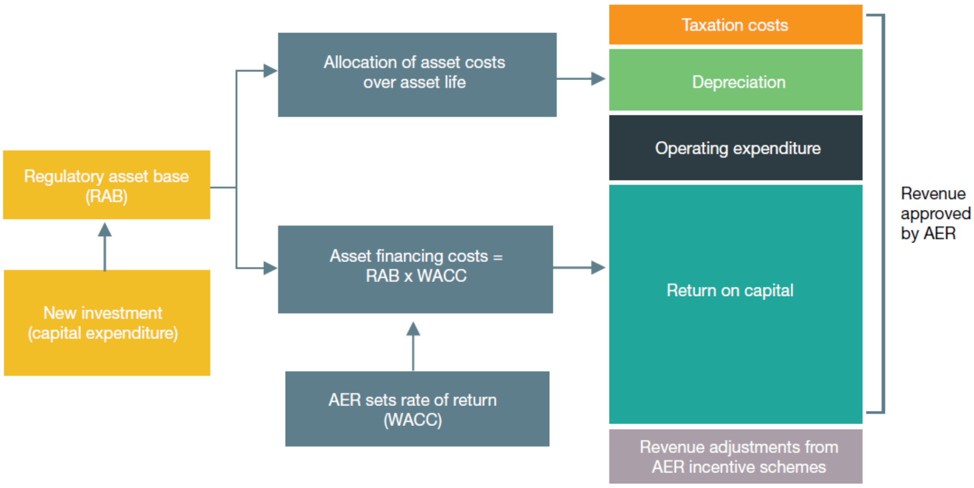
- efficient operating and maintenance costs
- asset depreciation[141]
- forecast taxation costs
- a return on capital.

As network businesses are regulated under revenue cap, the AER also makes revenue adjustments for over- or under-recovery of revenue in the previous regulatory period, and also for applicable incentive schemes.

140 AER, *State of the Energy Market 2020,* Chapter 3, June 2020.

141 While network businesses are entitled to earn revenue to cover their efficient costs each year, this revenue does *not* include the full cost of investment in new assets made during the year. Network assets have a long life, so the cost of investment in new assets is recovered over the economic life of the assets, which may run to several decades. The amount recovered each year is called *depreciation* and reflects the lost value of network assets each year through wear and tear, and technical obsolescence.

Figure B.1: Revenue determination — building block approach



Source: AER, *State of the Energy Market*, June 2020, p. 123.

Analysis of regulated revenue and key drivers

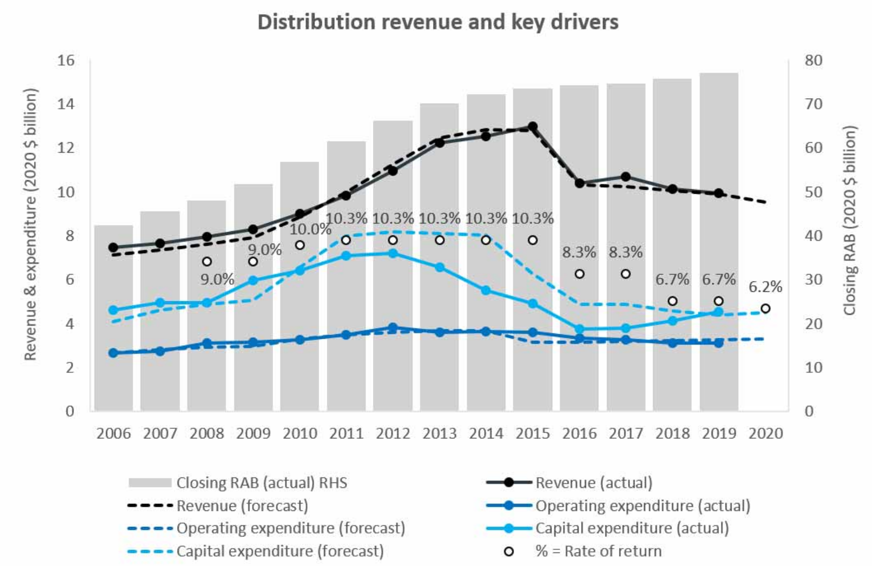
Data analysis by the AER shows that, since 2006, the regulated revenue earned by network businesses have exhibited two distinct trends: rapid growth for several years (until around 2013 in transmission and 2015 in distribution), followed by a significant reduction.

This is due to surging investment from 2006 to 2013 that led the network industry's asset base to rise by 62 per cent. Investment then weakened, along with the rates of return paid to network owners and lenders.

After reaching a peak of 10 per cent during the height of the investment period from 2009 to 2013, rates of return in 2020 have eased to around half that level.[142] This can be seen in Figure B.2, showing the aggregate trends of all DNSPs in the NEM from 2006 to 2022, and Figure B.3, showing the equivalent for TNSPs.

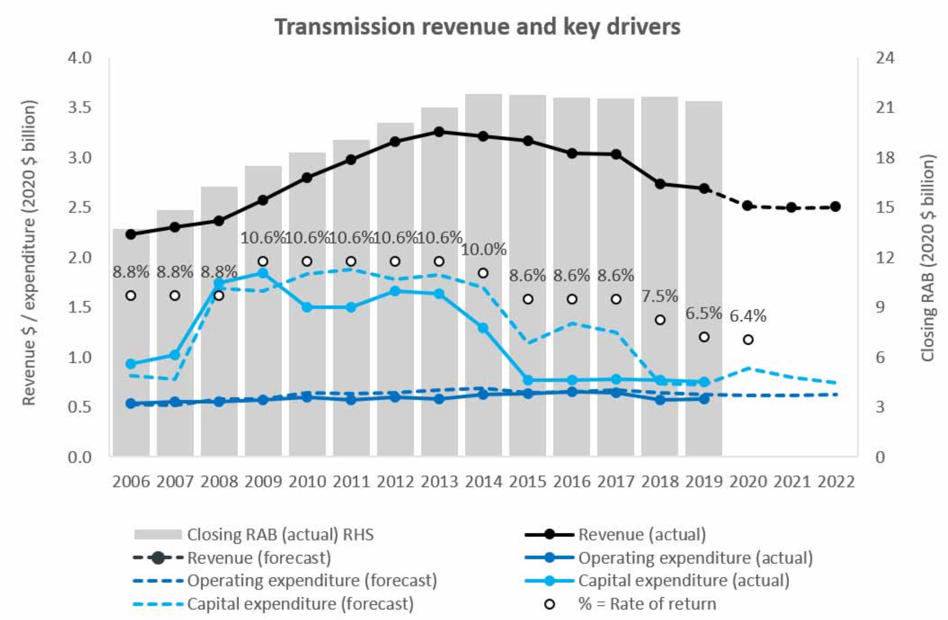
142 AER, *State of the Energy Market,* June 2020, p. 131.

Figure B.2: Distribution revenue and key drivers



Source: AER, *State of the Energy Market*, June 2020, p. 132.

Figure B.3: Transmission revenue and key drivers



Source: AER, *State of the Energy Market*, June 2020, p. 132.

B.1.1 Operating and maintenance expenditure (Opex)

What is operating expenditure?

Opex refers to operating and maintenance expenditures related to the operation of the network's business. It can include costs related to activities such as routine maintenance, testing, inspections, vegetation clearance, insurance, overheads, and corporate costs.

Opex as a driver of regulated revenue

Opex does not have a strong correlation with market conditions than other revenue drivers do, and show relatively stable trends. In 2009, these costs were about one third the size of asset investment, but by 2015 lower level of investment resulted in both asset investment and operating costs being at comparable levels. Operating expenditure later eased, as network businesses (especially distributors) implemented efficiency programs.

- **Distribution:** Opex increased by an average 7.1 per cent each year from 2006 ($2.7 billion, or $306 per customer) to 2012 ($3.8 billion, $403 per customer). From 2013 to 2019 operating costs fell by an average 2.6 per cent per year as distribution network businesses implemented more efficient operating practices. The reduction was overall less marked than it was for capital expenditure.
- **Transmission:** Opex peaked at $649 million ($65 per customer) in 2016, but then fell by an average 3.5 per cent per year to $581 ($56 per customer) in 2019.

