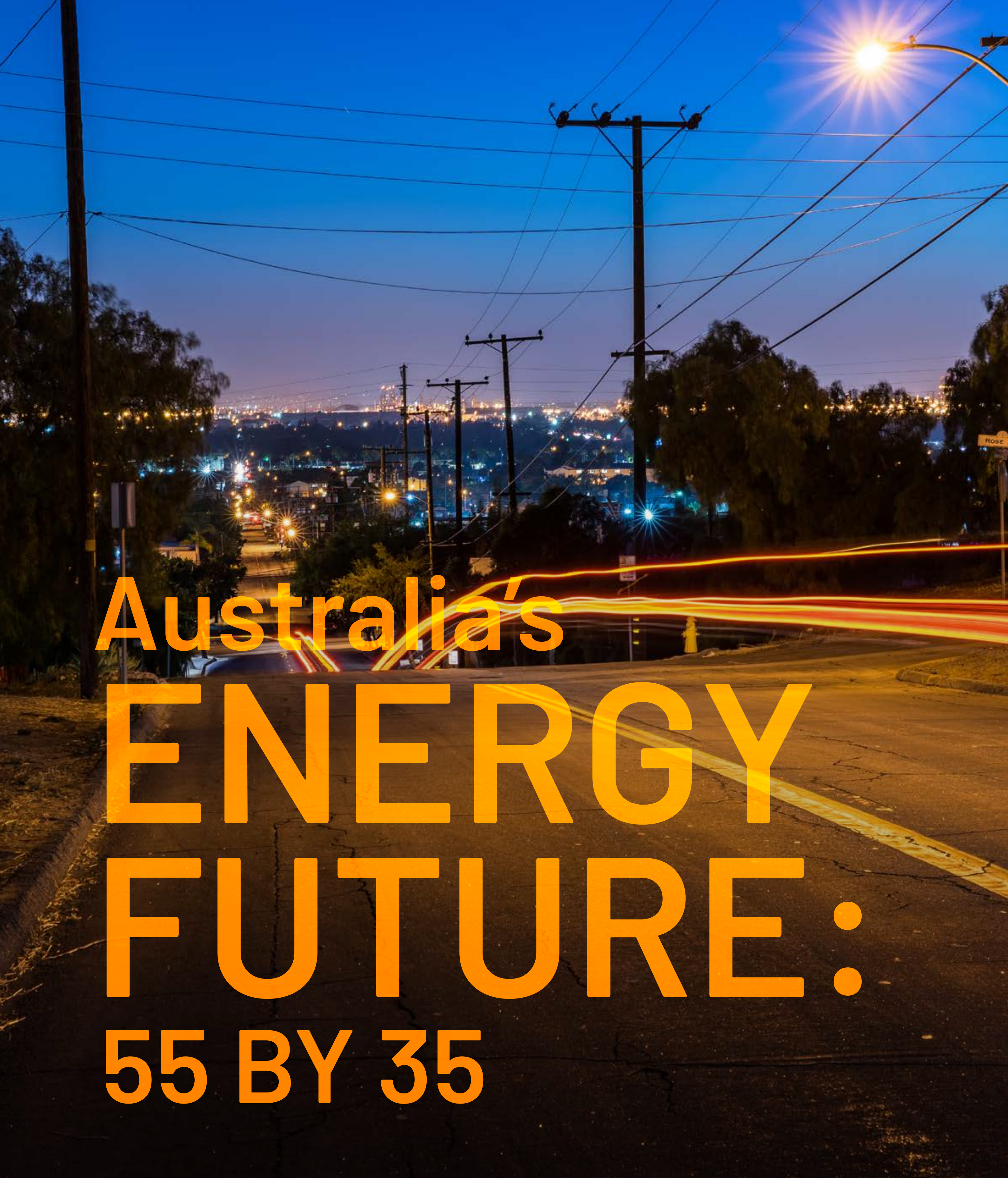

Australia's ENERGY FUTURE: 55 BY 35

Electricity Distribution

AUSTRALIAN ENERGY COUNCIL

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Executive Overview

The AEC has proposed an economy-wide interim emissions target of 55 per cent reduction on 2005 levels by 2035 as a milestone on the way to net zero. This paper is one in a series of papers exploring the implications of the 55 by 35 target. This paper looks at the implications of this target and the transition to net zero for Australia's electricity distribution networks.

The roles and responsibilities of electricity distribution networks are being challenged by the changing mix of resources in the grid. The energy transition is not just about reducing emissions by changing technologies in large-scale generation, it is also about a trend towards more localised, or distributed energy resources (DER). The most obvious example is the millions of solar PV systems on customers' roofs around Australia, but these are expected to be joined by batteries and electric vehicles as we move towards net zero.

These changes are creating issues in how distribution networks are regulated, how they charge for their services, boundary issues between networks and retailers, and how best to harness, or integrate, the collective resources of customer-owned assets such as rooftop PV and batteries. There is a wide range of estimates of the value of integration of DER, but all are substantial and indicate it is worth trying to get policy settings right.

The energy transition is not just about reducing emissions by changing technologies in large-scale generation, it is also about a trend towards more localised, or distributed energy resources (DER). The most obvious example is the millions of solar PV systems on customers' roofs around Australia, but these are expected to be joined by batteries and electric vehicles as we move towards net zero.

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Introduction

The Australian Energy Council (AEC) published its Net Zero by 2050 policy in June 2020. That policy has since been adopted by Australia, and focus has turned to interim targets to set the economy on a realistic pathway to this ambition. An interim target should be aspirational yet achievable, and consistent with the overall goal of net zero by 2050. An economy-wide target is more flexible and efficient than purely sectoral targets. With these factors in mind, the AEC has proposed an interim economy-wide target of a 55 per cent emissions reduction from 2005 levels by 2035 ("55 by 35").

