#

Network tariffs for the distributed energy future

Final paper for the Australian Energy Regulator

June 2022

Disclaimer

Contacts

Dr Alexandra Sidorenko, Argyle Consulting (Alexandra_sidorenko@argyleconsulting.com.au)
Oliver Nunn, Endgame Economics (oliver.nunn@endgame-economics.com)

Table of contents

Summary

Argyle Consulting and Endgame Economics have been engaged by the Australian Energy Regulator (AER) to prepare a strategic piece on the challenges that the advent of electricity storage (batteries) poses for the design of electricity distribution network tariffs and network regulation more broadly. The paper reflects the views of the authors and is written with the intention to stimulate discussion of the issues. It is our aspiration that the ideas discussed in this paper will help distributors think about the new tariff structures that can be tested with customers and retailers in the next round of tariff setting for the upcoming regulatory resets.

Batteries of all sizes — grid-scale, community, and behind-the-meter (BTM) **—** are rapidly being installed across the electricity supply system. Batteries offer the possibility of an entirely different power system, where supply from instantaneous generation need not always be perfectly matched with demand.

Batteries pose **challenges**, but also offer **opportunities**, to manage network and wholesale energy market **costs.** If we can fine-tune our tariff arrangements to harness the power of batteries, we may ultimately see a reduction in overall consumer costs. But if the network pricing fails to adapt, we may see batteries operating inefficiently, leading to an unnecessary rise in network costs and a poor outcome for consumers.

Non-cost reflective network tariffs have been recognised as a **barrier** to optimal investment in Distributed Energy Resources (DER), including batteries. Following the Access and Pricing rule change, tariffs can now become a solution to the efficient integration of DER.[1]

Ongoing tariff reform will ensure that our tariffs are fit for the new distributed energy environment. Tariff reform is guided by the **National Electricity Objective**, with **long term interests** of electricity consumers firmly in mind.

Long Run Marginal Cost, or **LRMC pricing** is a key feature of tariff reform, extended now to two-way services. Two-way marginal pricing would be based on the principle of **symmetric charges and rewards** where customers can be rewarded for helping avoid marginal costs by changing their consumption or generation behaviour. This pricing would be suitable for any bi-directional profiles including those of batteries. Importantly, **customers without DER** can also be **rewarded** for consuming more energy at the time of solar proliferation during the export peak time ('solar peak').

An alternative way to avoid marginal costs could stem from the application of some form of **control by the network,** to prevent the customer from behaving in a manner that gives rise to an augmentation cost. If the network is given a technical capability to curtail how batteries charge or discharge in a dynamic way (with time windows reflecting actual network conditions), a

[1] AEMC, *Final determination – Access, pricing and incentive arrangements for distributed energy resources*, 12 August 2021. https://www.aemc.gov.au/sites/default/files/2021-08/Final%20determination%20-%20Access%2C%20pricing%20and%20incentive%20arrangements%20for%20DER.pdf. Accessed on 1 June 2022.

dynamic tariff might be offered at a discount which reflects the reward to the customer up to the amount of avoided network costs.

Even if giving up some degree of control over the BTM installation offers customer savings, the distributor or a third party exercising this control needs to earn a **social licence**, a permission **to control customers' appliances**.

Sometimes there are **conflicting objectives** for battery behaviour, when the network seeks one outcome, and the wholesale market sends signals that may work in the opposite direction. In this case, a **hierarchy** of instructions could be established.

Technological change happens rapidly but the same pricing principles may apply to a battery as to any **flexible load** that can be a net generator at certain times. Appropriate price signals combined with new technology can facilitate new electricity services.

Shared batteries connected to the distribution system at the low voltage level (such as **community batteries**) have the potential to deliver the highest benefit to all network users. We need to ensure that network tariffs do not impede this development. Batteries and other flexible loads are well suited to respond to truly **cost reflective two-way tariffs** that offer both charges and rewards. Tariff response by these customers provide an opportunity to reduce network costs.

The concept of **Local Use of System (LUOS)** pricing recognises that the network costs should be reflective of the depth of network use. LUOS pricing can support development and operation of **community battery schemes**. Setting LUOS tariffs should aim to avoid creating cross-subsidies or wealth transfers between customer classes. Contribution of LUOS customers to **residual network costs** is required to avoid any cross-subsidy.

Locational LUOS prices could provide a more efficient signal for community battery scheme operations and other shared electricity exchange schemes. Because there is no legacy, **export charges** present a unique opportunity for **trialling** locational price signals, especially if paired with symmetric **rewards**. Successful trials would demonstrate benefits for the customers and may assist future **customers' buy-in** for locational signalling through tariffs.

Battery owners should contribute to total network cost recovery on the same grounds as other network users with a similar load and/or generation profile. The extent to which batteries drive **transmission costs** depends on the amount of energy sourced from the National Electricity Market (NEM). Batteries should not be treated differently from other customers in their contribution to the recovery of network **residual costs**, or to the costs of government **jurisdictional schemes**.

Cost reflective two-way tariff structures with charges and rewards can get very **complex.** Not all customers would be willing or able to deal with these price signals. It is necessary to **test** whether customers understand the tariffs or if not, whether retailers can implement them.

Retailers are the primary recipients of network price signals and agents for their customers in achieving savings on the total electricity bill. Retailers' response to two-way network tariffs will be key to successful integration of many battery applications.

To fully take advantage of the opportunities presented by batteries and other new DER technologies, we need to tackle **challenges** of legacy non-cost reflective network tariffs, limited access to smart metering technology, and market rules not keeping pace with technological change. New technologies such as batteries and electric road transport have potential to substantially increase network costs if not integrated efficiently. Consumer engagement with electricity tariffs and enabling technologies, especially among vulnerable customers, has to broaden.

Possible **pathways** to address these challenges are cost reflective tariff reform that incorporates two-way pricing as a key factor for the optimal integration of DER, supported by the regulatory reviews and rule changes to improve access to smart metering technology and more flexible electricity services. This may be achieved via continuing engagement with customers and retailers on collective action to keep the electricity costs down.

Two-way network tariffs supporting the development of shared storage assets and innovative electricity sharing services, promoting flexibility, and rewarding customers for behaviour that helps avoid future network costs, would pave the way for local communities into a resilient **distributed energy future**.

1. Introduction

Argyle Consulting and Endgame Economics have been engaged by the Australian Energy Regulator (AER) to prepare a strategic piece on the challenges that the advent of electricity storage (batteries) pose for the design of electricity distribution network tariffs and network regulation more broadly.

In this paper we lay out the general principles for setting distribution network tariffs that work well in integrating Distributed Energy Resources (DER) of various kinds, including batteries. The possibility of such tariffs was enabled by the recent change in the National Electricity Rules (NER) on Access and Pricing for DER which recognises the transformation of the energy distribution to a two-way system, with DER playing an increasingly important role as a generation source and a network user.[2]

The National Electricity Objective (NEO) as stated in the National Electricity Law (NEL) is:

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety and reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.[3]

Tariff policy setting is guided by NEO, with long term interests of electricity consumers firmly in mind. Our discussion is shaped by the accepted general principles for tariff setting, such as the need to achieve:

- efficiency
- cost reflectivity
- technological and competitive neutrality
- fairness
- network revenue stability
- customer bill predictability
- simplicity of understanding or practicality of implemetation.[4,5,6]

Other supporting factors for successful tariff design are advanced metering, data sharing provisions and actions by retailers. Smart meters are necessary to support advanced tariffs. Without timely information on electricity use, customers or their devices cannot respond to the price signal. The blunter the metering technology, the duller the price signal conveyed by the network tariff. Innovative tariff structures and design are constrained by the level of sophistication of metering and DER technology behind the meter.

---

[2] AEMC (2021), *Final determination – Access, pricing and incentive arrangements for distributed energy resources*, August 2021. https://www.aemc.gov.au/sites/default/files/2021-08/Final%20determination%20-%20Access%2C%20pricing%20and%20incentive%20arrangements%20for%20DER.pdf. Accessed on 1 June 2022.

[3] *National Electricity (South Australia) Act 1996*, Schedule—National Electricity Law, cl 7.

[4] Bonbright, J.(1961), *Principles of Public Utility Rates*, Columbia University Press, New York, pp 27-41.

[5] Faruqui, A. and M. G. Aydin (2017), “Moving Forward with Electric Tariff Reform,” *Regulation,* Fall 2017, pp 42-28. https://object.cato.org/sites/cato.org/files/serials/files/regulation/2017/9/regulation-v40n3-5.pdf. Accessed on 1 June 2022.

[6] Oakley Greenwood (2019), *Pricing structures to assist the economically efficient integration of DER*, Report for ARENA, October 2019, http://oakleygreenwood.com.au/wp-content/uploads/2020/07/DER-Pricing-Approaches-Oct2019.pdf. Accessed on 1 June 2022.

The consequence of flat tariffs is higher network costs than optimal, because customers are unaware of the fact that consumption is more costly at some times than others. Over the past decade, solar PV installations have been offsetting the growth in air conditioning loads during the day but have not dampened the late afternoon – early evening maximum demand that continues to be the major cost driver. Most recently, many distributors have been facing diminishing demand during the solar generation peak period accompanied by voltage fluctuations and reverse power flows. The phenomenon is more pronounced in South Australia, the world leader in rooftop solar, with New South Wales and Queensland now observing the same issues in some locations. Battery storage can provide a solution for addressing the minimum demand issue, by absorbing excess generation during the solar peak. Likewise, a flexible increase in load during the peak solar generation hours can achieve a similar effect, if such behaviour is rewarded via a price signal.

New challenges and opportunities to the networks will ensue from the electrification of road transport, both personal and public. It is important that these recent advances in technology and investment in new DER including batteries either do not increase pressure on the existing network or that they keep the required increase to a minimum.

Non-cost reflective network tariffs have been recognised as a barrier to optimal investment in DER. Following the Access and Pricing rule change, tariffs can now support the efficient integration of DER.[7] Well-designed cost reflective tariffs can pre-empt the potential escalation of network costs by the expansion of new technologies if they send timely price signals reflective of future costs.

In this paper, we focus on batteries as one of the DER technologies with a high degree of two-way flexibility. The network price signal is not the only signal that customers with variable or flexible resources, such as batteries, are facing. Energy services contracts, frequency response services, voltage control, system strength can all send a price signal that can cause the battery to act in the opposite direction to what would be optimal from the network perspective. Wholesale price events can also create strong incentives for the battery to act against the network price signal. We will discuss the conflict that might arise when the signals are pulling the battery operator in opposing directions, and how to deal with this conflict to the benefit of all network users.

Context – the emergence of batteries

Power systems all over the world are experiencing rapid and profound change. The last decade has seen an inexorable rise in the penetration of renewable generation technologies, ie, wind and solar farms. In the past, these technologies accounted for only a small fraction of total electricity supply. But now they are a critical part of our power system, and their significance will only continue to grow.

These new forms of generation have different characteristics to thermal and hydroelectric generators. Their availability is not entirely at the discretion of the operator — they only generate when the wind blows or the sun shines. These characteristics are changing how we plan and operate power systems. Most notably, these characteristics have created enormous demand for the ability to store energy at times when it is plentiful and discharge it at times of scarcity.

7 AEMC (2021), *Final determination – Access, pricing and incentive arrangements for distributed energy resources*, August 2021. https://www.aemc.gov.au/sites/default/files/2021-08/Final%20determination%20-%20Access%2C%20pricing%20and%20incentive%20arrangements%20for%20DER.pdf. Accessed on 1 June 2022.

At the same time, we have seen the emergence of new technologies within the distribution system that challenge the most fundamental tenets of power system operation. Distributed technologies such as small-scale solar photovoltaic systems (PVs) are now in widespread use across the globe, presenting an alternative model of energy supply to that of large-scale centralised energy generation. And most importantly for this paper is the advent of cost-effective energy storage – battery costs are decreasing rapidly and giving rise to the prospect that energy can finally be stored by technologies other than hydroelectric plants.

The emergence of cost-effective storage has been a story over a century in the making. In 1883, Thomas Edison wrote:

> The storage battery is, in my opinion, a catchpenny, a sensation, a mechanism for swindling the public by stock companies. The storage battery is one of those peculiar things which appeals to the imagination…[8]

Edison's statement proved true for over a hundred years. But at the turn of the millennium, advancements in technology, the increased demand for energy and government pledges to achieve a net-zero electricity system by 2050 have all contributed towards turning batteries into a viable technology.

Batteries offer the possibility of an entirely different power system – one where supply from instantaneous generation need not always be perfectly matched with demand. Put another way, the fundamental principle that energy cannot be stored cheaply no longer holds.

Batteries are no longer a fringe technology – they are rapidly being installed across the electricity supply system serving a variety of purposes. Grid-scale batteries are providing services in the wholesale energy and Frequency Control and Ancillary Services (FCAS) markets. Smaller batteries are providing network support and load-management services. Community batteries are trialled to provide additional customer storage services. And at the household level, customers are using behind-the-meter (BTM) batteries to smooth out their consumption of energy to make better use of their solar PV systems in response to existing tariff structures (see Appendix A for more detail).

Batteries pose challenges, but also offer opportunities, to manage network and wholesale energy market costs. Non-cost reflective network tariffs have been recognised as a barrier to optimal integration of new technologies in the grid. However, if we can fine-tune our tariff arrangements to harness the power of batteries, we may ultimately see a reduction in overall consumer costs. If the network pricing fails to adapt, we may see batteries operating inefficiently, leading to an unnecessary rise in network costs and a poor outcome for consumers.

Rapid take-up of batteries means that continued tariff reform is necessary to ensure that our tariffs are fit for the new distributed energy environment including batteries. It is in the long term interests of consumers to ensure that network price signals help and not hinder in the efficient integration of batteries into the power grid.

Context – supporting regulatory change

Reform processes launched by the Energy Security Board (ESB) post-2025 Electricity Market Design review are paving the way for the new regulatory framework that new tariffs will operate in. The ESB's DER Implementation Plan is a suite of technical, market and regulatory reforms that address the emerging risks associated with DER and deliver benefits to consumers. Efficient

8 Edison, T. (1883), *The Electrician* (London), Feb. 17, 1883, p. 329.

integration of batteries, Electric Vehicles (EVs) and Virtual Power Plants (VPPs) are all part of the plan (see Appendix C for more detail).

Recognition of exports as distribution services following the Access and Pricing rule change and the removal of the prohibition of export charges opened the way for distributors to propose two-way tariffs. Such tariffs would enable networks to charge their customers not only for *drawing* energy from the grid (consumption), but potentially for *supplying* energy to the grid (export). These tariffs would also allow a reward for the behaviour that helps avoid network costs. Two-way tariffs can become a powerful tool, advancing the tariff reform and taking it to the new level. Chapter 2 of the paper discusses this is detail.

Structure of this paper

In this paper we seek to explore the consequences of the advent of batteries for electricity networks and for network pricing. The emergence of such a powerful technology has consequences that are far-reaching, affecting virtually every aspect of the power system. Although our focus is on networks, we will also touch upon other aspects of the electricity supply chain, eg, the wholesale energy market, retail, and markets for ancillary services.

The remainder of this paper is structured as follows:

- **Chapter 2** explores the direction of future two-way tariffs including tariffs suitable for batteries.
- **Chapter 3** examines the enablers for the efficient integration of batteries.
- **Chapter 4** discusses the next steps in developing distributors' tariff structures.
- **Chapter 5** concludes the paper.

Supporting information in provided in appendices:

- **Appendix A** provides an overview of the outlook for the uptake of batteries.
- **Appendix B** provides context on the principles of tariff design and examines the current tariffs arrangements for batteries.
- **Appendix C** examines recent reform processes that will assist the integration of batteries.

2. Future tariff directions

To be fit for purpose, network tariffs should enable recovery of efficient network costs from customer classes in a predictable and equitable way amid the rapid transformation of the energy delivery system.

The growth of distributed energy resources (DER) is making the distribution system increasingly two-way. Many distributors are moving away from volumetric charges to demand or capacity-based charges that reflect more closely the underlying network cost drivers and allow a fairer allocation of network costs to customer classes. Three-part tariffs have been taking hold internationally for this reason.[9]

Recognition of exports as distribution services following the Access and Pricing rule change and removal of the former NER clause 6.1.4 (prohibition of export charges) opened the way for distributors to propose two-way tariffs. Such tariffs would enable networks to charge their customers not only for *drawing* energy from the grid, but potentially for *supplying* energy to the grid.

The first round of Tariff Structure Statements (TSS) for which export charging will be enabled is the 2024-29 regulatory reset for NSW, ACT, Tasmania and Northern Territory distributors. Consultations on this reset round have already commenced. As a customer protection measure stipulated in the Rules, networks cannot mandatorily assign existing customers to export tariffs before 2025.