B.1.2 Capital expenditure (Capex)

What is capital expenditure?

Capital expenditure (Capex) is money invested by a network to acquire or upgrade fixed, physical, non-consumable assets. Capex is often classified in two categories: augmentation expenditure (to expand the capacity of the network) and replacement expenditure (to upgrade ageing or obsolete assets).

Capex as a driver of regulated revenue

Network investment (capex) grew by an average of 8 per cent from 2006 until it peaked at $8.9 billion in 2012.

From 2006 to 2009, actual investment was 11 per cent above the approved forecast level. Lower demand for electricity began to reverse this trend from 2013, leading to projects being postponed or abandoned when it became clear that earlier projections of sustained demand growth would not eventuate.

Network businesses under spent on capital projects (compared with approved AER forecasts) by $12.9 billion (18 per cent) between 2010 and 2018. In 2019 network businesses overspent on capital projects by 3 per cent for the first time since 2009.[143]

In 2019, electricity networks invested $5.3 billion (or $505 per customer), which represented an 8 per cent increase (6 per cent per customer) on the previous year's investment. While

143 AER, *State of the Energy Market,* June 2020, p. 139.

network investment in 2019 rose for the third consecutive year, expenditure was still 41 per cent lower than the $8.9 billion ($937 per customer) invested when it peaked in 2012.

The AER forecasts network revenue and investment will plateau between 2020 and 2022, although continuing distribution investment will likely further raise the industry RAB over this period[144] as networks are augmented to accommodate the increasing penetration of distributed energy resources.

Distribution investment in 2019

- $4.5 billion ($433 per customer) in network assets
- 9 per cent increase (8 per cent per customer) on 2018 investment
- 37 per cent less (43 per cent per customer) than peak investment of $7.2 billion in 2012.

AER decisions in place at 1 July 2020 forecast distribution network investment to be 8 per cent lower on average over the current five-year regulatory period compared with the previous period.

Transmission investment in 2019

- $756 million ($72 per customer) in network assets
- 2 per cent decrease (4 per cent per customer) on 2018 investment
- 59 per cent (64 per cent per customer) than peak investment of $1.8 billion in 2009.

Transmission investment is forecast to be 15 per cent lower over the current five-year regulatory period compared with the previous period.

B.1.3 Capital expenditure by category

The two types of capital expenditure

Augmentation expenditure relates to investment in the expansion of the network's capacity. This may include meeting load growth, or managing DER integration. Replacement expenditure relates to investment to replace or upgrade ageing or obsolete assets.

There has been a significant shift in the composition of network investment over the past decade. Whilst growth expenditure accounted for 62 per cent of transmission investment and 41 per cent of distribution investment in 2009, many growth-related projects were shelved or delayed in response to a weaker demand for electricity and less stringent reliability obligations in the mid-2010s.

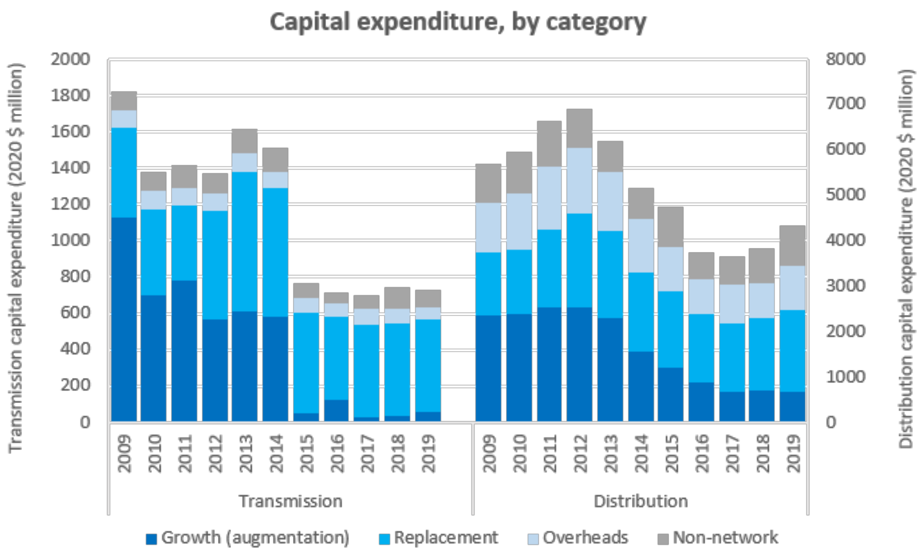
By 2019, growth-related investment had shrunk to 8 per cent of transmission investment and 15 per cent of distribution investment. In dollar terms, growth investment declined from $3.5 billion in 2009 to $732 million in 2019.

In contrast, over the same time period, replacement expenditure of ageing or degraded assets remained constant at $1.9–2.7 billion, rising strongly as a proportion of shrinking total investment. In distribution, replacement investment rose from 24 per cent of total investment in 2009 to 42 per cent in 2019. In transmission, it rose from 27 per cent to 69 per cent.

144 AER, *State of the Energy Market,* June 2020, p. 133.

Since 2018, investment in augmentation has been lower than investment in replacement projects, overheads and non-network assets (for example, IT, buildings and property, fleet and plant, minor asset tools and equipment, and motor vehicles). However, historically (from 2009 to 2016), investment in augmentation has always exceeded expenditure on overheads and non-network programs/projects.

Figure B.4: Capex by category



Source: AER, *State of the Energy Market*, June 2020, p. 142.

B.1.4 Regulatory Asset Base (RAB)

The capital expenditure approved by the AER, and incurred by a network business is added to its RAB, on which the network business earns returns. Escalating investment increased the industry RAB by around 8.9 per cent per year over the seven years from 2006 to 2013. However, over the past five years (from 2014 to 2019), lower network investment flattened RAB growth to around 1.4 per cent per year.

The high historical growth of the value of network assets (the RAB) between 2006 and 2014 has been a key driver of revenue in the past decade.

This growth is generally attributed to the introduction of higher reliability standards in Queensland and New South Wales and also unrealised forecast demand growth across the NEM, the impact of past over-investment remains in the asset base.

Inaccurate demand forecasts also contributed to investment that increased the electricity networks' RABs, which rose by 75 per cent from 2006 to 2019.

The subsequent revenue reduction was more gradual for transmission network businesses than for distribution and could reflect a combination of factors, including lower rates of return, weaker electricity demand, operating efficiencies implemented by network businesses and regulatory refinements such as the AER's wider use of benchmarking.

- **Distribution:** the RAB continues to rise, reaching a combined peak value of $77.2 billion in 2019.
- **Transmission:** the RAB fell to $21.4 billion in 2019 — the fifth consecutive year of decline since its peak in 2014 ($21.8 billion).

B.1.5 Rate of return

What is the rate of return?

The AER determines an allowed rate of return (a weighted average of the cost of equity and cost of debt) and sets regulated revenues for an upcoming period (typically every five years).

As the RAB grows, the returns paid to shareholders and lenders that fund those assets also grow. This cost is passed on to customers. Given some network assets have a life of up to 50 years, network investment will impact retail energy bills long after the investment is made.

Rate of return as a driver of regulated revenue

As part of the revenue determination process, the AER forecasts a network business's efficient investment requirements over the upcoming regulatory period. Efficient investment approved by the AER gets added to the RAB, while depreciation of existing assets gets deducted. A network's asset base will grow over time if approved new investment exceeds depreciation.

The rate of return is often one of the key drivers of regulated revenue. The approved rate of return peaked at over 10 per cent from 2009 to 2013, but had eased to around 6 per cent by 2020.