This paper is one in a series of papers exploring the implications of the 55 by 35 target. It focuses on the electricity distribution networks , which will play a critical role in integrating the new consumer-owned appliances and assets that will deliver a portion of the target. This will include rooftop PV and batteries, electric vehicles and deeper penetration of electric hot water, heating and cooking as a substitute for natural gas.

The role of distribution

A distribution network consists of the poles, underground channels and wires that carry electricity, as well as substations, transformers, switching equipment, and monitoring and signalling equipment. The role of distribution networks is to transfer electricity from the bulk power system (generators and transmission) to end users. In doing so, they must step down the voltage from the very high levels of the transmission network to a level that allows customer appliances and machines to safely operate. This role is being augmented by a growing requirement to transfer surplus electricity from customers' distributed energy resources (DER) back into the network. The primary activities of distribution networks are thus:

- **Network planning** – forecasting demand patterns to ensure the network can handle peak demand requirements.
- **Network operations** – keeping the network operating safely and securely on a day-to-day basis.
- **Network maintenance** – fixing the network when things go wrong – generally either due to failure of old assets or weather events. Most outages experienced by customers are due to faults or damage on the distribution network.
- **Connections** – ensuring new customers are safely connected to the network.

Metering used to be another core activity, but this now varies by jurisdiction, with retailers having taken on responsibility for metering in all NEM regions except Victoria.

Distribution networks are a natural monopoly – it is not efficient to have duplicate networks that customers can choose between, and so they are subject to economic regulation by the AER in the NEM and the Economic Regulation Authority (ERA) in Western Australia. The regulatory framework and its impact on distribution network incentives is covered later in this paper.

Distribution/retail boundary

In some overseas places, the distributor is also responsible for procuring electricity supply and billing customers. In Australia, however, these roles have been fully unbundled to better enable competition and efficient risk management. Retailers compete for the right to supply customers, but the customers are using the same network regardless of which retailer serves them. Transmission networks bill distribution networks who bundle transmission and distribution charges together and bill retailers for their customers' use of the network. Distribution networks also need to demonstrate competitive neutrality between the users of their network. For this reason, there are rules around networks' ownership of commercial businesses that compete on their network (see ringfencing section later).

The advantage of unbundling is to allow each part of the supply chain to focus on different activities: asset management for networks versus energy procurement and marketing for retailers.

The growth of DER is complicating these arrangements. As set out further below, the efficient integration of DER into the network will be important for keeping system costs down during the energy transition. However, retailers and networks face different incentives and have different tools available to encourage customers to use their DER in a way that minimises system costs.

The growing impact of DER

The energy transition is not just about changes to large-scale generation and transmission. It's also about what happens at the customer level, and the distribution networks that connect to small and medium-sized customers.

By 2030, AEMO expects around 50 per cent of consumers, including large businesses, to use some form of distributed energy resource (DER) to participate in the demand side of the national electricity market.

The starting point of DER is rooftop PV. This has been revolutionary for Australia's electricity systems and markets but it is a relatively passive technology. However, rooftop PV may in turn drive rapid battery uptake once battery costs start to decline. This is because the increasing gap between the value of solar exports and the unit cost of electricity creates an arbitrage opportunity for consumers to store excess solar in the daytime and release it in the evening.

As previous papers in this series have explained, the route to decarbonisation also lies partly in the electrification of other energy uses, notably transport and heat. These elements of the transition will further increase the potential for consumers to be active demand side participants. Electrification of transport will add to the stock of battery capacity owned by consumers, although there is an important question as to their appetite to use vehicles as ancillary storage, in what is called "vehicle to grid" (V2G) technology. Electrification of heat will increase the stock of electric hot water, which is a substantial load that is suitable for demand management (i.e. the water can be heated at a different time from when the hot water is being used).

Space heating may also be somewhat amenable to demand management, through tools such as direct load control (which is already being used for air-conditioning on hot days and so this technique could be extended to the same appliances being used for heating purposes) and smart thermostats.

Public support for ongoing decarbonisation will be dependent on maintaining an affordable electricity system - and for the system to be seen to be working in consumers' interests. All elements of the supply chain bear responsibility for achieving these goals - as do policymakers. However, distribution networks (DNSPs) have a central role to play as it is their infrastructure that enables the transfer of electrons to and from customer premises. The costs of the distribution network are usually also the single largest component of a residential retailer bill, at a little over a third of a typical bill. This is a higher share than in many other countries.

An indicative breakdown of household bills is shown in Table 1 below. Note that changes in macroeconomic conditions since this table was compiled (higher inflation, higher interest rates) are likely to increase network costs because of their direct impact on the way network revenues are calculated.

So, the efficient integration of DER into the distribution system is paramount. How well this will happen depends heavily on the regulatory frameworks.

Table 1 *AEMC retail price trends*

	2020/21 BASE YEAR		2021/22 CURRENT YEAR		2022/23		2023/24	
	c/kwh	$/year	c/kwh	$/year	c/kwh	$/year	c/kwh	$/year
Environmental policies	**2.45**	**$122**	**2.45**	**$123**	**2.24**	**$113**	**2.10**	**$106**
LRET	0.65	$32	0.49	$25	0.37	$19	0.29	$15
SRES	1.00	$50	1.11	$55	0.98	$49	0.93	$46
Jurisdictional Schemes	0.59	$30	0.63	$34	0.62	$33	0.61	$33
Efficiency Schemes	0.21	$10	0.21	$10	0.27	$13	0.28	$13
Regulated Networks	**12.43**	**$603**	**12.81**	**$622**	**12.93**	**$628**	**13.05**	**$634**
Transmission	2.07	$101	2.28	$111	2.34	$114	2.41	$117
Distribution	9.50	$460	9.70	$471	9.75	$473	9.81	$476
Metering	0.85	$42	0.82	$41	0.83	$41	0.84	$41
Wholesale	**9.61**	**$467**	**9.19**	**$448**	**9.71**	**$469**	**7.69**	**$375**
Residual	**3.02**	**$150**	**2.98**	**$145**	**3.03**	**$147**	**3.09**	**$150**
Total	**27.51**	**$1,342**	**27.43**	**$1,338**	**27.92**	**$1,357**	**25.94**	**$1,265**

