Australian Energy Market Commission

Integration of Energy Storage

Regulatory Implications

DISCUSSION PAPER
9 October 2015

This paper examines whether changes to regulatory frameworks are required to integrate energy storage into the electricity supply chain.

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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.

Executive Summary

Storage devices, including batteries and pumped hydro units, are not new technologies and some have been used in Australia's energy markets for decades. What is new is that technological advances, particularly in battery storage, are making the functions they perform cheaper and more accessible to a wider range of users. As a result, the potential range of storage applications is increasing and greater penetration, including at the residential level, has led to questions about whether the existing regulatory frameworks are sufficiently flexible to support the integration of storage technologies.

The AEMC has undertaken analysis of storage and its uses across the sector. Subject to stakeholder feedback, it is our view that while storage and particularly battery storage may become more pervasive, the functions it performs are not different to other types of technology and can be accommodated within the existing regulatory frameworks. This analysis has been informed by collaboration with the CSIRO who have provided a technical assessment of how different storage technologies could be utilised, as well as modelling the possible uptake rates across the NEM.

This draft report summarises the CSIRO's technical review before detailing our analysis of the regulatory framework. We are seeking feedback from stakeholders on both the range of issues identified, as well as any suggested solutions or proposed next steps. We anticipate publishing a final report in early December 2015.

Storage has the potential to interact with the entire electricity sector and therefore the applicable regulatory frameworks extend from rules impacting how storage is utilised on the customer side of the meter, through the economic regulation of networks, to the use of storage by a generator in the wholesale market. This has required an analysis of the National Electricity Law and the accompanying National Electricity Rules. There are aspects of the National Energy Consumer Framework – the National Energy Retail Law and the National Energy Retail Rules - that may be relevant to energy storage, particularly the consumer protection arrangements. Any consumer protection issues associated with storage penetration are best addressed by governments in the context of the current broader review of energy-specific consumer protection and the relationship with Australian Consumer Law.

In undertaking any assessment of whether the regulatory framework remains fit for purpose in the face of dynamic market forces, it is important to understand the original purpose of that framework. An underlying principle of energy market regulation in Australia has been technology neutrality. That is, the rules are not designed to bias the deployment of storage or any other technology. Rather the rules have been designed to encourage efficient, market-based outcomes and so not act as a barrier to the use of whatever technology delivers the most cost-effective service. In sectors that are not subject to competition – network businesses – the regulatory framework has again been technology neutral, seeking to mimic to the greatest extent possible those cost-effective market outcomes.

There are many reasons to welcome the opportunities that lower cost storage technologies could bring to the electricity sector. Like other technologies, such as solar PV, advanced metering devices and home energy management systems, they have the potential to greatly expand the choices that consumers have to manage their energy needs. Networks and generators are also likely to derive value from storage solutions with storage offering an alternative to network augmentation and potentially helping to smooth the intermittent nature of renewable generation.

Utilising the competitive market frameworks currently in place will allow consumer preferences to drive how the sector develops. This may not lead to an orderly deployment of this technology – rather new business models will be tested and those that offer value to consumers will thrive while those that do not will vanish. The way consumers value storage and associated services will determine the penetration rate and competition between providers will keep costs low.

The AEMC is therefore of the view that for the purposes of network regulation, storage should be considered a contestable service. This conclusion is based on a number of principles that are at the foundation of energy market development in Australia. Market arrangements should promote consumer choice while providing a level playing field for market participants. Consumer choice based on clear price signals then drives innovation, with costs minimised by each service provider seeking to provide a compelling value proposition to the consumer. Finally, it is only in instances where competitive forces cannot deliver these consumer benefits that economic regulation should be contemplated.

We have already seen a number of players entering the Australian storage market and there is nothing to suggest this market is not able to deliver the sorts of products and services required by consumers, network businesses and large-scale generators. Network businesses should only be allowed to own storage behind the meter through an effectively ring-fenced affiliate that separates this activity from the provision of regulated network services. There are however a range of options available to them, through commercial arrangements with other service providers, to leverage the benefits of storage. The ring-fencing provisions that help define how regulated and contestable services are provided by network businesses are due to be revised by the AER. These will need to be developed with very clear requirements for arms-length transactions and be accompanied by rigorous compliance and enforcement activities. This will enable networks to compete with other service providers on an equal basis.

This leads then to questions about how best to optimise the benefits of storage. Storage devices are often able to generate multiple value streams and could offer network support services while also being able to dispatch energy into the wholesale market, or offset a residential consumer's retail load. The value generated from these different services will depend to a large part on who has control of the asset – that is, whose benefit is the device seeking to maximise?

Network businesses may argue that it is inefficient having individual consumers buy storage devices when a network solution could provide benefits to all consumers at a lower cost. This, however, assumes that network optimisation is more highly valued by consumers than their individual preferences regarding the alternative uses of storage. It is also in conflict with the principles mentioned earlier that underpin the energy market frameworks, particularly the desire for consumer choices to drive energy market development. Moreover, networks could gain implicit control of the value from storage through onerous connection regimes or through requiring control of dispatch which could alter the investment case of a consumer or retailer.

The current regulatory frameworks in the NEM encourage market-based solutions to these sorts of control and optimisation issues. This sort of approach may not mean a measured, controlled deployment of storage, but the regulatory frameworks are in place to reconcile the needs of networks with the desire for consumer-led decisions on technology deployment.

The AEMC's preliminary findings therefore suggest that the current regulatory frameworks and associated processes for developing them, can accommodate the installation of storage across the electricity sector and are largely robust to this type of technological change. The analysis has highlighted that there may be a range of improvements made in certain areas of the framework to make installation simpler. The AEMC would welcome stakeholder feedback on the areas identified as well as any suggested solutions.

We request submissions on this draft report be submitted by **5 November 2015**. Consultation questions have been included in each chapter but we invite stakeholders to submit their views or questions on any relevant issues.

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1 Introduction

1.1 Purpose and scope of this work

The purpose of the AEMC's report is to gain a clearer understanding of whether the existing regulatory framework is sufficiently flexible to support the integration of storage technologies, or whether regulatory change is necessary.

Energy storage technologies are available in many different forms, each of which has different ways of storing and releasing energy.[1] Examples of different methods of energy storage include mechanical energy storage, such as pumped hydro and flywheel energy storage; chemical storage, such as batteries; and thermal energy storage. Each energy storage technology has advantages and disadvantages which must be considered when determining the applicability of particular storage technology to a specific circumstance.

The following chapters set out the components of the existing regulatory framework that may relate to the integration of storage. Storage technologies have the potential to touch every point of the electricity sector. As such, the regulatory framework that we need to consider is broad.

We examine three possible applications of storage across the electricity sector and highlight the key issues that may need to be considered at each level:

- Storage integration at the wholesale market level.
- Network businesses, both transmission and distribution using storage on their network.
- End users using storage behind the meter, and aggregators combining this capability.

By existing regulatory framework, we are referring to the National Electricity Law (NEL) and National Electricity Rules (NER). The NEL and NER establish the regulatory framework that underpins the operation of the National Electricity Market (NEM). The NER determine how companies can operate and participate in the competitive generation and retail sectors of the electricity market. They also govern the economic regulation of electricity transmission and distribution network service providers. The NEL and NER apply in all NEM jurisdictions, that is, the ACT, NSW, Queensland, South Australia, Tasmania and Victoria.

While there are aspects of the National Energy Consumer Framework - the National Energy Retail Law (NERL) and National Energy Retail Rules (NERR) - that may be relevant to energy storage, this report focuses on the regulatory framework set out by the NEL and NER. Further, this report does not consider instruments at the jurisdictional or sub-jurisdictional level that may affect the integration of storage;

1 CSIRO, Electrical Energy Storage: Technology Overview and Applications, July 2015, p9.

however we welcome input from stakeholders on the impact of the relevant jurisdictional instruments.

Specific aspects of storage integration that this report does not focus on include:

- Consumer protections. The COAG Energy Council and the AER are considering the impact of new electricity products and services, including storage, on consumer protections and the regulation of parties providing those products and services (see Appendix A). While we are not addressing specific consumer protection issues in this report, the AEMC does believe this is an important issue which requires thorough review and hence invite stakeholder views on the impact on the consumer protection framework.

- Standards, including technical, building and safety standards for electricity storage devices and their installation. While we recognise the importance of these types of standards, their development does not fall within the AEMC's remit.

Consultation questions

- **Do stakeholders agree that the appropriate scope for the AEMC's work is the NEL and the NER as they relate to the integration of energy storage?**

- **Are there elements of the current consumer protection framework that need to be reviewed in relation to the penetration of energy storage?**

- **Are there jurisdictional and sub-jurisdictional instruments relevant to energy storage that the AEMC should also consider?**

1.2 Related work

This report is intended to complement the range of work being undertaken by other parties in the area of electricity storage and its regulatory implications – see Appendix A. Of particular relevance are:

- The AER's review of ring-fencing guidelines, which aims to harmonise various state-based ring-fencing guidelines into a single, national guideline. As we discuss in Chapters 3 and 5 of this report, network-controlled storage devices, ring fencing will be need to be considered for network-controlled storage devices, which have the potential to provide both regulated and competitive services.

- AEMO's work to incorporate storage into its normal forecasting and planning activities, through the National Electricity Forecasting Report and National Transmission Network Development Plan.

- AEMO's examination of the regulatory arrangements applicable to registration of a storage device under the National Electricity Rules.

1.3 CSIRO technical analysis

The AEMC engaged the CSIRO to conduct two pieces of work to inform our understanding of the scale and scope of the impact that storage technologies may have. These reports are summarised below. Both are available in full on the AEMC website.

The first report, *Electrical energy storage: Technology overview and applications* is an overview of the technical aspects of storage in Australia and looks in detail at the prevailing issues that will be brought about by the widespread adoption of storage in the energy sector.

There are a range of existing grid-connected energy storage technologies, however a much smaller subset of these technologies is commercially available now or is likely to be in the near future. There are storage technologies available other than batteries; however, the report considers energy storage technologies that are likely to secure meaningful uptake in the Australian electricity system over the next 15 years, based on technical maturity, supply chain, manufacturing and recent development activities. Under these criteria five battery technologies are chosen for further examination in the report. The battery technologies considered are:

- advanced lead-acid;
- lithium iron phosphate;
- lithium nickel manganese cobalt oxide
- zinc bromine flow; and
- sodium nickel chloride molten salt.

The wide range of benefits that each of the above identified technologies may provide to the electricity grid was considered and the capacity for each of the technologies to deliver these benefits evaluated. The report finds that no technology will be best suited to all potential applications. Therefore the choice of storage technology for a particular application will depend on careful technical design to match its required operational characteristics with the main goals of its deployment. Figure 1.1 below shows the general applicability of the chosen battery technologies to application areas.

A number of issues exist to the broader uptake of electrical energy storage across Australia. These include:

- careful consideration of the effect of the Australian climate on storage technologies, given the effects of ambient temperature on their performance;
- more data on the relative performance of different technologies under a range of operating conditions, in particular life cycles when used for particular applications; and
- specific safety standards for storage technologies will have to be developed.

Most of the challenges identified relate to the lack of real-world Australian experience with each of the technologies across the broad range of usage scenarios.

Figure 1.1 Summary of applicability of battery technologies to application areas

	Application	Advanced lead-acid	Lithium iron phosphate	Lithium nickel manganese cobalt oxide	Zinc bromide flow	Sodium nickel chloride molten salt
Grid-side	Large-scale renewable integration	✓✓✓	✓	✓	✓	✓✓✓
	Distribution network support	✓✓	✓✓	✓✓	x	x
Customer-side	Commercial and industrial energy management	✓✓✓	✓✓	✓✓	✓✓	✓
	Residential energy management	✓✓	✓✓✓	✓✓✓	✓	✓
	Electric vehicles	✓	✓	✓✓	x	x

Key: X = very low (if any) applicability; ✓ = low applicability; ✓✓ = moderate applicability; ✓✓✓ = high applicability

1.4 CSIRO energy storage trends report

A second CSIRO report entitled *Future Energy Storage Trends: An assessment of the economic viability, potential uptake and impacts of electrical energy storage on the NEM 2015-2035* aims to provide an analysis of future trends in energy storage over the period 2015-35 for the technologies identified in the first report. The trends in the chosen technologies are based on their comparative economics for different grid and customer-side applications.

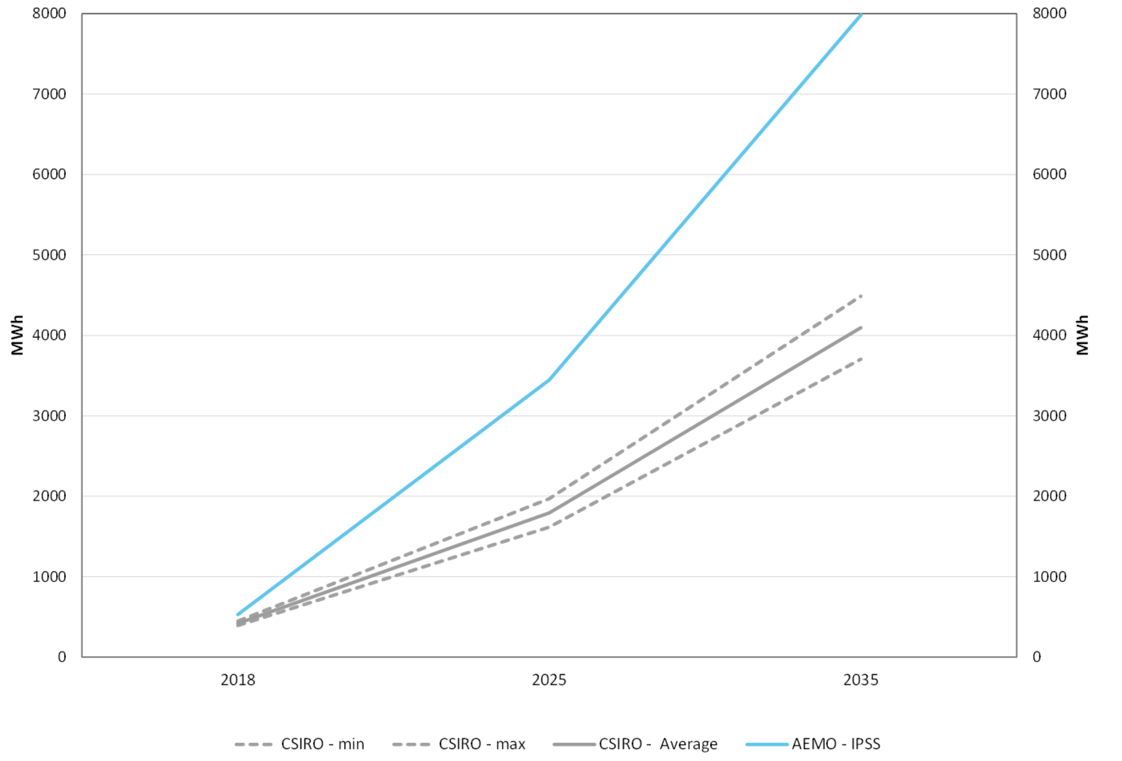
The report includes analysis of the economic viability of battery storage and provides projections for the adoption of battery storage in the Australian electricity grid. The report also calculates the impact of that level of adoption on the profile of electricity demand in Australia.

AEMO has also undertaken analysis of the economic viability of solar PV and storage.[2] Integrated systems of solar PV and storage are more attractive in the CSIRO study, when compared with similar retail tariff structures. However, the differences in payback period between large and small customers outweighs that between the two

2 AEMO, *Emerging Technologies Information Paper*, 2015.

studies, with both studies showing larger customers in New South Wales, Queensland and Victoria reaching a seven-year payback by 2020, medium sized customer by 2025, and smaller customers not reaching a seven-year payback period until after 2030. A seven-year payback period is chosen as a reasonable estimate of when adoption by mainstream consumers, primarily driven by economic considerations, will take place.[3]

Figure 1.2 NEM installed battery capacity (MWh) AEMO and CSIRO projections



Note: The chart compares the projections from AEMO for installed MWh of battery storage as part of an integrated photovoltaic storage system (IPSS) with the CSIRO projections on installed MWh of battery storage in an integrated system with solar PV and also the retrofit of battery storage to existing PV systems. The chart shows the range of installed MWh projected by the CSIRO, with the dashed lines indicating the maximum and minimum projected values and the solid line showing the average of these projections.

AEMO projections of installed battery capacity are based only on installation together with solar PV. The CSIRO projections shown in the chart are also based on integrated PV and storage systems but will include the retrofit of battery storage systems to existing PV installations. The chart above shows projected installed battery capacity in MWh across the five states of the NEM from both the AEMO and CSIRO studies. AEMO uptake projections for battery storage with integrated photovoltaic storage

3 As payback periods become shorter, it is expected that the proportion of the population that will eventually adopt the new technology becomes greater, and the speed with which the changeover takes place will increase. Generally though, it is reasonable to suggest that any adoption that is primarily driven by economic considerations will take place among mainstream consumers at somewhere between 5 and 10 years payback. The low end of this range represents a typical leasing period for a consumer product such as a motor vehicle, and the higher end represents a 10% return on investment comparable to interest rates for personal finance. When describing the results, seven years is chosen as a mid-way representative of that 5-10 year range.

system (IPSS) are approximately double that of the CSIRO projections. This difference is explained because the CSIRO projections are based on smaller battery system sizes, albeit with generally faster payback periods.

The battery costs used in the CSIRO analysis are lower than those assumed in the AEMO study. The CSIRO study also tailored the size of the system to each tariff type and customer scale instead of assuming a common size of battery and PV system across NEM states and tariffs. Finally, the CSIRO study is based in a heuristic battery management regime instead of the optimisation calculated by AEMO.[4]

Economic viability of the storage technologies in the CSIRO report is considered from the point of view of the investor. Investors could include network businesses, commercial or residential customers or vehicle owners, depending on the circumstances and the technology in question. The report assumes that battery adoption will only take place if there is a benefit to the investor.

The AEMC commissioned this work to get a better understanding of where in the sector storage was more likely to be deployed. This highlights which part of the regulatory framework is likely to interact with storage more immediately and therefore will assist the AEMC to target any findings to higher priority areas.

1.4.1 Main findings

There are nine key findings in the CSIRO report. These findings help to understand the economic viability, potential uptake and impacts of storage on different parts of the electricity sector.

1. The costs of energy storage technologies will decline significantly in the future

The costs of energy storage are projected to decline significantly. Cost reductions will be caused by technological learning, economies of scale in manufacturing and global cumulative capacity additions in transport and power applications.

Future developments in the cost of energy storage technologies are subject to uncertainty. However, the report estimates that the costs of battery technology will decline by around 53-85 per cent, depending on battery chemistry, in the next decade. The report's findings are within the range of estimates from other sources.[5]

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4 A heuristic battery operational regime identifies the most efficient strategy for battery use based on tariff type. For example, where there is a TOU tariff without PV, the battery is charged during off-peak hours until its maximum capacity is reached and discharged during peak hours until its minimum capacity.

5 Other studies on the costs of battery technology include those conducted by Bloomberg New Energy Finance and Navigant, the Rocky Mountain Institute and the US Energy Information Administration.

2. The economic viability of storage in networks is plausible but case specific

Electricity storage technologies have many potential uses for transmission and distribution networks and can be economically viable depending on the circumstances. Battery storage can be discharged to reduce peaks in electricity demand across the grid. This may allow capital expenditure to be deferred and improve the utilisation of the network. Co-locating storage with intermittent renewable generation, such as solar PV, may defer upgrades to existing voltage control or network protection schemes and improve power quality.

The steady state power rating of distribution transformers may need to be reduced from a cyclic rating towards a continuous rating.[6]This is because their capacity is dependent on the daily load profile, which is expected to be smoothed by residential-scale battery storage, thus reducing the periods of lower loading between peaks when the transformers can cool.

3. Energy storage can reduce connection costs for large customers

The report finds that the co-location of battery storage with a large load or a small renewable generation site (of under 30MW) could potentially reduce the costs of connecting to the grid. Cost savings could occur if battery storage could limit the maximum output from the generation site and facilitate connections at lower sub transmission levels. The potential savings will depend on the diversity of loads and/or the generation profiles of the individual customer.

4. The economic case for applying energy storage to reduce commercial electricity bills is sensitive to network tariff structure

The economic viability of storage is sensitive to a number of factors including region, tariff structure, and whether solar PV is installed. There are also differing views as to what constitutes a reasonable payback period for the storage investment.

The report finds that:

- The installation of an integrated battery storage system with solar PV is the most attractive investment for commercial consumers if the system size can be optimised to the customer's load. For baseline battery costs, the payback period on a standard tariff declines from 7-9 years in 2015 to 4-5 years in 2035.[7] For commercial sites without PV, the retrofit of battery storage is more attractive in Queensland and Tasmania under standard tariff structures, and NSW and South Australia under time-of-use (TOU) tariff structures.[8]

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6 Continuous ratings are represented by a factor of 1. Higher cyclic factors are often applied to distribution transformers depending on the daily load cycle defined by the use of the distribution transformer substation. The report provides indicative cyclic rating factors for the industrial case of 1.14, mixed of 1.38 and domestic of 1.47.

7 For a TOU tariff the payback periods are 17-29 years in 2015 and 7-11 years in 2035.

8 A standard tariff refers to the tariff that will be offered to the customer that may vary by State given their annual consumption. Standard tariffs may vary in terms of usage charges and a demand

- The retrofit of battery storage for commercial sites with existing PV is not viable under TOU tariff structures. Under standard tariff structures, battery storage at commercial sites is attractive in Queensland and, to a lesser extent, Tasmania.

5. Energy storage could be viable for households in seven years under current tariff structures

As with commercial customers, the economic viability of storage for residential customers is sensitive to region, tariff structure, whether PV is installed and differing views on a reasonable payback period.

The report finds that:

- There is greatest value of storage to households when it is installed in an integrated system with solar PV. Payback periods for households on a flat tariff are estimated to decline from 9-12 years in 2015 to 4-6 years by 2035.[9]
- For households without PV, battery storage under a TOU tariff provides the most value to households, particularly in NSW. Payback periods under a TOU tariff are projected to decline from 17-35 years in 2015 to 8-11 years in 2035.
- For households with PV already installed, battery storage does not provide significant additional benefits under a flat tariff or TOU pricing.
- There is greater value of storage for households with large loads in comparison to smaller customers.

6. Energy storage in the NEM could compete against gas in 20 years

There is currently excess generation capacity in the NEM. If a gap in peaking capacity were to emerge, batteries could be cost competitive with gas peaking plant to provide load-following services in some NEM states by 2035.

7. Electrical vehicle uptake is likely to be subdued in the next decade

The uptake of electric vehicles depends on future vehicle costs, projected oil prices and patterns of vehicle usages (km per annum). The report estimates that electric vehicle uptake will be subdued for the next ten years but may increase to 30 per cent by 2035.[10]Payback periods for electrical vehicles depend on customer vehicle preference and usage. The report finds that acceptable payback periods (of between 5 and 10 years) will be reached for some customers between 2021 and 2028.

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charge that varies by distribution network. Time-of-use (TOU) tariffs are also subject to variation depending on pricing structure , for example, there may be two or three tier rates depending on time of use. More detail on the standard and TOU tariffs used in this study can be found in the CSIRO Report.

9 For a TOU tariff the payback periods are 11-35 years in 2015 and 6-12 years in 20135.

10 This estimate is based on medium assumptions. Please refer to the report for a more detailed description of methodology used.

8. We should expect significant adoption of stationary and vehicle battery storage by 2035

Given the proposed relationship between the payback period and adoption, the report estimates that adoption of stationary and vehicle battery storage applications will be in the range of 5-30 per cent by 2035. The residential sector appears to be the most attractive market segment for the adoption of customer-side battery storage. The estimates are sensitive to region, tariff structure and the presence of solar PV.

9. The deployment of stationary battery storage could have a significant impact on peak demand growth but could be greater with more coordination of price signals

Battery storage reduces peak demand at times when it is encouraged to do so by current tariff structures. In particular, this means during the highest TOU cost period, for customers subject to that tariff. It is possible that peak demand times will shift in the future relative to those designed by tariff structures.

The report finds that if customer-side battery storage is discharged at system peak, NEM maximum demand could be reduced by 2.1-3.4 GW by 2035. The most significant opportunities for reductions (in percentage terms) are in South Australia and New South Wales.[11]

11 The estimates are based on the share of stationary battery adoption for each customer segment (residential or commercial) in each jurisdiction and will depend on the structure of the electricity market in each state. For more detailed description of the methodology used please refer to the Report.

2 End users and aggregators using storage

The falling cost of energy storage technologies is increasing the economic viability of residential and other small electricity end users installing battery capability 'behind the meter' for energy management purposes.

Storage capability can increase the utilisation of electricity generated by a solar PV system at a customer's site, and thereby reduce the amount of electricity drawn from the grid. Storage devices may also have value without a PV system, providing customers on an appropriate retail product with the means to draw electricity from the grid when prices are low and from the storage device when grid prices are high.

Parties can also aggregate the combined capability of a number of smaller storage devices across the network. An example is Reposit Power (Box 2.1). The aggregator business model is attractive because it attempts to capture the value of the multiple value streams that can be provided by electricity storage systems. Aggregated storage capability could be used to sell electricity into the wholesale market or provide services to other parties, such as demand management or ancillary services.

Box 2.1 Case study: Reposit Power

Reposit Power is an Australian-based technology company that has developed a software solution to aggregate the capability of residential storage systems. The company’s GridCredits platform is designed to capture the value of residential solar PV and storage systems on the customer’s behalf by maximising the customer's self-sufficiency and trading additional capacity in the wholesale market as an added value stream.

The software decides whether to store energy in the customer’s battery or trade it through the wholesale electricity market for a profit in times of high prices, all the while maintaining the customer’s supply. Reposit director, Dean Spaccavento says “the idea is to buy electricity from the grid when prices are lowest, consume as much of your own solar as possible and occasionally sell to the markets when prices spike".[12] A mobile phone app allows customers to see whether energy is being consumed, stored or sold. The software is designed to integrate with a range of storage systems, including Tesla’s Powerwall home battery system.

GridCredits could in future be extended to other uses of the storage system that can be monetised. Batteries under Reposit's control are delivering contingency frequency control ancillary service.[13] They are integrated with distributed energy dispatch tools which could enable network support agreements, with the batteries discharged at critical peak times to avoid network augmentation.

12 Business Insider, 4 May 2015, http://www.businessinsider.com.au/this-little-australian-startup-has-landed-an-agreement-with-tesla-to-support-its-new-home-batteries-2015-5.

13 See Appendix M for a description of ancillary services.

This chapter describes how the regulatory frameworks would apply to small-scale electricity end-users seeking to connect storage capability to a distribution network in the NEM, and aggregators seeking to utilise their combined capability.

2.1 Connection

To charge a battery using electricity from the grid, or export electricity from a storage device into the grid, it must be connected to the electricity network. Connection is defined in the NER for smaller scale connections as "a physical link between a distribution system and a retail customer's premises to allow the flow of electricity".[14]

The regulatory framework for smaller loads and generating systems connecting to a distribution network is set out in Chapter 5A of the NER.[15] These rules apply to parties that are not registered participants:

- retail customers;
- micro-embedded generators (eg, retail customers with residential rooftop solar systems); and
- non-registered embedded generators (connecting a system of less than 5 MW but larger than a micro-embedded system).

Retail customers are required to go through the connection process with their network service provider to establish a new connection to the network (eg, when building a new house) or to amend an existing connection (eg, to add a solar PV system to their house).

The Commission considers that any system which exports electricity to the grid is a generating system. A system that only ever draws electricity from the grid is a load. A system which both imports and exports is both a load and a generating system, and the person operating it is both a customer and a generator. The existing definition of micro-embedded generator therefore covers retail customers seeking to connect storage capability at their premises to the distribution system, with the intention of exporting electricity to the grid – whether in conjunction with a solar PV system, for example, or as a standalone device.[16]

Therefore the existing connection rules in Chapter 5A apply to storage systems which are intended (1) to export electricity to the grid, or (2) to complement existing micro-embedded or non-registered embedded generation systems (eg, to retrofit a solar PV system with storage capability). The relevant existing connection offers for micro-embedded generation therefore also apply to residential energy storage systems.

14 Rule 5A.A.1 of the NER for the purposes of Chapter 5A only. Connection otherwise refers to the formation of a "physical link to or through a transmission or distribution network".

15 Chapter 5A connection processes are summarised in Appendix B of this report. Appendix L sets out the connection requirements for generating systems connecting to a transmission network and for generating systems larger than 5MW connecting to a distribution network.

2.1.1 Process for connection under Chapter 5A

The connection processes under Chapter 5A are still relatively new, and distribution network service providers (DNSPs) are still in the process of implementing the requirements. The connection process is otherwise prescribed in Chapter 5A. The steps in the connection process for a micro-embedded generator are covered in detail in Appendix B.2.[17]

To assist the connection process, DNSPs are required to publish information on their websites relevant to the specifics of connecting to their network.[18] Some of this information is specific to the technicalities of embedded generation (but does not currently extend to storage).

The process, requirements and costs of connecting storage capability behind the meter at a customer's premises will depend on a number of factors, including:

- whether the storage device is being installed as part of a new connection or an alteration to an existing connection;
- whether the customer's system is to be used to export excess electricity to the network; and
- whether the DNSP is satisfied that its network can accommodate the connection of the device.

The connection process for retail customers seeking to install storage capability and export electricity is likely to be more technically complex than for systems that are not intended to export electricity to the grid. The process will also likely be more complex and more expensive if network augmentation is required.

DNSPs' existing connection offers for micro-embedded generators apply to storage connections but do not explicitly address any separate requirements or technicalities of energy storage devices, including any retrofitting of connected micro-embedded generators. In order to facilitate the streamlined connection process that was intended under Chapter 5A, it may be worth considering whether DNSPs should be required to have a standard connection offering that separately addresses the connection of micro storage capability.

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16 This is discussed further in section 5.1.2 in relation to generator registrations.

17 In November 2014 the AEMC made a rule giving embedded generator proponents for whom an AER approved connection offer is not available the ability to choose the more detailed connection process in Chapter 5 of the NER if they wish. In non-NECF jurisdictions (i.e. Victoria) embedded generator proponents seeking a connection of less than the standing exemption can use an applicable process in a relevant jurisdictional instrument or can seek to use the Chapter 5 process. Where no jurisdictional instruments for the connection of embedded generators exist, the relevant DNSP would determine the connection process.

18 Clause 5A.D.1 of the NER.

Consultation questions

- **Connection processes are new and still being implemented. Do you anticipate any issues with the connection process associated with storage?**
- **Do connection processes represent a barrier to storage? If so, what specifically is the issue?**
- **Should DNSPs be required to have a connection offering that separately addresses the connection of micro storage capability?**

2.1.2 Connection charging

The costs of connection services depend on how the provision of that service by the DNSP is classified by the AER and the AER's connection charge guidelines.[19] Generally, residential connections are treated as standard control services where they are not contestable. The associated costs are recovered from all electricity customers through general network charges.

Micro-embedded generators are required to make a capital contribution associated with their premises' connection assets and dedicated network extension. They are not required to fund any augmentation of the DNSP's shared network. Micro-embedded generators also pay any ancillary service fees and metering service fees associated with their connection.

However, if the capacity sought to be connected is above a certain level than is usually addressed in standard connection offerings then a capital contribution will need to be made to the augmentation of the DNPS's network.[20] To the extent installation of storage with a micro-embedded generator affects the capacity sought to be connected, there is a possibility that connection applicants may need to meet augmentation costs.

Capital contributions can be required as part of the connection charges, for standard control services. In relation to non-registered embedded generators that are also load customers, capital contributions will be calculated based on the total cost of the works required to support both the generation (expected electricity output) and load components of the connection service. Installing storage with embedded generation assets is likely to affect how the relevant connection charges are calculated, if it affects the gross peak demand of the load.

DNSPs are required to include in their connection policy and publish on their website a pioneer scheme. These allow a connection applicant that has funded a network extension to be refunded a portion of these costs when subsequent customers connect

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19 The AER is required under Clause 5A.E. 3 of the NER to develop and publish these guidelines.

20 Clause 5A.E.1(2) of the NER. The method used by the AER to calculate the shared network augmentation charge and relevant threshold level for 100A 3-phase low voltage supply is outlined in the connection charge guidelines.

to the extension. Schemes of this nature may become more significant if large consumers begin to install distributed energy resources, including storage, with the intention of selling some of their output across the network.