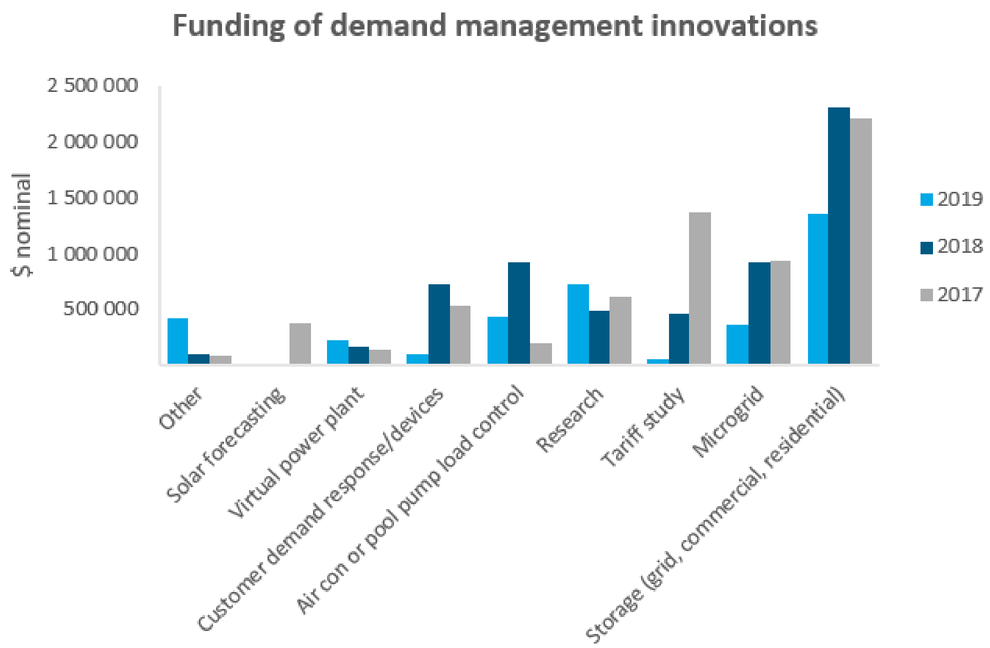
B.2 Funding of demand management innovations (non-network solutions)

The AER offers incentives for distribution network businesses to find lower cost alternatives to new investment to help cope with changing demands on the network and manage system constraints. There are two ways that DNSPs can access these funds:

- **Demand management incentive scheme (DMIS):** incentivises distribution businesses to undertake efficient expenditure on alternatives such as small-scale generation and demand response contracts with large network customers (or third-party electricity aggregators) to time their electricity use, in order to reduce network constraints. The scheme gives distributors an incentive of up to 50 per cent of their expected demand management costs for projects that bring a net benefit across the electricity market.
- **Demand management innovation allowance (DMIA):** a research and development fund to assist businesses develop innovative ways to deliver reductions in demand or peak demand for network services. The AER assesses expenditure claims to ensure distribution businesses appropriately use their funding, with under spends or unapproved spending returned to customers through revenue adjustments.

Figure B.5 below gives visibility of funding by project type, showing the largest component of funding has been related to battery storage.

Figure B.5: Funding of demand management innovations



Source: AER, *State of the Energy Market*, June 2020, p. 146.

Supported projects included:

- Energex (Queensland) installing a commercial battery and solar PV system
- TasNetworks (Tasmania) trialing an aggregation of customer batteries to manage network constraints on Bruny Island
- Endeavour Energy (NSW) trialing an aggregation of residential batteries to manage peak demand, and
- Ausgrid (NSW) running a feasibility study on community batteries.

Other significant funding was allocated to microgrids, air conditioning and pool pump load control projects, and tariff studies.

Research funding covered projects to, for example, laboratory test devices, make algorithms, look into future grid and electric vehicle demand, and fund scholarship studies.

Other funded projects included studies on the use of energy trading and distributed energy platforms for demand management.

Feedback on monitoring and reporting on key metrics

AGL noted in its submission that it would be useful if any data on non-network solutions could be disaggregated according to whether the non-network solutions were provided by third party providers or by related parties to the networks.[145] The AER has noted that it does not collect this information at the moment, but that it will consider requesting this level of detail going forward.

B.3 Distribution network utilisation levels

A network's utilisation rate indicates the extent to which a network business's assets are being used to meet maximum demand. The rate can be improved through efficiencies such as using demand response as opposed to new investment to respond to rising demand.

Data from the AER reveals that the average network utilisation amongst all distribution networks declined from 56 per cent in 2006 to 39 per cent in 2015, following over-investment at a time of weakening electricity demand.[146]

In 2019, average network utilisation among all distribution networks increased to 46 per cent, the highest rate since 2013.

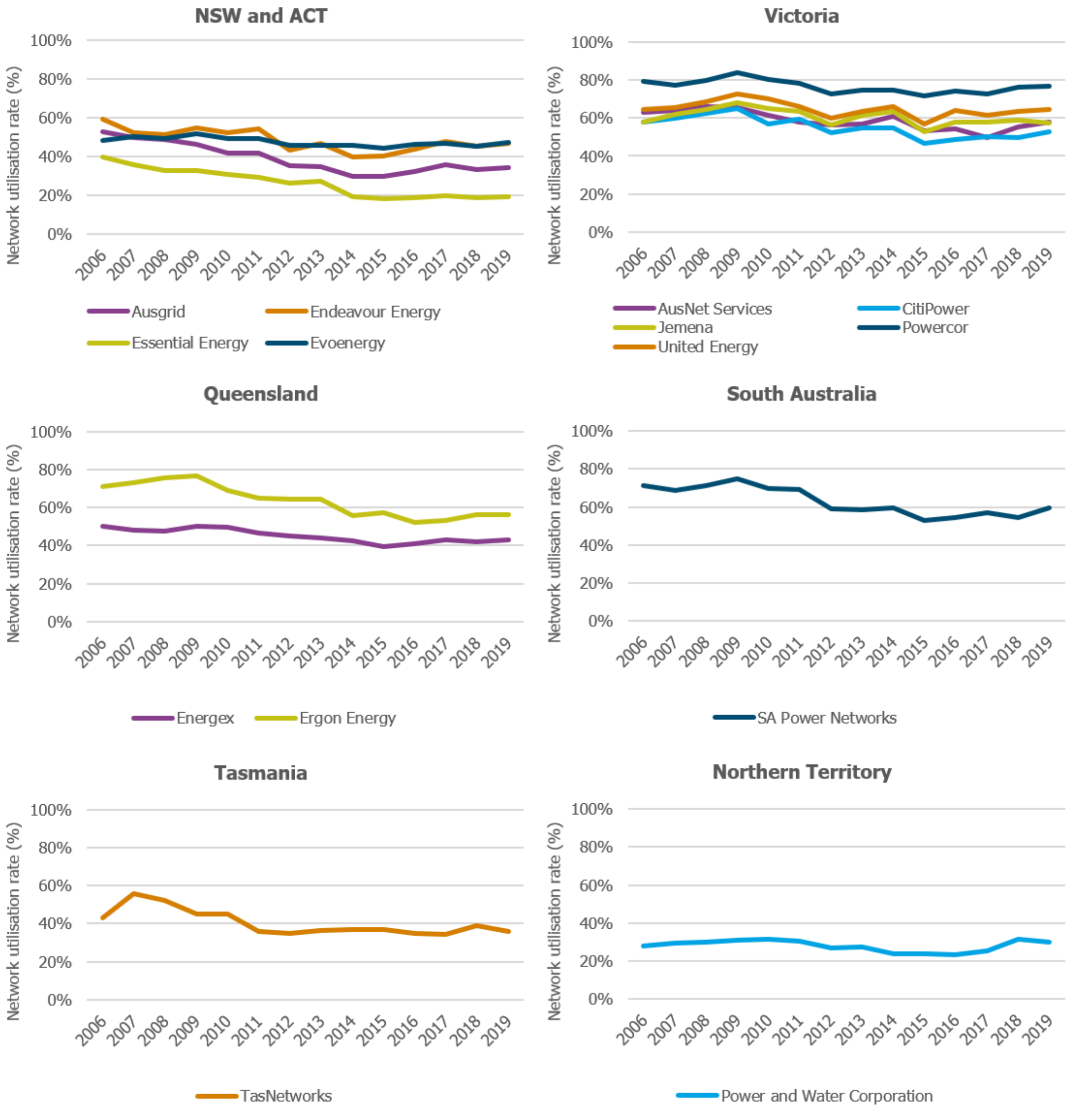
- **High:** Powercor (VIC) operates the most highly utilised distribution network in each year from 2006 to 2019, followed by United Energy (VIC) from 2016 to 2019.
- **Low:** Essential Energy (NSW) has been the most underutilised distribution network in each year since 2010, followed by Power and Water (Northern Territory).