Source: AEMC residential price trends 2021

Regulatory frameworks for distribution

The distribution and transmission networks in the NEM are treated as natural monopolies and so are heavily regulated by the Australian Energy Regulator (AER). The main activity of the networks - operating, maintaining and where necessary augmenting – the shared network is subject to a revenue cap that is set every five years. Because their revenue is fixed, the network businesses have a strong incentive to keep their costs down, although the rules require them to return a portion of any savings to customers through lower future prices. A set of standards (with penalties for non-compliance) and other incentives act as a safeguard against cost-cutting up until the point that the quality of service degrades.

This basic framework is known as incentive-based regulation and is widely used in the UK (where the framework was developed), Europe as well as Australia and New Zealand. By contrast, most US networks are subject to a simpler form of regulation called cost-of-service. Different forms of regulation result in different allocations of risk between the regulated business and its customers.

A key challenge for the regulator is what economists call information asymmetry (i.e. the network business knows their own costs better than the regulator). The regulator uses analytical tools like benchmarking the businesses against each other to estimate what the efficient costs of operating a network should be, although this works better for distribution than transmission, where costs are much "lumpier" due to the scale of projects.

The process, or determination, of setting the allowed revenue takes about two years all up, hence why it's set for a five-year period. Given the process is about trying to predict the future costs of the business, there are risks in extending the determination period too long. Until recently, the final determination could be appealed, but that right has now been removed.

Key to the effectiveness of this type of regulation is that the incentives are balanced between different types of expenditure. There is also an argument that it is best suited to driving costs down in a business-as-usual electricity system, with fairly predictable projections of customer load and costs of operating and maintaining the network. It may be less well suited to the uncertainty of a major energy transition or to driving innovation.

Regulatory investment tests

A distribution business must carry out a regulatory investment test (RIT-D) for any network augmentation project unless it meets certain criteria. As with transmission there is a cost threshold, which is also $6m. Unlike transmission, the smaller scale of distribution networks means that most investments will fall below this threshold. There is a proportionality issue to bear in mind, which is that the requirements of a RIT make it a lengthy process that has a material cost to the network, let alone to any participating stakeholders. Nonetheless, an argument has been made for reducing the threshold for the RIT-D in order to expose more investments to the test. The argument is primarily that the more public nature of the RIT-D compared to internal project appraisal would open up more opportunities to providers of non-network options, which might incentivise better customer outcomes.

Energeia's report for Renew reviewed RIT-D outcomes and found a very low level of non-network outcomes. For a sample of projects up to 2018, only 0.15 per cent of project expenditure was on rewarding DER. While this proportion increased over the period 2018-20, it was still well below the level Energeia estimated would be efficient based on network asset costs versus DER costs. Energeia note that this could be because RIT-Ds are only carried out on larger projects at the higher voltage level where network costs per kW capacity are lowest, making them more competitive with DER than other parts of the network.

Nonetheless Energeia posit that this discrepancy may reflect DNSPs' incentives being skewed towards investment on their own network versus rewarding DER. This is explored in the next section.

Incentives

A key concern among many stakeholders with an interest in DER is whether distribution networks face balanced incentives between incurring capital expenditure (such as building new poles and wires) and operating expenditure (such as paying DER owners for providing grid support).

There are many potential reasons for this low level of alternative expenditure.

1. The lack of sufficient DER capacity. To date most DER has been solar PV, which has been installed as passive capacity, and is not inherently dispatchable. Batteries are only just emerging and are not yet cost-effective for many customers. Controllable load represents an untapped opportunity.
2. The need for DER to be able to "value stack" to maximise its returns, with RIT-D opportunities representing only a part of this value stack.
3. Possible skewed incentives toward capex.

The AEMC considered this issue in its annual review of energy networks' economic regulatory frameworks in 2018 and again in 2019. The 2018 review found that there was no systematic bias towards capex in the framework, but that actual incentives varied with circumstances. These could include a difference between the actual cost of capital and the rate allowed by the AER or the duration of opex costs/savings that are an alternative to capex.

The 2019 review appeared to pick up where 2018 left off and began canvassing for different solutions to potential capex bias. For reasons not entirely clear it then put aside this workstream and focussed on a range of other emerging challenges relating to DER integration.

A report by CEPA for the 2018 review also provided a good summary of other possible reasons for a capex bias:

- An investor preference for DNSPs to 'grow the regulatory asset base (RAB)', to increase overall earnings and maintain long-term, stable shareholder returns.
- Risk aversion, resulting in a preference for deploying more commonly used capex approaches instead of adopting alternative solutions. This could be due to concerns about the ability to maintain service standards (avoid penalties) or uncertainty around the ongoing expected cost of alternative solutions.
- Reputational incentives. This could include avoiding solutions which may not be 'tried and tested', or concerns about public and investor perceptions if the company appears more inefficient than its peers due to its approach.
- Existing cultural biases that favour a 'poles and wires' solution over alternative solutions, resulting from an NSP's history, skill base and ownership/organisational structure.

This perceived capex bias and what causes it is important for ensuring network services are delivered as efficiently as possible (including optimal use of DER). If it does exist, distribution networks will forego efficient non-network options and customers will miss out on revenue to support their purchase and use of DER. However, clear proof and diagnosis of the reasons for a bias remain elusive. Nonetheless it is an area policymakers should keep under review. Apart from lowering the RIT-D threshold, an alternative proposal for enabling non-network options is to make them the default choice (at least for projects where they provide a plausible alternative). DNSPs would have to demonstrate why the network alternative is better to be allowed to add the capex to their RAB. This is a relatively radical approach and other options such as adjusting the relative incentives for capex and opex should be considered in the first instance.

