CLARKEFIELD ZERO-CARBON COMMUNITY

Neighbourhood Battery Feasibility Study

Contents

1 Introduction

APD Projects is developing approximately 2,000 residential lots at Clarkefield in the Macedon Ranges Shire. Phase 1 of the development will be 350 lots. APD has set a zero-carbon goal for the community and has partnered with Flow Power to investigate technical and commercial options for integrated initiatives to drive carbon neutrality in a manner that is affordable to residents and repeatable across future developments. Examples of these initiatives include solar PV on every home, high standards for building NatHERS and appliance energy efficiency ratings and solar-following hot water systems.

As well as incorporating Environmentally Sustainable Design (ESD) into the development, the team sees a battery storage asset as a key part of an integrated solution, particularly to:

- help alleviate network constraints associated with high penetrations of solar PV, EV charging and other near-future issues
- help return value to residents based on their participation in low-carbon solutions

This study is aimed at investigating the technical, commercial and regulatory feasibility of a community battery installation with input from Jemena (the local network operator), the surrounding community and other stakeholders. If a community battery is shown to be viable, this study would lead to a front-of-meter neighbourhood battery installation at Clarkefield, with strong and direct community benefits. It will also demonstrate a path for new developments of this kind to aspire to practical and affordable carbon neutrality supported by a community battery asset.

1.1 Project background

The Clarkefield Zero-Carbon Community is a greenfield development expected to launch in late 2023. Located in the Macedon Ranges Shire on the Jemena network, the development will extend the small existing suburb of a railway station, a few residences and a local pub.

To understand the potential electricity requirements of the suburb, Flow Power has developed a model simulating the community energy balance in 1-hour intervals for a full calendar year. Energy profiles for homes have been generated based on typical usage for individual dwelling types, broadly captured by the following three categories:

- Traditional or detached – separated dwellings with a large footprint
- Townhouse or attached – dwellings with at least one adjacent dwelling physically connected
- Multi-unit – multiple dwellings in a single lot (e.g. apartments or units)

In phase 1 of the development, there are 290 detached, 21 attached and 39 multi-unit dwellings.

The impacts of the initiatives have been explored by considering a business-as-usual (BAU) scenario, reflecting the development of typical homes in the absence of any specific sustainability ambitions. This is compared to a 'design' scenario where ESD initiatives have been incorporated as sub-models, replacing, altering or supplementing the contributions to the base energy profiles from different residential activities such as hot water supply, space conditioning and home appliance utilisation, such that the net scope 2 carbon emissions of the development (after export offsets) are zero. The assumptions that underpin the two scenarios are outlined in Table 1.

Table 1: *Assumptions used for the BAU scenario and design scenario. Rooftop solar PV output was determined by using a draft block plan and preliminary housing designs to estimate panel orientation and tilt.*

Feature	BAU scenario	Design scenario
NatHERS star rating	6 stars	7 stars
Home appliance energy efficiency star rating	3 stars	5 stars
Rooftop PV system uptake rate	25%	100%
Rooftop PV system size	4 kW (average)	4 kW (minimum)
Domestic hot water system	Typical new suburb technology mix	Solar-following electric storage

In each scenario, an energy balance for the suburb is generated by combining the contributions from each individual dwelling, as well as allowances for non-residential loads such as street lighting and several local amenities including a supermarket.

The scenarios are then compared using key outputs from the model, the first of which is a median daily profile representing the 50th percentile energy balance for the suburb. The charts in Figure 1 demonstrate the impact of the ESD initiatives on the time-distribution and volume of load throughout the day.