Figure B.6 illustrates the relative utilisation rates of distribution networks across jurisdictions in the NEM, as well as the Northern Territory.

145 AGL, *submission to approach paper*, p. 2.

146 AER, *State of the Energy Market,* June 2020, p. 158.

Figure B.6: Distribution network utilisation rate



Source: AER, *State of the Energy Market*, June 2020, pp. 159-161.

C DER UPTAKE TRENDS

Uptake of rooftop solar has experienced exponential growth in the past decade.

DER interactions with the NEM comprise the greatest source of innovation and challenges to the evolving Australian electricity network. Rooftop solar is changing the very nature of the energy market by empowering consumers to become active traders and producers on the grid, transforming a once unilateral system of supply and demand into an increasingly distributed, multi directional marketplace.

The rooftop solar sector has a current capacity of more than 10GW. However, research by the UTS Institute for Sustainable Futures, Australian PV Institute and the University of New South Wales (UNSW) for the Clean Energy Finance Corporation and Property Council of Australia estimated that Australia's total rooftop solar potential is 179GW with an annual output of 245TWh, which is more than Australia's current annual demand.[147]

The changing composition of the grid has also seen the escalating penetration and importance of batteries, electric vehicles, and other technologies such as stand-alone power systems.

As the energy system becomes increasingly distributed, it also becomes increasingly participatory, as consumers are empowered by unprecedented access to information about their own consumption and production and are able to respond accordingly to the movement of supply and demand.

In tandem, the energy system is becoming increasingly responsive —– not only to consumer needs, but to the realities of environmental challenges: from providing reliable energy to remote communities to augmenting grid resilience in the face of the greater frequency of extreme weather events.

The following trends map some of the key areas of development that will change the shape of the Australian energy system — both physically and conceptually — in the coming years.

C.1 Rooftop solar

Government incentives and declining installation costs mean Australia has one of the highest per person rates of rooftop solar PV installation in the world.

For individual consumers, the uptake of rooftop solar and battery systems can help them save on power bills and manage their energy use in ways to suit their needs, while also empowering them to take initiative on environmental concerns.

The capacity, quantity, and uptake of rooftop solar technologies have all exhibited accelerating growth over the past decade, alongside innovative new models for access and distribution enabling more consumers to benefit from the integration of DER than ever before.

147 UTS, UNSW, Australian PV Institute, *How much rooftop solar can be installed in Australia?,* June 2019.

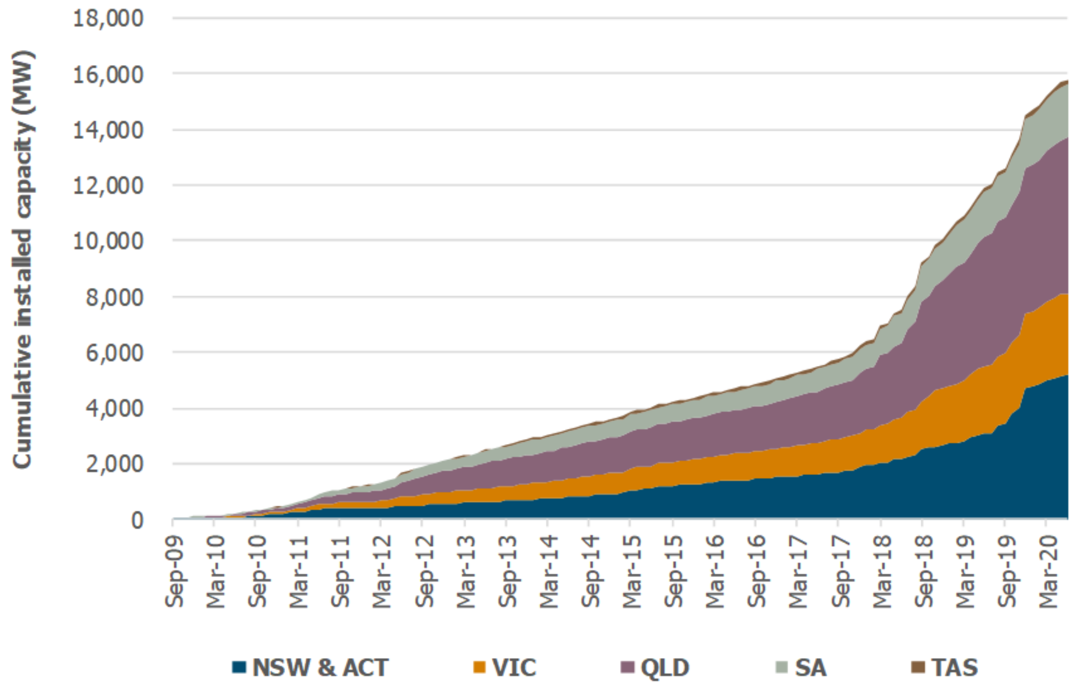
Installed capacity

The rooftop solar sector has a current capacity of more than 10 gigawatts (GW). However, recent research estimated that Australia's total rooftop solar potential is 179GW, with an annual output of 245 terawatt-hour (TWh), which is more than Australia's current annual demand.[148]

There were 287,504 rooftop solar installations in 2019, increasing the capacity of rooftop solar in the NEM to over 12,000 megawatts (MW). Queensland and South Australia have the mammoth's share of solar PV capacity in the NEM, with around 1 in 3 houses installed with rooftop solar.

Figure C.1 shows the total installed capacity of rooftop solar in the NEM over the last ten years, using data supplied by the Clean Energy Regulator.

Figure C.1: Small-scale solar PV installed capacity in the NEM



Source: AEMC adaptation of postcode data from the Australian PV Instituted, collected on 31 August 2020.
Note: Only systems below 100kW were included in the analysis.

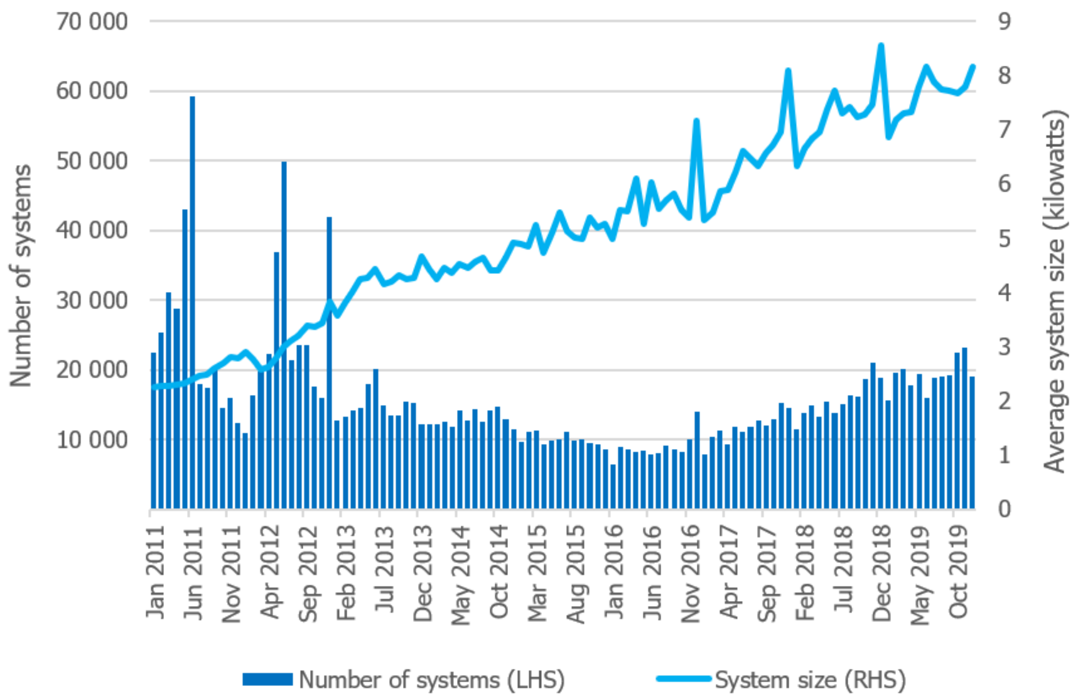
148 UTS, UNSW, Australian PV Institute, *How much rooftop solar can be installed in Australia?*, June 2019.