Of course, potential incentive bias is far from the only potential inhibitor of efficient DER integration. Some of the emerging challenges are set out in the next section.

Emerging challenges

There are numerous challenges to determining the right level and type of network expenditure in order to optimise for DER growth.

- Distribution networks currently have limited visibility of their low voltage network. In the previous paradigm of top-down supply, this was not a priority. It now is but remedying this itself requires expenditure by DNSPs, which will need to be justified to the AER. This is likely to be a foundational requirement for more sophisticated distribution management in the future, such as the distribution system operator (DSO) model explored below.
- Expenditure proposals should be well evidenced. However, there is a lack of precedent to rely on when some networks are at the technological frontier of rooftop PV penetration.
- It's not clear that current evaluation approaches (whether by the network or by the AER assessing the network's proposals) assign value to maintaining optionality. Once a capex project has been committed to, consumers will have to pay for it over several decades, irrespective of how well utilised it is. By contrast, opex approaches, such as paying for network support only last as long as the contract is for.
- Direct comparison of network and non-network solutions can be hard to make, given their quite different characteristics.
- There is a chicken-and-egg type problem in cultivating DER response at scale. The volume of DER may be suboptimal because it hasn't had access to the revenue stream that network support payments can provide. But in some cases there may not be enough DER to provide an effective alternative, so the market may never get started.
- DER response may not be 100 per cent (as assets do not always function to their nameplate capacity). It may take time to accurately assess what level of response can be achieved in order to procure the right amount (i.e. if a 9MW response is required and a 90% response rate can be expected, then a DNSP would have to contract with 10MW of DER).

- DNSPs need to make long-range plans in an environment of greater uncertainty over load than ever before. The take-up rate and load characteristics of EVs, batteries and electrified heat are all uncertain and can change due to changes in policy and regulation. This is one reason why an optionality approach may have more value than before.

In other words, compared to traditional network management based around tried and tested approaches to building new "poles and wires" assets and maintaining existing networks, there is more uncertainty about what the best approach is to meet a given network need. This applies to both the networks who have to propose a five year business plan and to the AER who has to review the plan (and indeed other stakeholder such as customer representatives, who participate in the process).

Ringfencing

Many network businesses have related parties that carry out businesses in the competitive sector, such as private electrical installations. The purpose of ring-fencing is to prevent the regulated side of these businesses from discriminating in favour of their related parties to disadvantage competitors operating in these markets. In recent years, the AER has stepped up its monitoring of the ring-fencing requirements as the rise of distributed energy resources (DER) has created greater opportunities for such discrimination. Conversely, network businesses argue that the ringfencing arrangements are expensive and onerous and potentially rule out efficient ways to roll out DER.

For example, it's likely that an efficient location for batteries is at nodes on the distribution networks, such as transformer stations. Battery investment can be supported by "value stacking" different revenue streams, and several of these are in competitive markets, which ringfencing typically excludes network businesses from participating in. So, does ringfencing inhibit the efficient deployment of network-located batteries? This depends on whether there are material barriers to networks contracting with market participants so that the battery can be used for both the network and in the market. This project is an example of where contracting outcomes appear to have been viable.

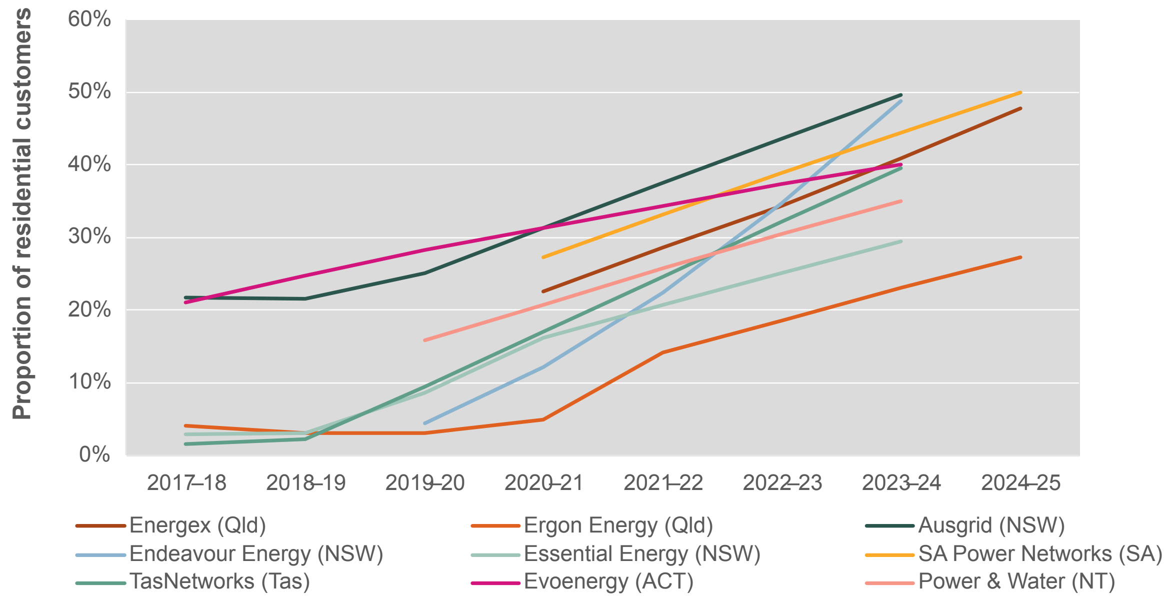
Tariffs

On the face of it, well-designed network tariffs (prices) have the potential to be a low cost but powerful tool to assist with integrating DER efficiently. Cost-reflective tariffs (i.e. tariffs that accurately reflect the costs imposed on the network by users provide incentives to use more or less electricity) can assist in maximising network utilisation and minimising the need for new capital expenditure to upgrade the network. Cost-reflective tariffs can take multiple forms, but all have some component where the cost of network services varies with the time of use. Examples include:

