ESB note on the ITP Distribution-level Storage Report

Summary

This Report was prepared by ITP for the Energy Security Board (ESB) in August 2020. It is part of work on the DER Integration Workplan and is intended to review different types of distribution-level storage (mainly batteries), their related business models, and any barriers to their uptake. The current and future roles of different types of storage within a transforming National Electricity Market (NEM) is an issue that needs better understanding.

ITP classified storage into four types and their report examined static storage. Vehicle-to-grid (V2G) was outside the scope of their project and will benefit from separate research.

Type 1: Autonomous behind-the-meter (BTM) storage, includes standard residential and commercial-scale batteries, as well as those in embedded networks and potentially Local Energy Trading schemes.

Business models: Batteries currently have a high capital cost and a long payback period under this use type.

Barriers: There are no regulatory barriers to this battery use type currently, only commercial ones. Local energy trading is being trialled in WA and Victoria.

Current and likely future deployment: Tariff reform and DER access to current and future markets (envisaged under the post-2025 market design) will improve commercial returns for BTM batteries. Local energy trading that is not in embedded networks would benefit from changes to distribution network access and pricing and potentially from distribution-level markets, but it will take some time to be able to assess the need for these.

Type 2: Orchestrated behind-the-meter storage includes controlled loads and Demand Response Enabled Devices (DRED), and the use of batteries in embedded networks and VPPs.

Business models: Demand response and controlled loads are viable through a number of mechanisms currently and will continue to be an important part of the energy system. Some embedded networks use batteries but none are orchestrated. Virtual Power Plants (VPPs) trialling batteries participating in spot and FCAS markets and providing network services are promising but are at the stage of technology trials and understanding customer acquisition, with financial viability uncertain and likely to require value-stacking.

Barriers: For BTM loads and batteries to participate in the Wholesale Demand Response (WDR) mechanism requires the development of an appropriate definition of third-party aggregation and, possibly, multiple trading relationships. It may also require the definition of market participants to change over time.

VPPs need to be seen by consumers as not only financially advantageous but offering additional benefits.

A significant challenge for the post-2025 market design is to allow 'value-stacking' across different possible DER value streams. Under current arrangements, complex contracting would make this prohibitively expensive (for example, the need to contract with a retailer to provide FCAS and participate in the spot market or a Market Ancillary Services Provider (MASP) for contingency FCAS alone). Enabling multiple trading relationships is likely to be important here too.

Current and likely future deployment: This will very much depend on the evolution of the WDR mechanism and two-sided markets, essential system services (ESS) and any ahead markets through the post-2025 market design process, and the effect these have on aggregator interest in VPPs. The aim of two-sided markets is to have demand participating equivalently to supply in electricity markets. The design of any ESS and ahead markets is being undertaken to allow DER participation.

Type 3: Storage owned by Distribution Network System Providers (DNSPs) in front of the meter.

Business models: There are several variations here. At the fringe of the grid, DNSPs can use batteries to provide network support. In Stand Alone Power Systems, DNSPs can apply for a waiver from the AER to provide generation services, and if that is granted then the assets used to provide those services, including batteries, can be included in the DNSP's Regulated Asset Base (RAB)). DNSPs can also use batteries to provide network peak demand support and to increase DER hosting capacity, which may be funded through the Demand Management Incentive Allowance (DMIA). Some DNSPs have also been trialling batteries with external innovation funding from ARENA. Western Power can own and operate community batteries, which are included in its RAB, however this is currently not possible for DNSPs in the NEM because of the overlap with contestable services.

Barriers: There are currently no regulatory barriers where DNSPs wish to use batteries, unless there is overlap with contestable services. The potential barriers to DNSP ownership of community batteries are as follows, with the first two not being regulatory barriers: i) the different consumers will have many different retailers (and the DNSP will need to interface with each of them, increasing complexity), ii) network charges are currently applied to electricity exported to any grid-located battery then again when the battery electricity is used by customers, iii) the DNSP cannot on-sell electricity from the battery to customers and so a third party is required for this, and iv) for financial viability participation in at least one of spot or FCAS markets will be needed, which not only also requires a third party but also value stacking that could involve multiple market participants.