Average system size

This strong growth in capacity was not only due to an increasing number of systems installed, but due to continued growth in the size of these systems themselves.

Figure C.2 graphs the growth of system size in the NEM over the past decade. As shown, average size increased to 7.62kW in 2019 from 7.19kW in 2018, meaning that the industry's 2.2GW of installed capacity was more than 35 per cent higher than last year's record. For historical comparison, system size in 2010 reached an average of 1.97kW.

Figure C.2: Average system size and number of small-scale solar PV systems installed in the NEM, by month



Source: AEMC adaptation of Mapping Australian installations' data from the Australian PV Institute.

Proportion of households with rooftop solar

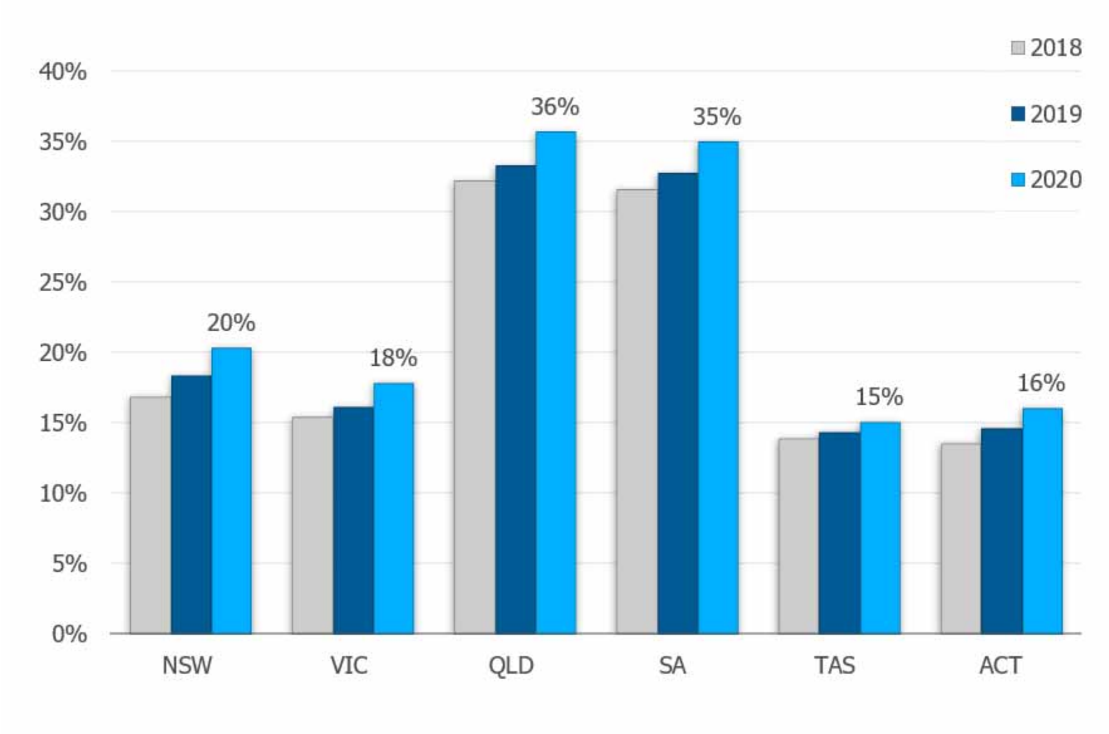
Around 20 per cent of all customers in the NEM now partly meet their electricity needs through rooftop solar generation, and sell excess electricity back into the grid, compared with less than 0.2 per cent of customers in 2007.

Figure C.3 shows the share of households with rooftop solar per region of the NEM.[149]

149 Estimated by comparing the total number of freestanding and semi-detached dwellings with the number of residential rooftop solar systems installed in each area, assumed as the number of systems smaller than 10kW.

As of September 2019, over one third of all households in South Australia and Queensland have installed rooftop solar. Queensland led the way, with four of the top five solar postcodes in Australia located in the state.

Figure C.3: Share of households with rooftop solar in the NEM



Source: AEMC adaptation of Mapping Australian installations' data from the Australian PV Institute.

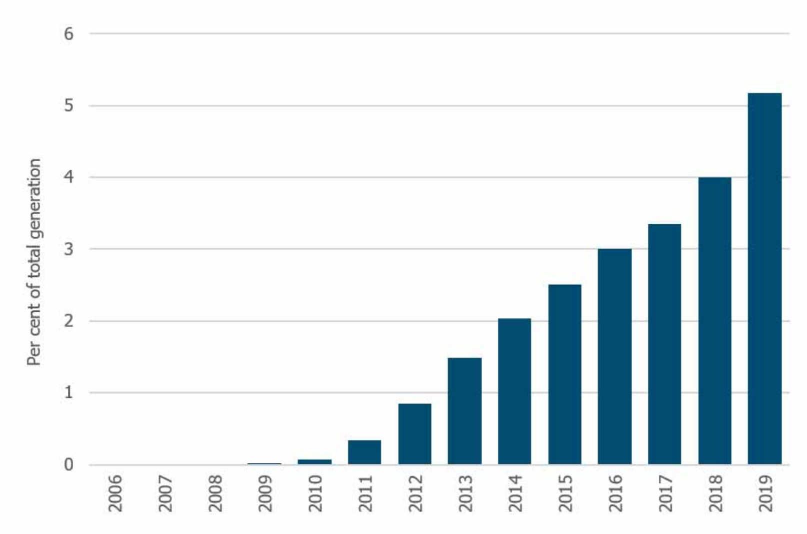
A changing generation mix in the NEM

Between 2014 and 2020, more than 4,000 MW of coal-fired generation left the NEM. Over this same period, more than 7,000 MW of new renewable supply came online.

Whilst a large proportion of this was supplied by wind and solar farms, energy generation from household rooftop solar is making an increasing impact on the overall output of the NEM.

As shown in Figure C.4, rooftop solar generation met over 5 per cent of the NEM's total electricity requirements in 2019.

Figure C.4: Solar generation share of total NEM generation



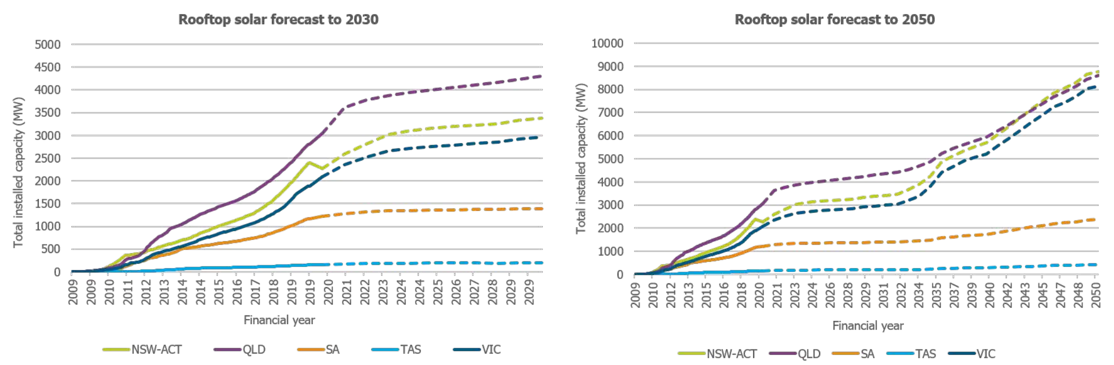
Source: AER, *State of the Energy Market*, June 2020, p. 37.

Actual and forecast uptake of rooftop solar

Strong growth in rooftop solar systems is forecast over the next decade while pricing support remains from high retail prices and government subsidies such as the small-scale technology certificates (STC).