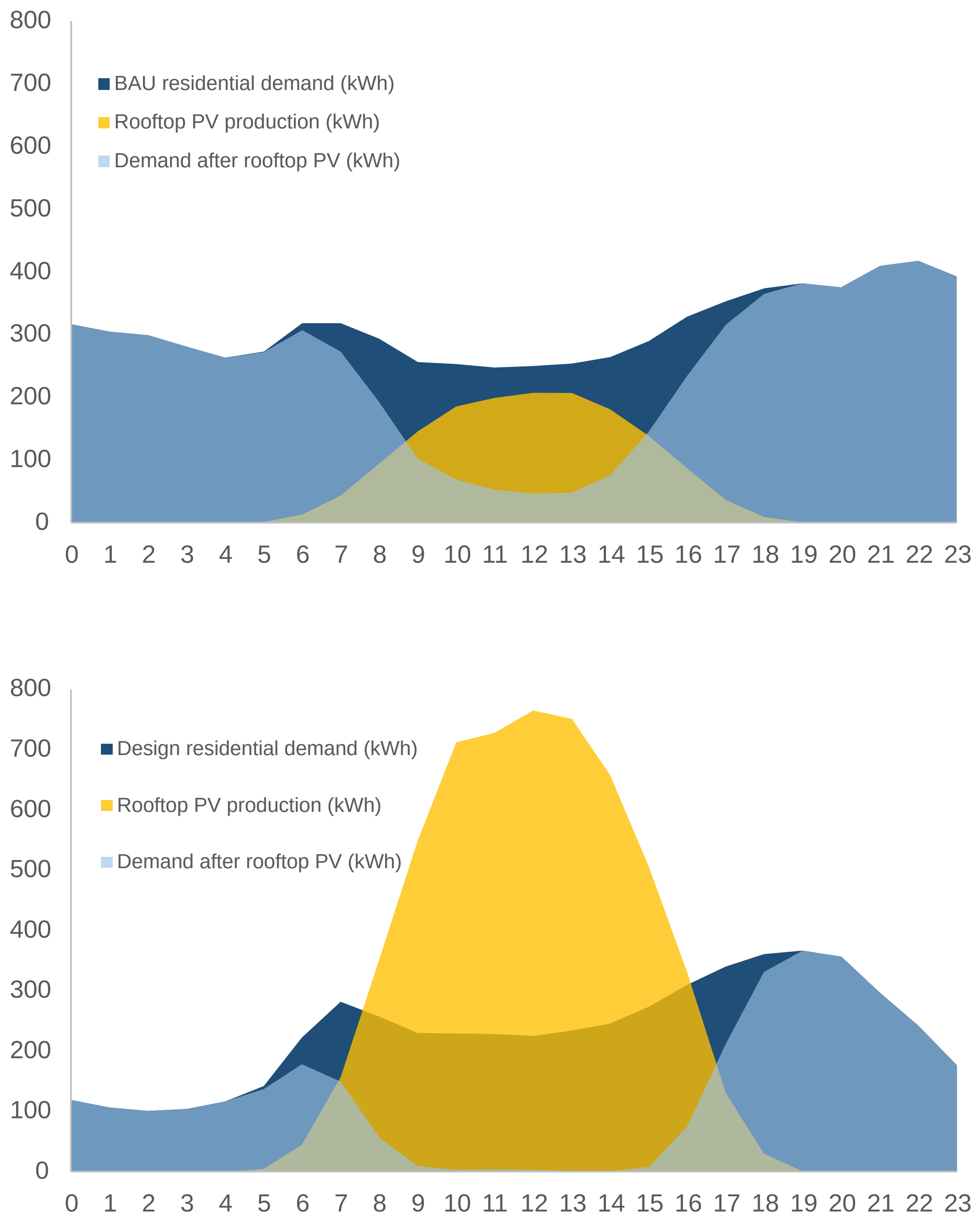


Figure 1: *Whole-of-development daily demand curves for the BAU scenario (upper panel) and design scenario (lower panel), showing the influence of rooftop solar PV in each case.*

While it is apparent that the ESD initiatives in the design scenario have a positive impact on net residential demand and morning/evening peak demand when compared to the BAU scenario.

To explore the comparison between the two scenarios further, five additional per-dwelling model outputs are considered:

- Annual nominal demand (kWh)
- Annual grid consumption (kWh)
- Annual solar export (kWh)
- Import ADMD[1] (kVA[2])
- Export ADMD (kVA)

Table 2 shows the outputs for each scenario.

Table 2: *Comparative per-dwelling model outputs between the BAU and design scenarios*

Per-dwelling metrics	BAU scenario	Design scenario
Annual nominal demand (kWh)	7,837	5,802
Annual grid consumption (kWh)	6,202	3,272
Annual solar export (kWh)	64	3,444
Import ADMD (kVA)	3.95	1.59
Export ADMD (kVA)	0.21	2.73

In summary, the ESD initiatives improve overall energy efficiency, reduce grid consumption and lower ADMD for import significantly. However, as indicated by Figure 1 and the export metrics above, a consequence of these initiatives is a large amount of exported solar generation and much higher export ADMD. This presents potential problems when designing the local network infrastructure, as it would need to be capable of supporting the solar export. This could lead to a higher cost network for the suburb, the cost of which would be passed on to APD as the developer and ultimately, lead to more expensive homes or electricity bills for residents.

The large amount of export also presents an issue for homeowners and the sustainability goals of the suburb. While the design scenario is technically carbon neutral because of the offsets from exported solar, there is still a substantial amount of consumption that occurs outside of solar hours which will need to be supplied from the grid. With the current mix of generation in the electricity market, this would likely be supplied by generators with higher carbon intensity. Furthermore, in the absence of a feed-in-tariff, the exported generation would not contribute to reducing homeowners' electricity costs.

The issue of export that arises from the design scenario offers a strong case for the implementation of a community battery. A battery that soaks up excess solar generation and discharge outside of solar hours could lower the cost of the local network by reducing ADMD for both import and export and provide a mechanism for delivering more zero-emission electricity to residents of the suburb.

1.2 Consequences of pursuing environmentally sustainable design

The positive impacts of practicing ESD – carbon neutrality and reduction in import ADMD – come with the downside of much larger export ADMD resulting from high penetrations of solar. There are several ways to manage this, including inverter curtailment, STATCOMs and other voltage regulation devices and batteries.