Possible solutions suggested by ITP to these are i) the use of multiple trading relationships (MTRs) which are currently the focus of the 2SM MDI, ii) the use of LUOS charges via an AER waiver, and for iii) and iv) this would be easier if the categorisation of market participants was streamlined so that participation in multiple markets was simplified

Current and likely future deployment: The use of batteries for network support is likely to increase as DNSPs become more familiar with both how to deploy and operate batteries and the effectiveness of batteries in meeting their objectives. The DNSP-ownership of community batteries in the NEM is very complex and will be influenced by the evolution of the two-sided markets, essential system services (ESS) and any ahead markets through the post-2025 market design process.

Type 4: Storage owned by a third party (such as a retailer or a solar farm) in front of the meter.

Business models: A number of different business models are currently being trialled by retailers, solar farm operators and community groups. They derive revenue from a mix of spot and FCAS markets as well as potentially from network support. Participation only in spot is unlikely to be viable, with inclusion of FCAS possibly resulting in financial viability.

Barriers: The main barriers are not regulatory, but are more related to the internal capacity of the organisations involved and the financial viability of their particular business models.

Current and likely future deployment: This is a nascent market, and so it is difficult to tell how this will develop.

Overall implications and next steps

The declining costs of energy storage have broad implications for the above business models. Declining costs may mean that ‘value stacking’ becomes less important and that storage locations can focus on specific benefit areas. The reducing costs for electric vehicles may provide competition for all of these business models as large volumes of storage capacity are contained in these modern vehicles. The adoption of Vehicle to Grid (V2G) technologies will increase the competitive options available to EV owners.

The report highlights that different models can provide access to different values and services for customers. The report also recognises that the existing regulatory frameworks can impose barriers to the efficient use of batteries in some models.

The report once again highlights the importance of electricity tariffs that more accurately reflect the costs of delivering energy will act to change consumer behaviour as well as provide new opportunities for energy storage. Tariffs such as the “solar soaker” in South Australia will act to move energy consumption to match with times of peak solar production. This may act to reduce the value of some storage business models. However, the avoidance of peak pricing periods should provide added stimulus for these models.

The review also draws a focus on how the separation of distribution and retail services can impact community batteries. While there appears to be very few barriers to the deployment of community batteries that are owned by third-parties (such as retailers), there are very few trials in this area. There are a number of community battery trials being undertaken by networks despite being subject to a larger number of regulatory barriers. The regulatory matters here are complex and there is a history of literature and evidence to show that monopoly participation in competitive markets will reduce access and distort pricing. The issue of community batteries will be examined through the AEMC’s 2020 Electricity Network Economic Regulatory Framework Review.

The pricing models for electricity networks around the world are traditionally based on shared costs. This is due in part to the instantaneous nature of electricity and the need to balance supply and demand on a second by second basis. The ability to store energy locally means that consumers can choose when to use their energy. When paired with modern communications architecture, this means that consumers can essentially trade their energy locally. Local trading would represent a major shift from the current shared cost pricing models and will require significant structural changes to be implemented. Local electricity trading will be considered as part of the post-2025 market design.

In particular, current pricing structures assume that energy flows only in one direction. This structure means that community storage options are not charged in a cost-reflective manner with a double-counting when energy is stored locally and then consumed later. A move towards a short-haul pricing option would alleviate this cost inequity, but would expose other flaws in the shared pricing models. Local Use of System (LUOS) charges will be explored in the AEMC’s consideration of the AEMO rule change on storage.

The ESB will consider the other implications of this report in its ongoing work through the DER integration workplan in and in the post-2025 market design.