2.1. NER pricing principles extended to exports

The pricing principles that guide tariff-setting under the NER have been extended to the newly recognised export services. In May 2022, the AER published Export Tariff Guidelines, setting out general principles on:

- customer protections should two-way pricing be introduced
- justification that distributors need to provide for any two-way pricing proposals
- potential two-way tariff structures
- the AER's approval process for a TSS with two-way structures
- AER expectations on customer engagement by distributors when developing two-way pricing proposals, and
- guidance on the basic export level, or free (intrinsic) level of access to export service capacity financed by consumption tariffs.[10]

The Guidelines note that a distributor's export tariff transition strategy should be included as part of the TSS proposal, informed by the learnings from any tariff trials. Stakeholder engagement should underpin the transition strategy. The proposed tariffs need to be either understandable by customers, or capable of being directly or indirectly incorporated by retailers or aggregators in their contract offerings to customers.[11]

9 Faruqui, A. and M. G. Aydin (2017), "Moving forward with electricity reform", *Regulation*, Fall 2017, pp 42-48.
10 AER (2022), *Export Tariff Guidelines*, May 2022, https://www.aer.gov.au/system/files/AER%20-%20Export%20Tariff%20Guidelines%20-%20May%202022_0.pdf. Accessed on 1 June 2022.
11 NER cl 6.18.5(i).

The basic export level will be offered during a ten-year transition period, with the potential adjustment to this level within the regulatory period if justified using the methodology.
Based on the submissions to the Draft Guidelines paper, distributors are already evaluating the introduction of export charges, engaging with their customers, and exploring the potential tariff options in the tariff trials. AER released its final Export Tariff Guidelines in time for the distributors in the 2024-29 reset period to incorporate in their draft TSS consultation and proposals.

2.1.1. Extension of marginal pricing principles

The underlying principle for two-way tariffs is marginal cost pricing, covered in detail in Appendix B. Long Run Marginal Cost (LRMC) pricing is enshrined in the NER cl 6.18.5(f). With two-way services provided for by a shared asset, each of the services would attract an appropriate LRMC, to signal efficient price for the additional unit of service.

Different LRMCs would apply to consumption and exports, reflecting cost drivers for these services: peak demand for consumption, and minimum demand (peak solar) for exports. Other cost drivers might emerge and would be considered when calculating the appropriate marginal costs and allocating total costs to customer classes.

2.1.2. Potential classification of export services

The principle of symmetry discussed in this section presumes that consumption and export are both classified as standard control services, contributing to the same bucket of revenue allowance. Treating export services as alternative control service would be somewhat limiting as it would break the symmetry of the application of the pricing principles and remove the option of negative prices (rebates).

Under a price cap (the current form of control for alternative control services), there would be no incentive for the distributor to be charging anything below the cap, hence negative payments would never materialise. Keeping the common bucket of charges and rewards, aligned across the charging windows and the LRMC values, is best implemented within the standard control services classification for both consumption and exports.

In the remainder of the paper, we talk about two-way tariffs under the assumption that both consumption and export charges are – or can be – part of the standard control service tariffs laid out in the TSS. We discuss how rewards and charges are connected in contributing to the common revenue pool for standard control services.

2.1.3. Symmetric rewards and charges based on LRMC

Based on the LRMC pricing principle, the marginal price signals for efficient battery operations are:

- charge for an extra unit of consumption or export, if it creates additional network costs
- reward for an extra unit of consumption or export, if it avoides nework costs.

Table 2.1 below depicts the application of the principle of symmetric charges and rewards for two-way tariffs suitable for any bi-directional profiles including those supported by the batteries.

Table 2.1. Pricing principles of symmetric charges and rewards

Time period	Consumption price signal	Exports price signal
Peak demand (load)	Charge (MC_1)	Reward ($-MC_1$)
Peak exports	Reward ($-MC_2$)	Charge (MC_2)

Note: MC_1 is LRMC of consumption; MC_2 – LRMC of exports. These values, in general, are different and apply at different non-overlapping peak periods.

Batteries are well positioned to benefit from two-way pricing with symmetric rewards and charges because of the technical flexibility of its operations and the ability to switch from load to generation practically instantaneously.

2.2. Export charges as the next step of tariff reform

Following the Access and Pricing rule change, all distributors are starting with tariff structures containing various one-way consumption charges. Most customers still face flat consumption tariffs: just under 17% of residential customers in the NEM faced cost reflective network tariffs on 30 June 2021.[12] Factors such as the availability of advanced metering technology, tariff assignment policies, customer impact and engagement, and jurisdictional responses influence the speed of tariff reform.

To be cost reflective, consumption tariffs need to be moving towards marginal cost pricing. The starting position for consumption tariff reform was a legacy position that, while different across distributors in levels, was a simple two-part tariff with a flat energy charge.

Flat charges reflected the concept of postage stamp pricing, where costs were shared equally across the units of consumption. More recently, technological developments and access to new technologies raised the issue of fairness of a postage stamp uniform charge. When customers with access to technology (such as air conditioning) drove network costs higher for everyone, with recovery shared across the general customer base, customers without technology ended up paying more for costs they did not create. Seemingly equitable, flat tariffs were, in fact, unable to control increases in network costs that were falling disproportionately on those customers who could not afford or access new technologies.

As tariff reform progresses, flat tariffs are being replaced by Time of Use (TOU) energy charges that vary by time of the day, and now TOU-demand tariffs that make it possible to charge customers for maximum consumption within a 30-minute interval within the peak window. These tariff structures allow a more accurate attribution of forward-looking network costs to those customers who cause them.

Because export charges were prohibited until now, export tariffs are starting from a clean slate, but also from the customer expectation of services that have been provided for free. One of the advantages of this starting point is that there is no legacy of averaging or postage stamp pricing like that which applies to consumption.

[12] AER (2022), *Network tariff reform*, https://www.aer.gov.au/networks-pipelines/network-tariff-reform. Accessed on 1 June 2022.

2.3. Locational export charges can improve efficiency

Distribution networks were built to enable customers to consume centrally generated electricity. Servicing load (consumption) was the main distribution service before the DER transformation commenced. As demand for export services by DER customers grew, it was accommodated by headspace of some level of capacity already provided by the networks and recovered by consumption tariffs. However, this hosting capacity is limited and becoming exhausted with increased penetration of DER.

The hosting capacity constraint is non-uniform. Some areas suffer from a higher level of congestion than others, with customers' inverters tripping and their DER installations unable to export or generate at the time of peak export constraint. When facing the localised constraint, customers might be more willing to accept a charge that allows alleviating this constraint.

Private benefits to the customer would be more tangible if the customer experienced the consequences of the hosting capacity constraint and understood that the charge would fund its alleviation. Hence, it is not unreasonable to expect that a locational LRMC as a charge or reward for the expansion of local hosting capacity may become acceptable to customers. More research and customer engagement is required to establish customer acceptability of locational price signals. For locational pricing to gain acceptance, the costs should be clearly and transparently communicated and the benefits to the customer from locational pricing should outweigh the costs.

2.3.1. Should locational charges be based on Long Run or Short Run Marginal Costs?

The average LRMC for exports can be low when there is sufficient headroom in hosting capacity, hence both charge and reward discussed in Table 2.1 are low. In localised pockets, however, augmentation might be required soon, and localised LRMC is much higher. A localised LRMC might become a basis for a locational price signal.

Short Run Marginal Cost (SRMC) might provide even a sharper locational signal, especially in the dynamic pricing context.[13] This measure is more volatile than LRMC and has not been adopted in the NER. We consider that disaggregated LRMC is appropriate as an efficient signal for locational or tiered pricing. Some distributors already calculate disaggregated LRMC by region within their distribution area, for consumption services.

Localised LRMC can be much higher and more variable than system average LRMC which forms the basis for the general tariff setting. More accurate signalling of locational costs would lead to more efficient consumption and investment decisions, including the customers' decisions to invest in batteries and other DER. For example, in areas with lots of headspace for exports but constrained for load, two-way LRMC-based pricing would promote the connection of west-facing solar PV and supporting batteries, ensuring efficient integration and operation of DER and keeping network augmentation costs to the minimum.

2.3.2. Locational rewards could be the first step towards locational pricing

The NER allows and even calls for locational pricing.[14] There are already ongoing tariff trials of critical peak pricing in certain locations. While price structures may remain averaged for a whole

---

[13] CEPA (2020), *Distributed Energy Resources Integration Program – Access and Pricing Reform Options,* Report for the Australian Energy Market Commission, 9 April 2020, p 113. https://arena.gov.au/assets/2020/03/distributed-energy-resources-integration-program-access-and-pricing-reform-options.pdf. Accessed on 1 June 2022.

[14] NER cl 6.18.5(f)(3).

distribution area, rewards might become locational, creating sharper signals for efficient investment in DER technology.

Distributors have learned from their customer engagement on cost reflective consumption tariffs that to support the new tariffs, customers must understand how they can benefit from them. To get customers' buy-in for locational tariffs, it would be easier to start with export charges where no precedent has been established. Export charges present a unique opportunity for trialling locational price signals, especially if paired with symmetric rewards. This would present a clear net benefit to the customer.

Arguably, customers would understand that intrinsic hosting capacity is unevenly distributed across areas and may therefore be willing to pay more (via locational charges) to help alleviate a local constraint. However, customer support of postage stamp pricing in consumption (load) has been strong. Locational pricing would add a new level of complexity to what is already a complex space for retail customers to navigate. Starting with locational rewards for exports seems to be the most realistic step in moving towards locational pricing.

2.4. Dynamic tariffs reflective of cost savings

Under the two-way marginal cost pricing, customers can be rewarded for helping avoid marginal cost by changing their consumption or generation behaviour. An alternative way to avoid marginal costs could stem from the application of some form of control by the network, to prevent the customer from behaving in a manner that gives rise to an augmentation cost.

2.4.1. Reduced tariffs when distributors exercise some degree of control

For some types of load distributors could offer their customers reduced tariffs in exchange for the distributor exercising some degree of control over the operation of customers' load.

Controlled load tariffs for hot water heating present an example of this idea in current tariff structures. By making the supply available within specified service parameters and only during the hours when a customer's load cannot contribute to peak demand, controlled load tariffs lead to substantial discounts. Note that controlled load is currently offered as a secondary tariff and only for certain classes of customers.

Using a similar approach, if the network is given a technical capability to curtail how batteries charge or discharge in a dynamic way (with time windows reflecting actual network conditions), a dynamic tariff might be offered at a discount which reflects the reward to the customer up to the amount of avoided network costs.

2.4.2. Dealing with conflicting drivers of battery behaviour

Sometimes there are conflicting objectives for battery behaviour, when the network seeks one outcome, and the wholesale market sends signals that may work in the opposite direction. A conflict would arise if the dynamic connection customer responded to a wholesale market price signal that triggered the behaviour that created network costs. Consider the example of a battery that can provide energy to support the network or sell its energy into the wholesale energy market. Suppose that there is a heatwave and prices in the wholesale market rise to the market price cap, but at a time where the network still has a degree of spare capacity. The battery now faces an incentive to discharge its energy to take advantage of high wholesale prices, but the network might prefer to keep the energy in the battery in reserve in anticipation of higher demand later in the day.

The challenge here is that, although high wholesale market price events may sometimes coincide with peak demand on the network, there is no guarantee that this will be the case. The problem is one of conflicting objectives – the network seeks one outcome, and the wholesale market sends signals that may conflict with the network objective.

In this case, a hierarchy of instructions could be established, eg, by using contractual arrangements to ensure the order of the battery's provision of services. AECOM's analysis considers a possible value stack of battery services which establishes priority of services based on the financeability of the commercial project at a reasonable interest rate. This approach places higher priority on direct contract for capacity and availability, followed by market services in order of volatility.[15] Penalties for the battery's failure to provide contracted network support services, or counter-acting incentives, could be set high enough to ensure that network support has the highest priority in the battery's hierarchy of instructions.

2.4.3. Distributors need a social licence to control customers' appliances

Even if giving up some degree of control over the BTM installation offers customer savings, the distributor or a third party exercising this control needs to earn a social licence, permission to control customers' appliances.

Research shows that customers willing to give up control of their appliances to devices are younger, wealthier and more tech-savvy. Older customers are not willing to give up control and lose as a result.[16] A recent study commissioned by Energy Consumers Australia investigates what is required to develop customer confidence to hand over control of their appliances.[17]

Technical and cyber concerns need to be addressed, to ensure that the required data is exchanged and available to all parties in a secure way, and that customer privacy is maintained. A different level of complexity arises if pricing signals are dynamic and called with short advance notification. Interconnected, real-time pricing would require an upgrade of distributors' data processes, aggregation, retailer communication protocols, billing, and reconciliation.

2.4.4. Customers without DER can benefit from two-way tariffs

Customers with more flexible load and the technology to control this load would benefit more from new two-way tariffs than customers who cannot change their consumption pattern. For example, customers with PV solar and BTM batteries are contributing to the network costs on a net load basis, enjoying total bill savings due to self-consumption (own generation) and avoiding at least some peak energy charges or shaving-off peak demand (own storage). Customers without similar DER can exercise less control and are contributing more to the network costs. In designing network tariffs, avoiding the potential cost-shifting (or cross-subsidy) from 'DER haves' to 'DER have-nots' should always be at the front of the tariff-maker's mind.

Another important feature of the potential new two-way tariffs is their ability to reward customers without DER for consuming more energy at those time when this consumption alleviates an

[15] AECOM (2019), *Grid vs Garage: A comparison of battery deployment models in providing low voltage network support and other services,* Report for ARENA, December 2019, p 25. https://arena.gov.au/assets/2020/04/arena-grid-vs-garage.pdf. Accessed on 1 June 2022.

[16] Nicholls L., Y. Strengers and S. Tirado (2017), *Smart home control: exploring the potential for enabling technologies in vulnerable, disengaged and regular households*, Centre for Urban Research, RMIT University, Melbourne, https://energyconsumersaustralia.com.au/wp-content/uploads/Smart-home-control-exploring-the-potential-for-enabling-technologies-in-vulnerable-and-disadvantaged-households.pdf. Accessed on 1 June 2022.

[17] CutlerMerz (2020), *Social Licence for Control of Distributed Energy Resources*, Final Report for Energy Consumers Australia, December 2020, p ii-iv. https://energyconsumersaustralia.com.au/wp-content/uploads/Social-License-for-DER-Control.pdf. Accessed on 1 June 2022.

export network constraint during the solar peak. The customer would require a smart meter to maximise this saving.

To receive a fully negative charge (rebate) at the retail level, the non-DER customer would need to face a wholesale spot price low enough to offset, together with the negative Distribution Use of System (DUOS) charge, the other, positive components of the total bill. These are the remaining network bill components — Transmission Use of System (TUOS) and Jurisdictional Scheme Amounts, as well as the cost of environmental polices collected by retailers, retail costs and profit margin.

2.4.5. Technology neutral tariffs rewarding flexibility

Technological change happens so rapidly that it is essential to stay technology neutral when discussing tariffs. Note that new technology triggering tariff reassignment is still appropriate as it advances the tariff reform. We consider that the same pricing principles should apply to the battery as to any flexible load that can be a net generator at certain times.

New electricity services will emerge, with non-network IT and data management solutions replacing the need for expensive assets. The level and shape of a community battery tariff, for example, should not disadvantage alternative provision of flexibility by a small generator aggregator (SGA) or a virtual power plant (VPP) response. Likewise, matching flexible load such as hot water heating, air conditioning or electric vehicle (EV) charging, to solar peak generation should be rewarded.

VPPs orchestrating behind-the-meter flexible responses would require advanced metering, with potentially new opportunities becoming available if the ESB post-2025 recommendation on flexible trading arrangements (FTA) progresses via the rule change. Model 2 of the FTA proposal considers multiple financial relationships for the sub-NMI channels. This would make network billing more complicated, less likely to be easily understood by a customer, and more heavily reliant on retailers or third parties to help customers benefit from the arrangements using supporting technology such as Home Energy Management Systems (HEMS).

Orchestration of the operations would prevent the load spikes caused by smart appliances responding to times when the network tariffs change from peak to shoulder or off-peak (eg, the start of the off-peak charging rate). Randomisation of the start time (to prevent simultaneous start) of appliances can be used, like the ripple control of hot water heating on controlled load tariffs.

Distributors are positioning themselves for the role of the Distribution System Operator (DSO) to orchestrate flexible response and dynamically control the load and generation behind the meter. With such an orchestration, congestion on the network can be avoided and more activities can happen over the same set of wires and transformers without creating the need to augment the network.

Conflict between network and wholesale market optimisation needs to be resolved with the help of smart network tariff solutions, supplemented by a network’s ability to over-ride or take control of the appliances when network conditions require it. Tariff trials are currently in place to test the customer willingness to accept a reduced tariff rate in exchange for the network’s ability to limit supply when system stability requires it (eg, a trial offering a rebate to customers for EV dynamically controlled load charging).

2.5. Local Use of System (LUOS) pricing

The concept of Local Use of System (LUOS) pricing recognises that the network costs should be reflective of the depth of network use. LUOS has been discussed since the unsuccessful 2014 rule change proposal on Local Generation Export Credits by the City of Sydney, Total Environment Centre and Property Council of Australia.[18] A consultant report accompanying the rule change proposal laid out general principles for calculating negative prices (reward) for exports during peak load times (so called Distributed Energy Credits), supported by Virtual Net Metering.[19] The AEMC rejected the proposal at that stage, but the idea that customers should be rewarded for the benefits they deliver to the system has been alive and discussed at various stakeholder and research forums. The Access and Pricing rule change process also raised the issue of LUOS, as it relates to battery storage.