Consultation questions

- **Do connection costs represent a significant barrier to storage? If so, what specifically is the issue?**

2.1.3 Additional connection requirements

Distribution connection applicants may have specific processes or particular technical requirements placed on them by their connecting DNSP before they can connect a storage device to the network. For example, Ausgrid requires that all battery energy storage systems with export to grid functionality be connected via an inverter compliant with AS 4777.[21] Other technical requirements may extend to the installation of protection devices to stop feed in to the network when the network is out of service. Depending on the size and proposed operation of a storage device, a connecting DNSP might undertake a technical assessment of the proposed system to determine the impact its connection may have on the network and whether the network is able to accommodate it. As such, connection arrangements are likely to differ between DNSPs and areas of the network.

Standardising technical requirements for the connection of storage capability to a distribution network may simplify the connection process and result in a uniform approach to connections across distribution areas.[22] The applicability of AS 4777 in this respect is discussed in section 2.3.

There may also be building restrictions or safety requirements imposed at a state/territory or local government level that affect whether or how a storage device is installed. As explained in Chapter 1 of this report, the AEMC proposes not to focus on these areas.

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21 Ausgrid, Guidelines for photovoltaic installations up to 200kW connected via inverters to the Ausgrid network, October 2014, p14.

22 In the absence of nationally consistent technical standards for connection more generally, in two recent rule changes the Commission created an obligation on DNSPs to establish a register of completed embedded generation projects: clause 5.4.5 and clause 5A.D.1A. of the NER. The obligation does not extend to micro-embedded generation projects. The register outlines generating plant and associated equipment that DNSP have found to comply with their minimum technical requirements. The intention was to increase the relevant and up-do-date information on the technical requirements available at the early stages of considering whether to invest in embedded generation. As these registers become populated with the details of storage systems connected to DNSPs' networks, information regarding the technical requirements for the connection of storage will increase (in the absence of any agreed standards).

Consultation questions

- **Would a separate industry standard for the connection of small or micro storage assets to a distribution network be appropriate? If so, what should be included?**

2.2 Retailer authorisation and aggregator registration

2.2.1 Retailer authorisation

Under the 'traditional' model of electricity retailing, authorised retailers buy electricity from the wholesale energy market and supply it, via a distribution network, to the end user. The retailer is the sole provider of a customer's electricity and it is sold as an essential service. However, there are a range of new products and services emerging, including energy storage, that are challenging the traditional business model of electricity retailing.

The existing regulatory framework does not restrict a retail customer's ability to contract with a business to install a storage device, or to have a party other than themselves manage how the device is operated. However, many innovative product and service offerings are emerging that involve onsite generation, such as solar PV combined with energy storage (see Box 2.2). This combined capability will challenge the traditional role of the retailer that sells energy through the distribution network to a customer.

Box 2.2 Case study: Vector battery leasing product

In 2013, Vector, the monopoly distribution network in Auckland, rolled out a solar battery leasing package that offered rooftop solar, lithium-ion batteries and control devices at no extra cost to consumers. The arrangement consists of an upfront payment and monthly lease to the utility network provider. Initially, Vector offered a $NZ 1,999 up-front payment and leasing options over 12 years which resulted in lower electricity bills for the household.[23]

The customer installs the solar, which is not subsidised by the government in New Zealand, and the network invests in storage in the customer's home. The storage is located behind the meter but is a network asset. Sunverge's Solar Integration System (SIS) is used to connect the storage assets to the grid. The SIS creates a "virtual power plant" in that units of storage are located at customer

23 Renew Economy, *Future grid: Networks focus on solar storage for consumers*, 8 August 2013, *http://reneweconomy.com.au/2013/future-grid-networks-focus-on-solar-storage-for-consumers-66152*, accessed on 13 August 2015.

sites but aggregated power and energy is reserved, scheduled and dispatched across the fleet of units.[24]

The value of the storage asset is shared between the customer and the utility customer. Customer benefits can include lower bills and a more secure supply of electricity. The network benefits can include avoided losses in transmission and distribution, wholesale market benefits, avoided transmission charges and avoided voltage corrections. Vector has developed a methodology for quantifying the contribution of individual benefits to the total value of such leasing arrangements.[25]

Given the rate of population growth in Auckland, Vector predict that take-up of this product could be up to 45 per cent of new homes. With retrofitting of existing homes, which is dependent on energy prices and the costs of the technology, market penetration of this product could be as high as 30 per cent in the future. Vector is also looking to expand their operations in the solar and storage field to include larger solar battery solution for the commercial market.[26]

Lessons for Australia:

The benefits of this product are shared between customers and the network and the revenue streams from both uses are realised. Customers contribute to the capital cost of the hardware and the revenues from network service provision are also recovered. This model, despite successfully realising the multiple benefits and value of storage technology, raises questions regarding the activities undertaken by different market participants in the electricity sector and the potential impact on competitive markets of allowing regulated entities to participate.

Under the NERL, anyone who sells energy for use at customers' premises must have either a retailer authorisation, or a retail exemption.[27] An authorised retailer is bound by a range of obligations under the NERL. Exempt sellers are not bound by the same obligations, but may have certain conditions imposed upon them that largely replicated the relevant obligations under the NERL. The AER is responsible for assessing and approving authorisations and administering the exemptions framework under the NERL.

24 Sunverge, Sunverge SIS on the Grid, website, accessed 2 September 2015, *http://www.sunverge.com/product/*, accessed on 13 August 2015.

25 Sunverge, Customers, Networks and Markets: Integrating the benefits of Customer Sited Energy Storage, Presentation to the AEMC Public Forum on Integration of Storage, Sydney, 18 June 2015.

26 Renew Economy, Interview: Vector CEO Simon Mackenzie, 8 August 2013, *http://reneweconomy.com.au/2013/interview-vector-ceo-simon-mackenzie-69896* Accessed on 13 August 2015.

27 See Appendix C.

In November 2014 the AER published an issues paper on regulating innovative energy selling business models.[28] The purpose of this work is to determine whether the current authorisations and exemptions framework is appropriate in relation to market entry for the providers of these new products and services, including storage. The AER is due to finalise the outcome of this work in 2015. The COAG Energy Council is also considering how third party energy service providers and new products and services in the NEM should be regulated.[29]

The viability of business models offering storage capability at retail customer premises may depend on whether the business is required to have a retailer authorisation, and hence subject to electricity-specific consumer protection requirements, or a retail exemption.

2.2.2 Aggregator registration

The installation of storage devices at end users' premises opens an opportunity for parties to aggregate the combined capability of distributed storage across the network. Aggregated storage capability could be used to sell electricity into the wholesale market, to provide ancillary services or to provide services to other parties, eg, through a network support agreement or another form of demand response.

The NEL and NER require that a party register to participate in the NEM.[30] AEMO has responsibility for registering parties in the category of registered participant that reflects the applicant's intended activities in the NEM. A party wishing to aggregate the output of small generating units must register in that capacity. We anticipate that parties that are aggregating distributed energy storage systems will register as small generator aggregators.

There are no exceptions of the types or sizes of small generating units that may be included in a small generation aggregator's portfolio. Micro-embedded generators – including storage systems – could be part of such portfolios. To be part of such a portfolio, a micro-embedded generating unit (including a retrofitted one) would face costs in purchasing and installing a separate meter.

Consultation questions

- **Do storage systems have characteristics, either individually or in aggregate, that mean regulation through the retail exemptions framework set out above is inappropriate for the relevant value stream? For example, there is no limit on the number or size of generating units a small generation aggregator can aggregate and so sell into the wholesale**

28 AER, Regulating innovative energy selling business models under the National Energy Retail Law, 2014.

29 See https://scer.govspace.gov.au/workstreams/energy-market-reform/demand-side-participation/new-products-and-services-in-the-electricity-market/.

30 See subsequent discussion in sections 5.1 and 5.1.3.

market. Does this present a concern?

- **Aggregating parties would be required to register with AEMO if they intend to participate in the NEM. Will this provide any kind of barrier?**

2.3 Standards for the installation, connection and operation of storage devices

Australia is at the early stages of standards development for the design, installation, testing, maintenance and safe housing of energy storage systems. Some parties perceive that this may be presenting a barrier to the safe, reliable and widespread installation of battery storage.[31] Lack of uniform technical standards may also be affecting the connection of energy storage systems.

In April 2015, the Clean Energy Council published an Australian energy storage roadmap, which outlines a program of initiatives to better define and address the safety, environmental, technical, commercial and informational barriers to the deployment of both large and small scale energy storage technologies.[32] These include installation guidelines, an accreditation regime and technology standards.

The Clean Energy Council with support from ARENA has also commissioned the CSIRO to undertake a storage safety performance study, which will advise on international best practice for battery installations, maintenance and disposal. This work is due to be published in October 2015.

Another focus of standards development is on grid connection using inverters compliant with Australian Standard 4777 (see Box 2.3).

Box 2.3 Australian Standard 4777

Australian Standard AS 4777 is an industry standard for grid-connected inverter systems. Micro-embedded generators are defined by reference to this standard.[33].

An inverter is an electronic device that converts direct current to alternating current. It is the means by which small-scale energy generation systems, like solar PV, are connected to the network. Customers who have a solar PV system that is connected to the distribution network have an inverter that complies with AS 4777.

AS 4777 sets out the minimum technical, safety and operating requirements for inverter systems connecting to the low voltage distribution network. The Clean Energy Council publishes a list of approved inverters that meet AS 4777. The purpose of this list is to give customers confidence in the work of the party

31 AECOM, Energy storage study: Funding and knowledge sharing priorities, 2015, p62.

32 See Appendix D.

33 See Appendix B.1

installing their solar PV system and in the system's safety, performance and reliability.[34]

The current version of AS 4777 was first developed in 2005 as a standard for connecting inverters up to 10kVA (or 30 kVA for three phase) inverters. The purpose of the standard is to establish basic safety and installation requirements, and prevent the operation of the inverter interfering with the quality of supply at surrounding premises. The standard is divided into three parts:

1. installation requirements;
2. inverter requirements; and
3. grid protection requirements.

Parts 2 and 3 are in the process of being reviewed, which is due to be finalised in 2015. The draft of the revised version of parts 2 and 3, among other things, increases the threshold for compliance from up to 10 kVA to up to 200 kVA. It also includes provisions for demand response and power quality response modes and implies that these are included so the DNSP can control the operation of the inverter. Specifically:

- The draft demand response provisions give the ability to remotely set the generation (or consumption) to 0, 50, 75 or 100%, as well as remotely disconnecting the inverter. It also gives the ability to generate or consume reactive power, which will help maintain the network voltage.
- The draft provisions regarding power quality response modes specify how the inverter should adjust its consumption (when consuming or charging) in low voltage situations or reduce its output (when generating) in high voltage situations. Another power quality response mode enables the inverter to inject reactive power when the voltage is low and absorb reactive power when the voltage is high.
- The draft provisions regarding power quality response modes also specify how the inverter should adjust its consumption (when consuming or charging) in low frequency situations or reduce its output (when generating) in high frequency situations.

2.3.1 Applicability of AS 4777 to storage devices

A customer who retrofits an existing solar PV system with storage capability, or installs a new solar plus storage system, would be captured by the definition of micro-embedded generator and would therefore require an inverter that meets AS 4777 to be installed in order to connect to the network.

34 See http://www.solaraccreditation.com.au/products.html

As the connection of a standalone storage device is caught by the definition of a micro-embedded generator, then it would also require an inverter that meets AS 4777 to be installed in order to be connected to the network.

2.3.2 Control of end user storage devices by the DNSP

The revised version of AS 4777 may give DNSPs the capability to control the operation of inverters that connect storage systems to the distribution network. While there are valid safety, security and reliability reasons for a DNSP to want to control these devices such control may present a barrier to the development of business models that also rely on a degree of control over the operation of the storage device. We note that this issue is not unique to storage capability – any energy system connected via a grid-connected inverter may need to be compliant with the revised AS4777 and may therefore be subject to a level of control over the inverter by the DNSP.

Consultation questions

- **Does standard AS 4777 represent a potential barrier to the deployment of storage by providers other than networks? What elements of the standard are problematic?**

As discussed subsequently in Chapter 4, the control of storage devices is a key issue given the potential for multiple value streams from this one asset. Any standard that precludes the appropriate valuation of these revenue streams will impact the competitive market.

With an increased penetration of distributed energy resources – including distributed generation, distributed storage and other forms of actively controlled demand management – there may be benefits from the more active management of the distribution system. Aggregators may build their own platforms and seek to harness a diversity of resources to the benefit of the system.

2.4 Provision of ancillary services

Only certain parties are able to provide ancillary services. Only market participants can provide non-market ancillary services (NSCAS and SRAS), and only market generators and market customers can provide market ancillary services (FCAS).[35] A retail customer would therefore not be able to provide ancillary services. Further, it is unlikely that a retail customer's storage device would be capable of providing ancillary services.

However, there may be commercial benefits in a party providing ancillary services using the aggregated capability of a number of storage devices. While it may be more complex for an aggregator to demonstrate its ability to provide ancillary services than for the traditional provider – a market generator – it is technically feasible, depending

35 See Appendix M.

on the aggregated size and capability of the devices. An aggregator may be able to provide non-market ancillary services if it is registered as a small generation aggregator. However, a small generation aggregator is not able to provide market ancillary services.

Under the current rules, aggregators are limited in their ability to provide ancillary services using storage capability or other sort of small generating unit. The Commission considers that there is cause to extend the provision of ancillary services to other parties, eg, allowing small generator aggregators to provide FCAS. This is discussed further in Chapter 5.

Consultation questions

- **Should aggregators be able to offer FCAS? If no, why not?**
- **What are the technical or data requirements that would need to be addressed?**

2.5 Preliminary findings

The analysis has led the AEMC to make the following findings:

1. The existing connection process under the NER for micro-embedded generation appears to accommodate a consumer seeking to install storage behind the meter. However, there may be value in DNSPs being required to have a basic connection offering that separately addresses the connection of storage capability.

2. The technical requirements that apply to storage behind a customer's meter should be investigated to assess their appropriateness and whether there is potential for standardisation.

   — Consider a review of the different requirements being applied to behind-the-meter storage by distributors in different regions.

   — Consider whether the technical requirements, including AS 4777, give network businesses too much control over what is connected to their networks, both in terms of:

     (i) specification of the equipment and technical performance; and

     (ii) remote control.

3. We recommend investigating, for the existing registration category of small generator aggregator, whether the ensuing rights and obligations are suited to storage behind the meter, for instance thresholds on what can be offered into competitive markets, and if so when scheduling requirements would apply.

— Consideration should also be given to whether the operation of end-user storage – either individually or in aggregate – creates system operation or network operation concerns. This is discussed in Chapter 4.

4. We are of the view that small generation aggregators should be able to offer FCAS into the wholesale market. We therefore recommend that further consideration be given to whether there are any technical limitations to them doing so, and whether any changes to market arrangements and procedures (eg, data validation) would be necessary to facilitate their participation in FCAS markets.

Consultation questions

- **Do you agree with these preliminary findings?**
- **Are there other issues which should be considered?**

3 Network businesses integrating storage

There are a number of reasons why a transmission network service provider (TNSP) or distribution network service provider (DNSP) might seek to utilise the services from storage capability on its network.[36] This section sets out how the economic regulation of network businesses would apply to energy storage. In particular:

- How the frameworks for the classification of transmission and distribution services would treat the services provided by storage assets:
  - whether as a regulated service, and therefore subject to economic regulation, or
  - as a contestable service, and therefore subject to ring fencing (including legal separation).
- How regulated services provided by storage assets would be treated under the current NER provisions, including:
  - expenditure forecasts;
  - incentive mechanisms in the NER; and
  - investment test (RIT-T and RIT-D) requirements.
- How unregulated services provided by storage assets would be treated under the current NER provisions and, in particular, the applicability of the current provisions regarding:
  - ring-fencing;
  - cost allocation; and
  - shared asset provisions.

3.1 The regulation of services provided by storage facilities

The framework for the economic regulation of electricity network businesses, as set out in Chapter 6 and 6A of the NER, is focused on the regulation of services, rather than the regulation of specific assets. It is therefore helpful to consider the range of functions that energy storage devices could provide to network businesses, subject to any competition concerns as discussed further in section 3.3.1. These can be separated into four general categories, which are described in Table 3.1.

36 Throughout, TNSPs and DNSPs are referred to as "network businesses".

Table 3.1 Potential functions provided by energy storage devices

	Function	Description
1	Network support	Services used by network businesses as an alternative to network augmentation to address network capacity or constraint issues. A storage asset could be used to address peak demand in a constrained transmission or distribution network by charging during times of low demand and discharging during peak demand events, thereby avoiding the need to upgrade existing network assets.
2	Quality and reliability of supply (NSCAS)	Network businesses must comply with the power system performance and quality of supply standards set out in schedule 5.1 of the NER.[37] Energy storage may assist with managing voltage imbalance, power factor correction, and various other power quality functions.
3	Market ancillary services	Services used by AEMO to manage the power system safely, securely and reliably. Frequency control ancillary services (FCAS) are market ancillary services, and are acquired by AEMO on a competitive basis as part of the spot market.[38]
4	Energy trading	The provision of electricity into the NEM. This can be thought of as similar to services provided by generators, except energy storage would draw energy from the grid during low price periods and discharge energy into the NEM during periods of high price.

Some of these functions may be best provided by grid-scale storage devices, which may be owned and operated by the network whereas others could be provided by storage devices behind the meter at customers' premises through a commercial arrangement with the customer or a retailer, for example. The appropriateness of networks installing storage behind the meter is discussed further in Chapter 4.

The functions above include both those that may fall within the scope of regulated services, and those that are not related to the provision of regulated network services. For example, stored energy could be used to provide a network service by avoiding network augmentation (a regulated activity) or used to sell electricity into the wholesale market (an unregulated activity). This is analogous to services provided by other network assets. For example, utility poles are used to distribute electricity, which is a regulated activity, but they can also be used to host a broadband network, which is an unregulated activity and therefore separated from the regulated business through ring-fencing.

37 Clause 5.2.3 of the NER.

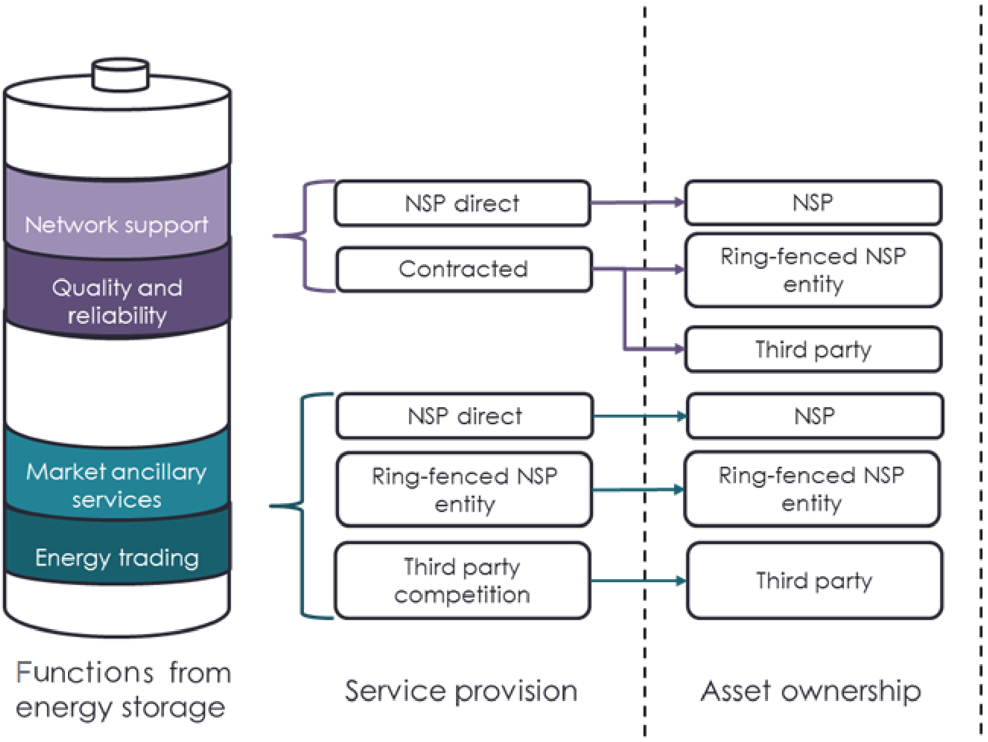
38 Clause 3.11.1(b) of the NER.

3.1.1 Method of service delivery

As shown in Figure 3.1, there are likely to be a range of ways in which the functions enabled by storage devices could be provided to the network business. For example the network business could either:

- own and operate the storage device; or
- contract for the service, either with a third party, or with its own ring-fenced entity.

Figure 3.1 Potential functions provided by energy storage and the method of service delivery



How services are classified determines how network businesses recover the associated costs (see section 3.2). As a separate AER decision, restrictions can be placed on the manner in which the network business provides the service, such as a prohibition on the business directly owning a storage device.

An analogous example is the provision of metering services under the AEMC's draft rule on Expanding Competition in Metering and Related Services. If a DNSP wants to provide advanced metering services to a competitive segment of the market, the service will be non-regulated and the DNSP will not be able to place metering assets in its regulatory asset base. The DNSP will also need to comply with ring-fencing guidelines developed by the AER – which may prevent a DNSP from owning metering assets as part of its regulated business. If a DNSP does not take on the role of providing metering services itself, it may be able to enter into contracts to obtain services from the metering assets to provide regulated services (eg, network management), where those assets are owned by a third party or a ring-fenced subsidiary of the DNSP.[39]

There is currently no restriction on the proportion of any one type of service that would need to be provided by an energy storage asset. This is because it is the services provided by an asset, not the asset itself, that are classified as regulated or non-regulated. A storage asset can therefore provide both regulated and unregulated services, with costs allocated to each of these activities via the Cost Allocation Mechanism (CAM) discussed further below.

An analogous example is an embedded generator, which may predominately supply energy to an industrial customer, but which may also provide network support to a regulated network business for a limited time during the year. The period for which the embedded generator provides network support may amount to only a few hours per year. However, the service of maintaining distribution reliability would still be classified as a regulated service. The costs the network business incurs in procuring this network support would be recovered as part of its regulated revenue, with costs allocated accordingly under the CAM.

The separation of regulated and non-regulated services, including ring fencing and cost allocation, is discussed in detail in section 3.3.

3.1.2 Classification of services

Services provided by network businesses comprise:

- regulated services, where the service is subject to some form of regulation under the NEL and NER; and
- non-regulated (or 'unclassified') services, where regulation under the NEL and NER does not apply.

The NER contain further provisions as to how regulated services are further classified into different categories.

This section describes the service classification definitions under the NER (for both transmission and distribution services) and discusses how the four types of functions provided by energy storage appear to fit within these service classifications.

Transmission service classifications

There are three transmission service classifications under the NER:

39 AEMC, Draft Rule Determination, National Electricity Amendment (Expanding competition in metering and related services) Rule 2015, 26 March 2015, p141.

- 'Prescribed transmission services' are subject to regulation under the NER and are largely services vital to ensure that consumers receive electricity supply through the transmission network.[40]

- 'Negotiated transmission services' are usually provided to a single or a small group of transmission-connected customers. These are typically connection services, so apply to the assets or services that are used to connect either loads or generation to the transmission network.

- 'Non-regulated transmission services' are those services that are not provided under prescribed or negotiated services, and so are not subject to economic regulation.

Figure 3.2 provides an overview of transmission service classifications and the economic regulation that applies to each.

40 See Appendix E.1 for detail.

Figure 3.2 Transmission service classifications

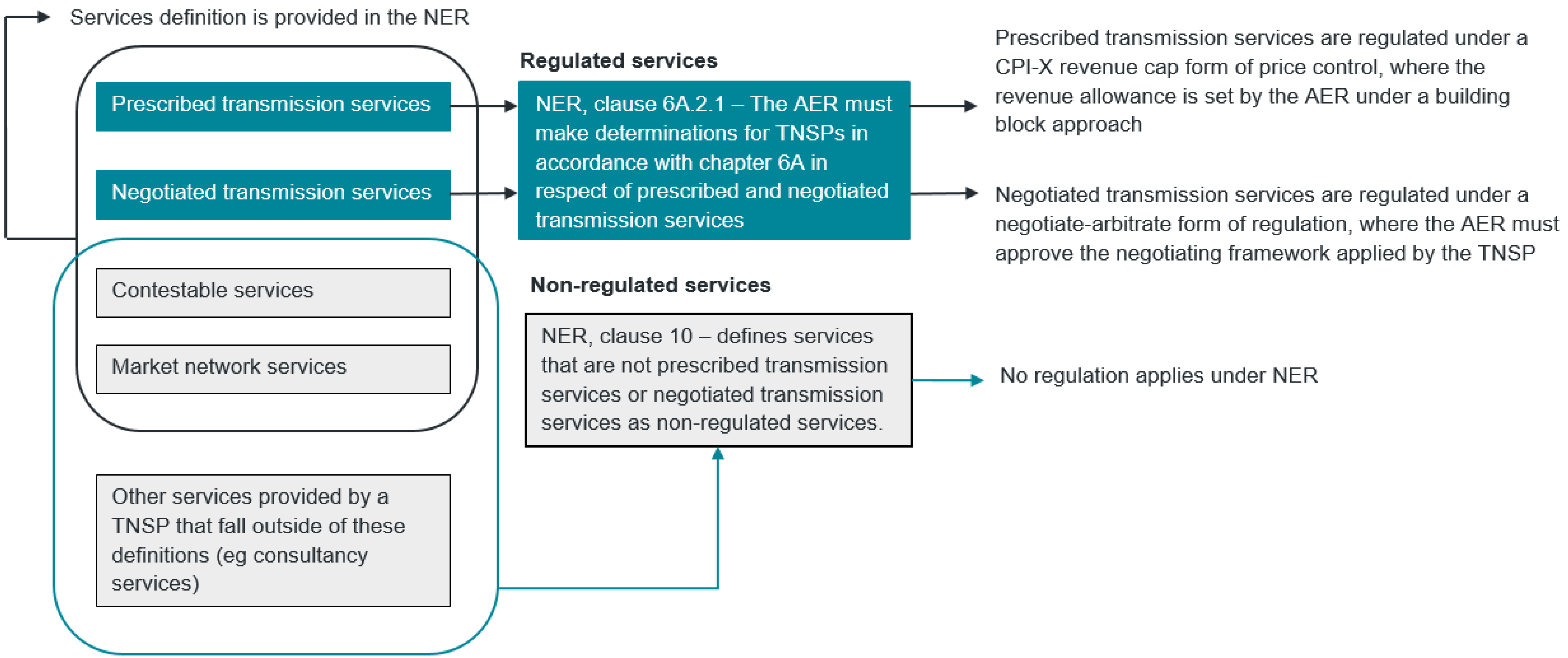


Table 3.2 shows that the current definitions for prescribed and non-regulated transmission services can accommodate potential energy storage functions. Further discussion about how non-regulated activities should be accommodated is discussed further in section 3.3.1 below.

Table 3.2 Likely transmission service classifications of storage functions

Function	Likely service classification	Comment
Network support	Prescribed transmission service, where providing a shared transmission service to meet standard network performance requirements	Storage functions that help to provide network services would be provided as a shared transmission service (ie, the service provided to loads and generators for the conveyance of electricity across the transmission network). TNSPs could contract with third party providers as well to provide this service, which is analogous to how current examples of network support (eg, demand management) are provided.
Quality and reliability of supply (NSCAS)	Prescribed transmission service	Where energy storage is used to meet a TNSP's requirements for how it operates its network and meets power system performance standards, it will fall within part (b) of the definition for prescribed services.[41] The classification of functions from energy storage can be approached in the same way as any other piece of network equipment, such as a synchronous condenser.[42]
Market ancillary services	Non-regulated	Market ancillary services provided by energy storage would be classified as a non-regulated transmission service as it is explicitly excluded from the definition of a prescribed transmission service[43] and does not meet the definition of a negotiated transmission service. The classification of a non-regulated transmission service is appropriate for market ancillary services provided by energy storage as market ancillary services are provided on a competitive basis.
Energy trading	Non-regulated	Energy storage assets can be used to provide energy to the NEM by storing energy during periods of low demand and discharging stored energy during periods of high demand. Using energy storage to supply energy to the wholesale market would be classified as a non-regulated transmission service as it does not meet the definition of either a prescribed transmission service or a negotiated transmission service. This classification is appropriate for energy trading using energy storage as it can be thought of providing an equivalent service to the market as a generator providing energy to the NEM, which is a competitive service.

41 See Appendix E.1.

42 Synchronous condensers are devices which can be used to provide reactive power to the network.

43 Chapter 10 of the NER under 'prescribed transmission service'. Exclusion under (b)(1), i.e. services acquired by AEMO under rule 3.11.

Distribution service classifications

Unlike transmission services, the NER does not define the distribution services in a way that results in them falling into a particular service classification. Instead, the AER is empowered to determine distribution service classifications, and it does so as part of the framework and approach stage of each distribution determination.[44]

The starting point for distribution service classification is therefore the definition and identification of a distribution service. Essentially, these are services provided by a distribution system (a distribution network plus its connection assets).[45]

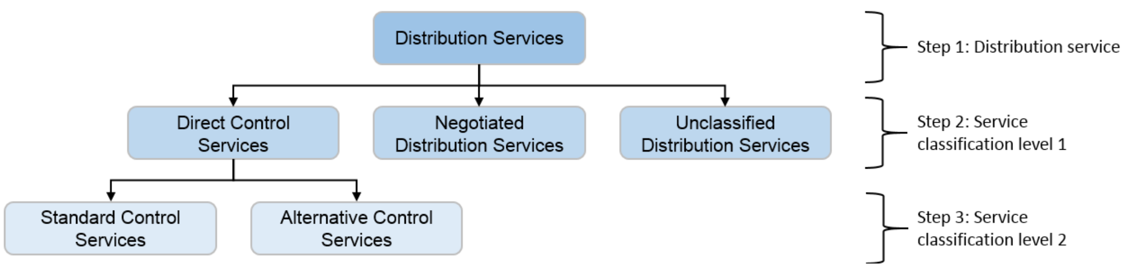
Distribution services can be classified as a direct control service or negotiated distribution services, which determines how the network business is paid for providing the service:

- A direct control service is regulated under a distribution determination, which specifies the price to be paid or revenue to be earned from the service. Direct control services can be either standard control, which are services provided to all customers, for example, the use of the distribution system to transport electricity from the transmission system to the household or alternative control which are services provided to only those customers who benefit from the service, eg, some metering services.

- The provision of negotiated services are subject to the DNSP's negotiating framework, which is approved by the AER in its distribution determination. Examples are new public lighting and non-standard connections.

A service falling outside the classifications of a direct control service or a negotiated distribution service is left unclassified and not subject to economic regulation. Although not defined by the NER, the AER typically refers to these services as unclassified or unregulated services. Figure 3.3 outlines the AER's process for classifying distribution services.

Figure 3.3 Classification of distribution services



The AER is required to have regard to a number of factors when classifying distribution services into direct control services, negotiated services or choosing to

44 Under clause 6.2.1 of the NER.

45 See Appendix E.2 for detail.

leave a service unclassified, including the form of regulation factors.[46] The AER further classifies a direct control service as either a standard control service or an alternative control service. Standard control services are paid for by all users of the network while alternative control services are generally only paid for by the users of that service. Among the things it must consider – and of particular relevance to a nascent market like energy storage – are the:

- potential for development of competition in the relevant market and how the classification might influence that potential; and
- desirability of a consistent regulatory approach to similar services.[47]

AER use of distribution service classification

The AER reviewed the issue of service classification for services provided by energy storage assets in its final Framework and Approach paper for the Victorian DNSPs in response to request from United Energy for clarity on the regulatory treatment of non-traditional network investments, including battery storage.[48] The AER stated that it is not necessary to separately classify a service for non-traditional investments, because the activity is directly concerned with the provision of network services. The AER also interpreted the NER to mean that services provided from behind-the-meter at customer premises would fall within the definition of 'distribution services', because the assets installed in customers' premises would form part of a 'distribution system', and are therefore subject to service classification by the AER.[49]

The AER's conclusion in relation to whether behind-the-meter storage automatically falls within the definition of 'distribution services' is not self-evident, not least because currently what constitutes an embedded network is not defined under the NER. This has led to suggestions that there is potential for ambiguity under the current NER definitions in relation to the classification of services provided by storage assets at the distribution level.