After this, future growth in rooftop solar uptake is projected to be slower, due to a combination of declining incentives and easing of retail electricity prices. However, the uptake of rooftop solar is still forecast to almost triple between now and 2050, as shown in Figure C.5 below.

Figure C.5: Rooftop solar forecast



Source: AEMC, *Annual Market Performance Review 2019*, final report, April 2020.

Note: Initially sourced from AEMO and the Clean Energy Regulator data. Available in the Annual Market Performance Review data portal.

C.2 Batteries

The impact of batteries on the market and their future potential in building a modern energy system is a current topic of debate in the energy sector at a time of steady growth in household battery systems and the emergence of grid-scale projects.

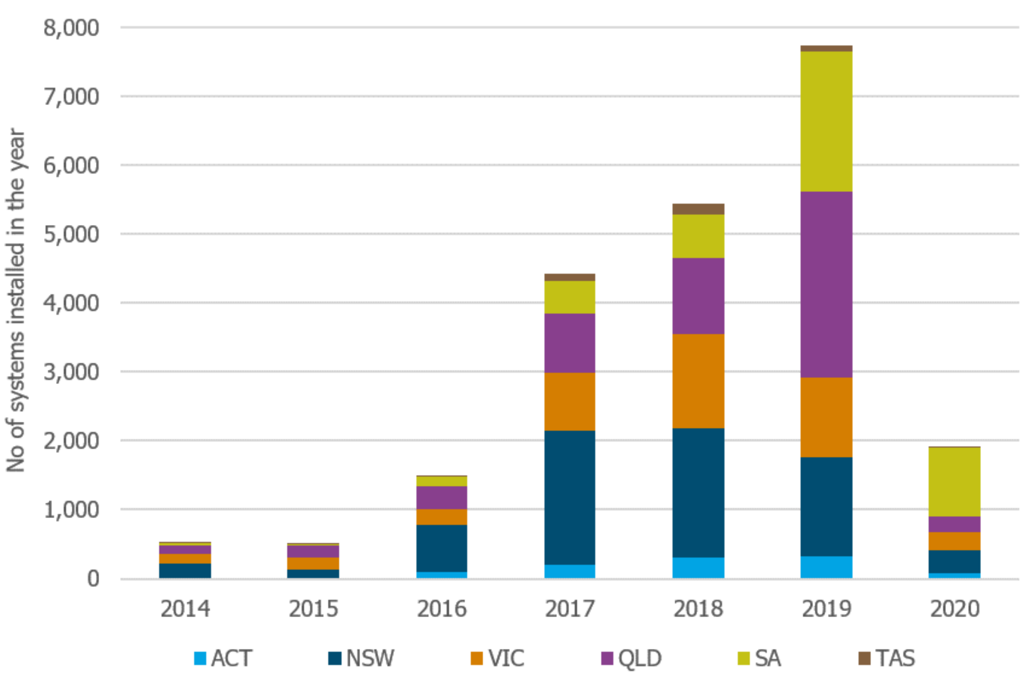
Combined battery storage and rooftop solar system installations

Batteries can charge and discharge energy generated by rooftop solar or imported from the grid at different times and can therefore provide more active control and ways to use electricity.

These could include selling stored energy when energy prices are high, providing network support in exchange for payments or using the energy stored by the battery for their own electrical appliances when the sun isn't shining.

While battery storage devices are more expensive than rooftop solar, their costs are dropping and consumers are adopting them in increasing numbers.

Figure C.6: **Number of batteries with rooftop solar systems installed in the NEM**

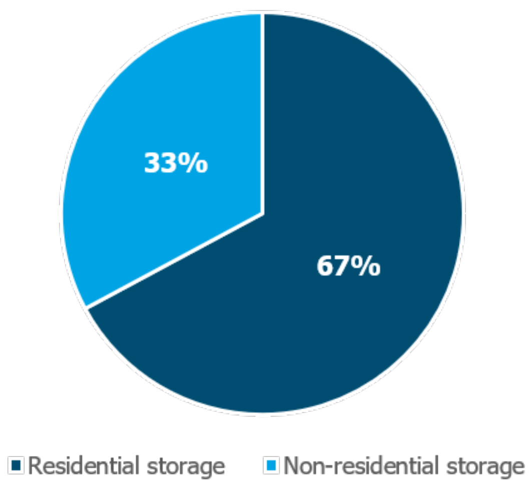


Source: AEMC adaptation of postcode data from Clean Energy Regulator, 30 April 2020.
Note: The graph is based on voluntary disclosed data for batteries that were installed at the same time as a rooftop solar system.

Australian households installed 22,661 battery systems over the course of 2019 with a total capacity of 233 MWh. This took Australia's household storage capacity past 1 GWh for the first time.

The NEM saw a cumulative total of 73,000 battery storage systems installed in 2019, equating to 1,099 MWh of battery storage capacity installed since 2015. Of this quantity, home battery systems remain by far the biggest contributor, with 738 MWh of storage, compared to 361 MWh of non-residential storage, as shown in Figure C.7. These numbers suggest that 1 in 13 Australian solar households also have battery storage, or 7.9 per cent.

Figure C.7: Installed battery capacity (MWh) in 2019 by type



Source: Renew Economy, 16 April 2020. See: https://reneweconomy.com.au/australians-installed-22661-home-battery-systems-in-2019/#:~:text=Australian%20households%20invested%20in%20almost,control%20over%20their%20energy%20supply.
Note: Article based on SunWiz 2020 Australia Battery Market Report.

Projections

The Australian Renewable Energy Agency (ARENA) states that, due to the technology's versatility and falling costs, the use of batteries for renewable energy and storage is expected to continue to increase over the coming years.

Given the number of variables that will influence the uptake of battery storage, the CSIRO has developed four scenarios to help predict industry growth.

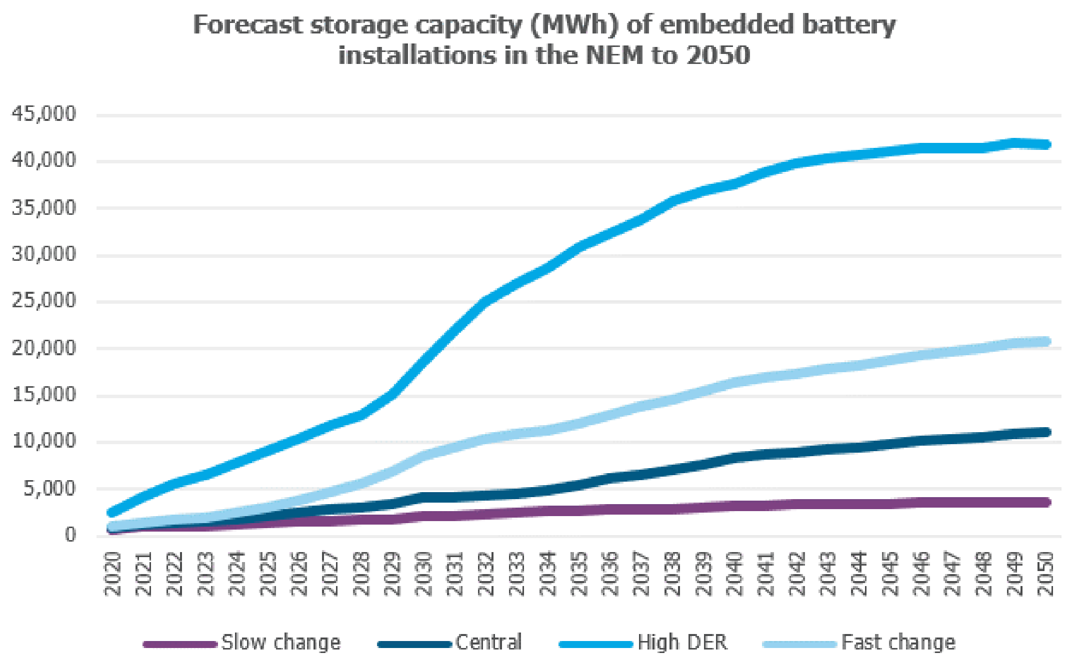
- The 'Fast change' scenario allows for potential attractive remuneration for owners if they make their batteries available for providing systems services.
- The 'High DER' scenario incorporates this eventuality alongside a broader subsidy scheme available for batteries in all states between 2020-2030.
- The 'Slow' and 'Central' scenarios assume the majority of customers are using batteries mainly to shift to solar, with differences constituted by varying minority numbers accessing smarter tariffs or contributing to grid services.