2.5.1. Network tariffs as an impediment to community batteries

Community battery schemes have been commercially disadvantaged by standard network tariffs that presume all energy travels the full way from a wholesale market reference point, via the transmission network, then the high voltage distribution network, to the local voltage area where the community battery and its users are located. Instead, the laws of electricity flow mean that a locally generated electron harvested by the community battery may not travel far and therefore may not utilise assets other than low voltage poles, wires, and transformers. The same electron released by a battery during the peak consumption period travels locally and helps to avoid the network augmentation costs that are signalled by the peak period network consumption charge.

Charging this customer's consumption at peak energy price makes using a community battery for shared customer storage less attractive. Compared to a collection of individual BTM batteries, community batteries may offer a more cost-efficient solution from a technological viewpoint. There are additional benefits in terms of services a community battery can provide both to the network and to the market. Multiple papers identified existing network tariffs as a major barrier to the feasibility of community-scale batteries.[20]

The network is a shared resource. With the DER revolution, the network becomes a platform with its value to users increasing as the number of users increases. The more customers sharing the network to receive services they value, the cheaper it becomes for each customer and each service as total costs are spread across a wider customer base and/or range of charging parameters – but only if system average costs are not rising. Increasing utilisation of local network assets without creating a new local constraint would be beneficial to all customers, provided that the local flows attract a cost reflective network tariff. Reduced local network tariffs have been

---

[18] AEMC (2016), *Final rule determination - National Electricity Amendment (Local Generation Network Credits) Rule 2016*, December 2016, https://www.aemc.gov.au/rule-changes/local-generation-network-credits. Accessed on 1 June 2022.

[19] Langham, E., J. Rutovitz, C. Cooper and C. Dunstan (2014). *Calculating the network value of local generation and consumption.* Report prepared for Total Environment Centre and the City of Sydney, pp 24-27. https://opus.lib.uts.edu.au/bitstream/10453/149165/2/ISF_TEC_CoS_VNM%20Stage%201_FinalReport.pdf. Accessed on 1 June 2022.

[20] ANU (2020), *Jacka community battery – Feasibility study*. https://suburbanland.act.gov.au/uploads/ckfinder/files/pdf/1_About/Sustainability/Attachment%20C%20-%20Feasibility%20Study%20Report.pdf. Accessed on 1 June 2022; ANU (2020), *Implementing community-scale batteries: regulatory, technical and logistical considerations*. 2020. https://arena.gov.au/assets/2020/12/bsgip-regulatory-technical-and-logistical-considerations.pdf. Accessed on 1 June 2022.

found to be crucial for incentivising battery charging from locally generated solar energy and the sale of energy to local customers.[21]

In their recent paper, Sturmberg, Shaw et al (2021) state that supported by discounted tariffs under certain conditions, a community battery scheme improves the mutual benefit to the community scheme participants (both exporters and net importers) while keeping network revenue constant.[22] The solution proposed in the paper was for distribution tariffs outside the local energy sharing scheme to increase, to keep the network's total revenue constant. It can be argued that the benefits to the scheme participants were in fact funded by the customers outside the scheme who were required to fund the discount afforded to the scheme participants. The unintended transfer (or cross-subsidy) from the general customer base to scheme participants is discussed in the following section.

2.5.2. Avoiding unintended consequences of network tariffs

Cross-subsidies or wealth transfers between customer classes might arise when tariffs do not reflect underlying costs or create perverse incentives. Tariff reform, driven primarily by economic efficiency considerations, addresses cross-subsidies when they become apparent.

For example, flat network tariffs do not allocate sufficient costs to the users responsible for the growth in peak demand due to large loads such as air conditioners. Recovery of network augmentation costs required to fund growing demand via flat volumetric tariffs allocates costs to those customers who did not contribute to the peak. Time of Use (TOU) tariffs are the answer to this problem using 'causer pays' principle, with volumetric (per kWh) prices set at a higher level during the peak demand period signalling the capacity constraint at those times.

The growth in DER such as rooftop solar PV led to lower average energy consumption from the grid due to generation and self-consumption by DER customers. Network costs, however, continued to rise driven by peak demand. With energy consumption (kWh) as a basis for charging, network costs would need to be recovered from volumetric consumption charges, increasing a relative burden on customers without DER who draw all their energy needs from the grid. Arguably, volumetric energy-based tariffs are no longer cost reflective nor equitable with the increasing penetration of DER.

Demand tariffs offer a solution that avoids this pitfall in the high DER environment, by introducing a variable charging parameter (kW or kVA) different from energy consumption (kWh). However, batteries can shave off peak demand, flattening the DER customers' load and minimising their demand charges. This could lead to lower network charges for DER customers if the peak shaving occurs during the entire peak demand period. An unintended consequence of demand tariffs could be their impact on the diversity of electricity use across customers. In the scenario when customers' loads are completely flattened by their BTM batteries, there will be no remaining diversity and the aggregate peak demand might go up. However, we expect that a significant variation in household composition and lifestyles will be able to preserve a sufficient level of diversity. Based on the recent research on smart home control, households are often reluctant to

---

21 ANU (2020), *Implementing community-scale batteries*. Final report for the ARENA-funded Community Models for Deploying and Operating DER project, carried out by the Battery Storage and Grid Integration Program, December 2020, p 3, https://arena.gov.au/assets/2020/12/implementing-community-scale-batteries-bsgip.pdf. Accessed on 1 June 2022.

22 Sturmberg, B., M. Shaw, C. Mediwaththe, H. Ransan-Cooper, B. Weise, M. Thomas and L. Blackhall (2021), "A mutually beneficial approach to electricity network pricing in the presence of large amounts of solar power and community-scale energy storage", *Energy Policy*, Vol. 159 (6), December 2021: 112599.

hand over their energy management to devices. Even when operating in the background, devices still require considerable user involvement and encourage new lifestyle expectations.[23]

BTM batteries help DER customers moderate their network bills. A better outcome for all customers, both in terms of cost and reliability, can potentially be achieved by utilising community batteries, with shared energy storage found to be overperforming individual storage both operationally and economically.[24] In designing tariffs suitable for batteries, it is important to test through tariff trials whether there are any unintended consequences from the network tariffs on the batteries' operational behaviour and the resulting revenue implications.

2.5.3. LUOS tariffs offer a solution to the community battery problem

If the network can demonstrate that a community battery only uses the local network, it is beneficial to price access to this asset at a reduced, Local Use of System (LUOS) level. Figure 2.1 depicts the composition of the total Network Use of System (NUOS) charge allowing for further separation of the local, low voltage (LV) component of these costs.

System costs are minimised when the load is near the generation. Hence, locating generation close to the load or providing a storage solution to achieve a temporary balancing of load and generation is beneficial to all parties, including the network.

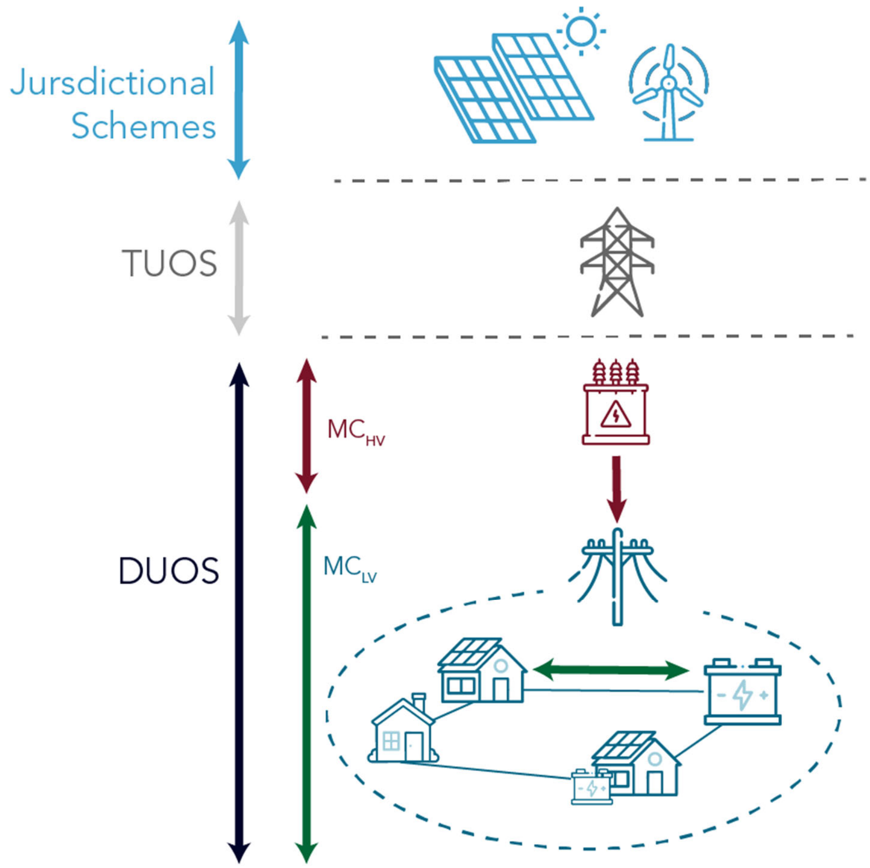
LUOS pricing can apply to balanced flows in community battery schemes or other local energy sharing schemes with DER (eg, vehicle-to-grid and VPP). Such schemes are represented by links and green arrows in the bottom part of Figure 2.1. Note that even without a formal recognition of local flows, the physical energy flows are already balanced locally, with distribution losses diminishing when DER generation is offset by matching local load. It is when the local load and generation are in disbalance that network issues such as voltage spikes and reverse flows occur.

---

23 Nicholls L., Y. Strengers and S. Tirado (2017), *Smart home control: exploring the potential for enabling technologies in vulnerable, disengaged and regular households*, Centre for Urban Research, RMIT University, Melbourne, pp 10-11, https://energyconsumersaustralia.com.au/wp-content/uploads/Smart-home-control-exploring-the-potential-for-enabling-technologies-in-vulnerable-and-disadvantaged-households.pdf. Accessed on 1 June 2022.

24 Walker, A. and S. Kwon (2021), "Analysis of impact of shared energy storage in residential community: Individual versus shared energy storage", *Applied Energy*, Vol 282(A), January 2021, 116172.

Figure 2.1. Local use of network (LUOS) concepts



At the time of export congestion (solar peak), a local (community scale) storage system should be rewarded for alleviating the export constraint (LV export congestion cost). If later in the day it discharges during the peak demand period, it should be rewarded for the avoided consumption LRMC ('upstream' LRMC). These are the principles discussed in Table 2.1 on the symmetry of charges and rewards. The reward is the avoided cost of upstream augmentation that is no longer required due to the battery discharging previously stored energy, locally. Shared battery storage systems are demonstrated to reduce total system costs by reducing total power peaks, with a sharper reduction than that achieved with individual storage solutions.[25]

To improve the price signal, the LUOS price should be locational (or at least tiered, by the degree of congestion/acuity of the constraint).[26] It is only natural that *local* use of system costs would depend on the location and its constraints. With the new LUOS concept trialled for network tariffs, it is important to keep it locational or at least tiered, to not create a new legacy of a system average cost that stops being reflective of actual local constraints.

[25] Skoglund, I., M. Rostad and K. Thorvaldsen (2021), "Impact of shared battery energy storage system on total system costs and power peak reduction in commercial buildings", *Journal of Physics: Conference Series,* 2042 (2021) 012108.

[26] Sturmberg, B., M. Shaw, C. Mediwaththe, H. Ransan-Cooper, B. Weise, M. Thomas and L. Blackhall (2021), "A mutually beneficial approach to electricity network pricing in the presence of large amounts of solar power and community-scale energy storage", *Energy Policy*, Vol. 159 (6), December 2021: 112599.

LUOS customers should pay their share of total network costs

With the LUOS concept, the issue of the fairness of a customers' contribution to total network costs remains. If customers do not disconnect from the grid due to the required reliability and the prohibitive – and inefficient – cost of going off grid but have enough autonomy to use LUOS most of the time, what would be their fair contribution to network costs? How much would the network need to recover from these customers who would require the broader network to service their load just 5% of the time?

Our view is that customers should be contributing equitably to the residual costs of running the distribution network, which is a shared resource for all customers. One way to establish equity is to charge customers for the capacity of the connection that needs to be maintained all the time to service them, even if the service is required just 5% of the time. This can be achieved, for example, via an all-time capacity charge. Scaled by the size of the customer connection, the capacity charge would be more equitable than an alternative fixed charge that would affect disproportionately smaller users. In summary, successful and sustainable LUOS pricing requires customers to make a fair and ongoing contribution to residual network costs.

2.5.4. Opportunities from LUOS pricing

LUOS pricing helps to unlock additional value streams and enable more activity on the network such as flexible response and trading. Pricing for the depth of network use was found to help avoid inefficient duplication of network infrastructure, demonstrated in virtual trials.[27] Flexible load can become orchestrated and operated by the third-party provider (aggregator or VPP), to increase retail offerings to customers, provide value to the operators, and increase network utilisation.

Tariffs supportive of flexible load might drive efficient investment in batteries and other flexible technologies. Together this may lead to a more resilient network capable of islanded short-term operations, preventing mass blackouts in the event of generation failure, bushfires, floods and technogenic catastrophic events.

If properly integrated, batteries are good for networks because they can make networks more reliable, more responsive, and stable. Batteries can provide a backup for the temporary failure of large generators, as well as cost-effective customer storage.

A new technology that shows great promise are batteries on wheels: electric vehicles, that are not only flexible bi-directional users but are also mobile. Bi-directional cost reflective tariffs with locational rewards and charges might support commercial models of mobile EV charging combined with parking, where third party providers would valet-park EVs at the location where they can earn money by charging and potentially at a different location (or time of the day), by discharging. Electric public transport with replaceable batteries could provide an even more powerful network support solution.

In the same manner as batteries, any flexible load at customer premises can be rewarded by an innovative tariff. It might be possible to separate out this flexible load and use a different retailer to maximise the market opportunities. The flexible trading arrangements rule change would support this.

[27] Rutovitz, J., S. Oliva, L. McIntosh, E. Langham, S. Teske, A. Atherton and S. Kelly (2018), "Local network credits and local electricity trading: results of virtual trials and the policy implications", *Energy Policy*, Vol 120, May 2018, pp 324-334.

LUOS pricing reduces the incentives for customers to build behind-the-meter assets or duplicate network infrastructure. Often there are cases of multi-site customers who install a large generation facility in one of the sites, trying to offset consumption on other sites with their own generation. Current tariff structures do not allow this to happen.

With the LUOS approach, if the generation and load are situated in different sites within the same location, a community energy sharing scheme might allow for this customer to achieve the effective outcome of consuming their own generation, and potentially earning rewards by supplying excess generation within the scheme or depositing it in the community battery for own consumption later in the day. This would also diminish the economic incentives for creating embedded networks, allowing more customers to stay directly connected to the shared distribution grid.

2.6. Contribution of batteries to transmission costs

Network tariffs recover the costs of using all components of the network – so called Network Use of System (NUOS) charges. The portion of NUOS that recovers the costs of transmission is called Transmission Use of System (TUOS), or in the NER definition, designated pricing proposal charges. Distributor's own efficient costs and allowed cost pass-throughs and adjustments are recovered via Distribution Use of System (DUOS) charges. And finally, the cost of government policies mandated into network tariffs is recovered via Jurisdictional Scheme Amounts (see Figure 2.1 above).

In the previous section we discussed local flows balanced by the battery that could be eligible for a discounted LUOS tariff to reflect the reduced depth of the system use for these matching flows. In this case, all upstream costs such as the high voltage component of DUOS as well as TUOS would not apply at the margin. However, this does not mean that the battery or the community battery scheme participants should not be paying TUOS. We discuss this point in the following section.

2.6.1. Relationship between LUOS and avoided transmission costs

In deciding whether the battery or another large customer with flexible load should be contributing to transmission costs, it is important to understand how the battery operates and what proportion of the flows would be traded to and from the NEM. A reasonable contribution to transmission costs depends on the customer's period of operation and on whether, during the coincident peak, the customer was a generation or a load. It would also depend on, for a community battery, whether the battery's load was balanced with its customers' generation and vice versa.

For the battery charging outside the peak export window or in excess of the combined generation of its customers, the energy is considered drawn from the upstream system, and full TUOS should apply. This should not be different from the treatment of any other customer with flexible load that can be net *generator* or net *load* at different times.

Large batteries (grid scale at distribution levels, with a consumption of 40 GWh per year and above) would likely face locational TUOS using their connection point. They would also be assigned their Distribution Loss Factor (DLF) calculated using the plausible operating profiles.[28]

Batteries connected under NER Chapter 5 (as an Embedded Generator or a Market Network Service Provider) would be eligible for avoided charges for the locational component of prescribed

[28] NER cl 3.6.3(b)(2)(i).

TUOS services.[29] There are tariff trials in place awarding the participating batteries avoided locational TUOS if it was generating at the time of coincident peak and charging TUOS if it was a load at that time.

As a load, all customers are sharing in transmission costs, including non-locational and common costs, as well as locational costs that have been passed through by distributors into different charging parameters. While it is more cost reflective to pass through transmission costs into the demand or capacity component of the network tariff, the non-coincident fixed time window for calculating the demand or capacity still makes the resulting charge not particularly cost reflective for any customer. It is an example of a cost allocation method based on general principles of fairness and reasonable attribution of costs. By avoiding charging during the peak load time window, large batteries can avoid the demand or capacity charge altogether. For the battery, it would make sense to reduce the amount of costs recovered via energy (kWh) charges to the bare LRMC discussed in Table 2.1. Other tariff components (such as fixed or capacity charges) could be used to recover the appropriate share of transmission costs.