Additionally, for storage used by network businesses, the AER is required to take into account various principles. For instance, if storage directly substitutes for traditional network assets, where the benefits flow to all network users (or cannot be clearly identified as flowing to a particular group of customers), then the AER would be guided to classify the services from the storage as subject to direct standard control. However, this will need to be considered in parallel with another principle – the potential for the development of competition in storage services – in particular if allowing the network business to finance a storage business from the regulatory asset base was likely to impede the development of competitive storage market, eg, in customer-facing applications, or in the wholesale market.

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46 See Box E.1in AppendixE.2

47 See Appendix E.2 for further considerations.

48 AER, Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016, October 2014, pp.68-70.

Previous classification determinations for 'similar services' can provide some indication as to how the AER may determine classifications for functions provided by energy storage assets in the future. Table 3.3 sets out the relevant current or proposed distribution service classifications.[50]

Table 3.3 Current and proposed distribution service classifications

<table>
<tr><th>Function</th><th>Vic[51]</th><th>NSW[52]</th><th>Qld[53]</th><th>SA[54]</th><th>Tas[55]</th><th>ACT[56]</th></tr>
<tr><td>Network support</td><td colspan="3">Standard control</td><td rowspan="2">Standard control or negotiated</td><td colspan="2">Standard control</td></tr>
<tr><td>Quality and reliability of supply</td><td colspan="3">Standard control</td><td colspan="2">Standard control</td></tr>
<tr><td>Market ancillary services</td><td colspan="6">Unclassified</td></tr>
<tr><td>Energy trading</td><td colspan="6">Unclassified</td></tr>
</table>

Distribution service classifications are ultimately determined by the AER with regard to jurisdictional circumstances and other factors as set out the NER. It is therefore not possible to determine the outcome of any classification determination with certainty. However, inferences can be made by taking into account the definition of distribution service and the AER's previous classification determinations. Table 3.4 provides a summary of the likely classification of distribution services provided by energy storage assets.

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49 Section 3.2.1 provides further detail.

50 The AER groups classification determinations for DNSPs based on individual jurisdictions, not individual DNSPs, except for South Australia.

51 AER, Final Framework and approach for the Victorian Electricity Distributors: Regulatory control period commencing 1 January 2016, October 2014, p31.

52 AER, Final Decision Ausgrid distribution determination 2015-16 to 2018-19 Attachment 13: Classification of services, April 2015, p19-32.

53 AER, Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20 Attachment 13: Classification of services, April 2015, p19-38. AER proposes to classify services consistently for both Energex and Ergon Energy.

54 AER, Preliminary Decision, SA Power Networks determination 2015-16 to 2019-20 Attachment 13: Classification of services, April 2015, p17-23.

55 AER, Final Decision Aurora Energy Pty Ltd 2012-13 to 2016-17, April 2012, p9.

56 AER, Final Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 13: Classification of services, April 2015, p13-22.

Table 3.4 Likely distribution service classifications of storage functions

Function	Likely distribution service classification	Comment
Network support	Standard control service, where the services are used as part of providing shared distribution services	The 'network service' grouping is defined in the NER as "a distribution service associated with the conveyance, and controlling the conveyance, of electricity through the network".[57] DNSPs utilise network support from embedded generators and other providers to help maintain and operate their network to meet electricity demand and network requirements. Similarly, they could contract with storage providers. Network support has typically been grouped into the network service grouping by the AER. Network services have been classified as standard control services by the AER, with one variation for SA Power Network where a distinction is made between a standard network service and a non-standard network service. This distinction allows the AER to differentiate network services that can be attributed to individual customers from those that are used for the shared network.[58]
Quality and reliability of supply	Standard control service, where the services are used as part of providing shared distribution services	Storage functions used to meet network business obligations and power system performance standards would come under network services as they are associated with the conveyance, and controlling the conveyance of electricity through the network. Quality and reliability of supply functions would fall under the standard control service classification, or in some circumstances, the negotiated distribution service classification where distinctions are made for network services attributable to individual customers.
Market ancillary services	Unclassified	Market ancillary services acquired by AEMO on a competitive basis have not been identified as a distribution service and therefore have not been classified by the AER.[59] Not classifying market ancillary services is consistent with the competitive basis which AEMO acquires those services.
Energy trading	Unclassified	Classification of energy trading using energy storage is currently not addressed by AER and is unlikely to be addressed. Energy trading activities by energy storage is more analogous to a generator providing energy to the NEM on a competitive basis, rather than a distribution service where a service provided by means of, or in connection with, a distribution system.

57 Chapter 10 of the NER under 'network service'.

58 This mirrors the network support classification for TNSPs, where network services for a shared network are classified as prescribed transmission services and network services for dedicated users are classified as negotiated transmission services (see Table 3.2).

59 Ancillary network services referred to in AER classification determinations are services related to non-routine services provided to individual customers on an 'as needs' basis and are not those defined by chapter 10 of the NER under 'market ancillary services'.

3.1.3 Summary of service classification issues

In summary, the existing regulatory framework provides capacity for the AER to classify the services provided by energy storage within the existing service classifications. However, there have been concerns raised that the service classification framework in relation to energy storage would benefit from clarification.

Consultation questions

- **Do stakeholders agree that there may be tensions and ambiguities within the distribution service classification framework that would benefit from clarification?**
- **Do these issues relate in particular to the potential for development of competition in the provision of energy services from storage?**
- **How should network business-controlled storage on the network be regulated – as standard or alternative control, or other?**

3.2 Network revenue regulation and energy storage

There is potential for network businesses to utilise energy storage as a cost effective mean of providing regulated services. For example, energy storage has the potential to provide network businesses with an alternative to existing network asset augmentation, as well as a means for maintaining or improving service quality and reliability.

Under the current arrangements, it would be possible for network businesses to obtain the use of energy storage assets via three main methods. Chapter 4 discusses whether this is appropriate.

1. A network business could purchase energy storage assets (a capital expenditure (capex) approach) that provides only regulated services.
    - Under this approach, the cost of the storage asset used for providing regulated services would be recovered through the network business's capex allowance, i.e. through its regulatory asset base (RAB).
    - Ring-fencing considerations could apply if the storage device displaces significant amounts of competitive energy services (such as wholesale electricity), even though it is being used solely for network purposes.[60]
2. A network business could purchase energy storage assets (a capex approach) that provides both regulated and non-regulated services.

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60 Under current jurisdictional ring-fencing guidelines which are being reviewed by the AER – see Appendix I.

— The network business may then use a portion of the energy storage asset to provide regulated services. However, where an energy storage asset provides both regulated and unregulated services, this would require cost allocation (see section 3.3.2) and would also likely require ring fencing.

— Under this approach, the relevant portion of the cost of the storage asset used for providing regulated services would be recovered through the network business's capex allowance, i.e. through its regulatory asset base (RAB).

3. A network business could enter into contracting arrangements with another party to provide regulated services (an operating expenditure (opex) approach).

   — The contracting party could be a third party or a ring-fenced entity.

   — Under this method, the cost of the storage asset would not enter the network business's RAB but would be recovered through the business's opex allowance.

The AER has a responsibility under the NER to regulate a network business's maximum revenue to ensure that it is consistent with the National Electricity Objective (NEO).[61] There are specific rules that the AER must apply in evaluating a network business's capex and opex forecasts as part of the regulated revenue calculations. These also provide incentives for network businesses to undertake investments that are consistent with the NEO. The framework:

- requires the AER to consider whether opex and capex forecasts are efficient;
- requires the AER to develop incentive schemes to encourage network businesses to undertake efficient operating and capital expenditure;
- allows the AER to the develop innovation allowances for TNSPs and DNSPs; and
- requires network businesses to apply either the Regulatory Investment Test for Transmission (RIT-T) or Regulatory Investment Test for Distribution (RIT-D) before undertaking network augmentation above a specified threshold.

3.2.1 Energy storage in current regulatory determinations

The AEMC is aware of two DNSPs that have included energy storage as part of their regulatory proposals: United Energy and SA Power Networks.

61 The objective of the NEL (section 7) is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, safety, reliability and security of supply of electricity; and the reliability, safety and security of the national electricity system.

United Energy

The AER considered the treatment of energy storage under the regulatory framework during the development of the Framework and Approach for the Victorian DNSPs.[62] As part of this review, United Energy sought the AER's view on the treatment of 'non-traditional network investments' that relate to the provision of a safe and reliable electricity supply for all customers, including energy storage on feeders experiencing voltage issues or requiring capacity augmentation, load control devices and distributed generation – for the purpose of cost recovery.[63]

United Energy identified that there may be some key differences between traditional network investment (ie, poles and wires) and non-traditional network investments, including that:

- non-traditional investments may in some cases be competitively provided and owned by third parties; and
- non-traditional investments may not form part of, or meet the full definition of, the 'distribution system' as currently provided under the rules, e.g. they could be located on the customer's premises.[64]

However, United Energy noted that it would operate and control the non-traditional investments and it considered that these investments should be treated in a similar way to traditional network investments. In particular, United Energy stated the cost of non-traditional investments should be shared by all customers through distribution use of system (DUOS) charges, and given that these investments may be owned by others (and therefore not included in its RAB) funding for these services could be through:

- an operating expenditure allowance to fund the cost of these investments; or
- a revenue adjustment.[65]

The AER addressed United Energy's comments in its discussion of classification issues in the final Framework and Approach for the Victorian DNSPs.[66] The AER stated that:

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62 AER, Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016, October 2014.

63 United Energy, 2016 to 2020 Electricity Distribution Price Review: United Energy's Response - AER's 2016 to 2020 Preliminary Positions Framework and Approach, July 2014, pp 6-7.

64 United Energy, 2016 to 2020 Electricity Distribution Price Review: United Energy's Response - AER's 2016 to 2020 Preliminary Positions Framework and Approach, July 2014, p7.

65 United Energy, 2016 to 2020 Electricity Distribution Price Review: United Energy's Response - AER's 2016 to 2020 Preliminary Positions Framework and Approach, July 2014, p.7. United Energy stated that "[a] revenue adjustment would be required to deal with all investments that United Energy has not identified in its Regulatory Proposal and for which it has therefore not been provided an opex allowance in the AER's Final Decision.

66 AER, Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016, October 2014, pp.68-70.

> "We do not consider it necessary to classify a service for non-traditional investments. This activity is directly concerned with the provision of network services, which is a classified service. Our expectation is that businesses will, in their day-to-day operations, consider the most efficient means of delivering regulated services. We consider that the rationale for an operating expenditure allowance or revenue adjustment is contingent on the business case for a particular investment. If the purpose of the investment is to efficiently deliver a network service, the expense should qualify as operating expenditure where the service is obtained through a contractual arrangement."

Further, the AER stated that assets installed in a customers' premises would still form part of a distribution system for the following reason:

> "When a distributor (or any other third party) installs an electrical asset within a customer's premises we consider that this will result in the customers' wiring becoming an embedded network, which is also a special type of distribution system. This is because the NER definition of a distribution system is traceable to the ownership of physical assets…Consequently, the investment by the network business in assets installed within the customer's premises would continue to form part of a distribution system as defined in the NER."

Subsequent to the AER's findings, United Energy included $2.5 million for storage behind the meter in its forecasts of augmentation capex as part of its regulatory proposal for 2016 to 2020.[67] The AER is due to release a preliminary decision on United Energy's proposal for the 2016-2020 regulatory control period by 31 October 2015.

SA Power Networks

SA Power Networks included $2.8 million for a trial micro-grid solution as part of its reliability expenditure – a component of its augmentation expenditure.[68] The micro-grid solution consists of combined distributed storage and centralised storage. SA Power Networks noted that its intention is to use this micro-grid trial as a template for future reliability remediation, or deferral of network augmentation to other remote communities.[69]

In its preliminary decision, the AER did not accept the capital expenditure forecast of $2.8 million to conduct the micro-grid trial and stated that:

> "We recognise that this is a trial, and therefore is difficult to accurately quantify the likely benefits in terms of reliability. However, SA Power Networks proposes this program on the basis of reliability improvement

67 United Energy, 2016 to 2020 Regulatory Proposal, 30 April 2015, pp63,66.

68 SA Power Networks, Regulatory Proposal 2015-20, October 2014, p.219.

69 SA Power Networks, Revised Regulatory Proposal 2015-20, July 2015, p.113.

rather than reliability maintenance. To allow for reliability improvement, we need to be satisfied that the proposed expenditure will encourage prudent and efficient outcomes and that it will not otherwise be funded through the STPIS regime.[70]"

The AER invited SA Power Networks to provide more information on the benefits of the micro-grid trial and how it fits within the company's proposed reliability improvement programs.[71] SA Power Networks provided further information on the micro-grid trial in its revised proposal.[72] The AER is due to release a final decision on SA Power Networks' proposal for the 2015-2020 regulatory control period by 31 October 2015.

Box 3.1 Case study: Italy

Background

Electricity generation in Italy has undergone a change over the past few years, with solar PV share of total generation increasing from 0.1 per cent in 2008 to approximately 7 per cent in 2013. This development placed increased pressure on the network.[73] There was a difficulty in developing the Italian grid at a satisfactory pace in the face of the increase in intermittent energy sources; there was also structural congestion in certain parts of the country.

These developments led to a response from the Italian regulator, the AEEG.

Regulatory response:

In 2010 a legal decree allowed Terna, the transmission service operator (TSO), to build and operate energy storage assets. The use of storage technologies must be justified by analysis which proves that storage is the most efficient way to solve the identified problem in the network.

A further decree in 2011 allows the TSO to develop and manage storage facilities in line with a Grid Development Plan, which must be formulated each year and requires the approval of the Ministry of Development.[74]

In the two years after the 2011 decree the AEEG has provided legal grounds for storage facilities which are deemed to be pilot projects. These projects are to

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70 AER , Preliminary Decision, SA Power Networks determination 2015-16 to 2019-20, Attachment 6 – Capital expenditure, April 2015, p82.

71 AER , Preliminary Decision, SA Power Networks determination 2015-16 to 2019-20, Attachment 6 – Capital expenditure, April 2015, p82.

72 SA Power Networks, Revised Regulatory Proposal 2015-20, July 2015, pp119-121.

73 Bloomberg New Energy Finance, *Of markets and monopolies: European network regulation,* Research Note, 28 January 2015.

74 The Grid Development Plan can include storage for the purpose of better dispatch of intermittent (non-programmable) generation plants.

assess different solutions and to increase the public knowledge of battery storage technologies.[75] A longer term decision on the regulatory treatment of storage technologies and their integration in to the electricity system has not been made.

Regulatory incentives:

The regulatory system in Italy incentivises investment in storage technologies. If an Italian DSO invests in energy storage projects or infrastructure it will earn an additional 2 per cent per annum on that portion of its RAB for 12 years.[76]

Terna is currently working on six pilot projects with a rated capacity of 6MW and two of 15MW. In addition, Terna has a subsidiary company, Terna Plus, which is responsible for the development of new business and is investigating the potential of energy storage alongside other emerging technologies.[77]

Terna's is the European leader in the development of energy storage projects, which is attributed to these regulatory arrangements.[78]

Lesson for Australia

The regulatory treatment of storage in Italy is an interesting case study as regulatory authorities have decided that network businesses owning and operating storage assets does not go against unbundling requirements. The regulatory system provides incentives, in the form of bonuses on regulated weighted average cost of capital, to encourage investment by network businesses in storage pilot projects. The regulatory decisions with regard to storage have led to large-scale demonstration projects which cover applications such as renewable integration, power quality and efficient network operation.

3.2.2 Inclusion in capex and opex forecasts

Both a TNSP's and a DNSP's revenue proposal must include the total forecast capex and opex for the regulatory period which the business considers necessary to meet or manage the demand for prescribed transmission services or standard control distribution services over the period.

The AER decides whether to accept, reject or form its own estimate of those forecasts, having regard to specified capital and operating expenditure objectives, criteria and

75 IPSI Energy Watch, Has time for batteries in Italy arrived or not?, available at: *http://www.ispionline.it/it/print/energy-watch/has-time-batteries-italy-arrived-or-not-13748*, accessed 20 August 2015.

76 Bloomberg New Energy Finance, Of markets and monopolies: European network regulation, Research Note, 28 January 2015.

77 Smarter Network Storage, Electricity Storage in GB: Regulatory and legal framework, available at: *http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Smarter-Network-Storage-(SNS)/Project-Documents/Smarter-Network-Storage-LCNF-Interim-Report-Regulatory-Legal-Framework.pdf.*

78 Bloomberg New Energy Finance, Of markets and monopolies: European network regulation, Research Note, 28 January 2015.

factors.[79] Essentially, the AER needs to allow revenue to cover enough capital and operating expenditure for an efficient and prudent network operator to maintain the quality, reliability, security and safety of its network, while earning a commercial rate of return. The business needs to consider efficient non-network alternatives and the possibility for substitution between capex and opex.

The AER has previously stated that feasible non-network options could include any measure or program targeted at reducing peak demand. It has explicitly referred to using energy storage systems as an increased local or distributed generation/supply option.[80]

Storage assets owned by the network business for the purpose of providing regulated services fall within the scope of transmission and distribution assets, and therefore within the NER provisions relating to capex forecasts. Where a network business contracts for the provision of services from an energy storage device that is owned by a third party, or by its own ring-fenced entity, this falls within the definition of a 'non-network option' and within the provisions relating to opex forecasts.

As described in section 3.1.2, the AER has explicitly indicated that it considers both energy storage at the network and behind-the-meter level to be potential non-traditional investments that could be used to deliver regulated network services, and that non-traditional investments that are obtained through contractual arrangements should qualify as opex:

> "We consider that the rationale for an operating expenditure allowance or revenue adjustment is contingent on the business case for a particular investment. If the purpose of the investment is to efficiently deliver a network service, the expense should qualify as operating expenditure where the service is obtained through a contractual arrangement.[81]"

Therefore, as the use of energy storage becomes more commonplace, the AER may consider storage at the network and behind-the-meter level when evaluating network businesses' expenditure forecasts. The AER could challenge a network business's proposed expenditure if it was simply continuing to propose traditional investment programs, without consideration of efficient alternatives.

For example, if a network business forecasts augmentation capex to address emerging constraints on its network, the AER may consider whether the network business could alternatively provide prescribed services or standard control services by:

- purchasing energy storage for a lower capital cost – a capex alternative; or

79 See Appendix F .

80 See: AER, Better Regulation Regulatory investment test for distribution Application Guidelines, 23 August 2013, section 7.1.

81 AER, Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016, 24 October 2014, p69.

- contracting for energy storage with a separate party – a substitution of opex for capex.

3.2.3 Incentive schemes

While energy storage is still emerging as a mechanism for the provision of regulated services in the NEM, it may not form part of the AER's assessment of capex and opex forecasts. However, the regulatory framework provides network businesses with incentives to undertake efficient operating and capital expenditure: the Efficiency Benefit Sharing Scheme (EBSS) and the Capital Expenditure Sharing Scheme (CESS).[82] These allow the business to retain part of the efficiency benefit that results from beating expenditure forecasts.

Where the network business incurs expenditure in relation to energy storage, which is related to the provision of regulated services, this expenditure would be included within the EBSS and CESS calculations in the same way as expenditure on other network or non-network solutions would be. The EBSS and CESS would encourage a network business to adopt energy storage solutions in circumstances where it is able to efficiently avoid or defer opex or capex, because it would retain a portion of the benefit of those efficiencies.

For example, a network business may include network augmentation in its capex forecasts for the current regulatory control period and subsequently identify that it could defer the network augmentation to a later regulatory control period by implementing an energy storage solution - either by purchasing storage assets itself (and incurring opex for the electricity to charge the assets), or by entering into contractual arrangements to utilise other parties' storage assets. CESS rewards (for the reduction in capex) and EBSS penalties (for the increase in opex) may apply.

The current regulatory framework therefore provides incentives for the adoption of energy storage, provided that it is expected to be more cost effective than alternative practices and falls within the scope of regulated services.

3.2.4 Innovation incentives and allowances

The current regulatory framework includes provisions for the AER to develop innovation allowances for network businesses. Specifically, the regulatory framework sets out arrangements for:

- DNSPs. The AER is required to develop and publish a Demand Management Incentive Scheme (DMIS) to provide incentives for DNSPs to implement efficient non-network alternatives, and to develop a Demand Management Innovation Allowance (DMIA), which provides DNSPs with funding for research and development in demand management projects.[83]

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82 See Appendix G.1.

83 Clause 6.6.3(a) of the NER.

- TNSPs. The AER is required to develop and publish a Service Target Performance Incentive Scheme (STPIS) that should provide incentives for TNSPs to improve or maintain the reliability of transmission network services.[84]

The AER is required to develop these schemes because the expenditure and incentives framework, set out in the sections above, may not be sufficient to remove any bias towards expenditure on network capital investment over non-network options. The potential bias towards network capital investment results from network businesses having limited financial incentives to factor in the broader market benefits of non-network options and to trial new non-network options, including energy storage solutions.[85]

As a consequence, network businesses may have limited incentives to adopt energy storage as an alternative to network augmentation. This is because network augmentation has a relatively known outcome and cost, whereas applications of energy storage are still under development and would likely require the network business to first carry out trials.

Further, while the AER has discretion to approve opex for demand management purposes, the framework does not require the AER to approve such programs as part of a network business's expenditure forecasts.[86]Instead, as discussed above, the expenditure objectives require a distribution or transmission proposal to include expenditure that is required in order to meet or manage the expected demand for standard control distribution services or prescribed transmission services over that period.[87] It is not clear that these objectives would include trials, which are more speculative and forward looking in nature – ie, that may result in the expenditure meeting or managing expected demand in later periods. For example, in its preliminary decision, the AER did not accept SA Power Networks' capital expenditure forecast of $2.8 million to conduct a micro-grid trial because the program was proposed on the basis of reliability improvement rather than reliability maintenance.[88]

Innovation allowances are intended to address this potential bias towards network capital investment, encourage trials of new technologies and provide greater regulatory certainty to network businesses. Similar regulatory incentives are used by

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84 Clause 6A.7.4(a) and 6A.7.4(b) of the NER.

85 AEMC, Final Rule Determination, National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015, 20 August 2015, p54.

86 For example, the AER approved Transgrid's proposed $1 million per annum opex allowance for undertaking demand management innovation activities for the 2009 to 2014 regulatory control period. TransGrid is continuing to receive $1 million per year for demand management over the 2014–18 regulatory period. See: TransGrid, Consultation Paper on National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015 (AEMC Reference: ERC0177), March 2015; AER, Draft decision, TransGrid transmission determination 2015-16 to 2017-18 Attachment 7: Operating expenditure, November 2014, p58; and AEMC, Draft rule determination – National Electricity Amendment (Demand management incentive scheme) Rule 2015, May 2015, p23.

87 Clauses 6.5.6(a)(1), 6.5.7(a)(1), 6A.6.6(a)(1) and 6A.6.7(a)(1) of the NER.

88 AER , Preliminary Decision, SA Power Networks determination 2015-16 to 2019-20, Attachment 6 – Capital expenditure, April 2015, p82.

electricity regulators in other countries to achieve similar objectives, for example in the UK under the Revenue + Incentives + Innovation + Outputs" (RIIO) model, explained in Box 3.2.

Box 3.2 Case study: Leighton Buzzard storage facility

Regulatory framework in the UK

The UK is the first country in Europe to have adopted an output-based regulatory model for the electricity market. The model was put in place the British Office of Gas and Electricity Markets (OfGem). The "Revenue + Incentives + Innovation + Outputs" (RIIO) model was introduced for transmission in 2013 and for distribution in 2015. This regulatory model aims to encourage to adapt and innovation in the face of a changing industry structure and technological advances. The RIIO model defines specific outputs and goals that network operators are expected to meet but allows the operators the freedom to decide how those goals should be achieved.

The goals of the RIIO are to encourage the adoption of low-carbon technologies, to ensure network operators are efficient, to ensure that network operators can attract capital and to limit the impact on consumer bills while increasing consumer satisfaction. To this end, OfGem have established the Low Carbon Emissions Fund. This initiative allocates up to £500 million to fund projects which facilitate the adoption of low carbon and energy saving initiatives by network service providers.

The purpose of the fund is to find innovative ways of managing the increasing demands on electricity networks while also managing costs to the consumer. Under the new RIIO regulatory structure OfGem is putting pressure on network operators to incorporate successful technologies into their business plans.

Smarter Network Storage Project

The aim of the Smarter Network Storage (SNS) project is to pilot and validate new business models for storage and identify any changes that may be necessary to help to integrate storage in to electricity distribution. Through this project it is hoped that wider adoption of energy storage will be enabled.

The project involves the installation of a 6MW energy storage facility at the Leighton Buzzard substation. The storage technology chosen for the project is Lithium Ion battery cells. The project commenced in December 2014.

SNS received funding from of £13.2 million from the Low Carbon Networks Fund. The investment from Ofgem is supplemented by £4 million of funding from UK Power Networks and £1 million from other project partners. The return to Ofgem from their investment will be in the form of increased learning about how best to structure a viable energy storage venture and the associated business models that this would entail. The project will "provide experience of real innovations required to bridge the gap between pure technical demonstrations and the knowledge required to understand the commercial viability of storage and the means to deploy it in the most economical way."

Lessons for Australia:

The RIIO model of regulation has shifted focus from cost reduction to improving the customer experience and seeking novel ways to adapt to changes in the energy system. Allowing trials of such innovative commercial arrangements could provide valuable insight in to how storage could be integrated to the current regulatory frameworks and/or what changes may be necessary to accommodate storage technologies. However, outcomes may be difficult to assess in practice and it is too early to evaluate the benefits of the RIIO framework.

Innovation incentives for DNSPs

The DMIS and DMIA will replace the previous Demand Management Embedded Generation Connection Incentive Scheme (DMEGCIS).[89] A number of DNSPs are undertaking trials of energy storage assets under the previous DMEGCIS arrangements (see Box 3.3), which will help them determine the costs of implementing energy storage as a permanent solution. This would support DNSPs in proposing the expenditure as part of their regulatory allowance.

Box 3.3 Examples of recent energy storage trials undertaken under the DMEGCIS

AusNet Services, Victoria

In December 2014, AusNet Services commenced a two-year trial using a battery system known as the Grid Energy Storage System (GESS).[90] The GESS is a 1MW chemical composition-lithium ion battery and smart inverter to supply power to around 300 homes during peak periods, with the battery being recharged during off-peak periods. The trial will allow AusNet Services to understand the technical use of network-connected energy storage and to evaluate its practical use as a way of reducing costs to consumers. The trial is partly funded under the DMIA.

AusNet Services is also trialling battery and solar power systems at 10 residential premises to provide demand management and simulate the capability of vehicle-to-grid enabled electric vehicles.[91] The battery systems are fully

89 See Appendix G.2.

90 See: AusNet, Media Release: AusNet Services' Australian-first network battery trial, 6 January 2015; AusNet, SP AusNet Grid Battery Storage Trial Presentation, http://www.australianenergystorage.com.au/site/wp-content/uploads/2014/05/Yogendra-Vashishtha.pdf.

91 See AusNet, Energy Insights, Demand Management and Smart Network Technologies, http://www.ausnetservices.com.au/CA257D1D007678E1/Lookup/Reports/$file/EnergyInsightsDemandManagement.pdf; AER, Applications by DNSPs for Demand Management Innovation Allowance for: 2013 calendar year (Victorian DNSPs); and 2012–13 financial year (all other DNSPs),

programmable and can be remotely controlled by AusNet Services. The trial is funded under the DMIA.

United Energy, Victoria

United Energy is conducting a virtual power plant (VPP) trial to assess the technical and economic feasibility of installing batteries as an alternative to network capacity augmentation to meet peak demand.[92] The VPP project attempts to combine the capabilities of residential solar PV generation and energy storage to flatten out the demand profile by charging the battery during the middle of the day when solar PV generation is at its maximum and discharging the battery during the early evening when residential demand is at its maximum.[93]

The capability of aggregated VPP units can be dispatched to manage network capacity constraints, which may be more efficient than traditional network solutions. United Energy claimed DMIA expenditure for the trial.[94]

Ergon Energy, Queensland

Ergon Energy finalised a trial of an electricity network energy storage device called the Grid Utility Support System (GUSS) in Far North Queensland in 2013.[95] The purpose of the GUSS is to improve the quality and reliability of electricity supply to rural customers on constrained single wire high voltage distribution voltage lines, known as SWER (Single Wire Earth Return). The system charges lithium-ion batteries overnight when demand for electricity is low and discharges them during peak demand periods.

Ergon Energy has stated that the GUSS is quicker to install and 35 per cent cheaper than traditional upgrades of its SWER network. Ergon Energy claimed DMIA expenditure for GUSS.[96]

Ausgrid, NSW

AusGrid undertook a trial during the summer 2014-15 period to investigate the

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April 2015, p20; and SP AusNet, Demand Management Innovation Allowance (DMIA) Annual Report 2012, March 2013, p4.

92 United Energy, 2016 to 2020 Regulatory Proposal, 30 April 2015, p19.

93 AER, Applications by DNSPs for Demand Management Innovation Allowance for: 2013 calendar year (Victorian DNSPs); and 2012–13 financial year (all other DNSPs), April 2015, p47.

94 United Energy, 2016 to 2020 Regulatory Proposal, 30 April 2015, p19; and AER, Applications by DNSPs for Demand Management Innovation Allowance for: 2013 calendar year (Victorian DNSPs); and 2012–13 financial year (all other DNSPs), April 2015, p46.

95 Ergon Energy, News Release, Battery storage systems arrive soon, 19 May 2015, https://www.ergon.com.au/about-us/news-hub/talking-energy/technology/battery-storage-systems-arrive-soon.

96 AER, Applications by DNSPs for Demand Management Innovation Allowance for: 2013 calendar year (Victorian DNSPs); and 2012–13 financial year (all other DNSPs), April 2015, p28.

potential benefits of using energy storage as a means of reducing peak demand on the network.[97] This project also investigated how a network grid-side battery can be operated reliably and effectively for summer peak reduction purposes and potentially improve the power and supply quality parameters of the network.

AusGrid undertook this project as part of the DMIA.

Innovation incentive for TNSPs

The network capability component of the STPIS incentivises TNSPs (with assistance and independent oversight from AEMO) to develop innovative, low cost projects that materially improve network capability. This component can provide TNSPs with an annual incentive payment of up to 1.5 per cent of its MAR to fund proposed projects.[98]

The network capability component is sufficiently flexible to allow TNSPs to undertake energy storage projects that are designed to improve network capability limitations. However, we note that the network capability component is limited to low cost projects. The total annual average expenditure of the proposed priority projects cannot exceed 1 per cent of the average MAR proposed by the TNSP in its revenue proposal.[99]

At least one TNSP has included an energy storage project under the STPIS. TransGrid included, and the AER approved, capex of $4.9 million in its Network Capability Incentive Parameter Action Plan (NCIPAP) for its current regulatory control period to install a pilot energy storage device in the Sydney area.[100]

3.2.5 Regulatory investment tests: consideration of wider benefits

The regulatory investment tests for transmission and distribution are cost-benefit assessments that must be undertaken for proposed network augmentation projects which are expected to cost more than $5 million.[101] Features of the tests provide a means of considering the range of potential benefits associated with energy storage,

Firstly, network businesses are required to consider all feasible network and non-network options. The AER states that non-network options include ‘any measure or program targeted at reducing peak demand’ and refers to ‘energy storage systems’ directly.[102] Not only do the RIT-T and RIT-D allow for network businesses to consider

97 AusGrid, Distribution and Transmission Annual Planning Report, December 2014, p215.

98 AER, Final Decision Electricity transmission network service providers Service Target Performance Incentive Scheme, December 2012, pp23,28.

99 AER, Final Decision Electricity transmission network service providers Service Target Performance Incentive Scheme, December 2012, p23.

100 AER, Final Decision, TransGrid transmission determination 2015-16 to 2017-18 Attachment 11 – Service target performance incentive scheme (STPIS) April 2015, p16.

101 See Appendix H. for the detailed requirements of the tests and market benefits that must be considered.

102 AER, Better Regulation Regulatory investment test for distribution Application Guidelines, 23 August 2013, section 7.1.

using energy storage at the grid level and behind-the-meter level as an alternative to network augmentation, but they require these businesses to consider energy storage, if it is a commercially or technically feasible alternative. This in line with the AER's comment that it considers both energy storage at the network and behind-the-meter level to be potential non-traditional investments that could be used to deliver regulated network services.[103]

To-date, network businesses have not found energy storage to be a feasible non-network option. For example, ElectraNet included utility scale storage as a potential non-network option in its RIT-T for the Heywood Interconnector Upgrade in 2011. ElectraNet noted that it was not in a position to suggest the technical characteristics of the storage solution or estimate the total cost, but welcomed submissions to enable further consideration of this option in the RIT-T assessment. No submissions were received that supported further consideration of a utility scale storage solution, with some submissions stating that significant utility scale energy storage was unlikely to be economic in the near term. However, as the technical characteristics of energy storage become better understood, and the costs decline, the feasibility of energy storage as a non-network option will increase.