- **Time of use (TOU) tariffs**
  This is where there is a different price (c/KWh) at different pre-set times of day - often designated "peak", "off-peak" and "shoulder". This also includes seasonal variation.
- **Peak demand tariffs**
  This is where there is a price (c/KW) for the maximum capacity required by a consumer during a billing period. Sometimes this will only apply to the maximum demand during a peak period.
- **Critical peak pricing (CPP)**
  This is where there is a large premium price (c/Kwh) associated with a few periods of very high demand on the network (hot summer days on most Australian networks). Typically, the network can "call" a CPP period with at least 24 hours notice on a fixed number of occasions a year. As this type of tariff is dynamic, communication protocols are important so customers know when a CPP period is.
- **Critical peak rebate (CPR)**
  This is a variant on CPP where customers are rewarded for using less electricity than usual (their "baseline" usage) during critical peak periods. It is seen as a more palatable alternative to CPP, but its weakness is the quality of the baseline data.
- **Solar Sponge tariffs**
  This is a newer concept, used to help manage periods of peak DER export by offering a discounted tariff during the middle of the day to encourage customers to use more at those times and "soak up" the solar exports.
- **Export tariffs**
  The AEMC has recently passed a new rule that allows DNSPs to charge customers for exporting electricity (typically surplus rooftop PV output) to the network. Such tariffs must still be cost-reflective, i.e. they must be based on underlying costs incurred in managing the flow of electrons back into the grid.

These tariffs are all more complex than the traditional flat tariff structure. Complex tariffs are not inherently more cost-reflective. Distribution networks are obliged under the national electricity rules to implement cost-reflective tariffs where possible (Victoria is effectively opted out from this). As discussed below, a limited rollout of interval

Figure 1 *Projected assignment of cost-reflective tariffs for residential consumers*



Source: AER, State of the Energy Market 2021

meters that can record the time of use has inhibited the spread of cost-reflective tariffs. The AER expects that this will increase over the next few years, but note that the chart below is based on DNSP forecasts (and excludes Victoria).

A complicating factor in the use of tariffs is that retailers are the intermediaries between networks and consumers. Retailers decide whether to "pass-through" network tariffs as they are or to design retail tariffs that have a different "shape". There is nothing untoward in this - after all it's what is expected of retailers with wholesale prices. These are highly variable, but most retailers package them up into a retail tariff that has a consistent consumption component. Retailers have faced criticism for not passing through network tariffs, but when they do not, it presumably reflects a judgment that their customers do not want to be exposed to that network tariff. In any event, retail competition means that if a retailer is smearing the tariff in an inefficient way, it's likely another retailer will come along and beat their offer.

The rules are ambiguous as to whether network tariffs should be aimed at the customer or at the retailer. There may be value in policymakers resolving this ambiguity to provide clarity about the purpose of network tariffs, along with the burden of proof, in the absence of any post implementation reviews.

Outside the NEM (i.e. in WA and the NT), tariffs are set directly by governments and so the issue of retailer versus network perspective is not as relevant. However, governments appear even less enthusiastic than retailers to expose customers to cost-reflective tariffs. The political nature of tariff-setting in these jurisdictions also can result in some significant anomalies. In the NT for example, there are different feed-in tariffs available for rooftop solar exports depending on whether the customer is a household or a small business. This means that installing a battery to soak up excess daytime solar has a payoff for small businesses but not for households.

Genuine cost-reflectivity also requires that governments refrain from using grid electricity as a tax base either for general funding or for specific activities such as energy efficiency. While such costs (often hidden within distribution charges) are only a small part of an overall bill, they are not negligible and distort choices between grid supply and DER (which does not incur these charges). The tariff discussion assumes that actual system costs are all recovered through electricity bills. Given the fixed nature of many of the costs, the shared benefits of having an electricity network, and the fundamental importance of having an electric supply to modern life, there is a case for recovering fixed costs through other means, such as property rates.

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Can customers respond to cost-reflective tariffs?

There is some doubt about the willingness of residential consumers to understand, let alone respond to, tariffs that indicate that the cost of supplying electricity may vary with time of use.

One way to think about ways in which households can respond is to consider which energy services are time-dependent (i.e. which ones could be shifted to another time of the day/night).

Necessarily time-dependent: These are uses where the electricity is required at the time the service is used and there is not much scope to move the time the service is used. Examples are TV, lighting, hair dryer, electric cooker, refrigeration.

Contingently time-dependent: These are uses where the technology exists (but may not be common in households at the moment) to decouple the time the electricity is used from the time the service is used. This is typically done by heating or cooling water or another medium and then efficiently maintaining the temperature so the energy service can be used at another time. Examples include heating, hot water and air-conditioning. In many regions, electric hot water is already decoupled and is charged at a lower rate because it is set to consume electricity in off-peak periods only.

The point is that the appliances or systems many households currently have may be time-dependent – e.g. instantaneous hot water and most air conditioner units, but if they are facing a price signal, then when the time comes to replace or upgrade the system, there is now a reason to choose a storage-based technology. Critically, these are amongst the biggest uses of electricity and a key driver of peak usage.

Non time dependent. These are uses where either the electricity use can be easily decoupled from the time the service is used or the time of the service is quite flexible. The obvious example for the former is charging of battery-powered devices, such as mobile phones, tablets, etc. Examples of the latter (which may depend on circumstance) are washing machines, dishwashers and pool pumps. These appliances are often already fitted with a timer or can be subject to direct load control by the electricity supplier if permitted.

Interruptible. Some services that are time dependent can have their power supply interrupted briefly without affecting the service that they provide. This can include aircon, refrigeration, heating, hot water, etc. The value of giving a electricity supplier permission to control their usage is it can smooth out peaks by, say, cycling a third of their customers off for 20 minutes each hour, then the next third, then the final third and so on.