Projected capacity of batteries increases strongest in the next decade when decreases in battery costs are the steepest.

Falling battery costs and an increase in electricity prices around the late 2020s and early 2030s see strong growth through those periods.

However, from the mid-2030s, when electricity prices ease and battery costs level out, growth in battery capacity slows dramatically due to mostly stagnant payback periods, with capacity only increasing a little in the early 2040s reflecting assumed increasing retail prices during that period.

Figure C.8: Battery storage capacity (MWh) forecast



Source: CSIRO, *Projections for small scale embedded energy technologies*, report to AEMO, 2020, p. 63.

C.3 Electric vehicles

The prevalence of electric vehicles (EVs) in Australia and around the world is growing due to declining costs and the introduction of government policies to reduce emissions in the transport sector.[150]

Recent analysis by the Commission suggests that, while early in the uptake phase of EVs, the wide variety of retailer sizes, strategies and skills within the NEM is facilitating innovation and diversity in early offers that will lead to the continuing growth of the EV market.[151]

150 The term 'electric vehicle' can be used to describe any vehicle that contains one or more electric motors that contribute, partly or entirely, to powering the vehicle.

151 AEMC, *Retail Energy Competition Review 2020,* June 2020, p. 175.

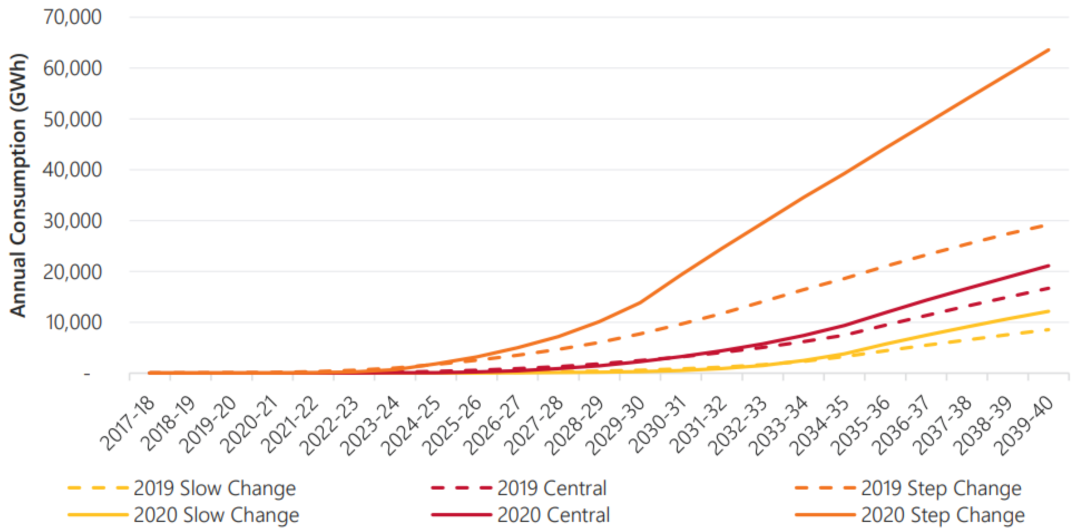
AEMO predicts that electrification of the transport sector could be the dominant driver of growth in electricity consumption in the future.[152]

Presently, electric vehicles (EVs) comprise less than 1 per cent of the total vehicle fleet across the NEM. Based on the current level of uptake, and in the absence of any policy incentives, AEMO's forecast projects that the uptake of EVs across the NEM will reach only 3 per cent, or half a million vehicles, by 2029-30 in the Central scenario.

However, growth is forecast to accelerate from 2030 due to increasing consumer choice of vehicle models, the growing availability of charging infrastructure, and consequent falling costs. Electrification of the transport sector is therefore projected to accelerate in the late 2020s and into the 2030s, as shown in Figure C.9 below.

Figure C.9: Electric vehicles forecast

Figure 14 NEM EV annual consumption forecast, 2017-18 to 2039-40, all scenarios, and compared to the 2019 ESOO



Source: AEMO, *2020 Electricity Statement of Opportunities*, August 2020, p. 37.

C.4 Smart meter uptake

A competitive electricity smart meter roll out is occurring across New South Wales, ACT, Queensland, South Australia and Tasmania in the wake of the AEMC's *Competition in metering reforms*. Since December 2017, all new and replacement electricity meters need to be smart meters.

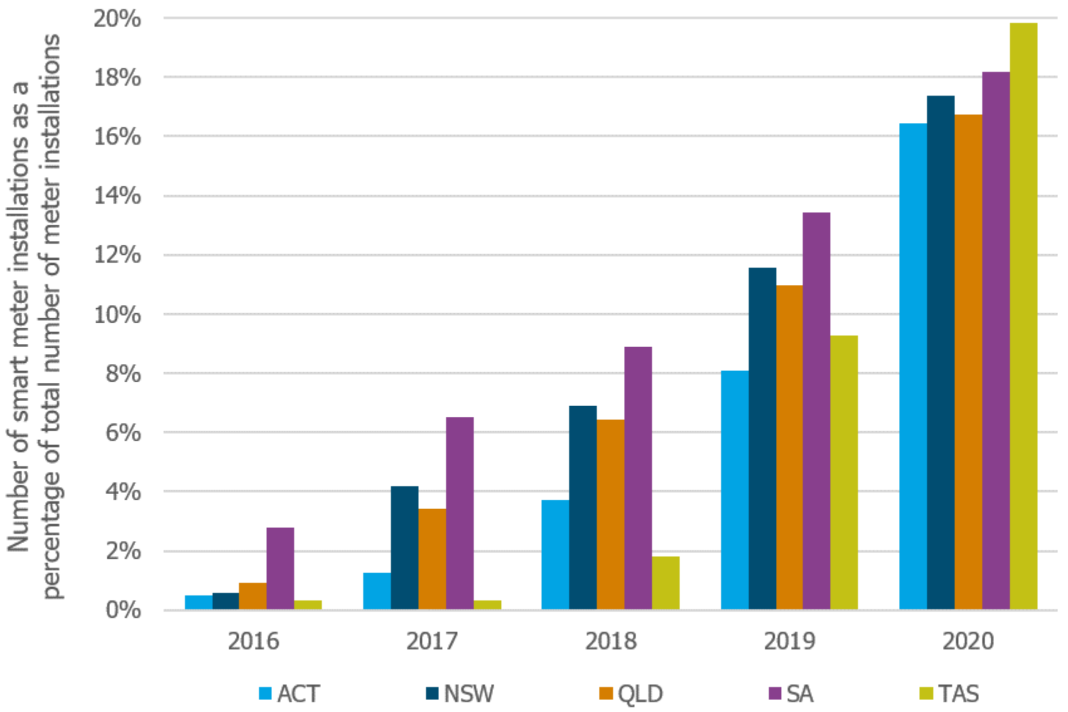
Figure C.10 shows all states have seen steady increases in the installation of smart meters over the past four years to 2020, with the sharpest rate of uptake occurring in Tasmania from

152 AEMO, *2020 Electricity Statement of Opportunities,* August 2020.

2 per cent in 2018 to 20 per cent in 2020, with South Australia just below at 18 per cent. Both New South Wales and Queensland have made progress at 16 per cent each, whilst ACT sits just behind at 16 per cent.

AEMC is currently engaged in a monitoring program to assess the general roll out of smart meters across the NEM.

Figure C.10: Share of smart meter installations in the NEM (excluding Victoria)



Source: AEMC analysis of AEMO's retail transfer statistical data (MSATS). Meter counts are at 30 June of each year.
Note: Victoria has been excluded due to the compulsory roll out of smart meters that occurred across the state between 2009 and 2013.