Second, network businesses have to consider a wide set of market benefits, not just benefits to their own business. For example, TNSPs are required to consider changes in ancillary services costs and DNSPs are required to consider changes in electrical energy losses.[104] This provides a means of considering the range of potential benefits associated with energy storage, including the wider benefits associated with possible impacts on the wholesale market and provision of ancillary service.

Third, an implication of using ranking to select the preferred option is that precise cost and benefit estimates are not required – assuming that range of possible costs and benefits of each option do not overlap. Consequently, the RIT-T and RIT-D are not limited to assessing options that have been previously utilised by the network business, for which the business is likely to have reasonably quantitative estimates. Further, NCIPAP or DMIA trials may allow for a reasonable quantification of the costs of installing and operating energy storage solutions. The costs of charging an energy storage solution can currently be estimated on a reasonable basis, eg, by using forecast electricity prices.

Fourth, network businesses are required to seek submissions from registered participants, AEMO and interested parties on the credible options considered as part of their investment test. The RIT-D requires the DNSP to prepare and publish a non-network options report, which includes information to assist non-network providers wishing to present alternative potential credible options and details of how to submit a non-network proposal for consideration by the DNSP. As a result, external parties are able to recommend network storage options to be considered as part of the investment test.

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103 AER, Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016, 24 October 2014, p69.

104 See Box H.1 in Appendix H.

Finally, the option value element of the investment test should lead network businesses to value the potentially incremental nature of a storage solution (as opposed to a "lumpy" network investment.) However, there may be value in reviewing the lead times in the planning process to test whether they are sufficiently long to capture a storage solution, especially one that needs to be implemented incrementally as loading of a network element increases in order to indefinitely defer an augmentation.

3.2.6 Risks from non-proven technologies

Storage technologies have been utilised for decades but some of the newer battery technologies are unproven to some extent, particularly in the Australian climate. It could therefore be suggested that battery storage, for example, is not a technology that is readily accommodated by an economic regulation regime designed to consider the prudent level of spending on mature and long-lived assets.

We do not, however, think extra powers are needed for the AER to exclude non-proven technologies from the RAB, because of:

1. The ability of the AER to question a network business's revenue proposal in terms of whether an unproven technology (in terms of lifetime cost/benefit, therefore covering both unknown lifetime performance and potentially decreasing costs) if the forecast expenditure is not consistent with that of a benchmark efficient business to cover its efficient costs plus a commercial return on capital.

2. The risk will be on the network business if it has to spend again because the asset does not last as long as expected.

3. The business will fail to meet its reliability standards if it builds an underperforming asset.

4. The investment test (RIT-T or RIT-D) requires storage to be a "credible option" if it is an alternative to a network solution.

3.2.7 Summary of network revenue regulation issues

The incentive-based regulatory framework treats storage like any other technology. Network businesses could leverage storage – *if* it is cost effective to do so. There are a range of incentives and innovation tools available to network businesses and the AER that would accommodate storage – if it is prudent to do so, and subject to any competition concerns being allayed.

Consultation questions

- **Do stakeholders agree that the current rules applicable to networks are capable of integrating storage?**

- **Is the incentive framework for distribution and transmission businesses**

creating any barrier to the deployment of storage where it is cost effective to do so?

- **Given the relatively unproven nature of battery storage should it be treated differently to other assets?**
- **Are any of the timelines associated with regulatory processes likely to be problematic?**
  - **For instance are the lead times in the planning process sufficiently long to capture the value of an incremental storage solution as a substitute for traditional network investment?**

3.3 Separation of regulated and unregulated services

Given the potential for network businesses to distort market outcomes by providing a non-regulated service through a regulated business, the current regulatory framework contains certain provisions regarding a network business's ability to provide non-regulated services, including:

- ring-fencing arrangements;
- allocation of costs between regulated and non-regulated activities; and
- a reduction of regulated revenues to account for unregulated revenues earned from ‘shared assets’.

The implications of these provisions for services provided by energy storage assets is provided below.

3.3.1 Ring-fencing

Ring-fencing refers to requirements to separate the regulated services and operations of a network business from its non-regulated services. Ring-fencing obligations are often imposed to address a concern that the monopoly position of network businesses would allow them to gain an advantage in the provision of contestable services. For example, an unconstrained network business might cross-subsidise regulated and unregulated services or exploit access to restricted information that may create a cost advantage.[105] The purpose of ring-fencing is to limit the areas in which a network business has monopoly power by subjecting network businesses to requirements that restrict or separate its regulated and non-regulated operations.

105 ICRC, Ring Fencing Guidelines for Gas and Electricity Network Service Operators in the ACT, November 2002, p2.

In addition to ring-fencing provisions, there were previously 'cross-ownership' provisions in some jurisdictional legislation.[106] However, our review of current jurisdictional legislation has not uncovered any continuing cross-ownership restrictions.

Ring-fencing requirements would apply to services provided by energy storage assets, as energy storage can provide both prescribed or direct control services and non-regulated or unclassified services. The extent and nature of separation required will depend on the requirements set out in the ring-fencing guideline applicable to the network business.

TNSP ring-fencing guidelines and their application to energy storage

AER ring-fencing guidelines apply to all TNSPs in the NEM. These separate the accounting and functional aspects of prescribed transmission services from other services provided by a TNSP via mechanisms that are set out in Appendix I.1 of this report. Of particular relevance, a TNSP is not allowed to carry on a related business which is defined as generation, distribution, and electricity retail supply that generates revenues of more than 5 per cent of the TNSP's total annual revenue.

These requirements are intended to make sure a TNSP does not gain any undue advantage in other areas of the electricity supply chain by virtue of its position as a monopoly supplier of transmission network services.

Under these guidelines, services provided by energy storage assets relating to shared transmission services or services to ensure the integrity of a transmission network would need to be ring-fenced from non-regulated services. This is no different to any other prescribed transmission service. Similarly, non-regulated services provided by energy storage assets (eg, providing energy to the NEM) are required to be separated from the provision of prescribed transmission services. Ring-fencing requirements for accounting, cost allocation, staff, information access, and notification obligations would apply accordingly.

The Commission's position is that the ring-fencing guidelines should apply to stored energy that is used to provide energy into the NEM. While the limitation on the supply of related business services does not explicitly cover stored energy that is used in this way, if the meaning of 'generation' within the NER is clarified to explicitly incorporate energy storage functions (see discussion in section 5.1.2), this may be sufficient to make the transmission ring-fencing guidelines apply. If not, the guidelines themselves should be amended.

Transmission system operators in the United Kingdom have been presented with similar challenges regarding the classification of storage services and consequential impacts on their ability to own and operate storage assets (see Box 3.4).

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106 Specifically, Section 68 of the Electricity Industry Act 2000 (VIC) prohibited DNSPs from holding other licences. This restriction was subsequently repealed in 2013 by No.11/2013 s.4.

Box 3.4 Case study: Service classification and ring fencing in the UK

As part of the Smarter Network Storage (SNS) project, discussed above in Box 3.2, the implications of the current regulatory arrangements for storage are discussed in detail. In particular issues regarding the classification of storage and the implications of arrangements for ownership and operation of storage are identified.[107]

How is storage classified?

As a result of energy market liberalisation, regulatory frameworks at both the national and European levels have explicitly defined the conventional electricity activities of generation, transmission, distribution and supply. Energy storage is not recognised as a discrete activity or asset class.

In the absence of an alternative option, energy storage has been treated as a type of generation asset. Exemptions from the requirement to hold a generation licence are available in certain circumstances, for example if the total output of the generator is below a specified threshold.

The classification of storage as a type of generation is not due to any particularly regulatory design, but rather as a product of history. In the past, the only type of energy storage that regulators had to consider was large-scale pumped storage facilities. It was more convenient to require these facilities to be classified as "generation" rather than find an alternative regulatory treatment.

It may be satisfactory for storage assets, which deliver energy on a comparable basis to generation assets, to continue to be classed as generation.

Implications for ownership and operation of storage:

Market liberalisation placed regulatory restrictions on ownership and operation of activities at different levels of the electricity market. In particular, operators of network assets are restricted from engaging in generation or supply activities. Given the discussion above regarding the classification of storage as generation, there are implications for the operation and integration of storage in to the electricity market.

For transmission system operators (TSOs) unbundling requirements mean that there has to be distinct ownership separation between a TSO and an entity engaged in market-related activities. This requirement does not allow TSOs to own any storage assets, as storage assets are classed as generation. Alternatively, under the independent transmission operator (ITO) model, common ownership is allowed but requires full operational independence and strict rules on ring

107 Smarter Network Storage, *Electricity Storage in GB: Regulatory and legal framework*, available at: *http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Smarter-Network-Storage-(SNS)/Project-Documents/Smarter-Network-Storage-LCNF-Interim-Report-Regulatory-Legal-Framework.pdf*

fencing apply.

For a distribution network operator (DNO), the requirement is for legal unbundling rather than ownership unbundling. DNO activities can be carried out by a vertically integrated entity, provided that there is legal, functional and accounting unbundling to ensure operational independence.

Smart commercial arrangements:

As part of SNS, project trials of new and innovative commercial arrangements are being conducted. These arrangements will address the current problems associated with operating storage on the National Grid.

The business models that are being trialled in this project comply with unbundling requirements. This is done by putting a third party in place to manage the interaction of the storage asset within the market. Third party involvement separates the DNO business from the operation of the storage asset within the market.

Commercial arrangements specifically designed for multi-purpose storage have not been studied in the UK. The results of this project may therefore present opportunities for the integration of smaller multi-functional storage devices.

Lessons for Australia:

The considerations of whether storage should, by default, be treated as generation, or whether it should be more explicitly defined according to the function it provides are pertinent to questions of network service classification.

The implications of the unbundling requirements for the ownership and control of storage by network businesses are similar to the conclusions we draw for how ring fencing should operate in Australia.

Concerns about undesirable outcomes that motivate restrictions on TNSPs providing generation services may equally apply to the provision of energy using energy storage. A competitive advantage can conceivably be created if TNSPs were to acquire sufficient energy storage capability which, combined with their transmission network, could adversely affect the efficiency of the wholesale electricity market.

Consultation questions

- **Would current ring fencing guidelines address any concerns about a TNSP being able to impact the wholesale market or does storage raise unique issues? If changes are required, what are they?**

DNSP ring-fencing guidelines and their application to energy storage

The AER has discretion to develop distribution ring-fencing guidelines for the accounting and functional separation of a DNSP's provision of direct control services from the provision of other services.[108] All DNSPs must comply with the distribution ring-fencing guidelines.[109]

Ring-fencing requirements for DNSPs are currently based on individual jurisdictional guidelines that were published by jurisdictional regulators prior to 2005. Consequently, ring-fencing requirements and restrictions on related businesses vary between jurisdictions. Appendix I.2 provides an overview of jurisdictional ring-fencing guidelines that currently apply to DNSPs and how they may apply to asset ownership and the provision of services from energy storage assets.

The current ring-fencing requirements prohibit DNSPs in the ACT and Queensland from producing, purchasing and selling electricity. It appears likely that energy storage devices would also be captured by these provisions. In South Australia, SA Power Networks can hold a licence for generation, but only if no revenue is earned. This would allow SA Power Networks to be licenced to use generation for the purposes of network support, but not for selling its output into the NEM. There are no prohibitions in place in NSW, Victoria or Tasmania, although generation activities are subject to different ring-fencing requirements in each of those jurisdictions.

The Competition in Metering and Related Services rule change currently proposes to require the AER to have developed, consulted on and published a revised ring-fencing guideline for DNSPs by 1 December 2016.[110]

Review of ring-fencing guidelines

The AER commenced a review of distribution ring-fencing guidelines in 2011, during which it noted that:

- While most DNSPs are no longer vertically integrated with retailers, there are a number of other markets, and emerging markets, in which DNSPs can compete to provide unregulated services. The nature of these markets is such that participants may compete in multiple jurisdictions, and/or the markets cover more than one jurisdiction.
- There appears to be an emerging trend for DNSPs to engage in generation activities to relieve network congestion and to offset electricity consumption. The extent that such activity is permitted varies across jurisdictions.
- The accounting separation approach adopted in the ring-fencing guidelines applicable to TNSPs provides more flexibility to address emerging technologies and markets than would arrangements that require physical separation or separate ownership.

108 Clause 6.17.2(a) of the NER.

109 Clause 6.17.1 of the NER.

110 AEMC, Information Sheet – Extension of time for final rule on provision of metering services, 2 July 2015, p1.

The AER concluded that the current jurisdictional ring-fencing arrangements are not adequate for either the current environment or into the future.[111] In light of the other markets (both existing and emerging), in which DNSPs can compete to provide unregulated services, the AER considered that the jurisdictional ring-fencing guidelines would potentially lead to different outcomes in each jurisdiction. Specifically, the AER stated that:

> "Effective ring-fencing of regulated businesses choosing to participate in emerging contestable markets will be essential if the markets are to operate efficiently and effectively in the long term.[112]"

Summary of ring fencing issues

The AER will soon assess the ring fencing guidelines. The AER's and AEMC's consideration of the appropriate regulatory arrangements for network businesses owning and operating generation assets may serve as a starting point in determining whether a network business should be allowed to own energy storage assets, the extent to which the business may provide services from energy storage, and the appropriate ring-fence settings to maximise benefit from energy storage while minimising undue advantage in supplying contestable services.

Consultation questions

- **What will be required in the ring fencing guidelines to maximise the benefit of network use of storage?**
- **What will be required in the ring fencing guidelines to minimise a network business's ability to unduly impact a contestable market?**

3.3.2 Cost allocation methodology

Cost allocation is the process of apportioning to the different services provided by a network business the costs incurred in providing those services. The costs that are allocated include those associated with the network's workforce and corporate assets, as well as its physical network infrastructure.

Cost allocation requirements would apply to energy storage where those assets are utilised for the purpose of providing services across more than one service classification (such as prescribed and non-regulated services). Appendix J.1 of this report describes the cost allocation requirements for transmission and distribution services. Importantly, the principles, policies and approach used by a network business to allocate costs must be consistent with the AER's ring-fencing guidelines.

111 AER, Electricity Distribution Ring-fencing Guidelines, Position Paper, September 2012, p12.

112 AER, Electricity Distribution Ring-fencing Guidelines, Position Paper, September 2012, p14.

In short, the existing provisions appear sufficiently broadly drafted to enable their application to energy storage assets. Moreover, the network businesses' cost allocation methodology is able to be revised and reviewed by the AER as required.

We have reviewed an example of a DNSP's and a TNSP's cost allocation methodology. These describe the categories of costs typically incurred by the network business and classify these costs into the different categories of distribution services or transmission services. The cost categories included in these methodologies appear sufficiently broad to capture the costs associated with energy storage. However, if a network business's cost allocation methodology set out cost categories that were too narrow to include the costs associated with energy storage, it would be able to apply to the AER to amend its methodology to include these costs.

Consultation questions

- **The current cost allocation arrangements do not appear to raise any issues in relation to the use of storage assets. Do you agree?**

3.3.3 Shared asset mechanisms

A 'shared asset' is an asset used to provide regulated services (ie, direct control services or prescribed transmission services) and another service that is not classified as a regulated service.

An example of a shared asset would be an energy storage asset which is used to provide both regulated services (eg, network services) and non-regulated services (eg, market ancillary services), but where the cost allocation methodology allocates all costs to the regulated service. In this example the network business is able to earn two streams of revenues, namely:

- revenue from the regulated services that is recovered from shared network customers though the regulatory asset base; and
- revenue from the non-regulated services that is earned on a competitive basis.

Without a mechanism to share those revenues, both streams of revenues in the example would fully accrue to the network business, which effectivity means additional revenue is earned on assets paid for by shared network customers. These issues have been considered in the context of storage by regulated network businesses overseas, including Oncor in Texas (see Box 3.5).

Box 3.5 Case study: Oncor

In November 2014, Oncor, a transmission and distribution service provider in Texas, published a paper exploring the value of deploying US$5 billon of energy storage across its network.[113]

The proposal by Oncor is motivated by the fact that the costs of electricity storage technology are decreasing and with lower systems costs many innovative applications of electricity storage could be cost effective. The paper explores the ways in which the cost effectiveness of an electricity storage investment can be measured, given the numerous benefits and value streams involved. The paper also provides suggestions as to how the regulatory framework should be altered in order to realise the full benefits of grid-integrated, distributed electrical energy storage.

The proposal has not been acted on and has not been discussed by the state legislature and so the regulatory reforms suggested are unlikely to be enacted at this time.

Measuring the value of electricity storage:

The Oncor paper provides some valuable insight in to how the benefits of an energy storage project should be measured. Three distinct perspectives are identified, each with different considerations and incentives. The three perspectives are the wholesale market participant, the policy maker and the T&D provider and ratepayer perspectives. Each of these three groups is described below:

- **Wholesale market participants:** The primary concern from this perspective is whether wholesale market rates by themselves are sufficient to attract investment in storage. This is determined by the net profit an investor could monetise by participating in the wholesale market for electric energy and ancillary services.

- **Policy makers:** The concern from this perspective is the total benefits of storage to the electricity system as a whole, regardless of whether the benefits accrue to the asset owner, retail customers or other market participants. This perspective would evaluate whether investment in storage would be in the overall public interest.

- **T&D provides and customers:** This perspective emphasises benefits that accrue directly to electricity users and include lower bills, reliability improvements and improved power quality.

The cost effectiveness of investment in storage is then estimated from these three

113 The Brattle Group, The value of distributed electricity storage in Texas: Proposed policy for enabling grid-integrated storage investment, Prepared for Oncor, November 2014.

perspectives, taking the particular considerations and benefits in to account. The analysis finds that:

1. Wholesale market benefits of storage are limited in comparison to costs. This means that investment in storage would not be supported solely by wholesale market participation.

2. When wider societal benefits are estimated and included in the analysis the incremental value of storage would exceed incremental cost up to approximately 5,000 MW. These societal benefits could include avoided distribution outages, deferred transmission and distribution investments, production cost savings and avoided generation investments.

3. Finally, it is estimated that customers are likely to experience significant net benefits under a regulatory framework that would allow the full value of storage assets to be captured. This framework is discussed in more detail in the next section.

Proposed regulatory framework for the integration of storage technology in Texas

The proposed changes to the regulatory system would be necessary because storage could provide benefits to the system as a whole. Currently, there are restrictions on the activities that transmission and distribution businesses can engage in. A new framework would be required to help investors to capture both the wholesale market and transmission and distribution system values that are associated with the electricity storage technologies.

The Texan policy proposal would allow storage investments to be employed by transmission and distribution businesses and allowing independent market participants to offer storage devices in the wholesale power market. This new regulatory framework would involve transmission and distribution companies "auctioning off" the wholesale market dispatch of their storage investments deployed on the transmission and distribution system.

The auction proceeds would be used as an offset to transmission and distributed costs, which would include the cost of the storage facilities.

The benefits of this system include:

- fully capturing the transmission and distribution reliability-related benefits of energy storage;
- retaining a clear delineation between the wholesale market provider and the transmission and distribution companies;
- facilitating an economically-efficient level of investment, as all potential revenue is exploited; and
- reducing barriers to investment in storage technologies.

Lessons for Australia

Oncor's proposal is a useful case study as it addresses a common barrier associated with the many roles of energy storage. The auctioning of the wholesale energy component of its battery to market participants ensures that the network service provider is not directly participating in the wholesale market. This structure would also allow transmission and distribution service providers to exploit all revenue streams of energy storage systems, which provide benefits to the grid as well as to the wholesale market.

The regulatory framework in Australia is similar to Texas in that network service providers cannot participate in the wholesale energy market. However, the policy proposal put forward in Oncor's paper provides suitable separation of network and wholesale activities which may be possible within the National Energy Rules.[114]

Arrangements for shared assets were introduced into the Australian regulatory framework as part of the AEMC's 2012 Economic Regulation Rule Change (see Appendix J.2). The Shared Asset Guideline contains a specific methodology the AER proposes to apply to calculate the reduction in building block revenues that will apply when a network business also earns revenue from shared assets by providing non-regulated services. Specifically, the Shared Asset Guideline sets out that revenue earned from non-regulated services using shared assets will reduce a network business's standard control service revenues by 10 per cent of the value of the service provider's expected total non-regulated revenues from shared assets in that year (subject to a materiality consideration).[115]

The shared asset mechanism complements a network business's approved cost allocation methodology. The Shared Asset Guideline notes that network businesses allocate costs usually when the assets are first established, based on the assets' expected future use. Where asset use changes, the initial cost allocation may no longer be accurate. The shared asset mechanism relates to assets whose costs were initially allocated to regulated services but come to be used to provide non-regulated services as well. This change from expected use means the assets are earning both regulated and non-regulated revenues, and have therefore become shared assets.[116]

The AER's statements in the Shared Asset Guideline support a view that the shared asset mechanism, rather than revisions to the cost allocation methodology, is likely to be the approach used to address any change in use of regulated assets (including regulated storage assets) over time to also provide non-regulated services.

114 AECOM, Energy Storage Study: Funding and Knowledge Sharing Priorities, June 2015.

115 AER, Shared Asset Guideline, November 2013, section 3.1.

116 AER, Shared Asset Guideline, November 2013, section 1.3.

Consultation questions

- **The current shared asset arrangements do not appear to raise any issues in relation to the use of storage assets. Do you agree?**

3.4 Preliminary findings

The analysis has led the AEMC to make the following preliminary findings:

1. **Service classification.** There is scope for the AER to classify storage for use by network businesses under existing service classifications. It is the AEMC's preliminary view that the provision of storage behind the meter is a contestable service and should therefore be unclassified. Networks should not be able to install storage behind the meter unless they do so through a ring-fenced business. Where storage behind the meter would be useful for providing network support, these services must be contracted from a third party or ring-fenced business. Storage used to provide services on the network would be subject to the AER's usual service classification.

   — Metering for small customers has been treated as an alternative control service but in future advanced metering will be non-regulated and subject to competition. Similarly, storage technologies should also be considered in this way as a contestable service.

2. **Cost recovery.** Once service classification is determined, the efficiency sharing incentives should lead network businesses to seek the most efficient trade-off between storage and traditional network assets, and between owning storage assets and procuring their services under contract. We do not recommend any blanket prohibitions on networks owning storage or requirements that they only competitively tender for storage services on their networks. It is unlikely that networks purchasing storage for their network will prevent the development of a competitive market for storage devices - given the amount of activity by retailers and direct sellers.

   — We do not think extra powers are needed for AER to exclude non-proven technologies from the RAB.

3. **Ring fencing.** It will be very important that strict ring-fencing provisions are in place for network businesses looking to set up separate entities to install storage behind the meter. These provisions must prevent any ability of the network to favour affiliated businesses or provide advantage to the affiliate in areas like connection processes. Strong enforcement and compliance obligations will also be required to give the market confidence that a level playing field is being maintained. This is also applicable to transmission businesses looking to enter contestable markets.

— Cross-ownership considerations may also need to be applied if the policy principles that underlie vertical separation of monopoly from competitive electricity activities are threatened – see next chapter.

4. **Annual planning process.** The existing network planning requirements and investment tests should lead network businesses to consider storage as an alternative to traditional network solutions. The option value element of the investment test should also lead them to value the potentially incremental nature of a storage solution (as opposed to a "lumpy" network investment.) However, the lead times in the planning process should be reviewed to test whether they are sufficiently long to capture an incremental solution, especially one that needs to be implemented incrementally as loading of a network element increases in order to indefinitely defer an augmentation.

Consultation questions

- **Do you agree with these preliminary findings**
- **Are there other issues which should be considered?**

4 Ownership and control

The regulatory framework that supports the operation of the NEM was originally designed under the paradigm of large-scale, centralised generation and transmission assets connected to loads at the fringes of a distribution system. The framework sets out defined roles and obligations for participants across the electricity sector based on the function or role they are carrying out, e.g. generation or transmission.

The interpretation of this framework has been relatively straightforward to date because most technologies have only been able to, or required to, perform one of these functions. As such, the current regulatory framework does not explicitly contemplate that one asset could perform multiple functions, e.g. a storage device that both produces electricity and substitutes for network services.[117]

However, the obligations set out in the current regulatory framework reflect the function that the participant is performing rather than the specific means by which they perform that role. In this way, the regulatory framework is technology agnostic. As demonstrated by the various case studies set out in this chapter, there is room for interpretation and parties are already looking at ways to connect storage assets within the existing rules.

We have found two areas where policy decisions may be required - as opposed to clarification of existing rules and regulatory processes in order to accommodate energy storage. These are:

1. Issues associated with the control of storage

2. Issues of competitive neutrality.

4.1 Control

An emerging theme in our consideration of the integration of energy storage within the electricity sector is that of control. We are seeing the launch of different business models involving energy storage which can be summed up in terms of who controls the device: the consumer, the energy services company, the retailer or the network business. It can be assumed that the storage devices will operate automatically, so it is not a case of active control but rather about who sets the objective for the device operation: ie, whose benefit is the device seeking to maximise?[118]

117 With a couple of exceptions: pumped hydro, which both consumes and produces wholesale electricity, and embedded generation used by distribution networks to maintain network reliability.

118 We anticipate that these "intelligent batteries" are the vanguard of more general "intelligent distributed energy", so these observations are likely to apply distributed energy generally as well as batteries specifically.

4.1.1 The consumer-controlled model

Consumers procure batteries directly, along with some optimising software (eg, from Tesla or Enphase). Alternatively, a third party or energy services company (eg, Reposit) optimises the device on behalf of the consumers. The device stores electricity at times of low prices or from the consumer's own solar PV generation and discharges at times of high prices.

The consumer-controlled storage would optimise against prices received from the retailer that would, in turn, incorporate pricing from the wholesale market and the distribution network business. The consumer would also input its objectives, eg, around reliability if the battery is to provide back-up power in the case of outages.

The control needs to be forward-looking (eg, to charge the batteries in advance of anticipated high prices), so works best if retail prices and distribution network charges are transparent and predictable.

4.1.2 The retailer-controlled model

Retailers provide storage (or a solar PV and storage package) to consumers. This may be through a lease or a power purchase agreement. Some of the benefit from the device is provided to the consumer: the net effect is that the consumer pays less than "socket price" for retail energy. In exchange, the consumer gives up a degree of control to the retailer.

The retailer-controlled storage device would optimise against wholesale prices and distribution network prices, and the retailer's own needs (eg, hedging). The control would be subject to some agreed constraints relating to consumer benefits, eg, to provide specified minimum comfort levels or reliability of hot water supply.

The retail price seen by the consumer can be fairly simple and transparent.

4.1.3 The network-controlled model

The network business provides storage to consumers that is sited "behind the meter" on the consumers' premises. The consumer contributes to the cost of the device, eg, through a lease. In exchange, the consumer can make use of the device to aid self-supply.

However, the network business controls the device, and would use it to provide network benefits – for instance to avoid network augmentation by discharging storage devices during times of critical network peaks, or to avoid the failure of reliability standards in areas that are prone to outages. This is the model being undertaken by Vector in New Zealand in partnership with Sunverge.

Alternatively, the network owns the asset and socialises the cost across all consumers, given the perceived network optimisation benefits. This model would negate any benefits to the retailer, and potentially to the individual customer, as it is maximising network benefits.

In a third alternative, network businesses might install storage devices directly on their networks in order to provide network benefits, but may use (or make the device available) to provide benefits to other parties – eg, to time shift energy between times of high and low wholesale prices. This is the regulatory model being investigated by EletraNet in its ESCRI trial.

4.1.4 Optimisation of storage assets

In each of these models the storage device can provide a range of benefits which may accrue in the first instance to the consumer, retailer, network business or wholesale market participant. The most successful business models will be able to capture all of these benefits or, at least, the most material ones. To do so, whoever is in charge would enable the storage device (or distributed energy more generally) to provide benefits to the other parties also.

However, there will be limits on the ability of some models to capture all benefits:

Physical limits

Where the energy storage is located will in some cases limit the number of different value streams that can be captured. For instance, transmission-connected storage is simply not able to provide local power quality deep within the distribution network, or to provide a back-up power supply to a household in the case of a distribution feeder outage.

A potential trade-off between optimisation and control

There are various ways of addressing the potentially conflicting uses for a storage device – for instance, providing network support or aiding consumer self-supply to avoid retail electricity costs:

- Retaining direct control of the device to provide the benefit that is most important to that party and allowing other parties to access the device at other times.
- Negotiating agreements that specify how the device will operate in various conditions, the split of benefits and the allocation of costs.
- Relying on transparent and efficient prices which reflect the underlying value of the avoided cost that is achieved by operating the storage device at a point in time, eg, the value of wholesale electricity or the impact on the distribution network.

In the absence of transparent and efficient prices, if the transaction costs of negotiating agreements are sufficiently high, or if the new business environment requires a change in approach, parties may rely on direct control instead. While the benefits of direct control may be easier to quantify and therefore appear attractive, this may in fact not be an optimal outcome because a trade-off is not made between the conflicting value streams. Rather it is implicitly assumed that the controlling party's interest is the most valuable.

For instance, a retailer- or consumer-controlled model may fail to provide some network benefits, because the parties are unable to negotiate a network support agreement that provides sufficient confidence that a network business would rely on distributed storage in the place of network augmentation. The network may then prefer to directly control the storage itself, if that is the cheaper alternative to augmentation.

Alternatively, network businesses may argue that it is inefficient having individual consumers buy storage devices when a network solution could provide benefits to all consumers at a lower cost. This, however, assumes that network optimisation is more highly valued by consumers than their individual preferences regarding the alternative uses of storage. It also limits consumers' ability to change their storage device, based on new technologies, if the investment decision is made on their behalf.

The regulatory and competitive frameworks have been created to drive efficient outcomes, and should allow the best model or models to prevail. Competition between models is also a good idea while the models and the technologies are still proving themselves. This issue was considered by the Commission in relation to the Expanding Competition in Metering and Related Services rule change. Consumer choice will require service providers to package multiple benefits in a way that is attractive (which is more likely if the model achieves a good optimisation between different benefits) but also consumer friendly. Imposing technologies on consumers that they do not understand and do not appear to benefit from usually reduces confidence in the market, particularly when consumers realise the associated costs.

4.1.5 Control should not be used as a barrier

The various models raise different implications for control of the storage device. We would be concerned if the control exerted as part of one of these business models acts as a barrier to the pursuit of the other models. Retailer- or consumer-controlled storage may come at the expense of some network optimisation, but does not seem likely to act as a barrier to network-controlled storage (because the network businesses always have the option of putting storage on their own networks). But network-controlled storage has the potential to act as a barrier to the other two models:

- In the requirements the network businesses impose in terms of what is connected to their networks – through connection agreements and standards. Networks have a legitimate interest in ensuring that nothing is connected that affects the safety, security and reliability of their network. But they may also make it onerous and costly if they have a competing business interest in pursuing network-controlled storage.

- By requiring through those agreements and standards some ongoing degree of control that affects the original business case for investing, eg, by preventing a consumer or retailer from discharging the storage onto the network at certain times or requiring remote control through AS 4777.

> **Consultation questions**
>
> - **Are the connection requirements that are being imposed by different distribution businesses for consumer- or retailer-controlled storage being used as a barrier? If so, how?**
> - **Does the ongoing degree of control that is being required by distribution businesses for consumer- or retailer-controlled storage represent a genuine safety, security or reliability need, or is it more appropriately a network interest that should be negotiated or signalled through prices?**

4.1.6 System operations

There is potential for a prevalence of distributed energy resources, including storage devices, to create system operation issues. In the short-term we have already seen instances of this with over-voltage issues in areas that are rich with solar PV and high insolation, where PV exports cannot be securely accommodated. Storage devices acting in aggregate (either because they are aggregated, or because they are responding in concert to the same price signal) could have the potential to cause system issues, such as through effects on frequency which can affect the whole power system.

4.1.7 Preliminary findings

The analysis has led the AEMC to make the following preliminary findings:

1. Storage has the potential to generate a number of value streams, but control of the device will be required for this to occur. The NEM's current framework is built on the idea that market-based outcomes tend to be the most efficient. Control of storage devices should therefore, in all but a narrow band of circumstances related to system security and safety, be based on market-based price signals.

2. AEMO should investigate the potential system operation effects of a prevalence of distributed energy devices, in particular in a scenario with a lower amount of synchronous generation, identify issues and their extent.