So peak pricing signals (which could include TOU, CPP/CPR or peak demand tariffs) provides incentives to:

- Choose the version of contingently time-dependent appliances/systems that are not (or are less) time dependent.
- Shift non time-dependent uses away from the peak (whether by their own choice or by DLC).
- Agree to interruptible services.

Business users may have a different set of appliances and face different constraints but similar principles apply to them. A key barrier may be that even if consumers can respond, they don't necessarily want to.

Metering

Metering is a key factor in tariff design. Traditional accumulation meters only record how much electricity was used by a customer between meter reads, which are carried out manually (and thus, for cost reasons only take place every few months). They can't indicate in which periods more or less electricity was used. So customers with these meters cannot be offered time-dependent tariffs (e.g. time-of-use, critical peak pricing, peak demand).

For widespread tariff reform, digital interval meters that can record electricity use on an hour by hour (or even potentially minute-by-minute) basis and be remotely read via communications infrastructure need to be rolled out. Such meters are sometimes known as "smart" meters, although there are differences of opinion on what level of functionality really makes a meter "smart". Why hasn't this rollout happened in Australia? To answer that we need to consider both history and incentives.

When retail and distribution were unbundled, metering remained with the DNSPs. The potential benefits of digital metering were identified at national level in the late 2000s, but it was left to individual jurisdictions to decide when and how to roll them out.

Victoria was first to move, and a relatively high specification was set for the meters in order to maximise the potential benefits. Additionally, since some of the benefits case rested on the meters being rolled out to everyone, there was an accelerated deployment over four years - meaning many functioning accumulation meters had to be removed. The result was a high-cost rollout that was highly visible to customers via bill increases. The rollout became politically toxic - not enough to halt it, but

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enough that the state government did not follow through to ensure the benefits were realised and made visible. In fact, the government acted to limit the benefits by passing an Order in Council to prevent the universal rollout of cost-reflective tariffs (although customers could still opt in).

The Victorian experience put other jurisdictions off mandating the installation of digital meters for all customers. Accordingly, the AEMC tried a different approach, transferring responsibility for metering to retailers in the rest of the NEM. Digital meters are required to be installed when a meter needs replacing and when a customer installs DER (so that exports can be measured separately). The logic was that competition would push retailers to find the lowest cost way to install meters where required and that the market would also identify where there was value in additional installations, i.e. where the customer wanted the services the metering provided or the retailer could see value in doing so itself.

In practice, other than indirectly via DER installation, customers do not have any interest in metering upgrades. And retailers have evidently struggled to find a business case to fund metering upgrades themselves. This reflects that in both cases, customers and retailers are only considering the private costs and benefits to themselves of metering upgrades. The broader shared benefits of metering upgrades – for example, enabling better tariffs, remote disconnection, outage monitoring, or even remote reading – are not a major factor.

Accordingly, digital interval metering penetration remains patchy. The AER's latest figures dating from February 2021, indicate rates from 15 percent of residential and small business customers (Queensland) to 25 percent (NSW). However, the AER forecasts these levels to increase over the next few years.

Death Spiral

Concerns have previously been expressed about a death spiral, where poorly designed tariffs result in inaccurate price signals that incentivise departure from the grid. The logic is that if some users decide to leave the grid, the largely fixed cost of the networks have to be shared between remaining customers. This makes grid supply more expensive, inducing further disconnections and the process becomes self-reinforcing.

Even though rooftop PV and household scale batteries - the two mainstays of a standalone system - have both experienced impressive declines in cost, they remain unlikely to trigger widespread defection from the grid. As this example shows, the amount of battery capacity required for full energy independence remains very high. In this case study, a 3KWh battery is sufficient when paired with rooftop PV to deliver 90% self-sufficiency. But to go to 100% self-sufficiency requires a 59KWh battery – or 20 times more battery. Alternatively, a smaller battery plus a small genset could also work. But while this kind of trade-off may make sense for a new house out in the bush, where paying for the initial connection to the grid can be very expensive, it doesn't for the typical suburban home that already has a grid connection. It's also doubtful whether a million gensets in a metropolitan area would be socially acceptable.

Other factors militating against the concept of the death spiral are:

- Full disconnection transfers responsibility for maintaining reliable supply away from the distribution network operator to the householder.
- It also removes the opportunity to earn money from providing network support, or even just general export revenue. The former is likely to grow, especially as virtual power plant (VPP) business models develop, even as the latter declines as solar capacity grows.

What goes for household customers equally applies to business customers of all sizes. Accordingly, DER is likely to continue to be available, at least in principle, for network support. The big question is - on what terms?

Aggregation and Orchestration

It's unlikely that many individual customers will be interested in directly managing their DER and their load or contracting directly with distribution networks for network support. The transaction costs of contracting with thousands of individual customers could also inhibit DNSPs from procuring network support. Accordingly, two key approaches for integrating DER are aggregation and orchestration.

Aggregation is the bundling together of many customers' resources to provide a larger potential resource, that can provide network support or even participate in wholesale markets. Fortunately, there is already a natural aggregator in the electricity sector - the retailer. Retailers already "bulk buy" their customers' electricity supply and so have a pre-existing relationship, comprising contractual arrangements and periodic communication. So, it's in principle a short step to "bulk sell" customers' DER on their behalf. This approach is already manifesting in the form of Virtual Power Plants (VPPs), which utilise customer solar and batteries to participate in the FCAS markets for example.

Retailers are not the only potential aggregators, and the existence of retail offerings that pass-through wholesale and network costs creates the opportunity for third parties to aggregate services too. Policymakers have looked over the years at other means of facilitating third party participation, which have typically included setting up systems to allow multiple suppliers through a single meter point. The costs of doing this on a widespread basis have to date appeared to outweigh the benefits.