2.6.2. Even playing field for transmission and distribution connected batteries

Currently, distribution connected grid-scale batteries, like any other load customer connected at the same voltage, would face a distribution network tariff that covers the NUOS charges defined in the TSS and counted towards the total revenue cap. At the same time, transmission connected batteries can negotiate access to the transmission services and its price with the transmission service provider.

Revenue from such negotiated services is additional to the revenue cap determination. Without a transparent methodology to establish the negotiated service price, there is a risk of transmission network service providers under-pricing access to attract batteries connecting at transmission level while it might be more efficient for them to connect at distribution level.

To ensure that the race for batteries does not end up with inefficient location of storage assets on the grid, it is important to maintain competitive neutrality between distribution and transmission connected assets. Renewable Energy Zones in their storage component should guide efficient connection of the battery assets where the net benefit from their operations is the highest. Allowing the distributors to offer negotiated services to large flexible customers such as grid-scale batteries and green hydrogen producers would also level the playing field between transmission and distribution. A negotiating methodology and a cost allocation methodology (CAM) would need to be put in place to ensure that negotiated services are not cross subsidised by the wider customer base.

2.7. Contribution of batteries to the cost of government policies

Multiple government policies provide incentives for DER including batteries. The NSW Government offers homeowners in eligible postcodes access to interest-free loans to install solar battery systems (up to $14,000 repayable over 8 years, for a solar PV and battery system, and $9,000 repayable over 10 years, to retrofit a battery system to an existing solar PV system).[30]

29 NER cl 5.3AA(h).

30 NSW Government (2022), *Energy Saver*, https://www.energysaver.nsw.gov.au/browse-energy-offers/household-offers/apply-empowering-homes-solar-battery-loan-offer. Accessed on 1 June 2022.

Similar programs, offering either interest free loans or rebates on battery installation, have been established in Victoria,[31] South Australia,[32] and the ACT.[33]

Large scale policies such as the NSW Climate Change and, from 2023-24, Renewable Energy Zones (REZ), are funded via Jurisdictional Scheme Amounts included in network tariffs. Allocation of these costs to customer classes depends on the scheme conditions and the distributor. Often there is a prescribed manner in which to allocate these costs. For example, less than 25% of the NSW Climate Change Fund can be recovered from residential customers.

These prescriptions mean that the resulting NUOS tariff might be less cost reflective than the DUOS component of it. The charging parameter to which the cost of government policies is allocated also influences the resulting cost reflectivity of the tariff at a NUOS level, and the strength of the marginal price signal that can be either sharpened or weakened by these add-ons.

2.7.1. Transparency of jurisdictional scheme costs

Government policies can result in a large increase in network bills. For example, the Australian Capital Territory (ACT) distributor EvoEnergy in its 2021-22 proposal required a 36% real increase in residential bills, driven by the cost of environmental policies.[34] EvoEnergy is obligated to recover via network tariffs the costs of jurisdictional schemes such as the Energy Industry Levy, Utilities Network Facilities Tax, and Feed-in Tariff (small, medium, and large scale). The ACT Government has made a commitment to 100% renewable and 250 MW of batteries.[35] The costs of these commitments are passed through into EvoEnergy's network charges.

It is important to maintain transparency of any jurisdictional scheme costs and of any related exemptions, to ensure that customers understand the reasons for their network bill movement.

2.7.2. Competitive neutrality

Storage assets are part of the new jurisdictional REZ schemes funded via distribution network tariffs. One may argue that assets funded by such a scheme – if connected at the distribution level – should be exempted from the Jurisdictional Scheme Amounts component of network charges. This argument would be akin to the familiar debate about whether public servants should pay taxes. Our view is that batteries should not be exempted for the reasons explained below.

For competitive neutrality and economic efficiency, customers with similar load characteristics and levels of services should be facing the same cost reflective tariff. Batteries should be treated no differently to other loads, sharing in the recovery of jurisdictional scheme amounts. In some battery tariff trials, batteries have been allocated jurisdictional scheme amounts on a net energy (energy losses) basis. It can be argued that this creates preferential treatment for batteries compared to other flexible loads.

---

31 Solar Victoria (2022), ***Solar Battery Rebate,*** https://www.solar.vic.gov.au/solar-battery-rebate. Accessed on 1 June 2022.

32 Government of South Australia (2022), *Home Battery Scheme*, https://www.homebatteryscheme.sa.gov.au/about-the-scheme. Accessed on 1 June 2022.

33 ACT Government (2022), *Everyday Climate Choices,* https://www.climatechoices.act.gov.au/policy-programs/next-gen-energy-storage. Accessed on 1 June 2022.

34 Evoenergy (2021), *Network pricing proposal 2021/22*, January 2022, p 1. https://www.aer.gov.au/system/files/Evoenergy_2021-22%20Electricity%20Network%20Pricing%20Proposal_30%20Apr%2021%20Public_2.pdf. Accessed on 1 June 2022.

35 ABC (2020), 'ACT Labor promise Canberra-wide network of renewable energy batteries if elected', https://www.abc.net.au/news/2020-09-30/biggest-renewable-battery-promised-act-labor-election/12715314?nw=0. Accessed on 1 June 2022.

Incorporating all relevant costs into NUOS tariffs would ensure efficient integration of innovative solutions in future, such as vehicle-to-grid (V2G), mobile batteries with roaming virtual NMIs, large flexible loads like pumped hydro and other technologies that might emerge.

2.8. Contribution of batteries to recovery of residual costs

We discussed the way in which marginal cost pricing based on LRMC provides a signal for efficient consumption decisions at the margin. However, tariffs also need to recover network revenues in full, while marginal cost prices cover only a fraction of these total costs.

More work needs to be done, but preliminary indications are that applying the pure LRMC charge to the corresponding charging parameter (eg, peak energy, demand or capacity) would recover between 10-30% of total efficient distribution costs, depending on the network. The rest of total network costs are residual costs that need to be recovered from a combination of available charging components in the least distortionary way.

Our view is that batteries should not be treated differently from other customers in their contribution to the recovery of residual costs. That is, batteries should contribute to the total network costs on the same grounds as other network users with a similar load and/or generation profile. Principles for the fair allocation of residual costs across tariff classes, specifically for batteries, could be tested during the upcoming consultation on the new TSS proposals for the 2024-29 regulatory reset. We anticipate this consultation could provide valuable insights on customers' willingness to pay for the export services above the basic level and for the different level of service.

2.9. Transitional arrangements

Basic export levels have been included in the Access and Pricing rule change as a consumer protection transitional measure.[36] During the tariff transition period, a distributor must not charge a retail customer for export services up to the basic export level applicable to the customer's tariff. Basic export level mitigates transition for existing DER customers who could become subject to export charges following the rule change.

The AER's Export Tariff Guidelines note that the distributors must justify their proposed basic export levels in their TSS. Basic export levels may vary during the ten-year transition period to account for potential changes in DER penetration, customer responses to export tariffs and government policy. [37]

It is essential that reform towards cost reflective *consumption* tariffs not only continues but accelerates over the next ten-year transition period for export charges. Without this reform, the opportunities to effectively integrate more DER into our distribution network would be underutilised.

The basic export level is a transitional measure made available to all customers for consumer protection reasons. Arguably, large commercial and industrial customers would not require such protection, however, the basic export levels still apply to these customers under the NER.

It would be necessary to test the appropriate basic export level for commercial customers in order to avoid unintended distortions for customer exports and services associated with these exports.

---

36 NER cl 11.141.12.

37 AER (2022), *Export Tariff Guidelines*, May 2022, pp 18-19,https://www.aer.gov.au/system/files/AER%20-%20Export%20Tariff%20Guidelines%20-%20May%202022_0.pdf. Accessed on 1 June 2022.

Potentially, a mismatch of basic export levels between commercial customers and residential or small business customers, coupled with two-way tariffs offering charges and rewards, may favour some service solutions over others.

For example, if the basic export level for a 1MW community battery was set too low, the battery would be disadvantaged compared to a VPP or an aggregator that could coordinate the output of 1,000 small customers with 1kWh output each. Ignoring customer diversity, the aggregator would be able to supply the first 1MW to the market without paying the export charge, as all individual customers would be below their basic export limit. To be on an equal footing, the battery might argue that it requires a comparable basic export level, accounting for customer diversity.

Note that the example above is hypothetical, as the battery would be unlikely to generate during the solar peak unless it responded to a price or FCAS event. It would more likely be charging to take advantage of low prices during the solar peak. But if the battery discharges in response to a market event that happens to coincide with the export peak, it would be competing with the VPPs responding to the same signal but operating under the favourable aggregated basic export level conditions (at least for the initial part of the operations).

There are costs involved to individual customers to become part of the VPP. Original set-up costs include smart metering (which would already be in place if the customers installed new DER after the Power of Choice rule change), Home Energy Management Systems (HEMS) and potentially rewiring of the flexible loads to be on a separate circuit. More opportunities would be supported with the flexible trading arrangements that were recommended by the ESB post-2025 review (see Chapter 3 for more detail).

2.10. Efficient tariff design

To effectively address network problems, send a price signal and gain acceptance by the industry, customers and retailers, we consider that two-way network tariffs should aim to achieve:

- efficiency (ensured by marginal cost pricing and symmetric system of charges and rewards)
- cost reflectivity (of the depth of system use and level of service; recovery of residual costs; revenue from the tariff class within the bounds between avoidable and standalone costs of serving this customer class)
- technological neutrality (applicability to different types of technology – batteries, EVs, flexible load)
- competitive neutrality (not advantaging certain servicing solutions by tariff arbitrage – transmission vs distribution connected batteries, synthetic services solutions vs assets, eg, VPPs vs batteries)
- equity (fairness in allocation of costs across customers)
- network revenue predictability (allowing networks to recover their efficient costs and manage cashflows)
- customer bill predictability (understanding the link between behaviour, actions and total bill – no surprises).

Tariff reform would be supported by complementary factors provided by wider industry partners such as:

- technical enablers for the reform (advanced metering, data sharing, flexible trading arrangements subject to the rule change)

- retailers helping customers access new value opened by two-way-tariffs and DER (complex tariffs gaining customer's acceptance and retailers' willingness to offer, prices for devices, customers participating in trading activities)
- retailers responding to customer preferences by offering a menu of retail tariff options that balance practicality and complexity (including simple insurance-type products for customers not willing to actively manage their electricity bill).

2.10.1. Potential tariff structures for cost reflective two-way tariffs

While these principles can be implemented in a multitude of ways, there are basic elements of tariff structures that can be combined to develop a two-way network tariff suitable for a particular customer class and metering technology. The exact combination of parameters in a specific tariff can be co-designed with customers during the TSS consultation process, and/or tested in tariff trials. To approve the proposed new two-way tariff structures, the AER would need to establish that they are cost reflective and comply with pricing principles, including marginal cost pricing and recovery of residual costs.

Marginal cost pricing in new tariff structures

The LRMC price signals can be conveyed by variable tariff components such as peak energy, critical peak energy, demand charge, and a corresponding component of export charges. Hypothetically, each of the variable components of the two-way tariff can be extended to offer a mirror reward (see Table 2.1). For example, if peak energy consumption is charged at its LRMC, the export during the consumption peak would receive a reward in this amount.

Charging parameters, charging windows and data frequency for the definition of peak energy, demand and capacity can vary across tariffs to send the most effective price signal suitable for the customer type and network conditions. For example, demand components of the network tariff can be made sharper with a finer (more granular) frequency of data available to distributors due to five-minute settlement.[38] As such, a five-minute demand measure can provide a steep signal for charges and rewards. This measure can be used to design critical peak demand products. This is also likely to result in very complex tariff structures.

Some of the current tariffs use capacity charges for signalling the peak demand window as well as for recovering residual costs. Arguably the signal could be strengthened if these functions were separated, eg, signalling could be conducted via monthly demand charge or a critical peak energy charge, and the capacity charge would serve purely to recover residual costs. Separating these functions would also result in more complex tariff structures.

More complex structures currently apply to commercial and industrial customers. There is usually no tariff choice for these customers once they are allocated to the network tariff appropriate to their annual consumption size or type of connection.

In residential and small business segments, there is usually a choice of cost reflective tariff options available within the TSS. We consider that it is worth testing whether customer choice can be extended to the larger low voltage customers, by developing cost reflective tariff options that signal LRMC via different tariff components.

---

[38] Converted to kW, a 5-minute maximum demand (measured as a maximum consumption during any 5-minute interval within the peak period, times twelve) is always at least as high as a 30-minute maximum demand (measured as a maximum 30-minute consumption within the peak period, times two). This is due to the additional averaging of consumption reading over the longer time that mitigates the extreme spikes.

Recovery of residual costs

Pricing principles require tariffs to recover total network costs remaining after the application of marginal pricing (ie, residual costs), in the least distortionary way. This is typically achieved by a combination of fixed and capacity charges, or by a mark-up on variable components with the lowest price elasticity (Ramsey pricing).[39] There is a degree of flexibility in the allocation of residual costs to charging components across tariffs and tariff classes when developing the TSS. The economic efficiency test under the NER only requires that revenue from the tariff class stays within the bounds between avoidable and standalone costs of serving this customer class.

The capacity charge deserves a special role in tariff design. Because it scales with the size of the customer (their maximum demand), the capacity charge can replace the fixed charge in its role to recover residual costs without creating distortions at the margin. Recovering more residual costs via capacity charge as opposed to increasing the fixed charge alleviates concerns about equity, with small customers contributing proportionately less to the total network costs.

Complexity of two-way tariff structures

It is necessary to test whether customers understand the tariffs or, if not, whether retailers can implement them with the help of technology. Note that customers' acceptance of complex tariffs cannot be presumed. Extensive customer consultation and retailer engagement would be required to explain tariff options and the ways to save on the total retail bill.

The way retailers re-package the network price signal into their final product offerings determines the ultimate savings customers can receive if they respond to the network price signal. Gaining and maintaining consumer trust will be a decisive factor for retailers and third-party service providers to succeed in bringing to life the advantages of the two-way tariff structures with symmetric rewards and charges.

2.10.2. Tariff design toolbox

To design tariff options for trialling and customer engagement as part of developing and consulting on the TSS proposals, distributors may consider choosing from the available toolkit of charging parameters, deciding which parameter's primary role is to signal the marginal costs. Making a peak (or especially, critical peak) energy price signal more pronounced removes the emphasis from the demand or capacity charge which might then be set at the level sufficient to recover residual costs associated with the required size of the connection. These tariffs could be more suitable for customers with peaky demand/low load factor, eg, commercial EV chargers, EVs (where there is recognition general take-up still low), or seasonal load such as irrigators. Alternatively, some form of dynamic load control can apply as discussed in the following section.

Customers with higher load factor (more *even* load) would benefit from a lower peak energy price offset by higher demand or capacity charges. If several cost reflective tariff options are provided as opt-in within the TSSs, calibrated towards a certain LRMC-signalling component while ensuring the recovery of residual costs, customers could opt into the best cost reflective option based on their own load profile.

These tariff options, if approved by the AER as part of the TSS proposal, would expand tariff choice (assignment options) compared to that currently available in most TSS's. Third party providers accessing electricity data under the Consumer Data Right (CDR) provisions, or

---

39 Laffont, J.-J. and J. Tirole (2000), *Competition in Telecommunications,* The MIT Press, Cambridge, MA, p 193.

distributors themselves as an additional proposition supporting their social licence, could evaluate the tariff options and propose to the customers the tariff choice which is best suited to their load and generation profile as part of the annual tariff reassignment assessment.

Additional tariff options, if approved, might temporarily make the distributor's tariff table more complicated (longer) overall. However, with time customers may opt into one of these complex two-way options, rendering existing tariffs redundant. The longer-term outcome of the complex cost reflective tariff structures might indeed be a shorter tariff table overall, and an automated process of tariff assignment based on the customer's expected load and generation profiles.

2.10.3. Trade-off between service levels and price – control by networks

In addition, there is an overlaying parameter to tariff design of whether the customer has a sufficient degree of flexibility to allow the network to control or curtail the use of the customer's DER or appliances, to ensure that no network costs are created from their operations. As discussed in the sections above, a discounted tariff would be warranted in this case, reflective of the marginal cost savings. Note that customers would still need to contribute to the residual distribution costs and other network costs such as transmission and jurisdictional schemes, as part of maintaining their connection and deriving benefits from the use of the shared network.

For example, a dynamically controlled load tariff could offer a lower price with a network ability to over-ride or curtail their service when the network is constrained. Extending the current hot water-controlled load tariffs, dynamically controlled tariffs could replace the pre-set time windows with flexible operating envelopes that respond to actual network conditions. Dynamically managing DER customer exports is the role that distributors are preparing to play as Distribution System Operators (DSOs) in their corresponding distribution areas. For the customers to give distributors a social licence – an informal permission – to control their DER, customers must have choices, perceive private net benefits, and trust their distributors to deliver these benefits.[40]

2.10.4. Alternative tariff models – a tariff for retailers

During the ARENA Distributed Energy Integration Program (DEIP) consultation on the Access and Pricing rule change, some stakeholders suggested that networks should be setting tariffs for retailers, using the aggregated load of their customers.