> **Consultation questions**
>
> - **Do you agree with these preliminary findings?**
> - **Are there other issues which should be considered?**

4.2 Competitive neutrality

We found in Chapter 3 that the current regulatory framework appears to allow network businesses to own and control energy storage, subject to some clarification of how the services provided by the storage devices would be classified. Where storage devices provide a mixture of regulated activities (substituting for traditional network services) and competitive energy services, then ring fencing, cost allocation and shared asset guidelines would apply.

The AEMC has identified three sets of behaviours (in general, not just in relation to energy storage) that have the potential to weaken competition to the detriment of consumers. Some form of ring fencing should then apply:

1. The network business is able to cross-subsidise a competitive service from its regulated activities. A cross-subsidy may impede competition in the competitive market.

2. In the course of performing its regulated activities, the network business acquires commercially sensitive information that may provide it with an advantage in a competitive market. Metering data or load profile data are examples.

3. The network business is able to restrict competition in a competitive market by restricting access to infrastructure or providing access on less favourable terms than to its affiliate.

The AEMC is broadly confident in the ability of ring fencing to address the first and second of these situations. The AER has discretion as to the type and strength of separation it would require between the regulated and non-regulated activities.

The third situation is more problematic and ring fencing must be sufficiently strong in the case that the business (or an affiliate) seeks to carry out a competitive energy service that could gain advantage through the way the business operates its network. There is a clear parallel here in the structural separation that has operated since the electricity industry was deregulated – with the generation and retail sectors subject to competition and structurally separated from monopoly networks.

The underlying logic that applied during deregulation still applies today. For this reason, we recommended in the Transmission Frameworks Review that transmission businesses should not control generation assets (and generators should not control shared transmission assets) – because the TNSP would have the ability (and incentive) to control the network in such a way that discriminates in favour of its downstream generation business and/or against its generation business's competitors.[119] That is, we would not rely on a ring fence alone, but rather prohibit network businesses from carrying out activities in very closely related competitive energy services that are dependent on the way the network carries out its regulated activities.

119 AEMC, Transmission Frameworks Review, Final Report, April 2013, pp.184-186.

This same logic appears to be relevant to energy storage, particularly if storage-related activities have the potential to become a significant part of a network business's revenue, or that of a ring-fenced affiliate. The network business may then use its network to advantage its storage assets (over other forms of distributed energy owned by rivals, or over conventional generation) when competing in the wholesale or retail market. It could use the connections process to make it difficult for rivals to install storage behind the meter, if the business or an affiliate were competing in that space.

It will therefore be very important in the context of storage, but indeed other potential technologies such as smart meters, that ring-fencing guidelines are robust and strongly enforced. Any lack of confidence in the practical reality of separating multiple revenue streams from a single asset, and only financing the regulated services from regulated revenue, will be damaging to the market and could potentially deter investment by non-network participants.

Box 4.1 Case Study: ElectraNet, AGL and Worley Parsons, Energy Storage for Commercial Renewable Integration in South Australia

This project is known as the Energy Storage for Commercial Renewable Integration in South Australia (ESCRI). Funding for the initial phase of the project has been provided by the Australian Energy Agency (ARENA), under their Advancing Renewables Program. The project examines the role of a non-hydro electricity storage device within the South Australian transmission system. The project will specifically examine the value that can be obtained from the energy market and through both ancillary and network services. A key objective of the project is to demonstrate that storage assets can add value to renewable energy.

This project is being undertaken by a consortium of AGL Energy Ltd, an electricity generator and the local retailer; ElectraNet, the TNSP in South Australia; and Worley Parsons, a company who provides services to the energy and resources sector. The project, if approved, would progress to Phase 2 of the Advancing Renewables Program and would be trialled at a location which was chosen as part of the first phase of the project.

The ownership model chosen involves ownership of the storage asset by ElectraNet with the market trading component leased to AGL. The recommended framework includes part of the storage device cost being included in the TNSP RAB. The TNSP would have maintain the device and operate isolating equipment. The regulated component would be limited to the value of the benefit identified in the required Regulatory Investment Test Transmission.

The siting of the storage device would be determined by the TNSP subject to network limitations while having regard to market trading requirements.[120] The

120 For the demonstration phase of this project the local retailer must be used, as it is not a market generator. In this case AGL is the local retailer. For a full scale commercial product registration would need to be addressed.

minimum capacity of the storage device would be determined by the TNSP network support requirements and the capacity would then be amended to maximise other intended revenue streams.

Network support is the primary function of the storage device. The TNSP would assign dispatch rights to the generator/retailer which would include specific provisions on how the storage device is to operate when required for network support. The generator/retailer is the registered market participant and the counterparty for settlement with AEMO for the purposes of this project.

A business case has been prepared for a 10 MW, 20 MWh electricity storage device sited at the Dalrymple substation on the Yorke Peninsula in South Australia. The storage technology chosen is a Lithium-ion battery. The business case will be assessed and may progress to Phase 2, if sufficient funding is secured to ensure the commercial viability of the project.

South Australia has the highest rate of renewable penetration in the NEM, and is among the highest in the world. This project is sited near a significant renewable generator, the Wattle Point Wind Farm (WPWF). This trial is intended to provide some insights in to the ability of storage to facilitate the integration of intermittent renewable generation.

The project has identified four major potential revenue streams for the energy storage device. These are:

1. **Market trading revenue**. Wind generation often occurs overnight, during times of low or negative pricing. The storage device would act as a load when prices are low or negative and be dispatched when prices are high. Market trading revenues will fluctuate year on year as they are dependent on pool price volatility prevailing in any given year. It is assumed that under current market conditions spot price volatility in South Australia is likely to increase.

2. **Marginal Loss Factor Impact**. Energy storage can modify marginal loss factors during network congestion, and therefore capture energy that would otherwise be lost. The proposal will enable improved loss factors on the Wattle Point – Dalrymple 132 kV line. To claim this benefit the energy storage device (ESD) has to operate as load when the WPWF is generating at high output and dispatch when WPWF is generating at low or zero output.

3. **Expected Unserved Energy (USE) reduction**. This may arise in the event of a network event or outage. Battery technology would enable energy dispatch during these events and reduce the volume of expected unserved energy. Thus, battery storage could increase the reliability of the network. Avoided expected unserved energy is in effect a “non-cash” benefit of the project. Avoided expected unserved energy reflects the potential value of the project to third parties impacted by the ESD. This does not have a real

cash impact on project revenue; instead it provides a basis on which a portion of the ESD capital cost could be included in ElectraNet's regulated asset base.

4. **Ancillary services support**. A grid-connected ESD can provide ancillary services operating in either charging or discharge mode. However, the provision of ancillary services may be in conflict with the generation strategy or market trading function of the ESD. Provision of ancillary services could provide significant upside to the business case for this project. This is due to the potential for changes to be made to the FCAS market in South Australia to address system security systems as conventional generation is retired.

In terms of how these benefits would be distributed across the market participants; the market trading benefits would accrue to AGL; the marginal loss factor benefit would accrue to AGL as the owner of the wind farm; the benefit of the expected avoided unserved energy accrues to customers; and the ancillary services revenue would accrue to AGL as the operator of the device.

Operating in market trading mode provides the greatest value in use of battery storage. Accordingly the proposal has been optimised to maximise the benefit of market trading mode. As a consequence, any ancillary service can only be provided if the battery is in operation during a network event.

4.2.1 Preliminary findings

The analysis has led the AEMC to make the following preliminary findings:

1. Storage is a contestable service and participation of network businesses in this market must be done on a level playing field with other market participants. The market-led installation of storage is most likely to lead to efficient outcomes. The Commission would not recommend any policy decisions to actively encourage the deployment of storage by networks in contravention of a framework that assumes that competitive energy activities should be market-led.

2. It will be important to monitor the impact of ring-fencing requirements to ensure the vertical disaggregation of the electricity supply chain between regulated monopoly and competitive activities is maintained. In relation to energy storage, we take this to mean:

    (a) Network businesses should use energy storage where it substitutes for traditional network (not behind the meter), where it is efficient to do, so long as it does not significantly displace competitive energy services. It is appropriate for the storage to be financed from regulated expenditure to the extent that it is providing network services.

    (b) If a network business installs storage on its network to provide network services, then its use for energy trading (or other competitive energy services) should be strongly separated from the regulated network business. The auctioning of energy trading rights from network-connected storage that has been proposed by Oncor, or the transfer of those benefits to a retailer in the ElectraNet trial, are attractive models.

(c) It is not appropriate for network businesses to own or directly control storage behind the meter except through a ring-fenced entity which is subject to strict compliance requirements and robust enforcement. If storage behind the meter is of value to network businesses, then they should contract with consumer, retailers or third parties to gain services, or create price signals or offer rebates that would reward consumers for operating storage in the desired way.

Consultation questions

- **Do you agree with these preliminary findings?**
- **Are there other issues which should be considered?**

5 Storage at the wholesale electricity level

There are a number of possible drivers for the utilisation of energy storage capability at the wholesale electricity level. These include:

- shifting energy between different times of the day (or longer) to manage differences between availability of generation and requirements of loads, or simply between times of different prices;
- managing the intermittency of renewable generation, by smoothing out the fast and significant variability in power output of wind and solar resources; or
- providing ancillary services, including frequency regulation.[121]

These applications are viable because energy storage technologies can act as both a consumer and producer of electricity. The existing regulatory framework supports, or is sufficiently flexible to accommodate, the connection and operation of energy storage at the wholesale level.

This chapter describes how the regulatory framework would apply to large-scale storage assets connected to a transmission or distribution network, including:

- registration requirements for a party seeking to participate in the NEM;
- connection requirements for a generator;
- fees and charges payable by a party participating in the NEM; and
- eligibility requirements for providing ancillary services.

5.1 Registration

5.1.1 Purpose of registration arrangements

To participate in the NEM, a person must become registered in relation to the activity they wish to pursue in the market. Four activities require registration as a prerequisite for participation in the NEM:

1. owning, controlling or operating a generating system that is connected to the grid;[122]
2. owning, controlling or operating a transmission or distribution system that is connected to the grid;[123]

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121 CSIRO, Electrical energy storage: Technology overview and applications, 2015, p44.

122 Section 11(1) of the NEL.

123 Section 11(2) of the NEL.

3. operating or administering a wholesale exchange for electricity (excepting the Australian Energy Market Operator (AEMO));[124] and

4. purchasing electricity directly through a wholesale exchange.[125]

Registration applies to the person, not the technology itself. However, the technology to be used is relevant to registration because it will affect what activities a participant intends to undertake and therefore the relevant registration category.

A registered participant may only participate in the NEM in the manner allowed for its registration category.[126] A registered participant may act in more than one of the registration categories, provided it is registered by AEMO in relation to each.[127] In this regard, a person using a grid-connected storage device could then be registered as a generator (if operating the device as a generating system that exports electricity for sale on the NEM) and/or as a customer (if operating the device as a load that imports electricity by purchasing it from the NEM).

AEMO undertakes a comprehensive registration process to determine whether the applicant meets the registration requirements and eligibility criteria set out in Chapter 2 of the NER for the relevant registration category. This process requires registration applicants to provide certain information and documentation to AEMO.

While most obligations of registered participants are specific to their category, certain rights and obligations apply to all registered participants under the NER, including:

- information provision to AEMO in relation to certain power system security issues,[128] as well as complying with a direction from AEMO to do anything that AEMO may consider necessary to maintain or re-establish the power system to a secure, satisfactory or reliable operating state;[129]
- power system security support obligations;[130]
- compliance with performance standards (as they may relate to that participant's plant);[131]
- compliance with dispatch instructions;[132]
- prudential requirements;[133]

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124 Section 11(3) of the NEL.

125 Section 11(4) of the NEL.

126 Clause 2.8.1(a) of the NER.

127 Clause 2.8.1(b) of the NER.

128 E.g. clauses 4.8.1 and 4.8.2 of the NER.

129 Clause 4.8.9 of the NER.

130 Contained in rule 4.11 of the NER.

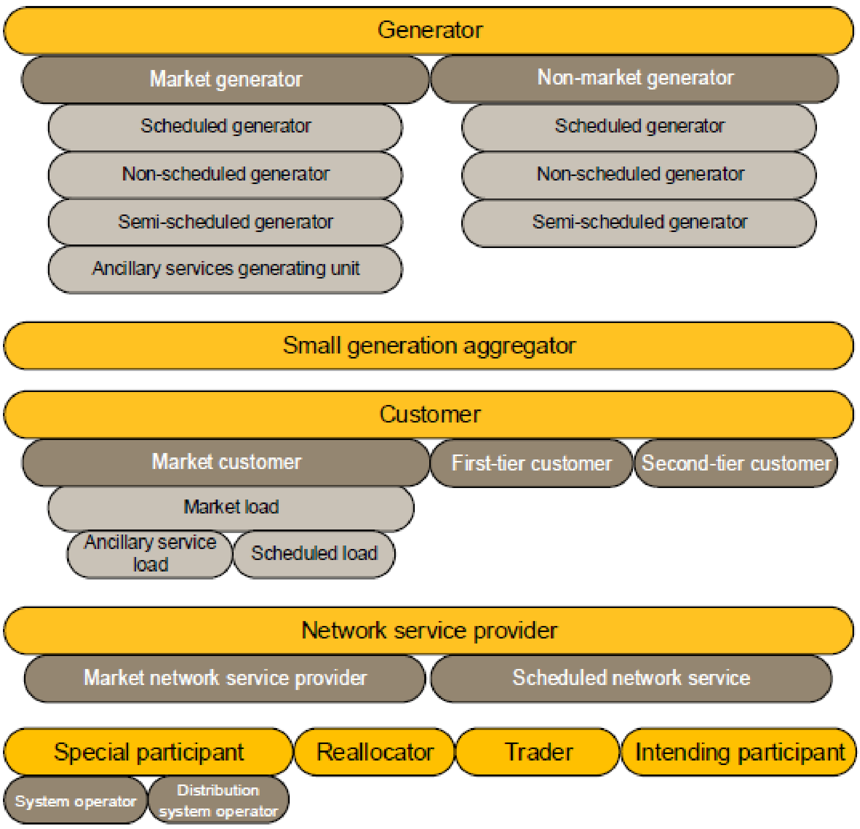
131 Rule 4.15 of the NER.

132 Clause 4.9.4 of the NER.

- participation in the NER dispute resolution process;[134]
- confidentiality obligations with respect to confidential information;[135]
- an obligation to pay participant fees to AEMO;[136]
- reporting requirements as determined by the AER.[137]

Figure 5.1 sets out the categories and classifications of registered participants in the NEM, each of which have different obligations under the NEL and NER.

Figure 5.1 Participant categories in the NEM



Source: AEMO, Participant categories in the National Electricity Market, 2014, p1.

Prior to recent amendments to the NEL, the AER's enforcement actions were largely limited to registered participants.[138] Therefore registration has historically been

133 Strictly these requirements only apply to a market participant, which is the market category of the relevant registered participant. See rule 3.3 of the NER generally.

134 Rule 8.2 of the NER.

135 Clause 8.6.1 of the NER.

136 Clause 2.1.2 (f) of the NER.

137 Clause 8.7.2(e) of the NER.

138 The AER's enforcement powers were in relation to the 'relevant participants'. This was defined to mean: (a) a Registered participant; or (b) AEMO; or (c) a person engaging in an activity in breach of section 11(1), (2), (3) or (4); or (d) a person prescribed by the Regulations to be a relevant

necessary to subject those participating in the market to the jurisdiction of the regulator. This altered with the adoption of the National Energy Customer Framework (NECF) – references to 'relevant participant' were replaced with 'person' (who is not necessarily registered to participate in the market).[139] Registration is therefore no longer necessary for the operation of the enforcement frameworks in the NEL.

In AEMO’s view, the purpose of registration is to maintain the integrity and security of the electricity market.[140] It is clear that registration helps to achieve this purpose. For example, if an applicant is seeking to register as a generator, AEMO must be satisfied that the applicant will, among other things, be able to respond to dispatch instructions, settle its financial obligations in the market and meet relevant performance standards.

The various functions that storage systems are capable of providing (eg, generation, load, network support) appear to fall directly within existing activities that require market registration. Given the potential impacts on the wholesale exchange of using storage devices to provide these functions, registration will be important for those owning, controlling or operating storage systems at the wholesale electricity level.

Registration options potentially affect the benefits that can be realised by the owner or operator of storage capability. Whether or how that person is registered is likely to depend on the technical specifications of the device and what its primary function is intended to be.

The various value streams that storage capability can provide fall directly within existing activities that otherwise require market registration in the categories of generator, customer or possibly network service provider. Which registration category is relevant depends on how the storage system is to be used. How a person registers will have flow-on effects for their obligations under the NER. The Commission's view is that a new category of registered participant specific to energy storage is not necessary because:

1. the existing categories of registered participant are sufficiently flexible to incorporate the use of a storage device; and

2. there are no specific rights or obligations peculiar to energy storage that would necessitate the creation of a new registered participant category.

participant, but does not include a Registered participant that is prescribed by the Regulations not to be a relevant participant.

139 *Statues Amendment (National Energy Retail law) Act 2011*, sections 5(4), 14, 30(1), 31, 33, 34, 36-41. These amendments to the NEL made by this amending act only apply to a jurisdiction that has adopted the National Energy Retail Law (clause 24, Schedule 3 of the NEL). This means that these amendments are not effective in Victoria (all other NEM jurisdictions have now adopted the NERL).

140 AEMO, How to register to participate in AEMO's energy markets, p1.

5.1.2 Registration as a generator

Anyone that owns, controls or operates a generating system that is connected to the national electricity system must register as a generator (unless exempted by AEMO – as is currently the case for systems less than 5 MW in size).[141]

Any system which purely exports electricity to the grid (or only draws electricity from the grid in order to operate the generating system) is a generating system – unless the system falls below the 5 MW threshold. A system which purely draws electricity from the grid is a load. A system which both imports and exports electricity from NEM is both a load and a generating system, and the person operating it should register as both a customer (if purchasing from the wholesale market) and a generator.

There has been some debate about whether the current definitions of generating system and generating unit would capture energy storage, and hence whether the generator registration category would apply.[142] Further, there have been suggestions that energy storage itself should be separately defined with the rules.[143] Some of the debate arises because the word 'generator' – as used in the definition of generating unit – is not itself defined in the NER.

Our view is that the accepted usage of generating unit to include solar PV systems (which are either generators, embedded generators or micro-embedded generators) avoids the need to refer to the dictionary definition. That is, it is clear that the NER and associated registration and connection processes have been able to function for solid state generating units with no moving parts. However, for the sake of clarity, it may be useful to include an explicit definition of 'generator' (within the NER definition of a generating unit) as something that produces electricity.

Another potential ambiguity which people have explored is a storage device's probable less than 100 per cent efficiency, meaning it will consume more electricity than it generates over its lifetime. That is it will be a 'net load'. It is the Commission's view that this is irrelevant. By analogy, a factory may contain an embedded generator that supplies part of the customer's electricity needs (but less than its total requirement) which at times is used for selling into the NEM. Over its life, this system will also be a net load, but the person will have to register as a generator if they want to sell into the NEM. It is the fact of exporting to the grid that is critical, not net consumption.

Market or non-market generating unit

Each registered generating unit must be classified as either a market generating unit or non-market generating unit.[144] All sent-out electricity from a market generating unit

141 See Appendix K.1 of this report.

142 See Appendix K.1 for these definitions.

143 See: Crossley, Penelope, Defining the Greatest Legal and Policy Obstacle to 'Energy Storage' (May 27, 2014), Renewable Energy Law and Policy Review, Vol. 2013, No. 4, pp.268-281, 2014; Sydney Law School Research Paper No. 14/56. Available at SSRN: http://ssrn.com/abstract=2442121

144 See Appendix K.1.1.

must be sold through the market, and the generator receives payments from AEMO for its output at the spot prices applicable to its connection point.[145] Sent-out generation from a non-market generating unit must be purchased in its entirety by the local retailer or by a customer located at the same connection point.

To the extent that storage was being used to arbitrage between high and low prices in the wholesale electricity market it should be treated as a market generating unit. But if a battery system is used to smooth wind generation and is attached to a factory that takes all of the output, then it would be a non-market unit.

Market generators can buy electricity through the spot market to support the operation of their generating system, eg, to supply on-site offices, mines owned by the generator, water pumps, conveyor belts or power station auxiliaries. They must satisfy AEMO that the electricity is used for that purpose and that all power station connection points are part of the overall connection of the generator to the network. Otherwise the generator's electricity purchases must be made through a market customer. (The generator can either register as a market customer itself or purchase the electricity from a third party who is a market customer.)

If a person who is operating a transmission-connected battery (in order to participate in the wholesale market) can convince AEMO that the electricity purchased to charge the battery is for the purpose of running a generating system, then the person can register as a market generator alone. As the electricity is actually the battery's 'fuel source', rather than auxiliary power being used to run the system, the Commission's view is that the person should also have to register as a market customer (or, if purchasing the electricity through a third party, a first or second tier customer). A consequence of registering as a market customer is that the person would pay use of system charges for its electricity imports which for a storage device would be a very substantial amount in comparison to its generation. Conversely, for a generator its auxiliary load is usually no more than about 5 per cent of its generation.

Box 5.1 Case study: Pumped hydro storage systems

Pumped hydro storage systems store the gravitational potential energy of water by pumping it to a high elevation from a lower elevation during low cost or off-peak hours when the cost of doing so is low. When required, such as during periods of high electricity demand, the water is released to the lower reservoir to turn turbines with a generator to produce electricity, similar to the way in which conventional hydroelectric power plants generate electricity. Pumped hydro storage is the largest and most widespread electrical energy storage technology in the world.[146] The technology helps to balance electricity supply and demand, and to moderate wholesale prices during periods of high demand.

145 'Sent-out electricity' refers to the amount of electricity supplied to the network at the connection point, and so effectively, in the context of power stations, means auxiliary load is netted off gross output. References to the export of electricity are for small-scale systems where self-consumption is netted off generation.

146 CSIRO, Electrical energy storage: Technology overview and applications, 2015, p91.

Wivenhoe Power Station is a 500MW, pumped storage hydroelectric power plant near Brisbane, Queensland. Owned by CS Energy, the power station consists of two 250MW generating units, which are registered with AEMO as scheduled market generators, and two pumps, which are registered with AEMO as scheduled market loads. The power station operates to conduct wholesale market arbitrage and also bids into FCAS markets.

Registration as a scheduled load enables a market customer to submit bids to purchase electricity for that load through the central dispatch process. A scheduled load must be able to be switched on or off as appropriate in accordance with submitted bids. Wivenhoe Power Station buys electricity through the central dispatch process at times of low prices and uses this to run the pumps that transport water up to the high reservoir. When CS Energy successfully offers Wivenhoe into the wholesale market (generally at times of high prices) water is released from the high reservoir through tunnels to the turbines that drive the generating units. The electricity generated is sold through the central dispatch process at the spot price applicable to the connection point.

Scheduled, non-scheduled or semi-scheduled

Each market and non-market generator unit must be further classified as scheduled, non-scheduled or semi-scheduled. Scheduled and semi-scheduled generators must participate in the central dispatch process managed by AEMO: semi-scheduled generators (typically intermittent generators) can be "dispatched down" but not up. A non-scheduled generator is not required to participate in dispatch.[147]

There may be risks involved if a large number of parties utilising storage capability are registered as non-scheduled generators. These risks are not unique to storage capability, but are likely to make the current issue regarding the visibility of such generation a problem, eg, for AEMO's forecasting purposes as part of central dispatch.

Generator classifications

The various generator classifications and examples of each are set out in Figure 5.2.

147 See Appendix K.1.2 for detail on these categories.

Figure 5.2 Generator classifications

		Typical Capability	Examples
Exempt		Less than 5 MW	1 MW backup diesel generator in a high-rise building
		Less than 30 MW, and annual export less than 20 GWh	20 MW biomass-fuelled generator with limited fuel supplies
Non-Scheduled	Non-Market	Less than 30 MW, all purchased locally	10 MW, all purchased by a *Customer* at the same connection point
	Market	Between 5 MW and 30 MW, not purchased locally	10 MW generator supplying pool
Semi-Scheduled	Non-Market	Intermittent output, greater than 30 MW, all purchased locally	150 MW wind farm, all purchased under contract to a *Local Retailer*
	Market	Intermittent output, greater than 30 MW, not purchased locally	150 MW wind farm supplying pool
Scheduled	Non-Market	Greater than 30 MW, all purchased locally	40 MW hydro station, all purchased under contract to a *Local Retailer*
	Market	Greater than 30 MW, not purchased locally	2000 MW power station supplying pool

Source: AEMO, NEM Generator Registration Guide, 2013, p18.

The registration process for a generator includes, among other things, an assessment by AEMO of the applicant's category of registration, its financial viability, compliance with jurisdictional regulations and organisational capability.

The installation of storage capability may affect the classification of an existing generating system and therefore how it participates in AEMO's dispatch process. For example, sufficient storage capacity attached to a wind farm may be able to reduce the intermittence of its generation, and so its semi-scheduled status. It may therefore be necessary for the generator to revise its classification based on the new characteristics or requirements of the generating system.

Applicants must also satisfy AEMO that their generation equipment will meet or exceed the technical requirements as set out in the NER.[148] Technical requirements are set out in detail in section 5.2.1.[149]

Registration exemption framework

AEMO may exempt a person from the requirement to register as a generator.[150] AEMO's *Guideline on Exemption from Registration as a Small Generator* sets out the criteria for the standing exemption for registration in respect of small generating systems. Small generating systems are defined as those that have a combined nameplate rating

148 Specifically those set out in clause S5.2.5 of the NER

149 Further information on registration as a generator can be found in AEMO's *NEM Generator Registration Guide*, 2013.

150 See Appendix K.1.3.

of less than 5 MW or if exporting less than 20 GWh per annum between 5 and 30 MW. If a person's generating system complies with the criteria detailed in the guideline, an automatic exemption from registration applies.

Exemption means, among other things, that the owner of the generating system is not required to pay participant fees and cannot be scheduled or settled in the market. The registration and exemptions framework is therefore likely to affect commercial decisions about the size and capability of a storage asset, if used as part of a generating system.

Because of the impact that storage devices may have on the wholesale exchange, either individually or in aggregate, it is useful to consider whether the 5MW threshold for registration as a generator is appropriate if storage constitutes part of the generating system. For example, a 4MW generator would be exempt from registration. However, if this generator had a 4 MW storage system attached to it or co-located with it, then effectively the generator could have the ability to export up to 8MW, taking it above the current exemption threshold.

5.1.3 Registration as a small generation aggregator

A small generation aggregator is a registered participant who supplies electricity aggregated from one or more small generating units (smaller than 30MW).[151] The small generating unit must have its own connection point that is separate from any load being purchased from the network at the relevant premises. All output aggregated by a small generation aggregator needs to be sold into the spot market. The aggregator is paid by AEMO for the sent-out generation at the relevant spot price for all market connection points it is financially responsible for.

To the extent that the generation value stream of a retail customer's storage device is treated as a generating unit under the NER, that value stream will be able to be aggregated (assuming the storage system has its own 'exporting' connection point).

5.1.4 Registration as a customer

Retailers and end users who buy electricity in the spot market must be registered as market customers.[152]

A storage system which purely imported electricity from the grid would be load. A person operating an energy storage system that acts as a load would need to be registered as a market customer or retailer if buying electricity through the spot market to charge the storage system.[153]As noted in section 5.1.2, if the system imports and exports electricity to the NEM, then it will be both load and generating system, and be

151 See Appendix K.2.

152 See Appendix K.3.

153 Small consumers, purchasing electricity through a retail contract, would not require registration. This is discussed in Chapter 2.

required to register for both, assuming the relevant requirements for registration as both are triggered by the relevant function.[154]

The definition of load under the NER, relies on the concept of delivery of electrical power. 'Electrical power' is not defined in the NER. Again, for the sake of clarity, it may be of assistance to include an explicit definition of 'electrical power' to remove any suggestion that electrical power need only have come from a mechanical source (see discussion above in section 5.1.2).

5.1.5 Registration as a network service provider

A network service provider is a registered participant that owns, controls or operates a transmission or distribution system.[155] Our position on network service providers, who are already registered as such, utilising energy storage was discussed in the previous two chapters of this report.

One specific instance in which the use of storage assets could require parties to register as a network service provider (who are not otherwise so registered) is if they are providing a storage facility to multiple generators as part of providing a connection to the transmission network. (This might be an attractive model for smoothing intermittent generation from multiple wind farms, for instance). While the NER make clear that the provision of connection assets alone does not constitute a distribution system, the same exclusion is not made in respect of the transmission system. The AEMC is due to consider the issue of how dedicated transmission connection assets should be treated as part of a pending rule change.[156]

Whether a storage system could fall within the scope of this definition should be explored to consider whether any uncertainty arises over whether it could provide such services and, if so, whether the ownership of a storage system connected to the transmission system for this purpose is something that should be subject to registration (or exemption from registration).

154 Again, for small customers, the level of generation they will be using is likely to be at the micro level, or otherwise be very small, and so not require registration.

155 See Appendix K.4.

156 See: http://www.aemc.gov.au/Rule-Changes/Transmission-Connection-and-Planning-Arrangements.

Consultation questions

- **Is more clarity required in the definition of a 'generating unit'? If so, what changes would be necessary? How would such changes be necessary to preserve the registration requirements and eligibility criteria currently in place for generators?**
- **Are current registration requirements appropriate for storage that may be used both as generation and load? Should a person operating storage to both buy and sell electricity through the spot market be required to register as both a market customer and a generator?**

5.2 Connection

The connection arrangements set out in the NER establish the obligations and processes by which generators and customers connect to a transmission or distribution system. The connection process and technical requirements applicable to the connection of a storage device will depend on a number of factors, including whether the storage device:

- constitutes an alteration to an existing connection or a new connection;
- is connected to a transmission or distribution network; and/or
- is directly connected to the network or constitutes part of a generating system (eg, at a wind farm).

The regulatory framework for connecting larger-scale generation, embedded generation and load – that is, registered participants – is set out in Chapter 5 of the NER.[157]

5.2.1 Connection of a generating unit

Generating units can range in size from a few kilowatts to hundreds of megawatts, and include coal-fired units and wind farms. The regulatory framework for the connection of generating units is used to help AEMO and network service providers coordinate the interaction between generation and the rest of the power system so that the quality, reliability and security of supply can be maintained.[158]

AEMO is involved in all stages of the connection process for generators seeking to connect to a transmission network in Victoria. The connecting TNSP manages the connection process in all other NEM jurisdictions, with AEMO involved in the

157 Chapter 5 connection processes are summarised in Appendix L of this report. Chapter 5A connection processes for non-registered participants are summarised in Appendix B and discussed in relation to storage in section 2.1of this report.

158 AEMO, Connecting new generation - A process overview, 2011, p5.

assessment and negotiation of certain proposed performance standards and the completion stage of the process. Similarly for distribution networks, the connecting DNSP manages the connection process, with some involvement from AEMO

Connection arrangements in Chapter 5 (Part A) of the NER apply to registered participants (and those exempted from registration but with generation capacity exceeding 5MW) seeking to make a connection to the network, including generators seeking to connect to a transmission or distribution network. Of relevance to energy storage that is connecting to the network as a generator, or forming part of an existing generator connection:

- A generator proposing to alter a connected generating system in a manner that will affect technical performance has to submit information to the network service provider and AEMO, including a description of the alteration and proposed amendments to automatic access standards or negotiated access standards.

- Each generating unit must meet a number of technical requirements. The technical requirements describe how a generating unit should perform under a range of conditions imposed by the power system, or by the generating unit on the power system. They form part of the technical terms and conditions of the generating unit's connection agreement with the network service provider.

- As part of the connection process, an applicant is required to submit its proposed performance standards for the generating system. An access standard is a benchmark for determining the appropriate performance standard for each generating unit. Schedules to Chapter 5 set out automatic and minimum access standards. Most performance standards are negotiated. Once performance standards are agreed by AEMO, the connecting DNSP or TNSP and the applicant, they become the agreed performance standards for the generating system.

- There are different connection processes for generators and embedded generators. Once a connection application is complete, the connecting network service provider prepares an offer to connect. The offer to connect is a formal part of the connection process that includes finalised performance standards agreed between AEMO, the connecting network service provider and the generator.

- The equipment associated with each generating system must be designed to withstand without damage the range of operating conditions which may arise consistent with the system standards, including those for frequency, system stability, voltage and fault clearance times.