Orchestration is the direct management of DER by another party to induce a "firm" response when requested. At its simplest, this has been used by distribution networks for decades, primarily via timed electric hot water systems. More recently, it has been extended to direct load control of air conditioners, such as Energex's Peak Smart program.

However, DNSPs do not need to be the orchestrators. Technological advances mean that aggregators can set up similar controls and sell these as network support services.

Aggregation and orchestration will be facilitated by adopting consistent protocols and standards across DNSPs as far as possible, given many aggregators will want to operate across multiple networks.

A key principle is customer sovereignty over their resources. Customers should have the ultimate right to choose which (if any service provider) they would like to manage their resources and on what terms.

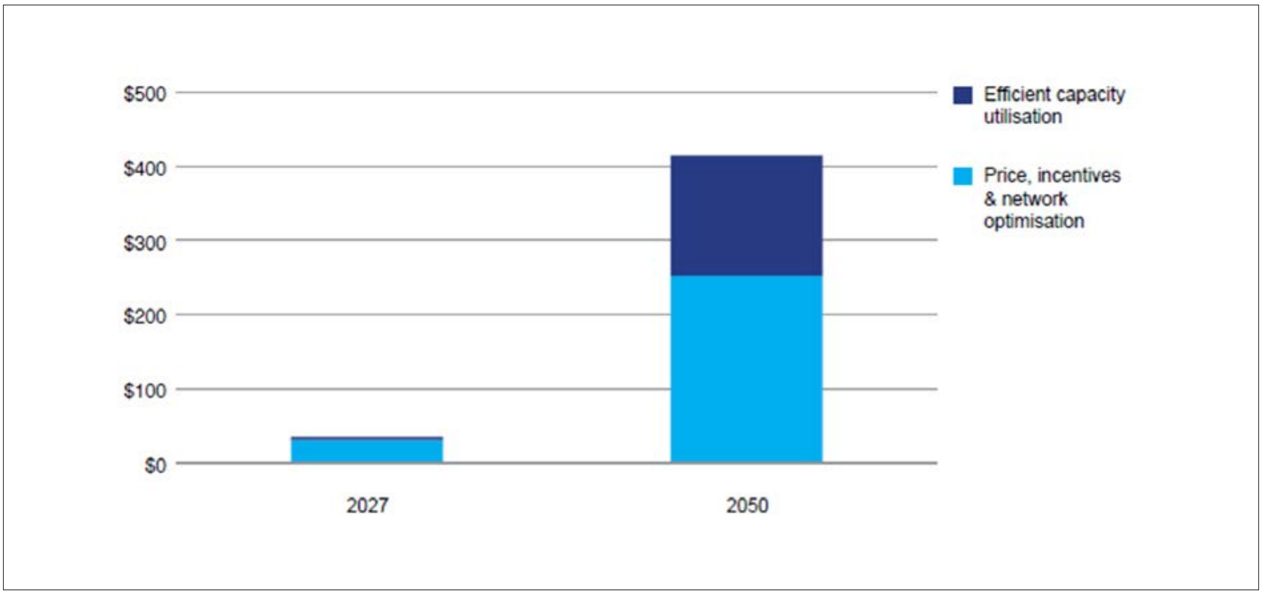
The benefits of integrating DER

In a world where DER on the customer side of the meter is a material contributor to the electricity system - and rooftop PV already meets around 8 per cent of demand in the National Electricity Market (NEM) and 14 per cent in the South West Interconnected System (SWIS) - then the traditional approach of treating demand as a fixed input and working out the most efficient supply mix is no longer sufficient. An efficient electricity system must take account of resources behind the meter, including flexible load as well as small-scale supply and storage. These need to be effectively integrated, using one or more of the techniques discussed above: price signals (tariffs); aggregation and orchestration.

The first attempt to estimate the benefits of effective integration of DER was carried out by the electricity networks' peak body, ENA, in conjunction with CSIRO. The Electricity Network Transformation Roadmap, published in 2017, envisaged up to 45 per cent of demand being met by customer-owned resources in 2050. Cumulative savings to 2050 of $101bn (out of a total spend of around $1,000bn) were projected if DER was efficiently integrated. Accordingly, annual customer bills were estimated to be over $400 less than under the counterfactual. Importantly, customers who were unable to install DER made savings too, due to tariff reform unwinding cross-subsidies. While these benefits were maximised in 2050, they began building up much sooner (noting that we are five years on from the publication of the Roadmap, but not all the recommended actions have been implemented).

However, the gains projected by the roadmap should be put into context. The counterfactual (i.e. what happens if the Roadmap is not implemented) included a number of other major differences as well as optimisation, including lower decarbonisation rates and no adoption of EVs. This means,

Figure 3 *Projected savings in average residential bills (in real terms) under the Roadmap scenario*



for example, that some of the projected savings are likely to be based on lower lifetime costs for EVs versus internal combustion engine vehicles.

A narrower comparison focussing purely on the impact of efficient DER integration was carried out last year by Baringa Partners for the Energy Security Board (ESB). In this exercise the savings were calculated on a narrower basis too, being the benefits of avoiding unnecessary network infrastructure build and avoiding unnecessary solar PV curtailment. The projections also only went out to 2040. Even so, by 2040 the savings are substantial. In the Step Change scenario, which is now AEMO's central scenario, they amount to $11.3bn, of which $9.9bn is distribution-related (the remainder is at the transmission level). Baringa notes that additional policy levers are required to achieve these gains. They identify both further tariff reform and the development of direct procurement by networks as key policy areas.

A third exercise was published in 2022 by Energeia for Renew. This was closer in scope to the Roadmap in that it considered the impact of greater electrification of heat as well as more rooftop PV and battery storage.