We consider that an aggregated tariff for retailers would be a step back from the current state of network tariff reform. Its seeming simplicity has several pitfalls:

- The tariff for retailers would involve a high degree of averaging, including geographic averaging. The aggregated load for all customers of one retailer would not reflect localised constraints. If any locational charges or rewards are implemented, they would not be visible at a customer level on the aggregated retailer bill.
- If retailers are charged on the demand or capacity measure calculated for the coincident demand of their customers, the benefit of customer diversity ('averaging out' of the usage patterns resulting in the lower aggregated load) will be transferred from the general customer base (the network) to the retailer. Retailers with less diverse groups would be at a disadvantage.

[40] CutlerMerz (2020), *Social Licence for Control of Distributed Energy Resources*, Final Report for Energy Consumers Australia, December 2020, p ii-iv. https://energyconsumersaustralia.com.au/wp-content/uploads/Social-License-for-DER-Control.pdf. Accessed on 1 June 2022.

- Smaller retailers might also be disadvantaged as their average customer might be in a different location, having access to a different technology and facing different tariff structures compared to the customers of large retailers. There is potentially a detrimental effect on retail competition from the aggregated bill structure.

To provide additional illustration of a potential effect of the aggregated load billing on retail competition, consider the status quo. Retailers already receive an aggregate bill for the collection of customer connections (NMIs) who are currently with this retailer as a Financially Responsible Market Participant (FRMP). Each customer bill contains their own (non-coincident) demand, where appropriate. These customers might be spread across various geographic areas, tariff classes and tariffs within the class. Calculating their coincident demand for the purposes of calculating the aggregated load bill might be meaningless because each of their local distribution kiosks or upstream zone substations can be peaking at different times. Retailers that service greenfield developments might have customers with more modern metering technology assigned to more cost reflective tariffs as part of the tariff reform. These customers might find it easier to control their network costs, resulting in overall lower costs allocated to the retailer. Legacy retailers might be left with a set of customers with accumulation meters and limited access to DER due to the higher prevalence of apartments in this customer segment. These customers would be less able to control their network costs. As a result, legacy retailers will bear a higher share of network costs due to the prevalence of legacy customers who could be turned down/not approached by more innovative retailers.

We consider that retailers can already optimise their total network bill for a collection of customers in a portfolio setting. They can target the customers with the most flexible load and technology, to help customers save on their bill. These savings can be achieved either by modifying customers' behaviour or by an automated response. We consider that replacing the current NMI level billing with an aggregated bill to the retailer appears to be a backward step, moving away from cost reflectivity of the network bill and visibility of the individual customers' consumption patterns.

3. Enablers for the efficient integration of batteries

There are several current regulatory reviews and rule change processes that can become the enablers for the efficient integration of batteries. In this chapter we consider:

- Flexible Trading Arrangements rule change.
- The availability of metering.
- The role of retailers.

3.1. The Flexible Trading Arrangements rule change

This is a project that emerged from the ESB's work on two-sided markets. The review is highly technical in nature but ultimately comes down to how we potentially accommodate multiple suppliers of retail services to a single customer.

Currently, there is a single retailer for each customer. Customers might be willing to try more innovative services offered by aggregators but may be unwilling to switch for all their energy needs. The current regulatory environment makes it hard for customers to access value streams other than reducing their own power costs (self-consumption) and earning feed-in-tariff on their generation. DER customers are required to sell their exports to a single retailer or Small Generation Aggregator (SGA).

The ESB is advising on the required changes to ensure it can accommodate a new mix of resources, particularly at the distribution level. Among these changes is the Flexible Trading Arrangements rule change, which is intended to allow customers to engage with more than one service provider, eg, different retailers for solar exports, charging an EV and so on. There are two models that have been proposed for this, but a fundamental challenge remains that a single National Meter Identifier (NMI) cannot easily accommodate multiple metering arrangements.

3.1.1. Consequences of the potential Flexible Trading Arrangements rule change for batteries

The ability for battery and EV owners to enter arrangements with multiple retailers can potentially allow for specialisation, the target of product offerings and price arbitrage. For example, a retail business can create a targeted product that focusses on EVs while allowing a customer to remain with their primary retailer for the rest of their retail supply.

However, under the first flexible trader model proposed by the ESB, consumers with multiple connection points (ie, one for EVs, another for other loads) will require additional metering installations. A critical concern is that each NMI is assigned a network access charge meaning consumers will have to pay multiple tariffs. On the other hand, the second model would leverage sub-meter connections. Net energy flows are calculated within the private network and then tariffs are allocated once based on this figure. Although, under this model, it may be difficult to determine true generation/load before netting out energy flows which should be identified to ensure that retailers are appropriately remunerated according to different devices attached to the small private network.

When considering this rule change, conflicts between simplicity and efficiency may arise. The former approach, charging separate tariffs, is less complex to implement since it requires fewer regulatory changes and will facilitate easier network charge calculations for retailers. However, this may not promote efficiency. Under the second potential structure, tariffs are allocated once which is expected to reduce costs. Further, since for each private network energy flows are calculated once, consumers will not be able to avoid charges related to high demand by separating their consumption across multiple connection points according to their different devices.

3.2. The availability of metering

Batteries are a sophisticated technology that requires an attendant level of sophistication of tariffs. Tariffs in turn are predicated on the type of metering that is available at a connection point. Hence availability of appropriate metering technology is essential for efficient integration of batteries into the grid.

3.2.1. The AEMC review of metering

The AEMC published a Directions Paper for its review of the regulatory framework for metering services on 16 September 2021. The review states that smart meters are key to enabling a more connected, modern, and efficient energy system that supports future technologies, services and innovation. In particular, it noted that many of the ESB's post-2025 market design initiatives rely heavily on the widespread availability of smart meters.

The Directions paper identified that:

> To realise the benefits [of DER], a high penetration of smart meters will be needed – with some services requiring a penetration in excess of 50 per cent.[41]

The review provides recent information about the uptake of smart meters outside of Victoria, stating that:

> While the pace of smart-meter uptake has increased in recent years, overall penetration of smart meters remains low. …. The penetration of smart meters varies from around 21 per cent in the Ausgrid area to around 34 per cent in the TasNetworks area. At the current overall rate of increase of around 6 percentage points per year, it would take around 13 years to completely replace the meter population with smart meters.[42]

At the same time, the services for installing smart meters have improved greatly in recent years. New installations of solar automatically receive a smart meter, as do some customers who sign up with retailers offering more flexible tariffs structures (eg, Amber).

Consequences of the uptake of smart metering for batteries

Batteries are a sophisticated technology that can dramatically alter the load profile of a customer. Tariffs that send signals to batteries need to be equally advanced to manage these altered profiles. Accumulation meters cannot support this type of sophisticated pricing – smart meters must be installed at a household to provide them with the type of tariffs that can signal marginal cost, and so promote efficient behaviour.

---

[41] AEMC (2021), *Review of the Regulatory Framework for Metering Services,* Directions Paper, September 2021, https://www.aemc.gov.au/sites/default/files/2021-09/EMO0040%20Metering%20Review%20Directions%20paper%20FINAL.pdf. Accessed on 1 June 2022.

[42] AEMC (2021), *Review of the Regulatory Framework for Metering Services,* Directions Paper, September 2021, https://www.aemc.gov.au/sites/default/files/2021-09/EMO0040%20Metering%20Review%20Directions%20paper%20FINAL.pdf. Accessed on 1 June 2022.

Although the roll-out of smart meters has been slow, there is now a sufficient presence in the sector of smart meter installers to support the uptake of batteries. The ease and cost of installing a smart meter will continue to improve as the penetration rises. This will enable retailers and networks to have the flexibility to provide customers with more dynamic tariffs that can ensure that batteries are used effectively, and act to provide benefits to the power system.

3.3. Jurisdictional responses

An additional consideration is how the jurisdictions respond and introduce reforms that can promote the efficient uptake of batteries. For example, following the completion of the AEMC’s 2014 Distribution Pricing rule change, jurisdictions responded with varying degrees of support. This has led to differing levels of potential benefits that can be provided by cost reflective network tariffs, and in particular their ability to promote the efficient uptake of batteries, solar PV, EVs and other devices.

Importantly, we distinguish between measures taken by jurisdictions to subsidise new technologies (eg, feed-in-tariffs, direct upfront payments) and measures that promote efficient integration. Jurisdictions primarily provide funding for the uptake of the new technologies, rather than adopting reforms that can provide microeconomic efficiency improvements. This is not to say that jurisdictions should avoid programs that provide subsidies. Rather, jurisdictions should also recognise that their role extends to implementing reforms that can support long-term efficient investment and use of new technologies.

As discussed, smart metering is a key enabler of more efficient tariffs that promote the National Electricity Objective. A key area for reform at the jurisdictional level that can support integration of batteries is therefore to remove impediments to the uptake of advanced metering. Generally, this encompasses regulatory arrangements, eg, jurisdictions deciding whether to facilitate remote re-energisation and de-energisation, or to mandate the rollout of smart meters (which is the case for Victoria). Jurisdictions are largely responsible for safety standards and electrical wiring. For example, in NSW metering providers must comply with the metering code. All these instruments need to be up to date to accommodate the rapid integration of DER into the power system. However, a systemic review of these rules requires time and careful consideration to preserve quality and safety standards. Other specific jurisdictional rules could be reviewed, eg, the Queensland Electricity Distribution Network Code has detailed rules governing changes to consumer connections and could possibly be streamlined. Over time, we anticipate that this will establish the foundation for faster, more widespread and efficient investment in batteries.

3.4. The role of retailers

The final enabler we consider in this paper is the role of retailers. Retailers have a direct relationship with customers including billing. Network price signals should work through retailers as discussed below.

3.4.1. Retailers mediate and deliver network price signals to customers

Network tariff is the interface between the network and the customer mediated by retailers. Price is the mechanism by which the network communicates with customers and seeks to influence their behaviour.

However, the customer is only exposed to the network price signal via a retail tariff. The signal is diluted by other components of the retail bill (such as wholesale energy, environmental policies, and retail costs and margin). Averaged across NEM jurisdictions, network costs (transmission and distribution) are about 46% of the retail bill.[43] A substantial portion of these network costs is fixed charges or non-cost reflective charges that do not signal optimal behaviour. In addition, the shape of the retail tariff offering and its structure does not have to follow the network tariff. Even the most cost reflective network tariff can be repackaged by the retailer into a flat tariff offering or any other product that suits the customer needs.

Historically, retailers have used relatively simple tariffs to signal cost even for complex, time-varying components of supply like wholesale market costs. Retailers have also tended to prefer simple price structures for network costs which has led to slow movements in retailers shifting the customers from flat tariffs to Time of Use and more efficient forms of pricing.

This does not make the case for cost reflective network tariffs weaker. In the competitive market, retailers are profit maximising/ cost minimising agents whose incentives align with saving on the network bills for the portfolio of their customers. Retailers are the primary recipients of the network price signals and agents for their customers in achieving savings on the total electricity bill.

Retailers know their customers and their preferences and can design retail plans and offerings that suit different customer needs. These needs range from sophisticated products passing through wholesale price signals and network demand tariffs for customers with technological means to control their peak demand and benefit from the negative or low wholesale prices at the time of abundant solar generation, to insurance-type products for risk averse customers who would like to limit their exposure to bill fluctuation or who would prefer a ‘set and forget’ approach to managing their electricity bills.

3.4.2. Batteries may prompt the role of retailers to expand

The continued development of the retail sector and the emergence of new business models that can signal to customers the full value that their devices can provide are important enablers for the uptake of batteries. Indeed, some retailers are already focussed on using batteries to meet large requirements for electricity supply. For example, Origin has announced that it expects to meet up to 2 GW of its future supply needs through the use of VPPs.[44]

As new services in the two-sided market emerge, retailers will be put under competitive pressure to innovate to retain their customers and grow their value. This might prompt retailers to roll out smart meters and devices that assist customers in managing their electricity bills and accessing rewards. We already observe an increasing number of more dynamic tariffs being offered by retailers that signal to customers the cost of using electricity at different times of the day and year. A more innovative retail product that passes through network rewards and is capable of incorporating two-way pricing could emerge as distributors are developing and trialling their network tariffs. A meaningful engagement between distributors and retailers, collaboration and mutual trust are required to deliver the benefits of two-way pricing with symmetric charges and rewards to all electricity consumers.

---

[43] AER (2021), *Annual Retail Market Report 2020-21*, November 2021, p 32. https://www.aer.gov.au/system/files/Annual%20Retail%20Markets%20Report%202020-21.pdf. Accessed on 1 June 2022.

[44] Origin Energy (2022), *Our Strategy,* March 2022, p 27, https://www.originenergy.com.au/wp-content/uploads/Origin_2022_IBD_final.pdf. Accessed on 1 June 2022.

4. Where to in the next Tariff Structure Statements

Consultations have already commenced for the distributors in the 2024-29 regulatory reset round, the first after the Access and Pricing rule change that could see export charges proposed in distributors' Tariff Structure Statements (TSS). Encouraged by the extended provision for sub-threshold tariff trials following the Access and Pricing change,[45] distributors are conducting tariff trials to test innovative tariff structures and principles of symmetric charges and rewards.

4.1. Early insights from tariff trials

Three distributors submitted tariff trial notifications to the AER for 2021-22, with eight notifications received from distributors to run tariff trials in 2022-23.[46] Proposed trials cover rich tariff structures with charges and rewards, critical peak pricing, more granular demand measures, complex tariffs combining many charging parameters suitable for the automated response, and simpler tariff structures that reward customers for their response to the price event.

Many of the trials are explicitly basing their price signals on LRMC. Some introduce the LUOS concept. Distributors are trialling various cost allocation approaches and principles: five export charges; six battery tariffs; and three will be testing dynamic controlled load tariffs of some sort.

Early learnings from the ongoing tariff trials will help distributors to form their tariff structures for their TSS proposals in January 2023.

4.2. Customer engagement

NSW, ACT, Tasmania and Northern Territory distributors have already commenced consultation with their customers on TSS for the 2024-29 regulatory reset. The AER's Export Tariff Guidelines outlined the expectation for the appropriate stakeholder engagement, consistent with the *Better resets handbook − towards consumer centric network proposals* (the Handbook).

In shaping their tariff proposals, distributors will consider their own network conditions and their customers' needs and priorities. Networks will likely co-design any two-way pricing with their customer groups in consultation with retailers and stakeholders, informed by the tariff trials. It would be beneficial if the AER takes the lead in drawing lessons from the current tariff trials for all distributors to rely on in shaping their TSS proposals. Some general principles discussed in this paper would also assist distributors in developing tariff structures fit for the DER future.

4.3. Practicality vs complexity

New tariff structures supportive of the new value streams for electricity users can be very complex. Not all customers would be willing or able to deal with these price signals. Access to DER technology also differs by customer type.

Customers' decision to invest in DER depends on factors such as motivation, ability, financial concerns, enthusiasm towards making energy decisions and participating in the two-sided

[45] NER cl 6.18.1C.

[46] AER (2022), *Tariff trials*, https://www.aer.gov.au/networks-pipelines/network-tariff-reform/tariff-trials. Accessed on 1 June 2022.

market, and technical support available[47]. Individuals may not have the capacity to respond to new technologies such as batteries or afford them.

Acil Allen identified the following six types of consumers who engage with a two-way market:

- Enthusiasts – accepts new technologies easily and are open to new ideas. Highly motivated to take action and adopt new technology only. May not adopt other forms of energy and cost-saving practices.
- Completers – high level of motivation and pursues all options to participate in the two-sided market.
- Dependent – are motivated to take action but depend on others to help.
- Stuck – are motivated to take action but there are no opportunities.
- Complacent – have the opportunity to partake in the two-sided market but have no motivation to do so.
- Competent – have the ability to participate but have no motivation to do so.
- Cautious – have opportunities to participate but have low ability.
- Hard to help – consumers that have no opportunities and have a low level of ability.
- Middle Australia – consumers who are a mix of all the above.

Customers from the first two archetypes are open to new technologies and are aware of the net-zero transition, wanting to move to a cleaner energy future. They are more likely to adopt a battery and less likely to need incentives. Those with low ability could face language barriers or are apprehensive about using new forms of technologies, not knowing how to operate an EV or battery, especially with smart technology. These individuals are under the cautious and hard to help classification which may need incentives to adopt.

Housing is another major issue when it comes to the decision of installing a battery. Those who own and occupy a house have smaller barriers towards adopting fixed and mobile batteries (EVs) since they can make decisions at their own discretion. However, customers who rent or live in apartments may have to go through an approval process to install a fixed battery or may not be able to afford such an investment. Their decision to buy an EV could be also impacted by the lack of charging infrastructure in their strata common areas, especially in older apartment complexes.

Without government subsidies, the economic case for BTM batteries is still weak. Batteries make more sense as a package with solar PV for large families and energy users with many flexible appliances such as air conditioning and pool pumps. Battery costs will need to come down substantially to make it an attractive investment.[48] The economic case for community batteries discussed in Chapter 2 is stronger, but we need to address the tariff problem that prevents the community battery's competitiveness with BTM batteries. The LUOS concept discussed in this paper provides a possible solution.