These requirements raise a number of questions in relation to storage, including:

- whether the performance standards/technical requirements set out in the rules are appropriate or even applicable for a storage device that is connecting as a standalone generating system or as a generating unit within a generating system;

- whether the negotiation process is suitable for determining standards as they relate to storage; and
- whether the time frames allowed for in the negotiation process are sufficient for the connection of storage capability.

5.2.2 Connection of a load

If a storage device is to be treated as a load, consideration will need to be given as to whether the existing standards for connection of load (set out in schedules to the NER) are appropriate or even applicable to storage devices.

Consultation questions

- **Do you see any issues with the current connections framework? For storage as a generator? For storage as a load?**
- **Do performance standards represent a barrier to storage connection? For storage as a generator? For storage as a load?**

5.3 Charges

This section sets out the existing regulatory framework as it relates to the charges payable by a registered participants, including generators, customers and small generation aggregators.

Chapter 2 of the NER set out the types of fees payable by registered participants. Registered participants may be subject to a range of fees and costs as a result of their registration, including:

- **Registration fees.** All applicants for registration in the NEM must pay a registration fee in accordance with AEMO's published fee schedule.[159]
- **Connection costs.** Connection applicants negotiate the payment of connection costs, use of system charges and access charges with the connecting DNSP/TNSP.[160] If a storage device influences the level of augmentation or upgrade required for a new or existing connection, the connection charges negotiated should reflect this. AEMO will recover its costs through the connecting DNSP/TNSP, who will invoice the applicant directly.
- **Participant fees.** AEMO charges registered participants fees to recover its budgeted revenue requirements. The NER states that the components of participant fees charged to each registered participant should be reflective of the

159 AEMO, NEM Registration Checklists, p4.

160 A NSP's connection offer must define the basis for determining transmission and distribution service charges and conform to the relevant access arrangements under the rules (rule 5.4A of the NER for transmission networks and rule 5.5 of the NER for distribution networks).

extent to which the budgeted revenue requirements for AEMO involve that registered participant.[161] As such, the fees differ between categories of registered participant.

- **Ancillary services payments.** AEMO recovers the costs of acquiring ancillary services, eg, frequency and network control services, from market participants.[162] A market participant is a person who is registered as a market generator, market customer, market small generation aggregator or market network service provider. The costs may vary from week to week as there is no fixed rate for ancillary services.

- **DUOS/TUOS charges.**

  — A generator will not pay transmission use of system (TUOS) charges if the generating system is connected to transmission network, unless it is a non-market generator or exempt from registration. A generator will pay distribution use of system (DUOS) charges if the generating system is connected to a distribution network either directly or behind the meter at a load.

  — A customer will pay DUOS or TUOS charges depending on what network its load is connected to.

- **Loss factor payments.** Loss factors are calculated and fixed annually to facilitate efficient scheduling and settlement processes in the NEM. Each generating unit/load will have a transmission loss factor (TLF) and will also have a distribution loss factor (DLF) if it is connected to a distribution network.

  — If a storage device is transmission connected and registered as a both a generating unit and a load, the NER now allows for dual loss factors to apply (one for the generating unit, one for the load).

  — If a storage device is distribution connected and registered as a both a generating unit and a load, the DNSP may need to amend its methodologies for calculating the DLF. If this does not produce sufficiently efficient DLFs, it may be necessary to consider a rule change to also allow dual DLFs.

- **Prudential requirements.** As part of the registration process, registered participants are required to satisfy the prudential requirements, including credit support requirements, set out in the NER.[163]

The category in which a party registers to participate in the NEM (whether as generation or load) will have flow-on effects with regard to the payment of registration costs, participant fees, ancillary service payments, TUOS/DUOS and prudential

161 Clause 2.11.1 of the NER.

162 Section 5.4.3 explains in more detail how the costs of acquiring ancillary services are recovered.

163 See rule 3.3 of the NER.

requirements. The differing obligations under the rules may create perverse incentives for parties to register in a particular way if the category in which they should be registered is not clear cut.

Consultation questions

- **Is there anything unique about the use of storage devices that makes the existing arrangements regarding fees/charges for participation in the NEM not fit for purpose?**

5.4 Provision of ancillary services

Ancillary services are those used by AEMO to manage the power system safely, securely and reliably. These services maintain key technical characteristics of the system, including standards for frequency, voltage, network loading and system restart processes.[164] The regulatory framework underlying the provision of ancillary services is summarised in Appendix M.

Only market participants are able to provide ancillary services. As such, the owner/operator of a storage device would not be able to provide ancillary services unless it is a registered participant and further classified as a market participant. A market generator with relevant capabilities can classify a generating unit as an ancillary service generating unit. Similarly, a market customer with relevant capabilities can classify its market load as an ancillary service load.

As noted above, a storage system that exports to the grid falls within the definition of generating unit, and so is eligible for registration as an ancillary service generating unit.

Energy storage has technical characteristics that may make it suitable for providing:

- network support and control ancillary services (NSCAS); and
- frequency control ancillary services (FCAS).

It has been suggested that in the future, energy storage could also be used for providing system restart services[165] and that a very fast response frequency control service could act as a substitute for inertia in a power system with a predominance of non-synchronous generation.

5.4.1 Network support and control ancillary services (NSCAS)

Network support and control ancillary services (NSCAS) are used to maintain power system security and reliability, and the power transfer capability of the transmission network. NSCAS consists of three main services: voltage control, network loading and

164 AEMO, Guide to ancillary services in the National Electricity Market, 2010, p3.

165 International Energy Agency, Energy Technology Perspectives 2014, p248.

stability control. Various pieces of equipment can be installed, or equipment operating regimes implemented, to provide these services.[166]

NSCAS can be delivered by a range of service providers using a range of power system facilities. This could include services provided by demand-side participants, including control of customer load in response to certain signals, or installation or utilisation of existing small scale generation.[167]

As market participants, market generators, market customers and small generation aggregators can tender for the provision of NSCAS and SRAS.

5.4.2 Market ancillary services

Market ancillary services consist of frequency control ancillary services (FCAS). FCAS are used by AEMO to maintain the frequency on the electrical system, at any point in time, close to fifty cycles per second as required by the NEM frequency standards. There are two types of FCAS: regulation and contingency.

Only market generators and market customers can provide market ancillary services. As such, small generation aggregators are unable to provide FCAS. This restriction may cut off a potential value stream available to a small generation aggregator combining the capability of a number of small storage systems

5.4.3 Payment for ancillary services and recovery of costs

Consultation questions

- **What are the implications of current arrangements for ancillary service provision and cost recovery for storage?**
- **Are there other services that could potentially be provided by storage – such as a substitute for inertia through very fast response services – and does a lack of a market for these represent a potential barrier or opportunity?**

5.5 Preliminary findings

The analysis has led the AEMC to make the following preliminary findings:

1. We do not see the need for a new category of registered participant to be introduced for persons operating a storage device. A person seeking to participate in the NEM using a storage device should be registered according to the value stream from the storage device in relation to which that person intends

166 AEMC, System restart ancillary services, rule determination, 2 April 2015, p103.

167 AEMO, NSCAS description and NSCAS quantity procedure, issues paper, 2011, p5.

to participate in the NEM. This would mean that the owner/operator of a storage device could be registered as a generator, customer, or both.

2. AEMO will need to be satisfied that the person intending to register can comply with the associated requirements of that role. It is not yet clear whether the obligations and requirements for each category of registered participant under the NER are appropriate to the operation of the storage device. For example, the following issues will need to be worked through:

   (a) whether the relevant technical standards are appropriate for the connection of a storage device;

   (b) whether the thresholds for registration continue to be appropriate in the context of storage;

   (c) the implications of registering in more than one category of registered participant, eg, participant fees, prudential requirements and other financial obligations.

Consultation questions

- **Do you agree with these preliminary findings?**
- **Are there other issues which should be considered?**

A Related Work

This report is intended to complement the range of work being undertaken by other parties in this area. Some of these projects are set out in the table below

Table A.1 List of related projects relevant to this report

Project proponent	Project Title	Description of project
COAG Energy Council - DSP Working Group	New products and services in the electricity market	The purpose of this work is to determine whether the existing regulatory framework is appropriate in the context of new products and services being offered to small customers, including embedded generation storage. A consultation paper was published in December 2014. A paper was submitted to the COAG Energy Council for its consideration in July 2015, after which COAG officials were tasked with further work to: • investigate whether the scope of existing energy consumer protections require change in light of consumers having an increasing range of electricity supply options; and; • identify options to manage any risks to power system operations where aggregators are controlling large amounts of load.[168]
COAG Energy Council - Network Strategy Working Group	Strategic assessment of network regulation	The purpose of this work is to conduct a strategic assessment of the adequacy of the current network regulation framework to accommodate future market and technological changes under four possible scenarios. A paper was submitted to the COAG Energy Council for its consideration in July 2015, after which COAG officials were tasked with further work to explore the implications of the issues that emerged from the stress-testing exercise, including: • network asset under-utilisation; • network incentives to invest and innovate; and • the frameworks needed to support competitive markets in alternative services.[169]
AER	Regulating innovative energy selling business models under the NERL	The AER is looking at the business models of alternative energy sellers, specifically those brought about by technological innovation, and the impacts that these may have on how energy is retailed to customers. It is also assessing the policy implications for the AER's regulation of this segment of the market options for future regulation. The AER plans to finalise the outcomes of this work in 2015.

168 COAG Energy Council, Meeting communique, 23 July 2015, p4.

169 Ibid.

Project proponent	Project Title	Description of project
AER	Ring-fencing guideline	In 2012 the AER signalled its intention to review ring-fencing arrangements for DNSPs and harmonise the various state-based ring-fencing guidelines into a single, national guideline.[170] The draft rule for the competition in metering and related services rule change, published in March 2015, would require the AER to develop ring-fencing guidelines for the separation of a DNSP's provision of direct control services from the provision of other services.[171]
Clean Energy Council	Australian energy storage roadmap	The roadmap, published April 2015, outlines a program of initiatives to better define and address the safety, environmental, technical, commercial and informational barriers to the deployment of energy storage technologies - large and small scale.[172]
AEMO	Emerging technologies report	AEMO is now taking initial steps to incorporate storage facilities into its normal business processes. In July 2015, AEMO published this paper as a companion to the National Electricity Forecasting Report (NEFR). The report contains an initial analysis of the potential uptake of storage devised in association with new build rooftop PV facilities.[173]
AEMO	National Transmission Network Development Plan	AEMO is exploring a range of scenarios as part of the scenario analysis for its 2015 National Transmission Network Development Plan. One of these scenarios includes high penetrations of distributed generation and residential storage. This plan will be released by the end of the year.
AEMO	Registration requirements	AEMO is examining the regulatory arrangements applicable to registration under the National Electricity Rules of a storage device.

170 See https://www.aer.gov.au/node/12493.

171 See http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv.

172 See http://www.cleanenergycouncil.org.au/cec/policy-advocacy/storage-roadmap.

173 See http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/NEFR-Supplementary-Information.

B Connection processes for small users

The NER establish a framework for the connection of generation or loads to an electricity network. This appendix sets out the requirements under Chapter 5A for small-scale electricity end-users seeking to connect to a distribution network in the NEM.[174]

B.1 The application of Chapter 5A

The connection framework in Chapter 5A of the NER applies to parties that are not registered participants, specifically:

- retail customers;
- micro-embedded generators (eg, retail customers with residential rooftop solar systems); and
- embedded generator proponents seeking to connect a system of less than the standing exemption to register as a registered participant with AEMO (currently 5 MW).

The requirements of Chapter 5A of the NER only apply in those jurisdictions that have adopted the NECF.[175]

A 'retail customer' is a customer who has a relationship with an authorised retailer.[176] Customers that do not fall within this definition (e.g. those in embedded networks) do not need to use the connection process set out in Chapter 5A of the NER when installing storage because they are already connected to the network.

The connection requirements in Chapter 5A cover both the establishment of a new connection and an alteration to an existing connection. A connection alteration is defined in Chapter 5A as "an alteration to an existing connection including an addition, upgrade, extension, expansion, augmentation or any other kind of alteration".[177]

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174 Appendix L of this report sets out the regulatory framework for generating systems connecting to a transmission network, and generating systems greater than the standing exemption to register as a market participant with AEMO connecting to a distribution network.

175 All NEM jurisdictions except Victoria have adopted the NECF . Until NECF applies in Victoria, connection takes place in accordance with local instruments, DNSP specific processes or, in the case of non- registered embedded generators, under the purpose specific connection process under Chapter 5.

176 The term 'retail customer' is defined in section 2 of the NEL as "a person to whom electricity is sold by a retailer, and supplied in respect of connection points, for the premises of the person, and includes a person (or a person who is of a class of persons) prescribed by the Rules for the purposes of this definition". The term 'retailer' is defined in section 2 of the NEL as "a person who is the holder of a retailer authorisation issued under the National Energy Retail Law in respect of the sale of electricity".

177 Rule 5A.A.1 of the NER.

Under the deemed standard connection contract[178] between small customers and their connecting distribution network service provider (DNSP) for supply services, customers must, among other things, inform the DNSP of any proposed change in plant or equipment, including metering equipment, or any change to the capacity or operation of connected plant or equipment that may affect the quality, reliability, safety or metering of the supply of energy to the premises or the premises of any other person.[179]

The consequence of these arrangements for retail customers is that they are required to go through the connection process with their connecting network service provider to establish a new connection to the network (eg, when building a new house) or to amend an existing connection (eg, to add a solar PV system to their existing connection).

Both micro-embedded generators[180] and non-registered embedded generators[181] also use the connection process in Chapter 5A. Central to both definitions is the definition of an embedded generating unit:

> "A *generating unit* connected within a *distribution network* and not having direct access to the *transmission network*."

To assist the connection process, DNSPs are required to publish information on their websites relevant to the specifics of connecting to their network[182]and a register of completed embedded generation projects.[183] The connection process is otherwise prescribed in Chapter 5A, as set out below.

B.2 Process for connection under Chapter 5A

There are a number of steps in the connection process for a micro-embedded generator, which are covered in detail below:

1. **Preliminary enquiry.** A connection applicant may make a preliminary enquiry to the DNSP in relation to the connection of a micro-embedded generator. The NER set out obligations on DNSPs in regard to preliminary enquiries to help the applicant make an informed connection application.[184]

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178 These contracts are deemed under section 70 of the NERL.

179 Clause 6.2 of the deemed connection contract in Schedule 2 of the NERR.

180 Defined in clause 5A.A1 of the NER as "a retail customer who operates, or proposes to operate, an embedded generating unit for which a micro EG connection is appropriate". A *micro EG connection* means "a connection between an embedded generating unit and a distribution network of the kind contemplated by Australian Standard AS 4777 (Grid connection of energy systems via inverters)"

181 Defined in clause 5A.A1 of the NER as "an embedded generator that is neither a micro-embedded generator nor a Registered Participant". An embedded generator is "a person that owns, controls or operates an embedded generating unit."

182 Clause 5A.D.1 of the NER.

183 Clause 5A.D.1A. of the NER . See also Section 2.1.3 of this report.

184 See rule 5A.D.2 of the NER.

2. **Connection application.** The applicant must make an application to the DNSP for a connection service (which includes connecting to the network or seeking an alteration to an existing connection). This requires the applicant to provide certain information in relation to the proposed connection or connection alteration. The NER set out the process for and obligations on parties regarding the connection application.[185] DNSPs charge customers a fee to process connection applications, which are set out in the DNSP's annual pricing proposals and approved by the AER.

3. **Connection offer.** The type of connection offer made to an applicant will depend on the nature of the service required. A DNSP must make a connection offer to the applicant if the connection service sought is a basic connection service or a standard connection service (and the applicant does not elect to apply for a negotiated connection contract). The NER sets out the timing and requirements of the connection offer.[186]

4. **Connection contract.** A connection contract is formed by the making and acceptance of a connection offer.[187] If a connection offer to provide a connection service is accepted by the applicant, the terms and conditions of the connection offer become terms and conditions of a connection contract between the DNSP and the applicant.[188]

5. **Connection services.** Connection services are the services provided by the DNSP to connect the applicant to the network. They include services relating to the establishment of a new connection at the premises and an alteration to an existing connection. Connection services are discussed in more detail below.

B.3 Connection services

There are three types of connection services within Chapter 5A for parties seeking to connect to the distribution network:

- basic connection services;
- standard connection services; and
- negotiated connection services for retail customers and non-registered embedded generator proponents not covered by a basic or standard connection offer, or those that elect to use this option.[189]

185 See rule 5A.D.3 of the NER.

186 See rule 5A.F.1 of the NER.

187 Clause 5A.F.5 of the NER

188 Clause 5A.F.5(a)(1) of the NER.

189 See section 2.1.1

B.3.1 Basic connection services

Basic connection services are defined in the NER as:

> "a connection service related to a connection (or a proposed connection) between a distribution system and a retail customer's premises (excluding a non-registered embedded generator's premises) in the following circumstances:
>
> (a) either:
>
> 1. the retail customer is typical of a significant class of retail customers who have sought, or are likely to seek, the service; or
>
> 2. the retail customer is, or proposes to become, a micro-embedded generator; and the provision of the service involves minimal or no augmentation of the distribution network; and
>
> (b) the provision of the service involves minimal or no augmentation of the distribution network; and
>
> (c) a model standing offer has been approved by the AER for providing that service as a basic connection service.[190]"

Basic connection services are generally provided to retail customers and micro-embedded generators where there is minimal or no network augmentation required. DNSPs are required to submit, for the AER's approval, a proposed model standing offer to provide basic connection services for each class (or subclass) of basic connection services on specified terms and conditions.[191] The NER sets out a number of factors that the terms and conditions of the proposed model standing offer must cover.[192]

If the service is a basic micro-embedded generation connection service, the terms and conditions of the proposed model standing offer must cover particular requirements with regard to the export of electricity to the distribution system. These include:

- the special requirements for metering and other equipment for the export of electricity;
- the required qualification for installers of relevant equipment (including reference to the jurisdictional or other legislation and statutory instruments under which the qualifications are required); and
- the special safety and technical requirements (including reference to the jurisdictional or other legislation and statutory instruments under which they are

190 Rule 5A.A.1 of the NER.

191 Rule 5A.B.2(a) of the NER.

192 Rule 5A.B.2(b) of the NER.

imposed) to be complied with by the provider of a contestable service or the retail customer (or both).[193]

B.3.2 Standard connection services

Standard connection services are defined in the NER as:

> "a connection service (other than a basic connection service) for a particular class (or sub-class) of connection applicant and for which a model standing offer has been approved by the AER.[194]"

Standard connection services are generally provided to retail customers and embedded generator proponents that are not covered by a basic connection but for which there is an AER approved model standing offer, e.g. if network augmentation is required to enable connection to the network. DNSPs may submit, for the AER's approval, a proposed model standing offer to provide standard connection services on specified terms and conditions.[195] The NER sets out a number of factors that the terms and conditions of the proposed model standing offer must cover.[196]

B.3.3 Negotiated connection services

The NER provides that:

> "A connection applicant and a DNSP may negotiate a connection contract (a negotiated connection contract):
>
> 1. here the connection service sought by the connection applicant is neither a basic connection service nor a standard connection service; or
>
> 2. where the connection service sought by the connection applicant is a basic connection service or a standard connection service but the connection applicant elects to negotiate the terms and conditions on which the connection service is to be provided.[197]"

Negotiated connection services are generally provided to retail customers, micro-embedded generators and non-registered embedded generator proponents not covered by one of the DNSP's basic or standard connection offers. However, applicants are entitled to negotiate a connection offer even if the DNSP has an appropriate model standing offer for basic or standard connection services. The negotiated connection process allows the applicant to negotiate the terms, conditions and/or charges of the

193 Rule 5A.B.2(7) of the NER.

194 Rule 5A.A.1 of the NER.

195 Rule 5A.B.4(a) of the NER.

196 Rule 5A.B.4(c) of the NER.

197 Rule 5A.C.1(a) of the NER.

connection service. The minimum content requirements that a connection offer for embedded generation (and so the basis for a connection contract) are set out in Schedule 5A.1. Part C of Chapter 5A of the NER provides the negotiation framework and process to establish a negotiated connection contract. In addition to any applicable connection application fees for the negotiated connection service, the applicant may be required to pay capital contributions for network extensions or augmentation to enable their connection to the distribution network.

C Retailer authorisation

The legislative and regulatory framework applicable to electricity retailers in Australia is set out in:

- the National Electricity Law (NEL) and National Electricity Rules (NER);
- the National Energy Customer Framework (NECF); and
- the Australian Consumer Law (ACL) and State and Territory consumer laws.

This framework was developed in the context of the regulation of the traditional energy services value chain. At the heart of this framework is the principle that consumers have a right to access energy (as an essential service) on fair and reasonable terms.

Sellers of energy and energy related services are regulated as follows:

- All energy service providers in Australia are covered by the ACL.
- Retailers with obligations in the NEM are required to be registered with AEMO.
- Energy service providers that sell energy for use at premises in jurisdictions where the NECF applies are required to be authorised as a retailer under the NECF unless exempted by the AER.
- In jurisdictions where the NECF does not apply, a state agency such as the Victorian Essential Services Commission (ESC) grants licenses to electricity and gas retailers and distributors, or exempts them from this requirement.
- If an energy service provider is regulated under the NECF and is an authorised retailer, or is licensed by a state agency, it must participate in jurisdictional ombudsman schemes in the jurisdictions in which it operates.

C.1 The National Electricity Law and Rules

The NEL and NER establish the wholesale electricity market, define power system security roles and obligations, apply an economic regulation framework and connections framework to electricity networks (as monopoly services), and define metering arrangements.

Parties that have roles and obligations in the NEM must be registered and/or accredited with AEMO. Some parties are also required to register with AEMO because they could affect power system security, even if they are not operating in the wholesale market.

The NEL and NER also allow for some parties to be exempted because their circumstances mean that the full regulatory framework is not appropriate, or would be costly to apply in return for little benefit. For example: embedded networks, and generators below 5 MW (and not selling into the NEM), which are normally too small to affect power system security.

A retailer must be registered as a market participant under the NER, and will be “financially responsible” under the NER for any connection points that connect its market loads. The credit risk associated with a retailer’s load is managed through the AEMO credit support requirements set out in the NER. If a retailer cannot meet minimum credit criteria, they must post credit support to AEMO.

C.2 National Energy Customer Framework

The NECF establishes consumer protections and obligations in relation to the sale and supply of electricity and gas to consumers, with a particular focus on residential and small customers. These consumer protections complement and operate alongside the generic consumer protections in the ACL. The NECF must be consistent with the ACL and not alter its effect.

The NECF is a suite of legal documents comprising the National Energy Retail Law (NERL), the National Energy Retail Regulations (Regulations) and the National Energy Retail Rules (NERR). Parts of the NECF are also contained in chapters of the NER and National Gas Rules (NGR).

The NERL is contained in the schedule to the South Australian National Energy Retail Law (South Australia) Act 2011. It is implemented in each participating jurisdiction by an application of laws mechanism.

Currently the NECF applies in New South Wales, South Australia, Tasmania, Queensland and the Australian Capital Territory.[198] Each State and Territory modified the application of parts of the NECF when it was implemented, resulting in different rights and obligations applying in each participating jurisdiction.

C.2.1 Application of the NECF

Parties are drawn into the NECF through a registration and exemption framework, depending on the products and services offered. If a business intends to sell electricity or gas for use at premises, it must have a retailer authorisation granted by the AER, or be exempted by the AER from needing an authorisation.[199]

The obligations and rights under the NECF attach to the relationship between retailer and small customer, and sometimes to the relationship between distributor and small customer. A customer is “a person to whom energy is sold for premises from a

198 That is, in all NEM jurisdictions except for Victoria.

199 National Energy Retail Law, section 88.

retailer". A retailer is "a person who holds a retail authorisation", and a distributor is an entity regulated as such under the NEL, NGL or NERL.[200]

A retailer authorisation under the NERL allows a business to sell a specific form of energy (gas or electricity) to all classes of customer, in all jurisdictions where the NERL has commenced. To obtain a retailer authorisation, a business must apply to the AER and demonstrate: the necessary organisational and technical capacity to operate as a retailer; the necessary financial resources, or access to resources, to operate as a retailer; and that it is a suitable person to hold a retailer authorisation.

This recognises that a retailer must have the appropriate financial and organisational capacity to provide energy to customers and to meet all compliance and regulatory obligations under the NERL.

C.2.2 Purpose of the NECF

The purpose of NECF is to create a unified framework to regulate the sale of energy to customers and enhance consumer protection. Under the NECF, residential and small business customers are supported by a range of energy specific customer protections which exist alongside the generic consumer protections in the ACL. These protections include:

- guaranteed customer access to an offer of supply for electricity and gas;
- prescribed terms and conditions for standard retail contracts and mandatory minimum requirements for market retail contracts;[201]
- information disclosure and explicit informed consent requirements on entry into market retail contracts that build on the requirements set out in the ACL and provisions holding retailers accountable for marketing conducted on their behalf;
- a customer hardship regime, requiring retailers to develop customer hardship policies that must be approved by the AER, with certain prescribed elements, to assist residential customers experiencing longer-term payment difficulties;
- limitations on disconnection, including the processes that must be followed, restrictions on when disconnections can occur, additional protections for customers experiencing hardship or financial difficulties, and a prohibition on disconnecting premises where life support equipment is required;
- information requirements for planned and unplanned interruptions;

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200 That is, a regulated distribution system operator under the NEL, a service provider who owns, operates or controls a distribution pipeline that is a covered pipeline under the NGL, or a nominated distributor under section 12 of the NERL.

201 Some retailers are required to offer *standard retail contracts*. Their terms and conditions are largely prescribed in the NERR. In some jurisdictions the price of energy sold under standard retail contracts is also regulated. Market retail contracts are all retail electricity or gas contracts that are not standard retail contracts.

- a requirement on retailers and distributors to have, and inform customers of, complaints procedures;
- the retailer of last resort (ROLR) scheme which ensures continuity of supply in the event of retailer insolvency or failure by requiring other retailers to be available to service consumers at short notice; and
- a requirement that authorised retailers report to the AER on their performance against defined indicators and on certain breaches of the NERL and NERR.

C.3 Australian Consumer Law

The ACL is a harmonised national set of laws covering consumer protection and fair trading. It is applied as a law of the Commonwealth, and each State and Territory, and is administered by the Australian Competition and Consumer Commission (ACCC) and State and Territory's consumer law agencies.

The ACL applies generally to arrangements between persons (including businesses) engaged in trade or commerce and consumers. Under the ACL a consumer is a person who acquires goods or services for less than $40,000 or where the goods or services are of a kind ordinarily acquired for personal, domestic or household use.[202] It also applies in a number of other specific circumstances. For example, it applies in relation to the terms and conditions of certain types of contract between businesses and consumers (consumer contracts).

The consumer protection regime provided under the ACL includes:

- a prohibition on misleading or deceptive conduct in trade or commerce;
- a prohibition on unconscionable conduct in trade or commerce and in consumer transactions;
- voiding unfair contract terms in standard form consumer contracts;[203]
- regulating unsolicited sales practices, including door to door selling, telephone sales and other forms of direct selling;[204]
- a single set of consumer guarantees when a consumer acquires goods and services that are supplied in trade or commerce;[205] and

202 This definition is subject to a limited number of exceptions. See section 3 of the ACL.

203 Consumer contracts are "standard form agreements for the supply of goods or services which is wholly or predominantly for personal, domestic or household use or consumption.

204 The ACL imposes obligations on sellers in how they approach customers including disclosures that have to be made about the making of contracts, consumer rights and obligations, a 10-day mandatory cooling off period and a right for the customer to terminate after the cooling off period in certain circumstances as well as regulating calling times.

- a national regime dealing with safety of consumer goods and product related services.

Remedies for breach of the ACL can include either common law remedies (such as damages, injunctions, compensatory orders, etc.) or civil penalties. The maximum civil penalties under the ACL are significantly higher than under the retail energy laws.[206]

205 For example guarantees of legal title, undisturbed possession, acceptable quality and fit for purpose. Services also have guarantees of due care and skill, fitness for purpose, and of reasonable time for supply.

206 Civil penalties under the ACL range from $50,000 to $1.1 million for bodies corporate. Under the NERL the maximum civil penalty for a body corporate is $100,000 plus $10,000 for every day during which the breach continues.

D Standards for end-user storage devices

In April 2015, the Clean Energy Council published an Australian energy storage roadmap, which outlines a program of initiatives to better define and address the safety, environmental, technical, commercial and informational barriers to the deployment of both large and small scale energy storage technologies.[207] The roadmap outlines several areas of work that relate to the development of standards and guidelines to make sure Australia has appropriate standards, accreditation programs and product stewardship in place to support the uptake of storage, specifically:

- Installation guidelines and accreditation

  While there are rigorous guidelines for the installation of solar PV in Australia, the Clean Energy Council notes that there are currently no consistent guidelines on storage for installers to follow or for consumers to use to give them confidence. This initiative will develop guidelines for the safe and correct installation of residential and commercial storage technology, and will also establish an accreditation regime to ensure these guidelines are followed by Australian installers.

- Technology standards

  The Clean Energy Council notes that there is no clear guidance on technology standards for storage devices. The Clean Energy Council will work with Standards Australia to establish standards for storage technology and develop a listing of products approved for installation in Australia.

207 Clean Energy Council, Australian Energy Storage Roadmap, April 2015.

E Network service classification

E.1 Transmission service classification

'Prescribed transmission services' are subject to building block regulation under the NER. The definition of prescribed transmission service is:

> "Any of the following services:
>
> (a) a shared transmission service[208] that:
>
> (i) does not exceed such network performance requirements (whether as to quality or quantity) as that shared transmission service is required to meet under any jurisdictional electricity legislation;
>
> (ii) [..];
>
> (b) services that are required to be provided by a Transmission Network Service Provider under the Rules, or in accordance with jurisdictional electricity legislation, to the extent such services relate to the provision of the services referred to in paragraph (a), including such of those services as are:
>
> (i) required by AEMO to be provided under the Rules, but excluding those acquired by AEMO under rule 3.11; and
>
> (ii) necessary to ensure the integrity of a transmission network, including through the maintenance of power system security and assisting in the planning of the power system; or
>
> (c) connection services that are provided by a Transmission Network Service Provider to another Network Service Provider to connect their networks where neither of the Network Service Providers is a Market Network Service Provider,
>
> but does not include a negotiated transmission service or market network service.[209]"

208 A 'shared transmission service' is a service provided to a Transmission Network User for use of a transmission network for the conveyance of electricity (including a service that ensures the integrity of the related transmission system). See Chapter 10 of the NER under 'shared transmission service'.

209 Chapter 10 of the NER under 'prescribed transmission service'.

E.2 Distribution service classification

The starting point for distribution service classification is the definition and identification of a distribution service. The NER defines a distribution service as:

> "a service provided by means of, or in connection with, a distribution system.[210]"

It defines a distribution system as:

> "a distribution network, together with the connection assets associated with the distribution network, which is connected to another transmission or distribution system. [..][211]"

A distribution network is defined as:

> "a network which is not a transmission network.[212]"

Finally, a network is defined under the NER as:

> "the apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity to customers (whether wholesale or retail) excluding any connection assets. In relation to a Network Service Provider, a network owned, operated or controlled by that Network Service Provider.[213]"

The NER allows a distribution service to be classified as a direct control service or a negotiated distribution services.

- A direct control service is defined in the NER as "a distribution service that is a direct control network service within the meaning of section 2B of the Law".[214] Section 2B of the NEL defines a direct control network service as:

  "an electricity network service:

  (a) the Rules specify as a service the price for which, or the revenue to be earned from which, must be regulated under a distribution determination or transmission determination; or

  (b) if the Rules do not do so, the AER specifies, in a distribution determination or transmission determination, as a service the price

210 Chapter 10 of the NER under 'distribution service'.

211 Chapter 10 of the NER under 'distribution system'.

212 Chapter 10 of the NER under 'distribution network'. The definition of transmission network is set out in Chapter 10 of the NER under 'transmission network'.

213 Chapter 10 of the NER under 'network'.

214 Chapter 10 of the NER under 'direct control service'.

for which, or the revenue to be earned from which, must be regulated under the distribution determination or transmission determination."

- A negotiated distribution service is defined in the NER as "a distribution service that is a negotiated network service within the meaning of section 2C of the Law".[215] Section 2C of the NEL defines a negotiated network service as:

  "an electricity network service:

  (a) that is not a direct control network service; and

  (b) that:

  (i) the Rules specify as a negotiated network service; or

  (ii) if the Rules do not do so, the AER specifies as a negotiated network service in a distribution determination or transmission determination."