C.5 Non-network solutions

Alongside the emergence of new technologies in a distributed energy system comes new and innovative ways of interacting with the grid. With greater availability of information comes an improved capacity to respond to the needs of the grid in real time, as well as participate in new forms of community energy sharing such as virtual power plants. Concurrently, stand-alone power systems can link consumers at the edge of the grid to safe and reliable energy supply, avoiding the need for expensive transmission upgrades in remote areas and mitigating the increasingly regular impacts of unpredictable weather events.

Virtual power plants and demand response

Consumers with more active forms of DER (meaning some form of battery storage or demand response) can participate in a virtual power plant (VPP). VPPs allow a retailer or other type of aggregator to bundle their DER-produced or stored electricity along with that of other consumers and then sell this energy.

A VPP consists of many systems connected at many points right across the grid. This helps improve grid asset utilisation, lowers losses in the system, and increases local grid stability. By 2050 it is estimated that $16 billion per annum in grid infrastructure investment can be avoided due to the use of VPPs, with the total reduction in expenditure in the grid valued at $101 billion.

Australia hosts some of the most advanced VPP projects in the world — particularly for rooftop solar and battery storage — on and off the grid. Though most are relatively small at around 5-10 MW of generation or storage capacity, AEMO anticipates up to 700 MW of VPP capacity by 2022.[153]

VPPx is an ARENA funded project which commenced in March 2018 and has been working to build the first virtual power plant (VPP) that will integrate with a distributed energy market platform. Led by Simply Energy, the VPP will host 1,200 energy storage systems (ESS) which will deliver 6.5 MW of flexible capacity to the South Australian electricity grid.[154] As of June 2020, Simply Energy is progressing the final stage of the three-stage project focused on VPP recruitment, testing, and knowledge sharing.

In July 2019, AEMO opened registrations for participation in its virtual power plant (VPP) demonstration program. Energy Locals, in consortium with Tesla, and AGL registered as participants. It is anticipated that coordinating DER through VPPs can benefit both:

- Consumers owning VPP assets who earn value from delivering grid services, such as reliability and emergency reserve trader, frequency control and ancillary services, or energy.
- All other electricity consumers who benefit from a more efficient power system, as more resources respond to market price signals rather than operating independently.

The AGL Virtual Power Plant, a VPP completed in September 2019 after the installation and connection of solar battery storage systems across 1,000 residential and business premises in Adelaide, South Australia is managed by a cloud-based control system. The batteries are able to 'talk' to each other through a cloud-based platform using smart controls, forming a connected system that will be able to operate as a 5 MW solar power plant.

Demand response is another option that is available to consumers, including via a VPP. Through demand response, consumers can reduce their reliance on the grid and consume energy produced by their DER instead, which can ease demand pressures on the grid or provide the grid with frequency support.

153 AEMO, *NEM Virtual Power Plant (VPP) Demonstrations Program — consultation paper,* November 2018, p. 3.

154 Simply Energy, *Stage 2 Knowledge Sharing Report — Simply Energy VPPx,* June 2020, p. 3.

Stand-alone power systems

DER may also facilitate consumers at the edges of the grid disconnecting from it and setting up a stand-alone power system (SAPS), which is an electricity generation and supply system comprising solar panels, a large battery and a backup diesel generator which can operate independently of the electricity grid.

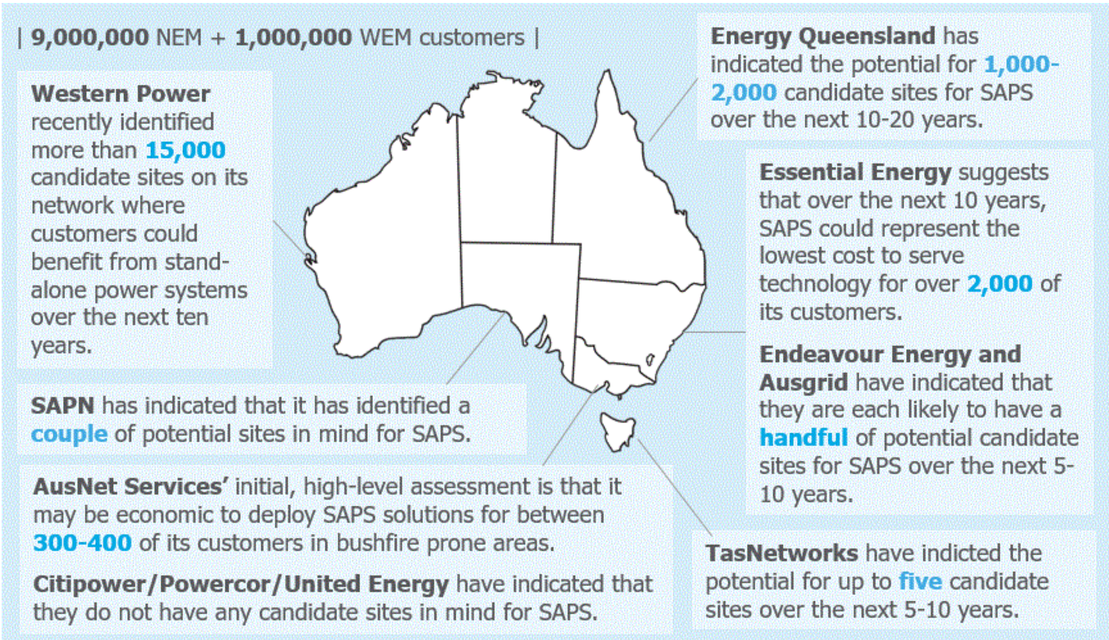
For these customers, switching to a SAPS can provide them with decreased costs and increased reliability, while also reducing the costs other consumers incur in maintaining distribution network infrastructure.

The overwhelming majority of SAPS customers are likely to be rural and remote customers with a minority coming from other expensive, environmentally challenging areas of the network.

On request, the AEMC has recently provided recommendations to Ministerial Forum of Energy Ministers (formerly COAG Energy Council) for regulatory changes related to stand-alone power systems through DNSPs or through a third party.[155]

If implemented, Energy Networks Australia and CSIRO predict that new regulatory arrangements could lead to up to 27,000 rural customers adopting SAPS and disconnecting from the grid.

Figure C.11: Potential uptake of distribution SAPS



Source: AEMC, *Updating the regulatory frameworks for distributor-led stand-alone power systems*, final report, May 2020.
Note: Numbers regarding the potential uptake of SAPS provided by DNSPs as of May 2020.

155 AEMC, *Review of the regulatory frameworks for stand-alone power systems,* 31 October 2019.

D OTHER ISSUES RAISED IN SUBMISSIONS AND INTERVIEWS

This appendix sets out a list of other issues raised in the consultation on this review process. If an issue raised in a submission or interview has been discussed in the main body of this document, it has not been included in this list.

They are categorised into distribution, transmission and others.

Please note that for many of the issues included in this list, there are already open rule changes, reforms and/or investigation taking place either by the AEMC, the AER, the ESB and industry organisations.

Distribution:

- Integrate two-sided markets with DER access and pricing
- Investment in distribution level monitoring and visibility projects
- Voltage management on low voltage networks
- Governance of DER technical standards
- Compliance with technical standards
- The role and roll out of smart meters
- The framework for investment by DNSPs in communications infrastructure
- Uneconomic connections and the potential for customers to bear significant costs
- Consider whether network tariff reform remains fit-for-purpose

Transmission:

- Cost allocation methodology for inter-regional transmission networks
- Inequity in cost allocation between generators and consumers
- Principles for allocating obligations to solve system security challenges for generation connection

Other:

- Increase flexibility in the regulatory framework
- Minimise inefficient network investment
- Enhance coordination to progress market reforms
- Consider alternative accountability mechanisms to ensure independence of regulator
- Greater appreciation for dynamic efficiency rather than technical efficiency
- More emphasis on output regulation (long-term)
- Consider establishing a nationally consistent concessions framework
- Consumer protections for new services
- National consistency for planning and local environmental controls for SAPS