Customers transact their energy with retailers and, in future, aggregators. Competition in electricity retail markets enables customers to find the product offer that suits their needs. The least engaged customers are protected by the AER's determination of the Default Market Offer.

---

47 Acil Allen (2021). *Consumer archetypes for a two sided market.* Final Report for the Australian Energy Market Commission, April 2021, p v. https://acilallen.com.au/uploads/projects/372/ACILAllen_TwoSidedMarketConsumerArchetypes_2021.pdf. Accessed on 1 June 2022.

48 Solar Choice (2022). *Solar Batteries – Are They Worth It?* https://www.solarchoice.net.au/is-home-battery-storage-worth-it/. Accessed on 1 June 2022.

It would be a missed opportunity to presume that the least engaged and the most vulnerable customers would be automatically excluded from the benefits that could be delivered by a two-way market and new two-way tariffs. With appropriate complementary measures such as education and information materials, even customers without DER could benefit from new two-way tariffs that offer a reward for consumption during the periods of peak generation. Simple consumer tools such as a fridge magnet with the best times to use electricity and the best ways to use it - a Shift, Stagger, Save message – can help the most disadvantaged and vulnerable customers get control over their electricity bills. We need smart meters, cost reflective network tariffs, and retailers' focus on their customers' needs, to enable everyone to benefit from our new, greener energy system.

5. Conclusion

They always say time changes things, but you actually have to change them yourself.

— Andy Warhol (1975), The Philosophy of Andy Warhol

We live in the time of rapid transformation of the electricity system from centralised to decentralised. Regulations including network pricing need to keep pace with this change. The recent Access and Pricing rule change opened the possibility for new kinds of tariffs. Perhaps for the first time in history, electricity consumption can be routinely rewarded – a negative network price can apply. If the wholesale price is also negative at the time, the full retail price of the unit of consumption might become negative. Customers might be paid to consume electricity at the time when it is good for the network and when generation is abundant.

The role of households and small businesses in the electricity market is changing. They are now not only consumers, but also producers of energy, both for own consumption and for sale. Innovative retailers and market players such as virtual power plants and aggregators help consumers derive maximum value from their DER. But customers without DER need not be left behind. With two-way pricing, vulnerable, disadvantaged and less technically engaged customers can still be rewarded for their consumption that alleviates constraints on the shared network.

Batteries are uniquely positioned in helping balance generation and consumption, allowing more customer DER to enter the system. Shared batteries connected to the distribution system at the low voltage level have the potential to deliver the highest benefit to all network users. We need to ensure that network tariffs do not impede this development.

Over the past decade, distribution tariffs have been progressing towards more cost reflective structures. This reform should continue and grow. A new chapter of the reform has been opened by the Access and Pricing rule change. Paraphrasing Andy Warhol, this new chapter of the cost reflective tariff reform will not happen on its own, we would need to actively work on making the tariffs better, more responsive, more accurate, capable to support the world with cheaper, cleaner and more reliable electricity for all.

Batteries open the opportunities to move from instantaneous balancing of electrical flows to inter-temporal electricity use decisions. The presence of batteries reduces network capacity constraints, pushing down the short run marginal cost and letting more distributed resources into the system.

Shared batteries and virtual power plants can expand the budget set and economic possibilities to its users in a win-win fashion. New electricity sharing communities might emerge, with various options that satisfy their customers' needs and preferences. For some, sharing in the profits from market trading activities would be the main driver to participate. For others, the opportunity to donate their spare generation to support vulnerable local users or broader communities – nursing homes, schools, social enterprises, local charities, or community groups – might be a more important motivator. Councils might emerge as strong players in developing local facilities and common areas where the local community needs them, to host third party community batteries and EV charging infrastructure that could balance local flows and provide supply/demand management to local facilities such as sport fields and community halls. Innovation, technology, and local communities will drive the growth in this area.

Two-way tariffs can enable a genuine sharing between customers, lifting the shared distribution network to a new level of belonging to a community. Instead of being 'takers' from the big, anonymous one-way distribution system, some people would want to start 'giving' to the community that would now be local and familiar. Just like the local council rates reflect the cost of servicing local communities, locational distribution charges might find customer support if they help the local distribution area alleviate its capacity constraint, with benefits also shared locally.

To fully take advantage of the opportunities presented by batteries and other new DER technologies, we need to tackle a number of challenges:

- A high proportion of legacy non-cost reflective network tariffs and flat retail tariffs preventing customers from accessing the full benefits of batteries, flexible load and other DER.
- A large proportion of customers not having smart metering technology and not able to access advanced and innovative tariffs even if they were offered by retailers.
- Market rules restricting innovative solutions or not keeping pace with technological change.
- New technologies such as electric road transport having potential to substantially increase network costs if not integrated efficiently.
- Limited consumer engagement with electricity tariffs and enabling technologies, especially among vulnerable customers.

Possible pathways to address these challenges are:

- Ongoing cost reflectve tariff reform that incorporates two-way pricing, where justified, as a key factor for the optimal integration of DER.
- Progressing the AEMC’s review that can pave the way to the accelerated roll-out of smart meters.
- Progressing the rule change on Flexible Trading Arrangements.
- Progressing the post-2025 DER Implementation Plan to ensure optimal integration of DER.
- Continuing engagement with customers and retailers on collective action to keep electricity costs down.

With the abundance of sun and wind, Australia can become a green energy super-power in the Asia-Pacific region and globally. Customers’ DER is a valuable resource that, supported by firming capacity such as community batteries, can ensure a higher degree of self-sufficiency and energy price stability even with the increased volatility of oil and gas prices.

It is our aspiration that the ideas discussed in this paper will help distributors think about new tariff structures that can be tested with customers and retailers in the next round of tariff setting for upcoming regulatory resets. Two-way network tariffs supporting the development of shared storage assets and innovative electricity sharing services, promoting flexibility, and rewarding customers for the behaviour that helps avoid future network costs, would pave the way for local communities into a resilient distributed energy future.

Appendix A. The outlook for batteries

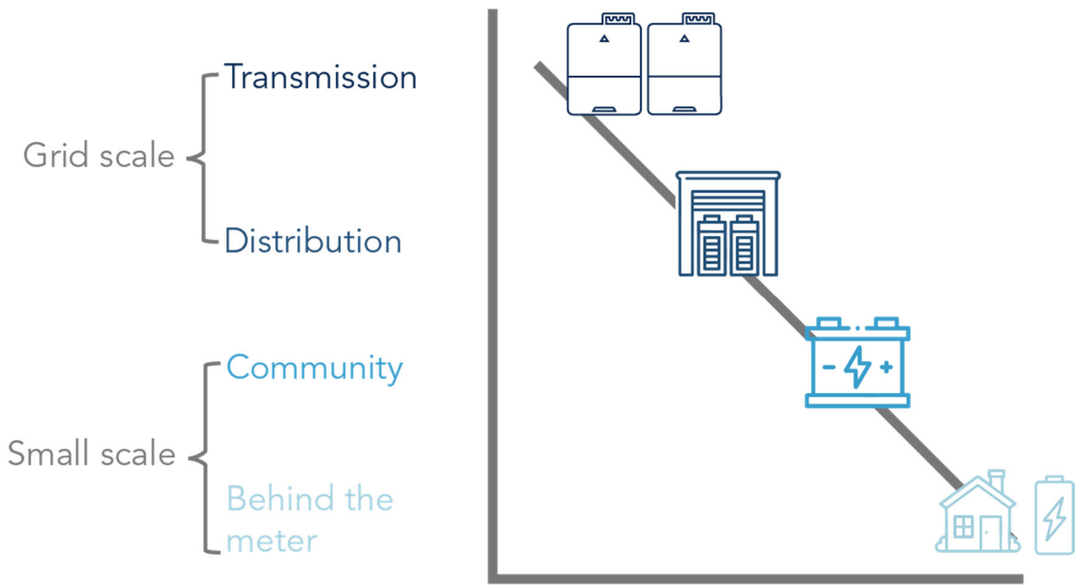
This appendix provides an overview of the outlook for the uptake of batteries as embodied by the Australian Energy Market Operator's (AEMO's) 2022 Integrated System Plan (ISP). The data presented in this appendix illustrates the rapid growth of batteries across all segments of the electricity delivery system.

A.1. Different types of batteries

In this paper we talk about four different broad types of battery systems:

- grid-scale transmission connected batteries
- grid-scale distribution connected batteries
- small-scale community batteries, connected typically in the distribution network, and
- small-scale behind the meter (BTM) batteries, located on premise in the distribution network (see Figure A.1).

Figure A.1 . Different types of batteries



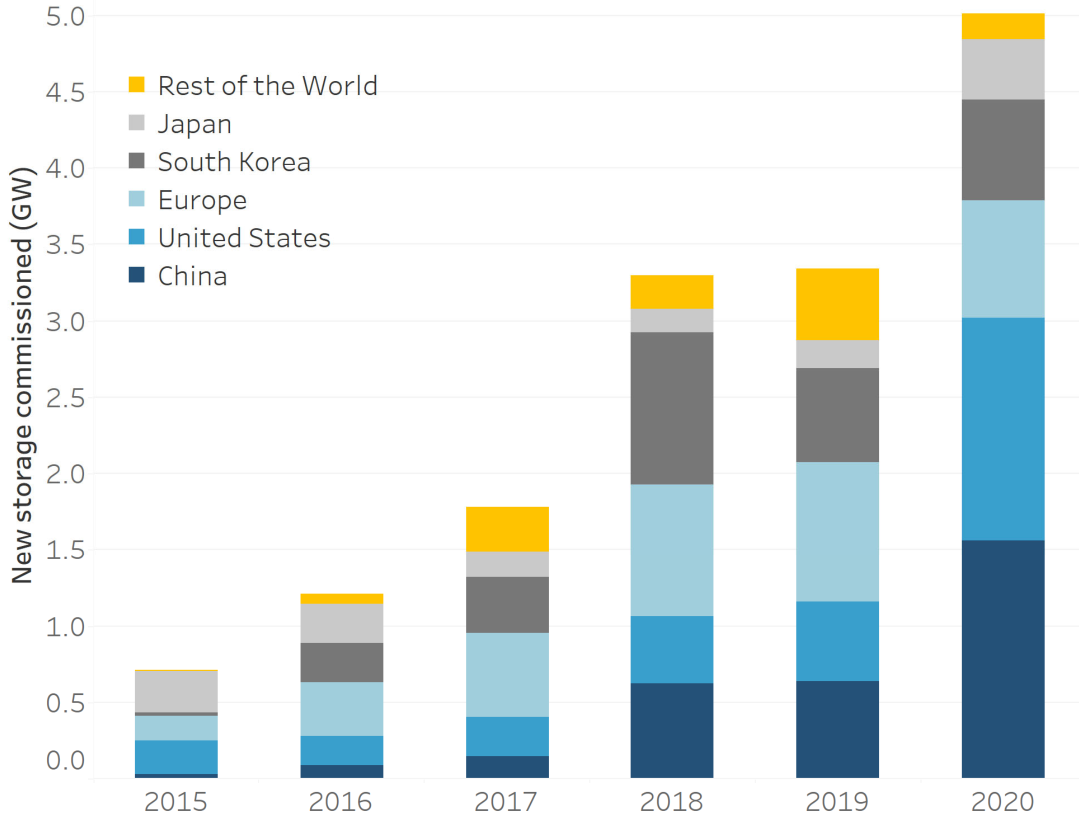
A.2. Trends in the uptake of batteries

Prior to the last decade, the use of batteries was relegated to highly specialised applications, eg, for servicing small loads in remote locations. But recent improvements in technologies have reduced battery costs and allowed batteries to be used in a wide variety of applications supporting renewable generation.

A.2.1. Global trends

Battery uptake is increasing worldwide, with over 5 GW of storage installed in 2020 (see Figure A.2 below).[49]

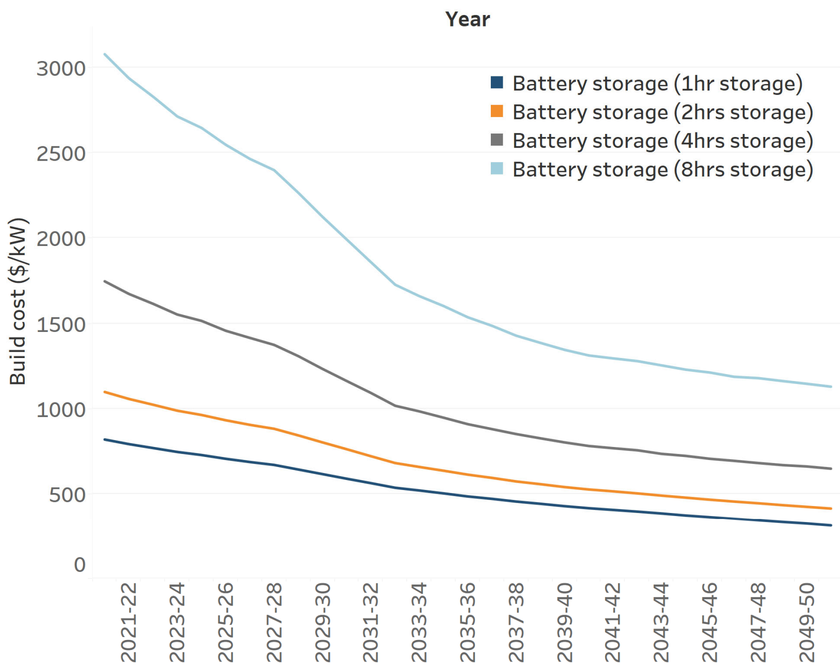
Figure A.2. Battery storage trends worldwide



This growth has been facilitated by decreases in battery costs due to technological advancements (see Figure A.3). The build cost of batteries is projected to decrease well into the future.

[49] IEA (2022), *Annual energy storage additional by country, 2015-2020,* https://www.iea.org/data-and-statistics/charts/annual-energy-storage-additions-by-country-2015-2020. Accessed on 1 June 2022.

Figure A.3. Estimated build cost for different battery storages ($per kW)



Source: ISP input assumptions (2021)

A.2.2. Battery uptake increasing in Australia

Grid-scale batteries

There are currently 9 grid-scale batteries with a capacity larger than 10 MW in operation across Australia, with 44 new projects proposed.[50] Some of these batteries are operating at the size of conventional power plants – such as the Hornsdale Power Reserve, which when initially constructed in November 2017 was, at 100 MW/129MWh, the largest battery in the Southern Hemisphere.

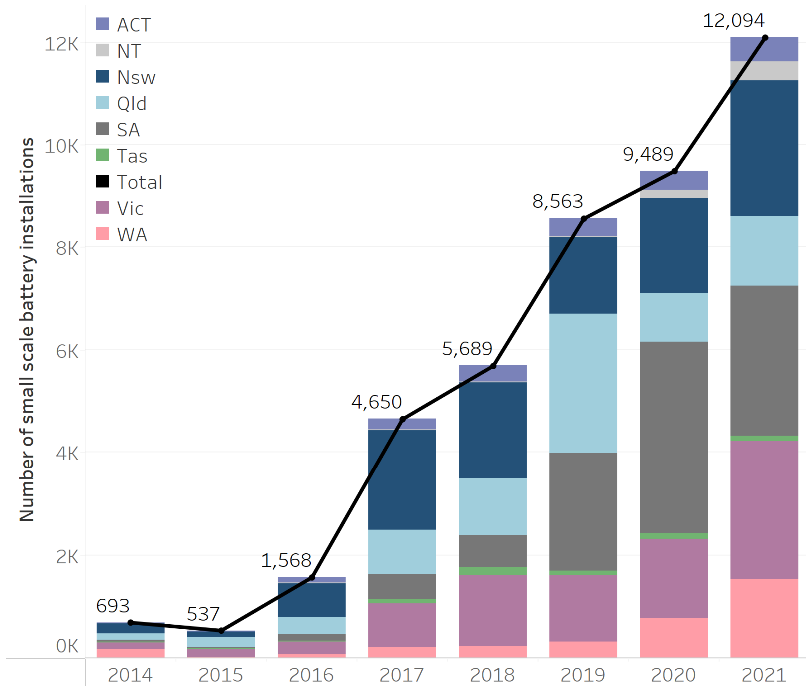
But in the last few years grid-scale batteries have become larger. The Victorian Big Battery which entered service in February 2022 is a 300 MW/450 MWh system. And in March 2022, the NSW Government announced its commitment to building the Waratah Battery, which is planned to be a 700 MW/1400 MWh system.

Small-scale batteries

At the same time many grid-scale batteries are being developed, there has been a rise in the penetration of small-scale BTM systems. The uptake of small-scale batteries has coincided with an enormous rise in the penetration of solar PV, which has led to households installing batteries minimizing their withdrawals from the grid. Over 12,000 small scale battery installations were installed in 2021 concurrent with a solar PV system. Almost a quarter of these systems were installed in South Australia.

[50] AEMO (2021), *Energy explained: big batteries,* May 2021, https://aemo.com.au/en/learn/energy-explained/energy-101/energy-explained-big-batteries. Accessed on 1 June 2022.