Clause 6.2.2 of the NER requires further sub-classification of direct control services into standard control services or alternative control services.

- A standard control service is defined in the NER as "a direct control service that is subject to a control mechanism based on a Distribution Network Service Provider's total revenue requirement".[216]

- An alternative control service is defined in the NER as "a distribution service that is a direct control service but not a standard control service".[217]

A service falling outside the classifications of a direct control service or a negotiated distribution service is left unclassified and not subject to economic regulation. Although not defined by the NER, the AER typically refers to these services as unclassified services.

The AER is required to have regard to a number of factors when classifying distribution services into direct control services, negotiated services or choosing to leave a service unclassified, including:

- the form of regulation factors (see Box Box E.1);

- the form of regulation (if any) previously applicable to the relevant service or services and, in particular, any previous classification under the present system of classification or under the previous regulatory system;

- the desirability of consistency in the form of regulation for similar services; and

215 Chapter 10 of the NER under 'negotiated distribution service'.

216 Chapter 10 of the NER under 'standard control service'.

217 Chapter 10 of the NER under 'alternative control service'.

- any other relevant factors.[218]

Box E.1 Form of regulation factors

The form of regulation factors are:

- the presence and extent of any barriers to entry in a market for electricity network services;
- the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other electricity network service provided by the network service provider;
- the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other service provided by the network service provider in any other market;
- the extent to which any market power possessed by a network service provider is, or is likely to be, mitigated by any countervailing market power possessed by a network service user or prospective network service user;
- the presence and extent of any substitute, and the elasticity of demand, in a market for an electricity network service in which a network service provider provides that service;
- the presence and extent of any substitute for, and the elasticity of demand in a market for, electricity or gas (as the case may be); and
- the extent to which there is information available to a prospective network service user or network service user, and whether that information is adequate, to enable the prospective network service user or network service user to negotiate on an informed basis with a network service provider for the provision of an electricity network service to them by the network service provider.[219]

Once it has determined how to classify the distribution service, the AER must further classify a direct control service as either a standard control service or an alternative control service. In doing so, the AER must have regard to:

- the potential for development of competition in the relevant market and how the classification might influence that potential;

218 Clause 6.2.1(c) of the NER.

219 Section 2F of the NEL.

- the possible effects of the classification on administrative costs for the AER, the DNSP and user or potential users;
- the regulatory approach applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made;
- the desirability of a consistent regulatory approach to similar services;
- the extent the costs of providing the relevant service are directly attributable to the person to whom the service is provided; and
- any other relevant factors.[220]

220 Clause 6.2.2(c) of the NER.

F Network revenue regulation

F.1 Capex forecasts

The regulatory framework establishes the capex requirements that a network business must include as part of its regulatory proposal. Specifically, the NER states that:

- a TNSP's revenue proposal must include the total forecast capex for the relevant regulatory control period which TNSP considers is required in order to meet or manage the expected demand for prescribed transmission services over that period;[221] and similarly
- a DNSP's building block proposal must include the total forecast capex for the relevant regulatory control period which the DNSP considers is required in order to meet or manage the expected demand for standard control services over that period.[222]

The AER is required to decide whether to accept, reject or form its own estimate of those forecasts,[223] having regard to:

- The capital expenditure objectives. These objectives require a TNSP (DNSP) to forecast capex:
  - to meet or manage expected demand for prescribed transmission services (standard control services);
  - to comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services (standard control services);
  - to maintain the quality, reliability and security of supply of prescribed transmission services (standard control services); and
  - to maintain the reliability, security and safety of the transmission (distribution) system through the supply of prescribed transmission services (standard control services).[224]
- The capital expenditure criteria. These criteria state that capex forecasts must reflect the efficient costs that a prudent network business would require to achieve the capital expenditure objectives, given a realistic expectation of demand forecasts and cost inputs.[225]

221 Clause 6A.6.7(a) of the NER.

222 Clause 6.5.7(a) of the NER.

223 Clauses 6.12.1(3) and 6A.14.1(2) of the NER.

224 Clauses 6.5.7(a) and 6A.6.7(a) of the NER.

225 Clauses 6.5.7(c) and 6A.6.7(c) of the NER.

- The capital expenditure factors. These factors include the extent to which the network business has considered and made scope for efficient and prudent non-network alternatives, and the substitution possibilities between opex and capex.[226]

If the AER is not satisfied that a network business's forecast capex allowance reasonably reflects the capex criteria, then the AER cannot accept it and must instead form its own estimate that would reasonably reflect the capex criteria.[227] That is, in determining whether to accept or to amend a network business's capex forecasts, the AER must have regard to the efficient costs of providing prescribed transmission services and standard control services, including whether the network business has considered the substitution possibilities between opex and capex, and considered and made provision for efficient and prudent non-network alternatives.[228]

F.2 Opex forecasts

The regulatory framework also establishes the opex that a network business must include as part of determination process. Specifically, the NER states that:

- a TNSP's revenue proposal must include the total forecast opex for the relevant regulatory control period that the TNSP considers is required in order to meet or manage the expected demand for prescribed transmission services over that period;[229] and similarly
- a DNSP's building block proposal must include the total forecast opex for the relevant regulatory control period that the DNSP considers is required in order to meet or manage the expected demand for standard control services over that period.[230]

The AER is then required to decide whether to accept, reject or form its own estimate of those forecasts,[231] having regard to:

- The operating expenditure objectives. These require a TNSP (DNSP) to forecast capex:
  - to meet or manage expected demand for prescribed transmission services (standard control services);
  - to comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services (standard control services);

226 Clauses 6.5.7(e) and 6A.6.7(e) of the NER.

227 Clauses 6.5.7(d), 6.12.1(3)(ii), 6A.6.7(d) and 6A.14.1(2)(ii) of the NER.

228 Clauses 6.5.7(e)(7), 6.5.7(e)(10), 6A.6.7(e)(7) and 6A.6.7(e)(12) of the NER.

229 Clause 6A.6.6(a) of the NER.

230 Clause 6.5.6(a) of the NER.

231 Clauses 6.12.1(4) and 6A.14.1(3) of the NER.

— to maintain the quality, reliability and security of supply of prescribed transmission services (standard control services); and

— to maintain the reliability, security and safety of the transmission (distribution) system through the supply of prescribed transmission services (standard control services).[232]

- The operating expenditure criteria. These criteria state that opex forecasts must reflect the efficient costs that a prudent network business would require to achieve the operating expenditure objectives, given a realistic expectation of demand forecasts and cost inputs.[233]

- The operating expenditure factors. These factors include the extent to which the network business has considered and made scope for efficient and prudent non-network alternatives, and the substitution possibilities between opex and capex.[234]

If the AER is not satisfied that a network business's forecast opex allowance reasonably reflects the opex criteria, then the AER cannot accept it and must instead form its own estimate that would reasonably reflect the opex criteria.[235] That is, in determining whether to accept or to amend a network business’s opex forecasts, the AER must have regard to the efficient costs of providing prescribed transmission services and standard control services, including whether the network business has: considered the substitution possibilities between operating and capital expenditure; and considered and made provision for, efficient and prudent non-network alternatives.[236]

232 Clauses 6.5.6(a) and 6A.6.6(a) of the NER.

233 Clauses 6.5.6(c) and 6A.6.6(c) of the NER.

234 Clauses 6.5.6(e) and 6A.6.6(e) of the NER.

235 Clauses 6.5.6(d), 6.12.1(4)(ii), 6A.6.6(d) and 6A.14.1(3)(ii) of the NER.

236 Clauses 6.5.6(e)(7), 6.5.6(e)(10), 6A.6.6(e)(7) and 6A.6.6(e)(12) of the NER.

G Network incentives and innovation allowances

G.1 Opex and capex incentives

The regulatory framework includes two schemes to provide network businesses with incentives to outperform their operating and capital expenditure forecasts:

- the Efficiency Benefit Sharing Scheme (EBSS) – designed to provide network businesses with a continuous incentive to reduce operating expenditure; and
- the Capital Expenditure Sharing Scheme (CESS) – designed to provide network businesses with an incentive to undertake efficient capex during a regulatory control period.[237]

The EBSS and CESS allow the network business to retain (for a specified period of time) any efficiency benefits that are realised as a result of decreased opex and capex, based on the difference between actual and forecast opex and capex.

G.2 Innovation incentives and allowances for DNSPs

On 20 August 2015, the AEMC made a rule amending the previous Demand Management Embedded Generation Connection Incentive Scheme (DMEGCIS) arrangements in Chapter 6 of the NER to provide greater clarity to the AER and stakeholders in respect of how a demand management incentive scheme should be designed and applied. The rule introduced clearer objectives and principles to guide the AER in developing and applying an effective incentive scheme and innovation allowance. The rule renames the DMEGCIS and separates it into two parts.

1. A demand management incentive scheme (DMIS). The objective of this scheme is to provide DNSPs with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management. The scheme rewards DNSPs for implementing relevant non-network options that deliver net cost savings to retail customers

2. A demand management innovation allowance (DMIA). The objective of the allowance is to provide DNSPs with funding for research and development in demand management projects that have the potential to reduce long term network costs. The allowance is intended to fund innovative projects that have the potential to deliver ongoing reductions in demand or peak demand, e.g. trials associated with decentralised energy and storage options.

The rule requires the AER to publish the DMIS and the DMIA by 1 December 2016.[238]

237 Clauses 6.5.8(c)(2), 6.5.8A(a), 6A.6.5(b)(1) and 6A.6.5A(a) of the NER.

238 Clause 11.82.2 of the NER.

The rule aims to balance the incentives for DNSPs to undertake demand management projects as alternatives to network options so that DNSPs will make efficient investments decisions.[239] The rule also addresses the concern that trials may extend beyond the length of a regulatory control period. Specifically, it clarifies that the AER may take the length of a project into account in determining the period over which the allowance may apply.[240]

G.3 Innovation incentive for TNSPs

The regulatory framework states that the AER must, in accordance with the transmission consultation procedures, develop and publish a Service Target Performance Incentive Scheme (STPIS) for TNSPs.[241] The AER's current STPIS (version 4) was published in December 2012, and applies to all TNSPs.[242] The AER recently published version 5 of the STPIS. The AER's intention is that the revised STPIS will apply to the next round of transmission determinations.

The STPIS aims to provide financial incentives to TNSPs to improve or maintain the reliability of transmission network services by providing for the TNSP to earn revenue (or, in some cases, to face a revenue decrement) in addition to its annual maximum allowable revenue (MAR).[243] The STPIS has three main objectives:

- to maintain high levels of reliability (or improvements where efficient);
- to encourage TNSPs to manage their network to reduce the impact of outages on wholesale spot market prices; and
- to promote innovation by TNSPs to deliver improved services through low cost alterations to their network.[244]

The current version of the STPIS consists of three components:

1. The service component, which is designed to incentivise TNSPs to reduce the occurrence of unplanned outages and return the network to service promptly after unplanned outages that lead to an interruption to supply

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239 AEMC, Final Rule Determination – National Electricity Amendment (Demand management incentive scheme) Rule 2015, 20 August 2015, pi.

240 AEMC, Final Rule Determination – National Electricity Amendment (Demand management incentive scheme) Rule 2015, 20 August 2015, p76.

241 Clause 6A.7.4(a) of the NER.

242 See: AER website, https://www.aer.gov.au/node/9780. Note that the AER published STPIS version 4.1 in September 2014, which included adjustments specifically for Directlink. Version 4.1 is the current version and is substantially the same as version 4. AER website, https://www.aer.gov.au/node/25268.

243 Clause 6A..7.4(b) of the NER.

244 AER, Final decision Electricity transmission network service providers Service Target performance incentives scheme, December 2012, p8.

2. The market impact component, which is designed to provide an incentive to TNSPs to reduce the impact of planned and unplanned outages on wholesale market outcomes

3. The network capability component, which is designed to incentivise TNSPs to deliver benefits through increased network capability, availability or reliability through the development of one-off projects that can be delivered through low cost opex and capex.[245]

The network capability component incentivises TNSPs (with assistance and independent oversight from AEMO) to develop innovative, low cost projects that materially improve network capability. This component can provide TNSPs with an annual incentive payment of up to 1.5 per cent of its MAR to fund proposed projects.[246]

There are a range of projects that could be included under the network capability component, so long as the project delivers material benefits. The AER has stated that it does not consider it is necessary to publish a guideline on the prioritisation, assessment and quantification of benefits associated with projects because such a guideline would likely stifle innovation and creativity by restricting the range of projects considered by TNSPs and AEMO.[247]

245 AER, Final Decision Electricity transmission network service providers Service Target Performance Incentive Scheme, December 2012, p.8-9.

246 AER, Final Decision Electricity transmission network service providers Service Target Performance Incentive Scheme, December 2012, pp23,28.

247 AER, Final Decision Electricity transmission network service providers Service Target Performance Incentive Scheme, December 2012, p28.

H Network investment tests

The regulatory framework includes an additional requirement for proposed network augmentation projects that exceed a specified materiality threshold – currently $5 million.[248] TNSPs and DNSPs are then required to apply the regulatory investment test for transmission (RIT-T) and the regulatory investment test for distribution (RIT-D).

The RIT-T and RIT-D are cost-benefit studies that require network businesses to consider all credible options before undertaking network augmentation. A credible option is defined as one that:

- addresses the identified need;
- is (or are) commercially and technically feasible; and
- can be implemented in sufficient time to meet the identified need.[249]

Further, the RIT-T and RIT-D explicitly require network businesses to consider all network and non-network options that are commercially or technically feasible, without bias as to energy source, technology, ownership and whether it is a network or non-network option.[250] The AER notes that the non-network options to be considered by network businesses could include the following:

- any measure or program targeted at reducing peak demand, including:
  - improvements to or additions of automatic control schemes such as direct load control;
  - energy efficiency programs or a demand management awareness program for consumers; and
  - installing smart meters with measures to facilitate cost-reflective pricing; and
- increased local or distributed generation/supply options, including:
  - capacity for standby power from existing or new embedded generators; and
  - using energy storage systems, load transfer capacity and more.[251]

248 Clauses, 5.16.3(a)(2) and 5.17.3(a)(2) of the NER.

249 Clause, 5.15.2(a) of the NER.

250 Clauses 5.15.2(b) and 5.15.2(c) of the NER.

251 AER, Better Regulation Regulatory investment test for distribution Application Guidelines, 23 August 2013, section 7.1.

After identifying all credible options, the RIT-T and RIT-D require network businesses to undertake a cost-benefit analysis to identify the credible network option that maximises the present value of net economic benefits to all those who produce, consume and transport electricity in the NEM.[252] The cost-benefit analysis includes an assessment of reasonable scenarios of future supply and demand if each credible option were implemented, compared to the situation where no option is implemented.[253] As part of this analysis, network businesses are required to consider a number of market benefits that could be delivered by the credible option (see Box H.1) as well as the following costs:

- the costs incurred in constructing or providing the credible option;
- the operating and maintenance costs in respect of the credible option; and
- the cost of complying with laws, regulations and applicable administrative requirements in relation to the construction and operation of the credible option.[254]

In other words, the network businesses are required to consider a wider set of benefits – market benefits – as opposed to their own benefits alone. For example, TNSPs are required to consider changes in ancillary services costs and DNSPs are required to consider changes in electrical energy losses.[255]

The RIT-T and RIT-D then require the network business to rank each credible option by its expected net economic benefit to identify the credible option with the highest expected net economic benefit. The net economic benefit of a credible option is the expected market benefit less the expected costs of the option.[256]

Network businesses are also required to seek submissions from Registered Participants, AEMO and interested parties on the credible options considered as part of their RIT-T or RIT-D.[257] The RIT-D requires the DNSP to prepare and publish a non-network options report,[258] which includes information to assist non-network

252 Clauses, 5.16.1(b) and 5.17.1(b) of the NER.

253 Clauses 5.16.1(c)(1) and 5.17.1(c)(1) of the NER.

254 Clauses 5.16.1(c)(8) and 5.17.1(c)(6) of the NER.

255 See Box H.1

256 AER, Final Regulatory investment test for transmission application guidelines, June 2010, p.5; and AER, Better Regulation Regulatory investment test for distribution Application Guidelines, 23 August 2013, section 2.

257 AER, Final Regulatory investment test for transmission application guidelines, June 2010, p.45; and AER, Better Regulation Regulatory investment test for distribution Application Guidelines, 23 August 2013, section 3.1.

258 We note that a RIT-D proponent is not required to publish a non-network options report if it determines on reasonable grounds that there will not be a non-network option that is a potential credible option, or that forms a significant part of a potential credible option, for the RIT-D project to address the identified need. See: NER, clause 5.17.4(c).

providers wishing to present alternative potential credible options and details of how to submit a non-network proposal for consideration by the DNSP.[259]

Box H.1 Market benefits that must be considered by the RIT-T and RIT-D proponent

The RIT-T requires TNSPs to consider whether each credible option could deliver the following classes of market benefits:

- changes in fuel consumption arising through different patterns of generation dispatch;
- changes in voluntary load curtailment;
- changes in involuntary load shedding, with the market benefit to be considered using a reasonable forecast of the value of electricity to consumers;
- changes in costs for parties, other than the RIT-T proponent, due to differences in:
  - the timing of new plant;
  - capital costs; and
  - operating and maintenance costs.
- differences in the timing of expenditure;
- changes in network losses;
- changes in ancillary services costs;
- competition benefits;
- any additional option value (where this value has not already been included in the other classes of market benefits) gained or foregone from implementing that credible option with respect to the likely future investment needs of the market;
- negative of any penalty paid or payable (meaning the penalty price multiplied by the shortfall) for not meeting the renewable energy target, grossed-up if not tax deductible to its value if it were deductible; and
- other benefits that the TNSP determines to be relevant and are agreed to by the AER in writing before the project specification consultation report is made available to other parties.[260]

259 Clause 5.17.4(b) of the NER.

The RIT-D requires DNSPs to consider whether each credible option could deliver the following classes of market benefits:

- changes in voluntary load curtailment;
- changes in involuntary load shedding and customer interruptions caused by network outages, using a reasonable forecast of the value of electricity to customers;
- changes in costs for parties, other than the RIT-D proponent, due to differences in:
  - the timing of new plant;
  - capital costs; and
  - operating and maintenance costs.
- differences in the timing of expenditure;
- changes in load transfer capacity and the capacity of Embedded Generators to take up load;
- any additional option value (where this value has not already been included in the other classes of market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the NEM; and
- changes in electrical energy losses.[261]

260 Clause 5.16.1(c)(4) of the NER; AER, Final Regulatory investment test for transmission, June 2010, paragraph 5.

261 Clause 5.17.1(c)(4) of the NER; AER, Better Regulation Regulatory investment test for distribution Application Guidelines, 23 August 2013, section 10.

I Ring-fencing guidelines

I.1 TNSP ring-fencing guidelines

Clause 6A.21 of the NER requires the AER to develop transmission ring-fencing guidelines and a TNSP to comply with those guidelines. The current transmission ring fencing guidelines were issued by the ACCC in 2002 and subsequently adopted by the AER. These guidelines apply to all TNSPs in the NEM.

The transmission ring-fencing guidelines separate the accounting and functional aspects of prescribed transmission services from other services provided by a TNSP,[262] via:[263]

- Limitations on the supply of related business services. A TNSP is not allowed to carry on a related business which is defined as generation, distribution, and electricity retail supply,[264] that generates revenues of more than 5 per cent of the TNSP's total annual revenue.[265]
- Accounting separation. A TNSP must maintain a set of accounts for the provision of ring-fenced services separate from an amalgamated set of accounts for its entire business.
- Cost allocation between services. A TNSP must allocate costs between ring-fenced services and any other activities. This is to prevent cross-subsidising of contestable services through regulated activates
- Provision of information publically where information is provided to associates. Information provided by the TNSP to associates who provided related services is required to be made available to any other party. This provision aims to limit associates of the TNSP gaining an unfair advantage by having access to restricted information
- Separation of marketing staff. A TNSP's marketing staff are not allowed to be staff of associates who take part in providing related services, nor are marketing staff of associates allowed to be the staff of the TNSP.
- Requirements to notify sharing of personnel. A TNSP has an obligation to inform the AER if staff, consultants or independent contractors who work for the TNSP also work for an associate providing related services.

The NER charges the AER with the responsibility for publishing the transmission ring-fencing guidelines and gives it the flexibility to amend those guidelines in

262 Clause 6A.21.2(a) of the NER.

263 ACCC, Transmission Ring-Fencing Guidelines, August 2002, clause 7.1 to clause 7.8.

264 ACCC, Transmission Ring-Fencing Guidelines, August 2002, p2.

265 ACCC, Transmission Ring-Fencing Guidelines, August 2002, clause 7.1(b).

accordance with the transmission consultation procedures. The AER has not reviewed the transmission ring-fencing guidelines since their adoption.

I.2 DNSP ring-fencing guidelines

The NER gives the AER discretion to develop distribution ring-fencing guidelines for the accounting and functional separation of a DNSP's provision of direct control services from the provision of other services.[266] All DNSPs must comply with the distribution ring-fencing guidelines.[267]

Ring-fencing requirements for DNSPs are currently based on individual jurisdictional guidelines that were published by jurisdictional regulators prior to 2005. Consequently, ring-fencing requirements and restrictions on related businesses vary between jurisdictions.

266 Clause 6.17.2(a) of the NER.

267 Clause 6.17.1 of the NER.

Table I.1 Summary of the current DNSP jurisdictional ring-fencing guidelines[268]

State	Services that are required to be ring-fenced	Allowed to produce or generate electricity	Allowed to sell electricity	Legal separation	Accounting separation	Allocation of costs	Physical/ functional separation	Have to inform customers of choice	Information and disclosure
NSW	Prescribed distribution services are ring-fenced from contestable services. Contestable services defined as work relating to extension of distributor's service or increase in capacity of distributor's service.	✓[i]	✓[i]	Not addressed	✓	✓	✓	✓	✓
ACT	Related businesses are ring-fenced. Related business defined as producing, purchasing or selling electricity services.	×[ii]	×[ii]	✓	✓	✓	✓	×	✓
Qld	Related businesses are ring-fenced. Related business defined as	×[iii]	×[iii]	✓	✓	✓	✓	×	✓

268 Sources: Review of current jurisdictional ring-fencing guidelines; and AER, Electricity Distribution Ring-fencing Guidelines, Position Paper, September 2012, Attachment A. Notes: (i) No limitation on generation ownership. Generation activities are subject to ring-fencing; (ii) Restriction on carrying on related businesses including "producing electricity services"; (iii) Restriction on carrying on related businesses including "producing electricity services in the same legal entity"; (iv) Permitted to be licenced for generation for network support purposes and where no revenue is earned from such generation.

State	Services that are required to be ring-fenced	Allowed to produce or generate electricity	Allowed to sell electricity	Legal separation	Accounting separation	Allocation of costs	Physical/ functional separation	Have to inform customers of choice	Information and disclosure
	producing, purchasing, selling electricity. Also refers to excluded services in relation to account separation, services which are not prescribed distribution services therefore excluded from revenue or price cap.								
SA	Related businesses are ring-fenced. Relate business defined as business carried on or activities undertaken in electricity supply industry which is subject to effective competition.	✓[iv]	✓[iv]	Not addressed	Not addressed	Not addressed	✓	×	✓
Tas	Contestable electrical services undertaken by a DNSP and related business are ring-fenced. Related business defined as any business in the electricity supply industry or other business that provides electrical services. Contestable electrical	✓[i]	✓[i]	Not addressed	✓	✓	✓	✓	✓

State	Services that are required to be ring-fenced	Allowed to produce or generate electricity	Allowed to sell electricity	Legal separation	Accounting separation	Allocation of costs	Physical/ functional separation	Have to inform customers of choice	Information and disclosure
	services defined as retailing of electricity services, any electrical service comprising work funded or partly funded by customer contributions for extension of distributor's system or an increase in capacity of a service, also contestable services as determined by regulator.								
Vic	Retail businesses are ring-fenced. Retail business defined as business carried on by a retailer under the retailer's retail licence.	✓[i]	✓[i]	Not addressed	Not addressed	Not addressed	✓	✓	✓

I.2.1 New South Wales

The New South Wales ring-fencing guidelines were published by the Independent Pricing and Regulatory Tribunal (IPART) in 2003. These guidelines require:

- cost allocation and accounting separation between those services that are prescribed distribution services or excluded distribution services on a causation basis
- communicating with customers in relation to customer choice in the provision on contestable services;
- separation of operational staff and physical separation of offices between those staff providing specified services and those who provide contestable services; and
- limitations on information flow between staff providing contestable services from information that relate to specified services which relate to independent accredited service providers.[269]

The guidelines do not discuss ownership limitations for any class or type of assets. Further, they do not discuss the concept of a related business or mention generation. This suggests that the New South Wales DNSPs do not currently face limitations on the type of services they are able to offer, including providing energy to the NEM or supplying market ancillary services.

I.2.2 Australian Capital Territory

The Australian Capital Territory ring-fencing guidelines were published by the Independent Competition and Regulatory Commission (ICRC) in 2002. The guidelines require:

- a DNSP not to carry on or cross subsidise a related business where related business is defined as 'the business of producing, purchasing or selling natural gas or electricity services, as the case may be;
- accounting separation, where separate set of accounts is required for the DNSP's distribution service and its other businesses;
- cost allocation between a related business and any other activity;
- limitations on information flow, between those that are involved with operations of the distribution network and those that are involved in related businesses;

269 IPART, Distribution Ring Fencing Guidelines, February 2003, p. i-iv.

- information access, which require information accessible to a DNSP's related business associates should also be made available to other parties which are similarly situated entities;
- staff separation, between those that are involved with operations of the distribution network and those that are involved in related businesses;
- physical separation of offices between related business staff and other staff; and
- operational separation between related business and other operations so that related businesses do not obtain a competitive edge or misleads customers.[270]

The guidelines restrict DNSPs from carrying on related businesses,[271] where related businesses is defined to mean the business of producing, purchasing or selling electricity services.[272] It is clear that this limitation would prevent DNSPs from participating in generation and electricity retailing, however it is also conceivable these limitations may apply to purchasing electricity to charge energy storage and selling energy into the NEM. If this interpretation of the restriction is valid, then energy trading using energy storage becomes impractical in the Australian Capital Territory. This issue may also apply to DNSPs providing market ancillary services depending on the meaning of 'electricity services'.

I.2.3 Queensland

The Queensland ring-fencing guidelines were published by the Queensland Competition Authority in 2000. The guidelines require:

- a DNSP not to carry on a related business in the same legal entity as the DNSP, where related business is defined as the business of producing, purchasing or selling electricity;
- accounting separation of excluded services provided by the DNSP and those that are prescribed distribution services;
- cost allocation between excluded services provided by the DNSP and those that are prescribed distribution services; and
- limitations on information flow between those parts of the business providing prescribed distribution services and those provided excluded services.[273]

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270 ICRC, Ring Fencing Guidelines For Gas and Electricity Network Service Operators in the ACT, November 2002, p. 13-16.

271 ICRC, Ring Fencing Guidelines For Gas and Electricity Network Service Operators in the ACT, November 2002, clause 3.1(b).

272 ICRC, Ring Fencing Guidelines For Gas and Electricity Network Service Operators in the ACT, November 2002, p17.

273 Queensland Competition Authority, Electricity Distribution: Ring-Fencing Guidelines, September 2000, p20-27.

This definition of related business is similar to those in the Australian Capital Territory but with an important distinction. The related business limitation for the Australian Capital Territory relates to electricity services, while the Queensland limitation relates to electricity. This suggests a Queensland DNSP is unable to sell energy to the NEM, but could provide market ancillary services.

Another important feature of Queensland's related business limitation is that it only applies to the legal entity containing the DNSP. This suggests a separate legal entity owned by the DNSP could carry on the business of producing, purchasing or selling electricity. The separate legal entity could then operate energy storage (or generation) to supply energy to the NEM and provide market ancillary services, subject to the other ring fencing requirements.

I.2.4 South Australia

The South Australian ring-fencing guidelines were published by the Essential Services Commission of South Australia in 2003. The guidelines require:

- a limitation on retail and generation, where a distribution licensee (i.e. a DSNP) must not hold a retail licence or a generation licence. The generation licence prohibition applies to distribution licensee except in circumstances where generation is carried out for network support purposes and where no revenue is earned from such generation;
- limitations on information flow between the parts which are a licenced business (meaning the business providing prescribed distribution services and excluded distribution services) and those that are related businesses;
- non-discrimination in the provision of monopoly services and use of operations staff in relation to a related business and its competitors; and
- staff separation, where marketing staff for the licensed business is not to be involved in a related business.[274]

These guidelines allow DNSPs to hold a generation licence only for the purposes of network support. This limitation may impose restrictions on a DNSP's ability to own energy storage if the meaning of generation is clarified to apply to energy storage using batteries. In addition, the guidelines do not restrict DNSPs participating in related businesses, except for electricity retailing and generation by way of licence restrictions as discussed above. It appears that DNSPs are able to trade energy and supply market ancillary services using energy storage under the current guidelines as there are no explicit restrictions against these services.

A DNSP supplying energy to the NEM or providing market ancillary services will be subject to ring fencing requirements because the term 'related business' is sufficiently

274 Essential Services Commission of South Australia, Operational Ring Fencing Requirements for the SA Electricity Supply Industry – Electricity Industry Guideline No. 9, June 2003, p5-6.

broad to capture energy trading and market ancillary services. The definition of 'related business' in the South Australian ring-fencing guidelines means any business carried on or activities undertaken in the electricity supply industry which is subject to effective competition as determined by the Commission from time to time.[275] The supply of energy to the NEM and market ancillary services appears to meet the definition of a related business as both services are subject to effective competition and relate to the electricity supply industry.

I.2.5 Tasmania

The Tasmanian ring-fencing guidelines were published by the Office of the Tasmanian Energy Regulator in 2004. The guidelines require:

- non-discrimination in conducting its regulated distribution service business and should not be against or in favour of any businesses providing contestable electrical services, including access to information;
- operational separation, where a DNSP's regulated distribution business is required to operate independently and have separate work areas from its related business;
- separation of staff, whereby staff in a DNSP's regulated business are required to be separate from staff of its related business;
- information separation, where the DNSP must establish, maintain and enforce access controls so a DNSP's information system does not have discriminatory access;
- customer communications must not favour the DNSP or its related business over another service provider and advise customers contestable electrical services can be obtained from independent service providers; and
- website publications may only relate to regulated distribution services and not of its contestable services unless equal access is provided to other businesses providing those services.[276]

The Tasmanian ring fencing guidelines also do not restrict services that can be provided by a DNSP, suggesting DNSP's would be allowed to supply energy to the NEM and provide ancillary market services. Services from energy storage would fall under the definition of related business, which is defined in the guideline any business in the electricity supply industry or other business that provides electrical services.[277]

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275 Essential Services Commission of South Australia, Operational Ring Fencing Requirements for the SA Electricity Supply Industry – Electricity Industry Guideline No. 9, June 2003, p8.

276 Office of the Tasmanian Energy Regulator, Decision: Guideline for Ring-fencing in the Tasmanian Electricity Supply Industry, October 2004, p33-38.

277 Office of the Tasmanian Energy Regulator, Decision: Guideline for Ring-fencing in the Tasmanian Electricity Supply Industry, October 2004, p. 38.

Accordingly, those services would require ring-fencing from regulated distribution services.

I.2.6 Victoria

The Victorian ring-fencing guidelines were published by the Essential Services Commission in 2004. The guidelines require:

- non-discrimination in a DNSP's conduct and should not discriminate in favour of any electricity business or in favour of the customers of any electricity business;
- information sharing, where a DNSP must ensure distribution information it provides to any retail business is available to all retail businesses;
- separation of organisational units, where a DNSPs electricity distribution and marketing is to operate independently and have separate work areas from those in its retail business;
- staff separation where staff of a retail business should not be those in the distribution business;
- IT access controls so that the retail business cannot access information from distribution parts of the business;
- marketing and customer communications should minimise confusion for the customer with regards the distribution business carrying on a distribution business and the retail business carrying on a retail business;
- website publications must make clear if it relates to distribution or retail and the subject matter may only relate to either distribution or retail on each page. A website must provide non-discriminatory access or links to other retailers if the DNSP advertises its retail services on its website.[278]

It appears that DNSPs in Victoria could provide market ancillary services and supply energy to the NEM using its own energy storage assets, as long as those services were ring fenced from the provision of regulated services.

278 Essential Services Commission, Electricity Industry Guideline No. 17 Electricity Ring-Fencing Issue 1, October 2004, p1-3.