This report estimated net benefits of $25bn over a 15-year time horizon or $69bn over a 30-year horizon. In both cases the main sources of savings were large-scale generation costs (as these are displaced by higher volumes of behind the meter generation) and avoided network investment.

There is a caveat to bear in mind when considering an "optimal" system that incorporates DER. Consumers are making investment and operational decisions about their DER (the latter could be simply who to delegate control to - many customers will not want to be directly managing their DER themselves). They will be motivated by their own needs and wants. Much of this can be expressed financially, which can be harnessed by price signals, but consumers may also be motivated by non-financial factors.

This could include energy security - they may seek more storage than is technically optimal. It could include a desire for lower carbon electricity - this could result in overbuilding PV if space allows. If peer to peer (P2P) networks evolve, then some consumers may choose to "donate" surplus solar to deserving recipients rather than seek to profit-maximise. So, an "optimal" system that fully reflects customer goals may not be synonymous with a purely least cost system. Nevertheless, cost-based optimisation exercises are useful to illustrate the broad value of efficient integration of DER into the system.

There is limited value in trying to parse the differences in savings between the three exercises cited above. The salient fact is that they all find large savings from optimising DER.

Potential future developments

Distribution System Operator

As discussed, the integration of DER is expected to require more active management of distribution networks. This could result in the creation of two new roles, the distribution system operator (DSO) and the distribution market operator (DMO).

The DSO manages the network within the technical constraints of the assets, identifies when network issues emerge and acts to manage these issues. The DMO operates the market in energy, network support and other services amongst DER such as rooftop solar and batteries. In doing so, it interacts with the main wholesale market so that supply and demand balances across the whole system and settles at the lowest price (note that there will be 13 of these distribution markets in the NEM, assuming one for each current distribution network).

These roles were explored in the Open Energy Networks program (OpEN) which was a joint project between Energy Networks Australia and AEMO.

Where these respective roles should sit were tested by modelling the costs and benefits of four different options:

1. An AEMO-based single integrated platform (SIP) that co-optimises across wholesale and distribution markets.
2. A two-step tiered platform (TST) where the distributor controls their own network and the platform for trading services on that network and then provides the aggregate outcomes to AEMO who factors these into its wholesale market dispatch.
3. An independent system operator (IDSO) that is neither AEMO nor the distributor but would need an interface with each of these parties.
4. A hybrid of options 1 and 2.

Although the options had different costs and benefits, the headline result was that the high upfront costs of setting up the platforms outweigh the benefits until around 2039 – unless there is a step change in the rate of DER take-up by customers. The hybrid model was the most promising option.

The conclusion was that instead of diving in to setting up the DSO role and the DER market, the networks should focus on some "least regrets" next steps that will help them manage the network in any case as well as lay the groundwork for moving to DSO/DER when the cost/benefits are more favourable.

These included:

- Defining network visibility requirements and network export constraints through real-time monitoring;
- Industry guideline for operating envelopes for export limits;
- Defining communication requirements for "operating envelopes" – these are the states within which the distribution network can operate securely, and;
- Continuing with tariff reform.

As the grid develops and as other reforms such as the two-sided market are implemented, conditions may emerge that allow the bottom-up emergence of market-like platforms. These would be developed by competitive businesses such as retailers and aggregators. Providing interoperability issues can be overcome, these could ultimately provide a cheaper route to developing DER markets than the regulated models envisaged in the position paper.

A two-sided market

The ESB, as part of its post-2025 market design work, has flagged a long-term goal of moving to a fully two-sided market, which they define as one that "promotes direct interaction between suppliers and customers", as in most other commodity markets. This would not mean the end of central scheduling and dispatch but would introduce the dynamic of a downward-sloping demand curve to those processes.

The issues that may arise in transition to the two-sided market include:

- Working out how to increase the proportion of resources (supply or load) that participate in scheduling and dispatch, noting that current rules were designed for large generators. Of particular note, the paper is canvassing views on incentivised rather than absolute compliance with dispatch.
- The extent to which participation in a two-sided market should be opt-in for different types/size of resources.
- Interaction with other (potential) reform processes, such as network access, network tariff reforms and ahead markets.
- Consideration of whether customers can effectively choose their own level of reliability.
- Implications for consumer protection frameworks.
- How to encourage innovation in service provision, recognising that new service offerings will be required to unlock participation.
- Transitional pathways.

While the emergence of a two-sided market is not a given, it appears likely to inform the direction of reforms across the NEM (no such goal has been set for the WA market to date). It will have implications at the wholesale level as well as the distribution level. It will certainly require the effective integration of DER, widespread orchestration and aggregation to allow DER to participate in wholesale markets, and an effective DSO. The computational requirements of scheduling 10 million customers as individual participants are likely impractical, so it will not simply be a case of replicating current dispatch algorithms on a larger scale.

Conclusion

The energy transition is a central part of Australia's pathway to net zero and includes the ongoing growth of DER owned by customers. Keeping the lights on and bills affordable requires effectively integrating these resources into the electricity system and a key interface is with the local distribution networks.

Because these networks are heavily regulated, this in turn requires fit-for-purpose regulatory frameworks. These will need to evolve to keep up with the transition. Amongst the key issues are:

- Whether incentives are balanced when networks are choosing between a capex solution (building more assets) and opex solution (paying someone else a revenue stream to provide services to the network).
- Whether DNSPs and the AER know enough about the pros and cons of different solutions to arrive at the right revenue determination.
- The pros and cons of accelerating take-up of smart meters – and implementing more cost-reflective tariffs.
- How we can efficiently accelerate smart meters and tariff reform.
- Whether ringfencing rules to preserve equality of network access help or inhibit the integration of DER.
- Who is best placed to aggregate and orchestrate customers' DER?
- At what point will we need a distribution system operator to actively manage the network, and who should carry out that role?

These are challenging issues and there may be few easy answers. However, the benefits to consumers for getting these settings approximately right appear to be large so it is worth pursuing effective reform.

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