Figure A.4. Small scale battery installations Australia

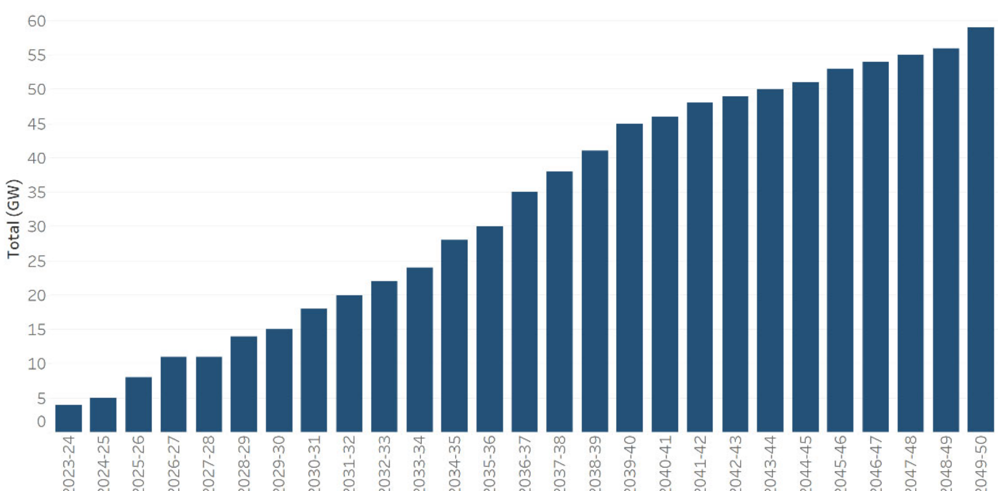


Source: Clean Energy Regulator

A.2.3. Integrated System Plan sees batteries accelerating

In its Draft 2022 ISP, AEMO predicts that storage will play a critical role in the future power system. Figure A.5 shows the projected build of new storage capacity out to 2050. A proportion of this storage capacity is forecast to come from pumped-hydro – a different technology, which affords the potential for medium and deep storage capacity (ie, beyond 12 hours duration).

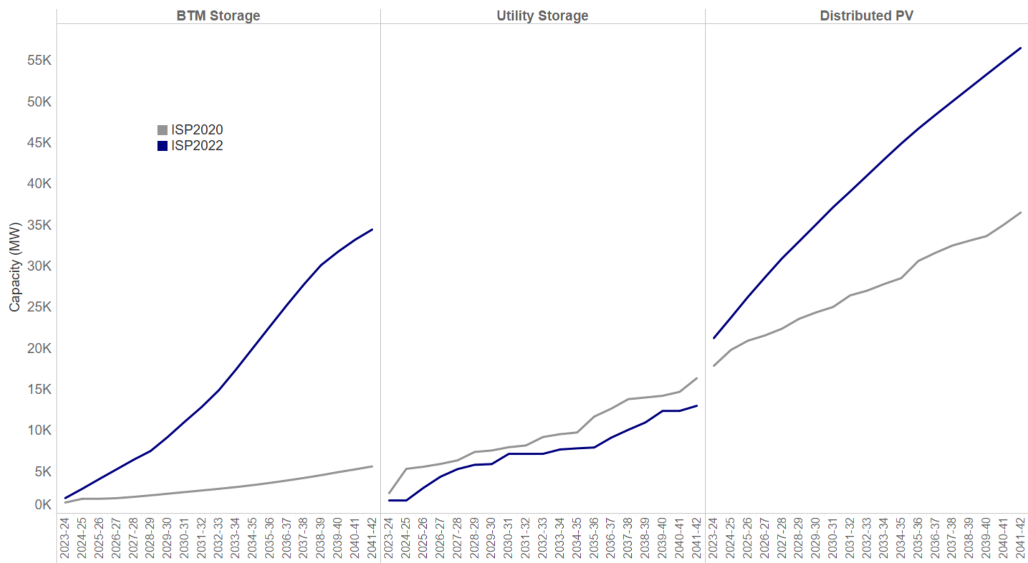
Figure A.5. Energy storage capacity projected by the ISP 2022



Source: ISP Draft 2022

Of interest is that the 2022 Draft ISP predicts larger amounts of BTM battery storage than previously forecast in the 2020 ISP. This is in part due to an increase in the predicted uptake of solar PV. By 2042, AEMO projects that total BTM storage capacity will reach 35 GW.

Figure A.6. Projected battery and PV capacity for the two most recent ISPs



Source: ISP 2020 and Draft 2022

A.3. Summary of trends and implications

Batteries are no longer a fringe technology – they are rapidly being installed across the length and breadth of the power system and are serving a variety of purposes. Grid-scale batteries are providing services in the wholesale energy and Frequency Control and Ancillary Services (FCAS) markets. Smaller batteries are providing network support and load-management services. Community batteries are trialled to provide additional customer storage services. And at the household level, customers are using batteries to smooth out their consumption of energy to make better use of their solar PV systems in response to existing tariff structures.

A.3.1. Tariffs need to ensure efficient integration of batteries

Against this backdrop, now is the time to ensure that we have the right regulatory and market arrangements for batteries. We need to learn from the experience of solar PVs over the last decade and its legacy issues driven by a failure of tariffs to reflect the marginal value, and also cost, of changes in consumer load profiles.

Batteries pose challenges, but also offer opportunities, to manage network and wholesale energy market costs. If we can alter our tariff arrangements to harness the power of batteries, we may ultimately see a reduction in overall consumer costs. But if the network pricing fails to adapt, we may see batteries operating inefficiently, leading to an unnecessary rise in network costs and a poor outcome for consumers.

Appendix B. Current tariff arrangements for battery storage

This appendix discusses the current tariff arrangements for batteries and associated limitations.

We start by describing the general principles of good tariff design starting with the basic principle of marginal pricing. We then examine how well those principles are being met by existing tariff arrangements for each of the following:

- Grid scale batteries – both transmission and distribution connected.
- BTM batteries, whether they be part of a Virtual Power Plant (VPP) or standalone.
- Community batteries, such as those being trialled by Ausgrid.
- EVs with vehicle-to-grid capabilty.

We find that there is scope to improve the marginal price signal to batteries and other flexible load.

B.1. NER pricing principles and LRMC

An important part of the regulatory framework is to assess the costs of individual customers on the network. This has important consequences for tariff assignment and design. Following a rule change in 2014, cl 6.18.5(e) of the National Electricity Rules requires that:

> "Each tariff must be based on the long run marginal cost of providing the service to which it relates…"[51]

DNSPs must therefore estimate long run marginal cost (LRMC), and base their tariffs on, these estimates. An important challenge for the network businesses in constructing tariffs is to ensure that these tariffs are indeed 'based on' LRMC.

As we will describe, the challenge is not so much one of calculation, but rather to make sure that the entire approach to developing tariffs is consistent with the economic principle of marginal cost pricing.

B.1.1. Concepts related to marginal cost

It is helpful to have a sound understanding of the economic concepts related to NER pricing principles under cl 6.18.5(e). There are three principal concepts:

- marginal cost
- the service the network provides, and
- efficiency and the signalling of network costs.

The following subsections elaborate on each of these in turn.

Marginal cost

Marginal cost refers to the additional expense incurred to produce one extra unit of output. Marginal cost is a key concept in microeconomics and economic regulation. There are both short

51 NER cl 6.18.5(e).

run and long run notions of marginal cost. The distinction is whether all factors of production are fixed or can be varied, ie:

- short run marginal cost (SRMC) is the cost to produce one extra unit holding at least one factor of production constant; and
- long run marginal cost (LRMC) is the cost to produce one extra unit when all factors of production can be varied.

In application to network industries, the factor of production that needs to be varied is the capacity. When preinstalled capacity reaches its technological constraint, a lumpy investment is required to alleviate the constraint. Just before such an investment, the SRMC is very high, reflecting the scarcity of the available capacity. Once the investment is made and the capital is sunk, the SRMC drops sharply.

The LRMC is the envelope of the SRMC curves. We will focus on the LRMC. Marginal costs (both short run and long run) are inherently forward-looking concepts. Again, in the words of Kahn:

> Marginal costs look to the future, not to the past: it is only future costs for which additional production can be causally responsible; it is only future costs that can be saved if that production is not undertaken.[52]

We highlight Kahn's use of the phrase 'causally' responsible. Marginal cost is a causal concept – the cost that is *caused* by, or that *arises from*, the production of the additional unit. Storage plays a special role in alleviating the capacity constraint and dampening the increase in short run marginal cost, moving it closer to the long run marginal cost.[53] Theoretically, SRMC provides the optimal price signal for consumption decision but is relatively volatile. The LRMC provides a more stable price signal that is used as the basis for tariff setting.

The service provided by the network

One of the key aspects of the NER cl 6.18.5(e) is that the tariff must be:

> '…based on the long run marginal cost of providing **the service** to which it relates...'

The definition of the service is therefore critical. If we seek to estimate the additional cost of supplying one more unit of a service, we must understand what that service is.

Under the recent DEIP Access and Pricing rule change, export service has been recognised as a distribution service.[54] Additional obligation was created for distributors to provide export services as well as consumption services, recognising the new, two-way energy system of today and tomorrow.

Actions of customers give rise to additional network costs

Some obligations on distributors are of little consequence. For example, the obligation to ensure that sufficient capacity to supply the load is available at 4 am in the morning on a Sunday has almost no *incremental* effect on network costs. The obligation is currently superfluous but it might change with the increase in overnight charging of electric vehicles (EVs) or due to the network

52 Kahn, A. (1988), *The Economics of Regulation: Principles and Institutions*, Vol. I, p 88.

53 Tooth, R. (2014), "LRMC Pricing for Water Services – Background Paper on LRMC Pricing". Paper for the Essential Services Commission of South Australia, March 2014, p 9.

54 AEMC (2021), *Final determination – Access, pricing and incentive arrangements for distributed energy resources*, 12 August 2021. https://www.aemc.gov.au/sites/default/files/2021-08/Final%20determination%20-%20Access%2C%20pricing%20and%20incentive%20arrangements%20for%20DER.pdf. Accessed on 1 June 2022.

price signal being structured around this particular time of the day, creating an unintentional spike in demand from appliances programmed to take advantage of the lower tariff rate.

Typically a single binding obligation dominates all others – the obligation to provide power when demand on the network is at its greatest. This might be during the system-wide peak, or it might be during a localised peak (eg, at a zone substation). This obligation tends to supersede all others – if it is met, all of the other obligations of the network are typically met by default.

Because maximum demand is the primary driver of network costs, the marginal cost of the network service is therefore typically expressed in terms of the cost *per kVA of system or local maximum demand.* For emphasis, the 'additional unit' of the network service is one more kVA of system-wide or local maximum demand.

Recently, minimum demand emerged as a new driver of network costs. Network investment to address minimum demand, manage spikes in voltage and control power quality during peak DER solar exports can be avoided if tariffs send a signal about these future costs. Two-way tariffs enabled by the Access and pricing rule change provide such a solution.

B.1.2. Efficiency and the signalling of network costs

We have described the concept of marginal cost and have defined the specific service to which it should be applied. What then is the significance of marginal cost to setting network prices?

Marginal cost sits at the centre of microeconomics and particularly economic regulation. Its significance is well described by Kahn, who states that:

> The central policy prescription of microeconomics is the equation of price and marginal cost. If economic theory is to have any relevance to public utility pricing, that is the point at which the inquiry must begin.[55]

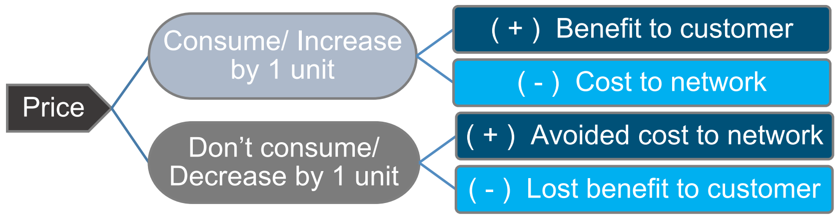
Kahn goes on to explain why economic efficiency requires prices equal to marginal cost:

> The reason is that the demand for all goods and services is in some degree, at some point, responsive to price. Then if consumers are to decide intelligently whether to take somewhat *more* or somewhat *less* of any particular item, the price they have to pay for it (and the prices of all other goods and services with which they compare it) must reflect the cost of supplying somewhat more or somewhat less – in short, *marginal* opportunity cost. If buyers are charged more than marginal cost for a particular commodity … they will buy less than the optimum quantity; …if price is below incremental costs … production of the products in question will be higher than it ought to be.[56]

Figure B.1 illustrates this concept for a customer choosing whether to consume one more unit of the network service, equating a marginal cost to marginal benefit.

55 Kahn, A. (1988), *The Economics of Regulation: Principles and Institutions*, Vol. I, p 65.
56 *Ibid.,* pp 66-67.

Figure B.1. Efficient outcomes with price equal to marginal cost



To make efficient decisions about whether to consume one more unit of the network service, consumers must face a price that signals the marginal cost of that unit to the network.

- If the marginal cost exceeds the price, a customer may consume even though the cost to the network exceeds the benefits to them. Put another way, the network and customer would *collectively* be better off with a more accurate price signal.
- Conversely, if price exceeds marginal cost, a customer may choose *not* to consumer even though the benefit to them exceeds the costs to the network. For emphasis, the network and customer would *collectively* be better off with a more accurate price signal.

B.2. Arrangements for grid-scale batteries

There are two types of grid-scale battery tariffs that we need to consider: transmission and distribution. In essence, this means understanding the network costs for batteries in the form of Transmission Use of System (TUOS) and Distribution Use of System (DUOS) charges.

B.2.1. Transmission connected grid-scale batteries

The arrangements for network charges for grid-scale batteries have recently been reviewed by the final decision of the AEMC in its *Integrating Energy Storage systems into the NEM* rule change.[57] The Commission's final decision:

> maintains the existing framework to allow transmission connected storage to choose between connecting under a negotiated agreement at a negotiated price, or the prescribed service and corresponding prescribed transmission use of system (TUOS) charge. The Commission does not consider that storage should automatically pay network charges, including the prescribed TUOS charge. Rather, storage participants can choose the service they need and whether they go through the process of obtaining a negotiated or prescribed shared transmission service.

As we understand, batteries will ultimately be subject to TUOS for energy that they draw from the network, unless they enter a negotiated agreement. However, this could strengthen the bargaining position of the network and decrease the probability of a negotiation succeeding which could leave batteries liable for TUOS.

Background on TUOS cost allocation

Transmission network service providers (TNSPs) aim to deliver a reliable supply of energy to consumers by investing, managing network assets and procuring services such as generation.

[57] AEMC (2021), *Rule Determination, National Electricity Amendment (Integrating Energy Storage Systems into the NEM) Rule 2021*, December 2021, https://www.aemc.gov.au/sites/default/files/2021-12/1._final_determination_-_integrating_energy_storage_systems_into_the_nem.pdf. Accessed on 1 June 2022.

Customers pay TUOS charges to access the transmission distribution network. However, generators do not pay for any form of TUOS, because there is no guarantee that they can export all their output. Although, they do pay an entry charge which is a fixed annual fee to generators for connection services. Since a battery can be thought of as a generator, they do not pay TUOS for exporting to the grid but may incur an entry charge.

Therefore, most revenue is recovered from loads (consumers). Charges to loads are based on locational use and common services. Common services provide an equivalent benefit to all users without any differentiation due to location, such as the cost of planning and operating the network. Common service charges are based on postage stamped prices where prices per unit is the same for all connection points and users. Locational TUOS charges are based on a locational price that is calculated for each connection, it is based on average maximum demand and reflects the long run marginal cost (LRMC) of transmission at each connection point. From these principles, batteries will need to pay for TUOS when charging/importing. Moreover, large scale batteries that are directly connected to the transmission network will need to pay an exit charge which is a fixed annual payment for loads directly connected to the TNSP’s network.

How well do the current arrangements signal marginal cost and what does this mean for signals to batteries?

The cost allocation mechanisms that are used by transmission networks stem from a system of 'cost reflective network pricing' (CRNP) using the TPRICE model. The model is not forward-looking as it uses the assets that are already in the system. While transmission pricing is beyond the scope of this paper, we note that the use of the TUOS framework for batteries may be missing an opportunity to send forward-looking price signals.

B.2.2. Distribution connected grid-scale batteries

Again, the final decision of the AEMC in its *Integrating Energy Storage systems into the NEM* rule change states that:

> … storage is not exempt from paying network use of system charges, for load, whether it is connected to the transmission or distribution network. The Commission notes that the Access, pricing and incentive arrangements for distributed energy resources final rule removes the prohibition on DNSPs charging for export services, which means distribution level generators and small and grid-scale storage may eventually face cost reflective DUOS export charges which could also include DNSPs making payments to providers of energy import or export services.

The AEMC therefore signals that, not only are new batteries subject to DUOS for any load that they draw from the network, but there may be a prospect for DUOS export charges for batteries.

Background on DUOS cost allocation

The current approach to network tariffs for grid-scale batteries connecting to the distribution network is to assign them to a default tariff class, and a tariff within the class, applicable to their connection voltage. For very large customers (>40 GWh consumption per year or 10MW demand), some distributors can offer an individually calculated tariff, reflective of the customers’ contribution to the system peak and a corresponding share of the appropriate network costs that would be reasonable to recover from this customer. A site specific Distribution Loss Factor (DLF) would also be calculated.[58]

Most of the tariffs for large customers have a capacity charge and a Time of Use energy charge. Batteries are treated as both load and generation. Before the Access and Pricing rule change, DUOS charges for exports were prohibited by NER cl 6.1.4, now removed. With the introduction of two-way tariffs and an attempt to reflect the depth of network use by the customer, new tariff structures might emerge for customers such as batteries.