J Cost allocation and shared assets

J.1 Cost allocation methodology

TNSPs are required to allocate costs between prescribed, negotiated and non-regulated services on the basis of a cost allocation methodology (CAM) that relates to both the attribution of the TNSP's direct costs to prescribed, negotiated and other services, as well as the allocation of shared costs between these different services. Similarly, DNSPs are required to allocate costs between standard control, alternative control, negotiated and unclassified services on the basis of a CAM.

Network businesses are required by the NER to propose their own CAM, which must be consistent with the Cost Allocation Guidelines issued by the AER.[279] A network business must comply with the CAM approved by the AER and is required to apply that CAM in submitting its forecast of required capex and opex.[280]

The NER requires the Cost Allocation Guidelines published by the AER to give effect to and be consistent with the Cost Allocation Principles:[281]

- The detailed principles and policies used by a TNSP (DNSP) to allocate costs between different categories of transmission (distribution) services must be described in sufficient detail to enable the AER to replicate reported outcomes through the application of those principles and policies.
- Cost allocations must be determined based on the substance of a transaction or event rather than its legal form.
- The only costs that can be allocated to a particular category of transmission or distribution services are costs directly attributable to those services and costs not directly attributable but that are incurred in providing those services. The allocation of costs not directly attributable but that are incurred in providing those transmission services should be based on a causal allocator and clearly described.
- Costs must not be allocated more than once.
- The principles, policies and approach used to allocate costs must be consistent with the Ring-Fencing Guidelines.
- A TNSP's costs which have been allocated to prescribed transmission services must not be reallocated to negotiated transmission services.

279 Clauses 6.15.4(a), 6.15.4(b), 6A.19.4(a) and 6A.19.4(b) of the NER.

280 Clauses 6.5.6(b)(2), 6.5.7(b)(2), 6A.6.6(b)(2), 6A.6.7(b)(2), 6.15.1 and 6A.19.1 of the NER.

281 Clauses 6.15.3(b) and 6A.19.3(b).

- A TNSP's costs which have been allocated to negotiated transmission services may be reallocated to prescribed transmission services.[282]

- A DNSP's costs which have been allocated to a particular service cannot be reallocated to another service during the course of a regulatory control period.[283]

The NER allows the Cost Allocation Guidelines to specify the format of a TNSP's (DNSP's) CAM, the information to be included in the CAM, the separate categories of transmission (distribution) services to be addressed in the CAM, and the acceptable allocation methodologies and supporting information to be included in the CAM.[284]

The AER published Cost Allocation Guidelines for transmission in September 2007[285] and Cost Allocation Guidelines for distribution in June 2008.[286] Unlike some AER guidelines, the Cost Allocation Guidelines are binding on both the AER and the network business.[287]

The NER provides the AER with the flexibility to make amendments to the Cost Allocation Guidelines in accordance with the transmission and distribution consultation procedures.[288] To date, the AER has not amended the initial transmission and distribution Cost Allocation Guidelines.

Transmission and distribution networks can change over time, affecting the way assets are used and how costs should be allocated. The NER exhibits sufficient flexibility to accommodate changes in the way costs are incurred and allocated by allowing amendments to a network business's CAM from time to time. Amendments to a network business's CAM may be initiated:

- by the network business applying to the AER for written approval of the amendment;[289] or

- by the AER requesting a network business to amend its CAM, i.e. to ensure that changes in the Cost Allocation Guidelines are reflected in a network business's CAM.[290]

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282 This principle reflects the fact that over time assets used to provide services to one user on a negotiated basis may evolve to service a larger group of users where those services are prescribed transmission services.

283 Clauses 6.15.2 and 6A.19.2 of the NER.

284 Clauses 6.15.3(c) and 6A.19.3(c) of the NER.

285 AER, Final decision Electricity transmission network service providers Cost Allocation Guidelines – Appendix B, September 2007.

286 AER, Final decision: Electricity distribution network service providers Cost Allocation Guidelines, September 2007.

287 Clauses 6.15.3(d) and 6A.19.3(d) of the NER.

288 Clauses, 6.2.8(e) and 6A.2.3(e) of the NER.

289 Clauses 6.15.4(f) and 6A.19.4(f) of the NER.

290 Clauses 6.15.4(g) and 6A.19.4(g) of the NER.

In making a decision regarding whether or not to approve a network business's proposed amendments, the AER states in its Cost Allocation Guidelines that it will have particular regard to whether:

- there has been a material change in the network business's circumstances;
- the amendment is necessary for the business to effectively promote the Cost Allocation Principles;
- the resultant amended CAM would give effect to and be consistent with the Cost Allocation Guidelines;
- the amendment will not jeopardise the comparability of the resultant financial information with earlier information provided by that network business to the AER; and
- the network business can quantify and demonstrate to the AER the impact of the proposed amendment.[291]

The AER will only approve an amended CAM to take effect from the start of a new regulatory year, or such other dates as agreed with the AER.[292] The AER Cost Allocation Guidelines also state that the AER, in consultation with the network business, will review a network business's CAM as part of each revenue determination for the relevant network business.[293]

J.2 Shared asset mechanisms

The arrangements for shared assets were introduced into the regulatory framework as part of the AEMC's 2012 Economic Regulation Rule Change. The NER sets out 'Shared Asset Principles', which the AER must have regard to in determining what reduction in building block revenue would be appropriate in relation to the use of shared assets, with the detailed mechanism being left to the AER to develop.

The Shared Asset Principles in the NER are:

- A network business should be encouraged to use assets that provide prescribed services for the provision of other kinds of services to the extent that provision is efficient and does not materially prejudice the provision of those services.

291 AER, Final decision Electricity transmission network service providers Cost Allocation Guidelines – Appendix B, September 2007, clause 4.2(c); and AER, Electricity distribution network service providers Cost allocation guidelines, June 2008, clause 4.2(c).

292 AER, Final decision Electricity transmission network service providers Cost Allocation Guidelines – Appendix B, September 2007, clause 4.2(d); and AER, Electricity distribution network service providers Cost allocation guidelines, June 2008, clause 4.2(d).

293 AER, Final decision Electricity transmission network service providers Cost Allocation Guidelines – Appendix B, September 2007, clause 4.3; and AER, Electricity distribution network service providers Cost allocation guidelines, June 2008, clause 4.3.

- Shared asset cost reduction should not be dependent on the network business deriving a positive commercial outcome from the use of the asset other than for standard control services.

- Shared asset cost reduction should be applied when the use the asset other than for standard control services is material.

- Regard should be had to the manner in which costs were recovered or revenues reduced in respect of the relevant asset in the past and to the reasons for adopting that manner of recovery or reduction.

- Shared asset cost reduction should be compatible with the Cost Allocation Principles, Cost Allocation Method, and other incentives provided under the NER.[294]

The NER requires the AER to develop and publish a Shared Asset Guideline, in accordance with the transmission and distribution consultation procedures, which sets out the approach that the AER proposes to take in applying the shared asset principles, and which may also include a method the AER proposes to use for determining the reduction to building block revenue for prescribed transmission services and standard control services.[295]

The AER published its Shared Asset Guideline in November 2013. The Shared Asset Guideline contains a specific methodology the AER proposes to apply to calculate the reduction in building block revenues that will apply when a network business also earns revenue from shared assets by providing non-regulated services. Specifically, the Shared Asset Guideline sets out that revenue earned from non-regulated services using shared assets will reduce a network business's standard control service revenues by 10 per cent of the value of the service provider's expected total non-regulated revenues from shared assets in that year.[296] This reduction is conditional on a materiality consideration where standard control service revenues are adjusted only when non-regulated revenue exceeds 1 per cent of the network business's total smoothed annual revenue.[297]

The AER's Shared Asset Guideline notes that the shared asset mechanism relates to assets that are:

- already established, so have had their costs allocated to regulated services using a service provider's approved cost allocation method (CAM);

- used to provide both regulated and non-standard control services, but whose costs are allocated only to regulated services; and

294 Clauses 6.4.4(c) and 6A.5.5(c) of the NER.

295 Clause 6.4.4(d) and 6A.5.5(d) of the NER.

296 AER, Shared Asset Guideline, November 2013, section 3.1.

297 AER, Shared Asset Guideline, November 2013, section 2.3.

- defined in regulatory terms, rather than physical terms.[298]

The AER's Shared Asset Guideline makes it clear that the shared asset mechanism does not apply to assets that are new, so have not yet had their costs allocated using a service provider's approved CAM and used to provide regulated services and non-regulated services, consistent with their cost allocation.[299]

The shared asset mechanism complements a network business's approved CAM. The Shared Asset Guideline notes that network businesses allocate costs usually when the assets are first established, based on the assets' expected future use. Where asset use changes, the initial cost allocation may no longer be accurate. The shared asset mechanism relates to assets whose costs were initially allocated to regulated services but come to be used to provide non-regulated services as well. This change from expected use means the assets are earning both regulated and non-regulated revenues, and have therefore become shared assets.[300]

298 AER, Shared Asset Guideline, November 2013, section 2.2(a).

299 AER, Shared Asset Guideline, November 2013, section 2.2(b).

300 AER, Shared Asset Guideline, November 2013, section 1.3.

K Participant registration

K.1 Registration as a generator

The NEL requires that:

> "A person must not engage in the activity of owning, controlling or operating, in this jurisdiction, a generating system connected to the interconnected national electricity system unless:
>
> (a) the person is a Registered Participant in relation to that activity; or
>
> (b) the person is the subject of a derogation that exempts the person, or is otherwise exempted by AEMO, from the requirement to be a Registered Participant in relation to that activity under this Law and the Rules.[301]"

Central to the definition of the 'generator' category of NEM registration are the terms *generating system* and *generating unit*. To be eligible for registration as a generator a person must own, operate or control one or more *generating units* that form a *generating system*.[302]

A *generating system* is generally defined as a system comprising one or more generating units:

> "(a) Subject to paragraph (b), for the purposes of the Rules, a system comprising one or more *generating units*.
>
> (b) For the purposes of clause 2.2.1(e)(3), clause 4.9.2, Chapter 5 and a jurisdictional derogation from Chapter 5, a system comprising one or more *generating units* and includes auxiliary[303] or *reactive plant*[304]

301 Section 11(1) of the NEL. Failure to do so can attract a civil penalty.

302 The term *generating unit* is also central to the related definitions of the following participants: embedded generator, market generator, non-registered embedded generator and micro-embedded generator, the last two not being registered or market participants.

303 Under paragraph (b) of the definition of *generating system*, auxiliary plant located on the generator's side of the connection point that is necessary for the *generating system* to meet its performance standards will also be considered part of the *generating system*. There is no definition of 'auxiliary plant' in the NER. Auxiliary is a term used to describe things that give support to, aid or otherwise assist. Auxiliary can also be used to mean 'used as a reserve'. It is therefore possible that a storage device, retrofitted to an existing generating system, may be captured by the definition of 'auxiliary plant', but only to the extent that it is necessary for the system to meet its performance standards. 'Standalone' storage systems would not fall within any understanding of 'auxiliary plant'.

304 The NER defines *reactive plant* as 'plant which is normally specifically provided to be capable of providing or absorbing reactive power and includes the plant identified in clause 4.5.1(g).' Reactive power is defined as "The rate at which reactive energy is transferred. Reactive power is a necessary component of alternating current electricity which is separate from active power and is predominantly consumed in the creation of magnetic fields in motors and transformers and produced by plant such as: (a) alternating current generators; capacitors, including the effect of

that is located on the *Generator's* side of the *connection point* and is necessary for the *generating system* to meet its *performance standards*."

A *generating unit* is defined as the actual generator of electricity and all the related equipment essential to its functioning as a single entity.[305] The word 'generator' (in this context) is not itself defined.

K.1.1 Market or non-market generating unit

Each registered generating unit must be classified as either a market generating unit or non-market generating unit.

Market generating unit

A generating unit must be classified as a market generating unit if its output is not purchased in its entirety by the local retailer or by a customer located at the same connection point.[306]

A generator is taken to be a market generator only insofar as its activities relate to any market generating units (ie, a generator can have generating units not classified as market units). A market generating unit must sell all sent-out electricity through the market, and accept payments from AEMO for its output at the spot prices applicable to its connection point.[307]

Market generators may seek to buy electricity through the spot market to support the operation of their generating system, e.g. to supply on-site offices, mines owned by the generator, water pumps, conveyor belts or power station auxiliaries.[308] Market generators seeking to purchase electricity directly through the market must satisfy AEMO that:

- the electricity is used for the purpose of operating the relevant generating system; and
- all power station connection points are part of the overall connection of the generator to the network.

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parallel transmission wires; and synchronous condensers." See Chapter 10 of the NER under 'reactive power'.Storage systems would not fall within any understanding of reactive plant.

305 Chapter 10 of the NER under 'generating unit'.

306 See clause 2.2.4 of the NER.

307 'Sent-out electricity' refers to the amount of electricity supplied to the network at the connection point, and so effectively, in the context of power stations, means auxiliary load is netted off gross output. References to the export of electricity are for small-scale systems where self-consumption is netted off generation.

308 AEMO, NEM Generator Registration Guide, 2013, p29.

If the applicant cannot demonstrate both requirements, then those purchases must be made through a market customer. A market generator can either register as a market customer itself or purchase the electricity from a third party who is a market customer.

Non-market generating unit

A generating unit must be classified as a non-market generating unit if its sent-out generation is purchased in its entirety by the local retailer or by a customer located at the same connection point.[309] For a local retailer, this means the generating units must be connected within the local area of that retailer. For a customer, this means that the load and the generating unit effectively need to be connected in such a way that the metering installation for the common connection point measure the net energy flow of the customer load and the generator output.

A generator is taken to be a non-market generator only in so far as its activities relate to any non-market generating unit. A non-market generator is not entitled to receive payment from AEMO for any electricity sent out at its connection point, except for any electricity sent out in accordance with a direction issued by AEMO to a scheduled generator.

K.1.2 Scheduled, non-scheduled or semi-scheduled

Each market and non-market generator unit must be further classified as scheduled, non-scheduled or semi-scheduled. Scheduled and semi-scheduled generators must participate in the central dispatch process managed by AEMO. A non-scheduled generator is not required to participate.

Scheduled generator

A generator with an aggregate nameplate capacity of 30 MW or more is usually classified as a scheduled generating unit if it has appropriate equipment to participate in the central dispatch process managed by AEMO

Non-scheduled generator

A generator will normally be classified as non-scheduled if its primary purpose is for local use and the aggregate sent-out generation rarely, if ever, exceeds 30 MW; or its physical and technical attributes make it impracticable for it to participate in central dispatch (see Figure 5.2 for examples). Non-scheduled generators do not participate in the central dispatch process, but AEMO can specify additional conditions with which they must comply, usually for power system security reasons.

309 See clause 2.2.5 of the NER.

Semi-scheduled generator

A generating system with intermittent output (such as a wind or solar farm), and an aggregate nameplate capacity of 30 MW or more is usually classified as semi-scheduled, because it can be "dispatched down" but not up. AEMO can limit a semi-scheduled generator's output in response to network constraints or because it is out of merit in the wholesale market, but at other times the generator can supply up to its maximum registered capacity

K.1.3 Registration exemption framework

AEMO may exempt a person from the requirement to register as a generator in accordance with guidelines issued from time to time.[310]

Exemptions may apply for certain generating systems under 5 MW, or under 30 MW with annual exports below 20 GWh.[311] The NER distinguishes between:

- generating systems with a nameplate rating of 30 MW or above that are required to be classified as scheduled generating units or semi-scheduled generating units in order to participate in central dispatch; and
- smaller generating systems (classified as non-scheduled) that are not so classified and do not participate in central dispatch.

AEMO considers that this division reflects the likely impact of generating units on the NEM. It is therefore more likely to exempt persons from registering as generators where their generating units have nameplate ratings below 30 MW.[312]

K.2 Registration as a small generation aggregator

A small generation aggregator is a registered participant who may supply electricity aggregated from one or more small generating units classified as market generating units to a transmission or distribution system.[313] A small generating unit must have a nameplate rating under 30MW and the owner, operator and controller must have an exemption under clause 2.2.1(c) of the NER from the requirement to register as a generator in respect of that unit. A small generating unit, the subject of a small generation aggregator's portfolio, must have its own separate connection point that is separate from any load being purchased from the network at the relevant premises

The only category of small generation aggregator registration is a market small generation aggregator; that is, there is no non-market category of small generator aggregator. This means all output aggregated by a small generation aggregator needs

310 Clause 2.2.1(c) of the NER.

311 AEMO, Guide to NEM generator classification and exemption, 2014, p6.

312 AEMO, Guide to NEM generator classification and exemption, 2014, p11.

313 Clause 2.3A.1 of the NER.

to be sold into the spot market. Therefore, a small generating unit within a portfolio is one that effectively has all of its sent-out generation being sold on the wholesale exchange through the small generation aggregator.

To be eligible for registration as a small generation aggregator, a person must satisfy AEMO that they intend to classify, within a reasonable period of time, one or more small generating units each as a market generating unit with a separate connection point.[314] The applicant must confirm that its facility is either exempted from the technical requirements of Chapter 5 of the NER or will be able to meet or exceed its performance standards.[315]

K.3 Registration as a customer

The NEL requires that:

> "A person must not engage in the activity of purchasing electricity directly through a wholesale exchange unless:
>
> (a) the person is a Registered participant in relation to that activity; or
>
> (b) the person is the subject of a derogation that exempts the person, or is otherwise exempted by AEMO, from the requirement to be a Registered participant in relation to that activity under this Law and the Rules.[316]"

A customer is a registered participant that purchases electricity supplied through a transmission or distribution system to a connection point.[317] There are three customer registration categories – first tier, second tier and market customers.

End users who purchase electricity through a retailer can elect to register as a first-tier customer or second-tier customer, depending on whether the load is purchased directly or indirectly in its entirety, from a local retailer.

To be eligible for registration as a customer, an applicant must satisfy AEMO that they intend to classify electricity purchased at one or more connection points, that is, their load, as one of the following: first tier, second tier or market loads.[318] Alternatively, the applicant may be intending to seek customer registration for the purpose of acting as a retailer of last resort.

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314 Clause 2.3A.1(b),(e) of the NER; AEMO, NEM Small Generation Aggregator Registration Guide, 2012, p4.

315 AEMO, NEM Small Generation Aggregator Registration Guide, 2012, p4.

316 Section 11(4) of the NEL

317 Clause 2.3.1 of the NER.

318 Clause 2.3.1(b) of the NER.

K.4 Registration as a network service provider

The NEL requires that:

> "A person must not engage in the activity of owning, controlling or operating, in this jurisdiction, a transmission system or distribution system that forms part of the interconnected national electricity system unless:
>
> - the person is a Registered participant in relation to that activity; or
> - the person is the subject of a derogation that exempts the person, or is otherwise exempted by AEMO, from the requirement to be a Registered participant in relation to that activity under this Law and the Rules.[319]"

A network service provider is a registered participant that owns controls or operates a transmission or distribution system.[320] A distribution and transmission system is defined in the NER as, effectively, the distribution or transmission network, respectively, together with the connection assets associated with that network.[321] The definition of a distribution system makes clear that 'connection assets on their own do not constitute a distribution system'. This same exclusion is not made in relation to the definition of transmission system.[322]

Connection assets are defined as "those components of a transmission or distribution system which are used to provide a connection services".[323]

319 Section 11(2) of the NEL

320 Clause 2.5.1 of the NER.

321 Chapter 10 of the NER under 'distribution system' and 'transmission system'.

322 Dedicated transmission connection assets were considered by the AEMC as part of the Transmission Frameworks Review: AEMC 2013, Transmission Framework Review, Final report , 11 April 2013, Chapter 13.

323 An entry service (being a service provided to serve a Generator or a group of Generators, or a Network Service Provider or a group of Network Service Providers, at a single connection point) or an exit service (being a service provided to serve a Transmission Customer or Distribution Customer or a group of Transmission Customers or Distribution Customers, or a Network Service Provider or a group of Network Service Providers, at a single connection point).

L Generator and large customer connections

The NER currently provide for a number of connection processes in relation to generation and load. This appendix summarises the process in Chapter 5 of the NER for connecting larger-scale generation, embedded generation and load – that is, registered participants.[324]

L.1 Connection of a generating unit

Connection arrangements in Chapter 5 (Part A) of the NER apply to registered participants seeking to make a connection to the network, including generators seeking to connect to a transmission or distribution network. AEMO is involved in all stages of the connection process for generators seeking to connect to a transmission network in Victoria. The connecting TNSP manages the connection process in all other NEM jurisdictions, with AEMO involved in the assessment and negotiation of certain proposed performance standards and the completion stage of the process. Similarly for distribution networks, the connecting DNSP manages the connection process, with some involvement from AEMO.

L.1.1 Generator proposing to alter a generating system

The NER requires a generator proposing to alter a connected generating system, or a generating system for which AEMO has accepted performance standards, in a manner that will affect technical performance, to submit certain information to the NSP and AEMO.[325] This includes a description of and timing for the alteration, design and setting data in accordance with relevant guidelines and proposed amendments to automatic access standards or negotiated access standards.[326]

L.1.2 Connection requirements

Schedule 5.2 of the NER sets out the requirements and conditions that generators must satisfy as a condition of connection of a generating system to the power system. This includes an obligation on generators to:

- cooperate with the relevant Network Service Provider on technical matters when making a new connection; and

324 Chapter 5A contains a process for the connection of smaller-scale embedded generation (where the generation capacity is less that AEMO's current standing exemption from registration), including micro-embedded generation, and load for retail customers. Chapter 5A connection processes for non-registered participants are summarised in Appendix B of this report.

325 Rule 5.3.9 of the NER.

326 Rule 5.3.4A of the NER applies to proposed amendments to a negotiated access standard.

- provide information to the Network Service Provider or AEMO.[327] Chapter 5 (and schedules to Chapter 5) outline in detail the information that needs to be made available during the connection process.[328]

The NER requires that each generating unit must meet a number of technical requirements. The technical requirements describe how a generating unit should perform under a range of conditions imposed by the power system, or by the generating unit on the power system. They form part of the technical terms and conditions of the generating unit's connection agreement with the NSP.

The technical requirements for the connection of a generating unit do not apply if the facility is eligible for exemption from registration and is connected or intended for use in a manner the Network Service Provider considers is unlikely to cause a material degradation in the quality of supply to other network users.[329]

A generator must plan and design its facilities and ensure that they are operated to comply with:

1. the performance standards applicable to those facilities;

2. subject to subparagraph (1), its connection agreement applicable to those facilities; and

3. subject to subparagraph (2), the system standards.[330]

L.1.3 Performance standards

As part of the connection process, an applicant is required to submit its proposed performance standards for the generating system. Performance standards generally refer to the automatic access standards, negotiated access standards and minimum standards set out in Schedule 5.2.5 of the NER. An access standard is a benchmark for determining the appropriate performance standard for each generating unit. Standards

327 S5.2.1(c) of the NER.

328 For example, *Schedule 5.4: Information to be provided with connection* provides that certain information must be submitted with an enquiry for connection or modification of an existing connection. This includes (amongst other things) information about the type of plant, maximum power generation or demand of whole plant, expected energy production or consumption, plant type and configuration, and 'other information…requested by the NSP…' Generators must provide information in accordance with certain guidelines and data sheets. *Schedule 5.5: Technical details for connection* sets out the range of data that registered participants may be required to submit to NSPs and AEMO. This data comprises preliminary system planning data (required for submission with an application to connect), registered system planning data (included in the connection agreement) and registered data (which consists of data validated and agreed between the NSP and registered participant, being data derived from manufacturers' data, detailed design calculations, works or site tests etc prior to actual connection and, after connection, data derived from on-system testing.

329 AEMO, NEM generator registration guide, p14.

330 Clause 5.2.5(a) of the NER. This clause is a civil penalty provision.

are usually negotiated between the connection applicant and the NSP, given the nature of the existing automatic access standards.[331]

Under clause 5.3.4A of the NER, AEMO is involved in the negotiation process if the standard involves an AEMO advisory matter, being a matter in which AEMO has a role under the 'technical' schedules of the NER (5.1a, 5.1, 5.2, 5.3 and 5.3a). AEMO's Guidelines for Assessment of Generator Performance Standards explain the method by which AEMO assesses whether the applicant's proposed standards are acceptable. Once performance standards are agreed by AEMO, the connecting DNSP/TNSP and the applicant, they become the agreed performance standards for the generating system.

AEMO is responsible for maintaining a register of the generator performance standards, and monitors compliance to ensure that power system security is maintained. The NER sets out the course of action in the event the generator is non-compliant with the performance standards.

L.1.4 Connection agreement

The process for connecting generators (excluding embedded generators) and customers involves a single stage enquiry process followed by a connection application. There is a two stage enquiry process for embedded generators.[332] An information pack, containing information to facilitate the connection of embedded generating units, must also be published by DNSPs to assist connection applicants in making an enquiry.[333]

Once a connection application is complete, the connecting DNSP/TNSP will prepare an offer to connect. The offer to connect is a formal part of the connection process that is governed by the NER and will include finalised performance standards agreed between AEMO, the connecting DNSP/TNSP and the connection applicant. AEMO is not party to the contractual arrangements made between the generator and the connecting DNSP/TNSP.

Contractual arrangements other than those that form part of the offer to connect may also be made between the connecting DNSP/TNSP, the connection applicant and other organisations. Schedule 5.6 of the NER sets the minimum terms and conditions that a connection agreement needs to meet.

L.1.5 System standards

The NER establishes the NEM system standards that:

331 See clauses S5.2.5.3, S5.2.5.4, S5.2.5.5, S5.2.5.7. S5.2.5.8, S5.2.5.9, S5.2.5.10, S5.2.5.11, S5.2.5.12, S5.2.5.13 and S5.2.5.14. of the NER.

332 See rules 5.3A.6 - 5.3A.8 of the NER.

333 Rule 5.3A.3 of the NER.

(a) are necessary or desirable for the safe and reliable operation of the facilities of registered participants;

(b) are necessary or desirable for the safe and reliable operation of equipment;

(c) could be reasonably considered good electricity industry practice; and

(d) seek to avoid the imposition of undue costs on the industry or registered participants.[334]

These include standards relating to frequency, system stability, voltage and fault clearance times.

The NER require that the equipment associated with each generating system must be designed to withstand, without damage the range of operating conditions which may arise consistent with the system standards.[335]

L.2 Connection of a load

Similarly as for a generator, a customer must plan and design its facilities and ensure that its facilities are operated to comply with:

- its connection agreement with a Network Service Provider;
- subject to subparagraph (1), all applicable performance standards; and
- subject to subparagraph (2), the system standards.[336]

Schedule 5.3 of the NER sets out the requirements and conditions that customers must satisfy as a condition of connecting their load to the power system. Similar to the obligation that exists under Schedule 5.2 for generators, customers must provide relevant network service providers with technical information and meet technical requirements and standards, including the negotiation of access standards under clause 5.3.4A.

334 Schedule 5.1a of the NER.

335 S5.2.1(d) of the NER.

336 Rule 5.2.4 of the NER. This clause is a civil penalty provision.

M Ancillary services

The regulatory framework underlying the provision of ancillary services is set out in rule 3.11 of the NER.

An ancillary service provider is defined in the NER as "a person who engages in the activity of owning, controlling or operating a generating unit or market load classified in accordance with Chapter 2 as an ancillary service generating unit or ancillary service load, as the case may be".[337]

There are two types of ancillary services: non-market ancillary services and market ancillary services

M.1 Non-market ancillary services

M.1.1 Network support and control ancillary services (NSCAS)

NSCAS are used to maintain power system security and reliability, and the power transfer capability of the transmission network. NSCAS consists of three main services: voltage control, network loading and stability control. Various pieces of equipment can be installed, or equipment operating regimes implemented, to provide these services.[338]

TNSPs have primary responsibility for acquiring NSCAS. Each year AEMO will identify, in its National Transmission Network Development Plan (NTNDP), any gaps between the NSCAS needs of the power system and the known acquired NSCAS. NSCAS is acquired by TNSPs under connection agreements or network support agreements to meet an NSCAS need. NSCAS could be procured by TNSPs from their own assets (as prescribed transmission services) or from other parties.

NSCAS can be delivered by a range of service providers using a range of power system facilities. This could include services provided by demand-side participants, including control of customer load in response to certain signals, or installation or utilisation of existing small scale generation.[339]

If the NSCAS gaps remain unmet after TNSP’s attempt to procure, AEMO acts as an NSCAS 'procurer of last resort'. If AEMO proposes to acquire NSCAS, it must call for offers from persons who are in a position to provide the NSCAS in accordance with the NSCAS tender guidelines.[340] These guidelines include a requirement that the NSCAS provider be a registered participant, or a party intending to become a registered participant.

337 Chapter 10 of the NER.

338 AEMC, System restart ancillary services, rule determination, 2 April 2015, p103.

339 AEMO, NSCAS description and NSCAS quantity procedure, issues paper, 2011, p5.

340 Clause 3.11.5 (a1) of the NER.

M.1.2 System restart ancillary services (SRAS)

These services provide the capability to restart the power system if there has been a major loss of power in the system, or if the system has collapsed due to a 'black system' condition.[341]

SRAS is generally only provided by generators with the capability to start, or remain in service, without electricity being provided from the grid. These generators must be capable of delivering electricity to a connection point within specified timeframes and be able to control frequency and voltage.

As market participants, market generators, market customers and small generation aggregators can tender for the provision of NSCAS and SRAS.

M.2 Market ancillary services

Market ancillary services consist of frequency control ancillary services (FCAS). FCAS are used by AEMO to maintain the frequency on the electrical system, at any point in time, close to fifty cycles per second as required by the NEM frequency standards. There are two types of FCAS: regulation and contingency.

M.2.1 Regulation

Regulation frequency control can be described as the correction of the generation / demand balance in response to minor deviations in load or generation. There are services to increase the frequency and services to decrease the frequency. Regulation services are controlled centrally from one of AEMO's two National Dispatch and Security Centres.

M.2.2 Contingency

Contingency frequency control refers to the correction of the generation / demand balance following a major contingent event such as the loss of a generating unit or a large transmission element. Contingency services are provided by technologies that can locally detect the frequency deviation and respond in a manner that corrects the frequency. Contingency services are controlled locally and are triggered by the frequency deviation that follows a contingent event.

M.2.3 Requirements for providing FCAS

Market ancillary services can only be provided by market generators and market customers. Clause 2.2.6 of the NER states that:

> "If the Market Generator in respect of a generating unit wishes to use that generating unit to provide market ancillary services in accordance with

341 Defined in Chapter 10 of the NER.

> Chapter 3, then the Market Generator must apply to AEMO for approval to classify the generating unit as an ancillary service generating unit."

Similarly, clause 2.3.5 of the NER states that:

> "If the Market Customer in respect of a market load wishes to use that market load to provide market ancillary services in accordance with Chapter 3, then the Market Customer must apply to AEMO for approval to classify the market load as an ancillary service load."

The definition of eight separate and exclusive FCAS requirements has directly led to the development of eight distinct FCAS markets. The market generator or market customer must indicate which of the eight FCAS they will offer, and the parameters within which each service can be provided. AEMO will review this information and indicate whether the generating unit or load can be used to provide the nominated ancillary services in accordance with the market ancillary service specifications.

Once registered, a service provider can participate in a FCAS market by submitting FCAS offers to AEMO. It must comply with dispatch instructions in accordance with the NER.

M.3 Payment for ancillary services and recovery of costs

Payments for ancillary services include payments for availability and for the delivery of the services. Ancillary service costs are dependent upon the amount of service required at any particular time and, as these amounts can vary significantly from period to period, costs will also vary.

Chapter 2 of the NER sets out who AEMO pays for the provision of ancillary services, and who AEMO recovers the costs of sourcing ancillary services from. These arrangements are summarised in the table below.

Figure M.1 Ancillary services payments and cost recovery

	Ancillary service type	Payment	Cost recovery
Market ancillary services	Regulation FCAS	Paid by AEMO to the scheduled Generator/Customer based on the market clearing price and quantity of the service provided.	Recovered on a 'causer pays' basis from Market Participants with Market Participation Factor, and residual from Market Customers.
	Contingency FCAS		Recovered in proportion to energy consumption / generation. Raise services are recovered from Generators. Lower services are recovered from Market Customers.
Non-market ancillary services	NSCAS reactive power services	Paid by AEMO to the contracted Market Participant based on contractual agreements.	Recovered in proportion to energy consumption in benefiting regions from Market Customers only.
	NSCAS load shed services		
	SRAS		Recovered in proportion to energy consumption in benefiting regions from Market Customers and Generators equally.