How well do the current arrangements signal to batteries the marginal cost?

Current network pricing structures assume that each electron is sourced from the centralised generation/wholesale market (NEM), travels via transmission network into sub-transmission, high voltage and down to the low voltage network (for the LV connected batteries). Currently the marginal price signal charges for all parts of the journey. This signal might not be appropriate for the battery that matches the local load with its discharge, or charges during the solar peak alleviating the hosting capacity constraint. Alternative tariff arrangements are discussed in Chapter 2.

B.3. Arrangements for behind-the-meter batteries

In most cases, individual customers with batteries face the same network tariffs as would any other customer. The exception here is if small customers are assigned to a Time of Use tariff or demand tariff on the basis that they have a smart meter.

As we understand it, individual customers in VPPs face the same network tariff as if they were not connected to a VPP. For example, a customer that is part of a VPP in the distribution network will be subject to the same network tariff as their neighbour who is not part of a VPP.

B.3.1. Batteries potential to provide network services via VPPs

An important question is, what is the potential for VPPs to provide network services? At the moment, most VPPs are providing services exclusively in the wholesale and ancillary services markets. As we understand it, aggregators are not seeking to negotiate to provide network support services, or at least have not done so to date.

This raises an important issue – the ability of VPPs to provide services both to the local network and to the wholesale market. There may be conflicts between the optimal use of batteries for the network, and the optimal use of batteries in the wholesale market. For example, a network operator may wish to keep batteries in reserve, avoiding load-shedding on a network asset on a very hot day. In contrast, those batteries may be able to earn the market price cap in the wholesale market if they discharge their energy. But this might render them unavailable at a time when they are needed.

The critical observation is that the ability to reduce costs is largely a function of who ultimately controls the battery. If the battery is controlled by an aggregator that seeks to operate in the wholesale market, it is the wholesale market costs that the battery can earn. In contrast, if the battery is ultimately controlled by the network, owners will see a reduction in network costs.

---

58 NER cl. 3.6.3(b)(2)(i)(B).

B.3.2. What does the continued use of consumption tariffs mean for batteries?

Battery operators talk about 'stacking benefits' from different parts of the power system. There are clear conflicts between providing services in multiple markets. For example, a battery cannot simultaneously provide contingency FCAS and discharge its energy in the wholesale energy market – the two services are incompatible with one another. Rather, a battery must accept that it must optimise its operation *across services*.

The consequence for network tariffs is that network operators are, by setting their tariffs, competing with different services (eg, ancillary services, wholesale energy) for use of battery assets. It follows that using the simplistic, non-cost reflective consumption-based tariffs that provide only a vague or no signal of marginal cost may leave networks in a poor position to gain access to battery assets.

Alternatively, sophisticated battery algorithms can game simple network tariffs for large periods of the year, only to move to more lucrative opportunities at times of system stress. This could mean that networks see reductions in revenue from customers with batteries for a majority of the year, but do not see the change in behaviour that is required when battery operation can limit costs.

Potential two-way cost reflective network tariffs suitable for batteries are discussed in Chapter 2.

B.4. Community batteries

There are currently several trials of tariffs for community batteries, utilising the idea of rewarding the battery for its behaviour that saves network costs, while making the participants indifferent for whether they use the shared community battery or install their own BTM battery (see Chapter 2 for more detail).[59]

B.5. Electric vehicles with vehicle-to-grid capabilty

For residential and small businesses, most EV tariff trials proposed by distributors are based on either Time of Use tariffs, a standard cost reflective volumetric tariff, or some form of a controlled load tariff (eg, dynamically controlled load).

Development of commercial fast charging stations has been occurring in the environment dominated by capacity-based tariffs for commercial and industrial customers. These tariffs contain a capacity charge that, for some distributors, carries the peak demand measure for up to twelve months since its reading. Without a sufficiently high throughput, the capacity charge would make such a tariff uneconomical for the new EV charging station. This, however, does not diminish the case for cost reflective network tariffs.

Capacity charges are essential to not only signal the peak demand times, but also to recover the total efficient costs of running the network in an equitable way from all network users. Instead of deviating from the cost reflective tariff structures, the roll-out of EV charging stations could be supported by direct Government subsidies aligned with the policy objectives. Some alternative forms of cost reflective pricing could also be trialled by DNSPs, such as critical peak pricing. Two-way pricing with rewards for charging in the locations where extra load should be promoted during solar peak hours could also benefit the fast-charging stations (see Chapter 2 for more detail).

---

59 Synergy (2021), *Alkimos beach energy storage trial,* July 2021, https://arena.gov.au/assets/2021/07/alkimos-beach-energy-storage-trial-report.pdf; Ausgrid (2021), *Community Batteries*, https://www.ausgrid.com.au/In-your-community/Community-Batteries. Accessed on 1 June 2022.

Appendix C. Regulatory arrangements for batteries

This appendix examines recent reform processes that have consequences for the integration of batteries. Specifically, we consider the following three major reviews in the reform process:

- The AEMC's 2019 framework for the integration of DER.
- The recent rule changes undertaken by the AEMC that relate to DER.
- Reform processes undertaken by the Energy Security Board related to DER.

C.1. The AEMC's framework for the integration of DER

On the 26 September 2019, the AEMC published a framework review on how to best integrate DER into the system[60]. The intention was to create a dynamic market whilst managing challenges that may arise. The AEMC noted that the rise in the penetration of DER has changed the way energy markets operate from a centralised system to a system that increasingly incorporates large amounts of customer involvement and generation. The AEMC's proposed system aimed to maximise returns on DER investment for the customer by decreasing energy bill costs and allowing them to participate in the broader energy market.

The AEMC identified a number of reforms that need to occur to facilitate this transition.

C.1.1. Facilitation of two-way electricity flows

First, DNSPs need to facilitate two-way electricity flows and in doing so must consider the costs. Traditionally, network charges have only applied to imports from the grid. As a result, consumers only pay to consume electricity, access poles and wires. Therefore, these network charges do not apply to DER. The AEMC foreshadowed that as DER penetration increases, networks may reach their limits due to larger amounts of exports being transported. This would give rise to constraints on the networks leading to extra costs especially when there are very high or low levels of demand. Because DNSPs only incur revenue from consumption, customers without a form of DER are also paying for these increased costs. To create a more equitable provision of costs, the AEMC identified that those using DER should also be liable for network payments and required upgrades to facilitate greater amounts of exports within the grid.

C.1.2. Export tariffs for batteries

The AEMC also highlighted that when developing tariffs for batteries, use of system costs must be considered. Under the Rules at the time, generators – including batteries when exporting –do not pay for using the network and consequently do not receive guaranteed access. However, the AEMC identified that if batteries were to incur costs for exporting, they would have to receive something in return. Specifically, distributors would need to consider the different levels and types of services available that they can provide to battery owners.

C.1.3. Problems with existing flat tariffs structures

Prices are signals that help guide the decisions of consumers and the allocation of resources. Costs should reflect the impacts the user has on the network and the cost of generating electricity. The AEMC noted that to date the system has mainly made use of time-independent (flat) tariff

60 AEMC (2019), *Integrating Distributed Energy Resources for the Grid of the Future – Economic Regulatory Framework Review*, September 2019, https://www.aemc.gov.au/sites/default/files/2019-09/Final%20report%20-%20ENERFR%202019%20-%20EPR0068.PDF. Accessed on 1 June 2022.

structures where households pay similar prices regardless of how and when they use energy. Put simply, there are no price incentives to influence consumers when they use energy. The AEMC stated that if changes were not to occur this could lead to inappropriate times of charging batteries, as well as inefficient outcomes for the use of EVs. This could lead to higher prices for all consumers, and unnecessary generation or network investment. In particular, non-cost reflective flat tariffs could encourage owners of batteries or EVs to charge and discharge at inopportune times, leading to challenges in operating the power system as the penetration of these technologies increases.

The AEMC, therefore, recommended that customers need incentives to ensure that they operate these powerful technologies in a manner that benefits the whole grid. This could be based on a combination of traditional and fixed charges that vary with time or volume. Other flexible tariffs could include a subscription with a top-up, where customers pay for an agreed base level and then pay extra if they consumer or export more than the defined initial level.

Importantly, the AEMC identified that for the smooth integration of batteries the market needs smart pricing and smart technology to automate the charging and discharging of storage.

C.2. Recent rule changes that relate to DER

The AEMC's initial review set the scene for the emergence of pricing for exports. Eventually, this gave rise to two rule changes that are particularly relevant to batteries and other forms of DER. Namely:

- the Access, Pricing and Incentive Arrangements for DER rule change, and
- the Integrating Energy Storage Systems into the NEM rule change.

C.2.1. Access, pricing and incentive arrangements for DER

On 12 August 2021 the AEMC published its rule determination for Access, Pricing and Incentive arrangements for DER.[61] This clarified that export services fall under the obligations of DNSPs primarily due to the large uptake in DER. The rule change also allows DNSPs to create tariffs for exports enabling them to signal and recover the cost of providing these services. This can lead to price signals that promote the efficient use and investment in export services and reward customers for their actions. Additionally, the rule change includes arrangements that expand the DNSPs' capacity to develop and trial new, innovative network tariffs in response to consumer requests or changing consumption patterns. This will further assist in finding the most efficient outcome to integrate batteries within the network.

As a transitional measure, DNSPs must offer a basic export level.[62] This is set at a level where export services can be provided with minimal to no additional investment (see Chapter 2 for more detail).

[61] AEMC (2021), *Access, Pricing and Incentive Arrangements for DER* rule determination, August 2021, https://www.aemc.gov.au/sites/default/files/2021-08/Final%20determination%20-%20Access%2C%20pricing%20and%20incentive%20arrangements%20for%20DER.pdf. Accessed on 1 June 2022.

[62] NER cl. 11.141.12.

C.2.2. Integrating energy storage systems into the NEM

On 2 December 2021, the AEMC published an amendment for integrating energy storage systems into the NEM.[63] The amended rule crates a new technology-neutral participant category – ie, the integrated resource provider – with bi-directional energy flows. Batteries can now dispatch as a single bi-directional unit rather than registering under two categories. The rule change made the integration of batteries easier by lowering costs and barriers. It aligns cost recovery with the individual unit based on a more accurate accounting of their generation or load providing stronger incentives for more efficient behaviour.

Importantly, the Rule has established that batteries are liable for TUOS and DUOS for their withdrawals from the grid. This has been a highly controversial decision that has been met with resistance by battery developers who have argued that this undermines the business case for batteries.

C.3. The ESB post-2025 market review

The ESB has developed a DER Implementation Plan to integrate and manage the high volume of DER, including batteries and electric vehicles, projected to enter the market[64]. The DER Implementation Plan is a suite of technical, market and regulatory reforms that address the emerging risks associated with DER and deliver benefits to all consumers. These reforms effectively seek to respond to the rapid growth in batteries, electric vehicles and VPPs expected to occur as technological improvements continue and capital costs for these devices decrease.

The specific reforms that the ESB has proposed to support the integration of DERs include the following:

- Technical standards and governance.
- Arrangements for consumers to use their batteries to participate in the NEM.
- Consumer protections and enhanced information provision.

C.3.1. Technical standards and governance

This involves the introduction of technical standards for new inverter-based battery storage installations.[65] These standards are to be continually monitored and developed for other storage technologies in the long term. They will include identification and development of processes to enable batteries to operate alongside other DERs, including registration, telemetry data collection and management of access control. Consideration will also be given to cyber-security for DER interoperability. The ESB will coordinate with the Department of Industry, Science, Energy and Resources (DISER) to deliver the security design and other policy measures as needed. Development and confirmation of EV technical standards, such as flexible trading arrangements will allow customers to choose how service providers manage their EV charging. The intention is

---

63 AEMC (2021), *Integrating energy storage systems into the NEM* rule determination, December 2021, https://www.aemc.gov.au/sites/default/files/2021-12/1._final_determination_-_integrating_energy_storage_systems_into_the_nem.pdf . Accessed on 1 June 2022.

64 ESB (2021), *Post-2025 market design – Part A*, July 2021, https://www.energy.gov.au/sites/default/files/2021-10/Post%202025%20Market%20Design%20Final%20Advice%20to%20Energy%20Ministers%20Part%20A_0.pdf. Accessed on 1 June 2022.

65 ESB (2021), *Post-2025 market design – Part B*, July 2021, https://esb-post2025-market-design.aemc.gov.au/32572/1629945809-post-2025-market-design-final-advice-to-energy-ministers-part-b.pdf. Accessed on 1 June 2022.

that these measures will also provide support to aggregators and other service providers to encourage entry into the market.

C.3.2. Arrangements for batteries to participate in the wholesale energy market

Arrangements for batteries to participate in the wholesale energy market proposed by the ESB include the following:

- Establishment of new roles and responsibilities related to Dynamic Operating Envelopes for retailers, service providers and DNSPs.
- Clarification to networks regarding flexible pricing solutions (reward or negative pricing) to either incentivise or deter consumers from injecting energy into the grid.
- Enabling aggregators and managers of virtual power plants to participate in the wholesale market on behalf of small customers with EV chargers, batteries and other controllable storage technologies and devices.

The intention is that these reforms will increase the potential for batteries to participate in the wholesale energy market, allowing retailers to harness the power of DER to support the use of grid-scale assets to provide energy.

C.3.3. Consumer protection and enhanced information provision

Finally, the ESB has also identified the need for additional consumer protection arrangements and enhanced information provision to support the rising penetration of DER. These arrangements include the following:

- Development of regulatory processes and other arrangements to ensure that consumers can easily and safely switch between DER and non-DER service providers.
- Development of risk assessment tools for market bodies to assess whether retail offers from DER providers meet appropriate levels of consumer protection.
- Information reporting of the conditions that lead to minimum system load events. This will ensure that consumers know how to derive the most value from their batteries and manage minimum system load events.

C.3.4. Batteries and the transmission and access reform pathway

Another part of the ESB reform process that relates to batteries – particularly grid-scale batteries – is the Access Reform Pathway[66]. Under the current access regime, the decision of where a new generator should locate is based on price outcomes at the regional reference node (RRN) and this can lead to detrimental outcomes. An example of these outcomes is congestion, which may occur if the generator is located far from the load centre. Accordingly, the ESB has developed a package of access reforms, which aim to encourage favourable, coordinated generation investment (including batteries) in terms of timing and location.

Locational marginal pricing as the signal to indicate where new generation investment would best be located on the transmission network has been raised in the recent review of Coordination of

---

[66] ESB (2021), *Transmission access reform project initiation paper,* November 2021, https://esb-post2025-market-design.aemc.gov.au/32572/1637195631-access-reform-project-initiation-document-nov-2021-final.pdf. Accessed on 1 June 2022.

generation and transmission investment implementation – access and charging (COGATI review).[67] Development of the renewable energy zones (REZs) follows from these ideas.

The primary reform concerning batteries includes the design and provision of efficient incentives and signals to encourage battery investment in REZs. The proposed device to achieve this is the congestion management model, which uses selective availability of congestion rebates to create locational signals.

[67] AEMC (2020), *Transmission access reform: Updated technical specifications and cost-benefit analysis*, Interim Report, September 2020, https://www.aemc.gov.au/sites/default/files/2020-09/Interim%20report%20-%20transmission%20access%20reform%20-%20Updated%20technical%20specifications%20and%20cost-benefit%20analysis%202020_09_07.PDF. Accessed on 1 June 2022.

Glossary of terms

AER	Australian Energy Regulator
AEMC	Australian Electricity Market Commission
AEMO	Australian Energy Market Operator
ARENA	Australian Renewable Energy Agency
BTM	Behind the Meter
CDR	Consumer Data Right
CRNP	Cost Reflective Network Pricing
DEIP	Distributed Energy Integration Program
DER	Distributed Energy Resources
DISER	Department of Industry, Science, Energy and Resources
DLF	Distribution Loss Factor
DNSP	Distribution Network Service Provider
DOE	Dynamic Operating Envelope
DSO	Distribution System Operator
DUOS	Distribution Use of System
ESB	Energy Security Board
EV	Electric Vehicle
FCAS	Frequency Control and Ancillary Services
FRMP	Financially Responsible Market Participant
FTA	Flexible Trading Arrangements
HEMS	Home Energy Management System
kVA	Kilovolt-ampere
kW	Kilowatt
kWh	Kilowatt-hour
ISP	Integrated System Plan
LRMC	Long Run Marginal Cost
LUOS	Local Use of System

LV	Low Voltage
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NMI	National Metering Identifier
NUOS	Network Use of System
PV	Solar Photovoltaic System
REZ	Renewable Energy Zone
RRN	Regional Reference Node
SGA	Small Generation Aggregator
SRMC	Short Run Marginal Cost
TNSP	Transmission Network Service Provider
TOU	Time of Use
TSS	Tariff Structure Statements
TUOS	Transmission Use of System
V2G	Vehicle-to-Grid
VPP	Virtual Power Plant