Curtailment is effective at preventing high export ADMD but causes a variety of additional issues. Carbon accounting can be affected by reducing the export credits from producing renewable generation and the viability of solar ownership is impacted as systems no longer operate at optimum output. There is also the question of equity, in the sense that mass inverter curtailment may penalise those who are consuming more solar behind-the-meter during peak generation hours.

STATCOMs and other voltage regulation devices are useful for maintaining system strength and stability. However, these devices are limited in their function, and ultimately do not provide the necessary service of preventing large amount of export generation passing through the local network.

1. ADMD stands for after diversity maximum demand, a critical quantity used by network operators to specify the level of servicing required in new developments

2. Apparent demand in kVA is determined assuming a power factor of 0.85 at maximum demand

Battery systems are the preferred solution, reducing export into the network without penalising the solar PV system owner. Neighbourhood battery systems present a strong opportunity to collectively reduce ADMD without requiring significant capital expenditure from individual residents.

Therefore, to promote and encourage a high penetration of rooftop solar in new housing developments, there is a need for network operators to accommodate or facilitate solutions that manage the resultant network impacts. This will be particularly important if policy makers have a goal of zero emission new housing developments, or simply a goal of mitigating cost of living pressures on new homeowners, by mandating or encouraging ESD solutions such as rooftop solar PV.

1.3 Objectives

APD's core sustainable development objective for the Clarkefield project is to give new residents the opportunity to live a carbon neutral lifestyle, in a way that is affordable and replicable to other subdivisions. The affordability and replicability criteria provide an important commercial discipline over the project, ensuring ESD measures are not imposed on new home buyers without a clear financial benefit.

In order to achieve the development goal, APD asked Flow Power to:

- Develop two energy load profiles for the Clarkefield subdivision, the first based on a business-as-usual development specification (BAU), and the second based on APDs preferred ESD measures being included in every home (design)
- Assess the economic benefits of a shared community battery in delivering the project objective, assuming APDs preferred ESD measure are implemented
- Assess technical constraints and opportunities to a shared community battery
- Engage the local network operator and other authorities as required, to assess any regulatory or system-wide constraints and opportunities to a shared community battery

To this end, the objectives of this study are to investigate the technical, commercial and regulatory feasibility of installing and operating a neighbourhood battery in the Clarkefield development. The outcomes of the study are intended to serve as a demonstration of the potential for community batteries to support low-cost, zero-carbon developments.

2 Stakeholder Engagement

2.1 Jemena

Initial engagement with the local network operator Jemena had significant ramifications for the neighbourhood battery modelling. Their two key pieces of feedback included a view that:

1. multiple, distributed battery installations at kiosk substation level would have better network benefits than a single, centralised battery at the suburb feeder level; and
2. At this stage, they do not have the mechanisms or internal policy to provide cheaper network infrastructure or tariff offerings for developments with neighbourhood battery installations.

The main reason for viewing distributed batteries more favourably is the potential for reducing the required amount of substations, and so ther cost of network infrastructure required to accomodate the Clarkefield ESD specifications. If the batteries are connected on the LV side of substations (i.e. downstrea of a substation, on the customer side), they can reduce the peak demand (import or export) that each individual substation must be designed to manage.

Consequently, it is possible that fewer substations could be installed for the same number of homes, which for ground mounted kiosk substations is a saving of approximately $200,000 per substation. How this network saving might be passed through as a benefit for the community is unclear but could be in the form of reduced developer contributions to network infrastructure, or a reduction in network tariffs for residents. Dialogue with Jemena on these points remains ongoing.

The favourable view for distributed batteries is also partly founded in concerns about voltage stability across the local network. In Jemena's view, voltage stability issues resulting from large amounts of exported solar PV generation would be best managed with multiple batteries at kiosk substation level, helping to prevent voltage fluctuations in the local network behind the main feeder to the community. They felt that a centralised battery connected at the feeder level on the high-voltage network could potentially exacerbate voltage stability issues caused by the high amounts of export from rooftop solar PV. As voltage control can also be a limiting factor to reducing network infrastructure requirements, this is an important consideration when selecting a battery system configuration, and may point to a distributed system as optimal.

The unlikelihood of cheaper network infrastructure and resultant tariff offerings derives from an uncertainty around the potential for neighbourhood batteries to reduce ADMD consistently and reliably over the lifetime of the local network. Jemena typically designs its residential networks to accommodate an ADMD of 4.5kVA per dwelling with a lifetime of 50 years. They feel that, given the industry is in its infancy with respect to neighbourhood battery installations, they are not ready to take on the risk of installing a cheaper network designed for a lower ADMD. It is their perspective that there is no guarantee that a neighbourhood battery would still be operational in 10 years, leaving an under-rated network intended to last 50 years. Further inquiries were made as to what level of contractual certainty Jemena would require to recognise a lower ADMD and defer network upgrades, for example guaranteed O&M by a homeowner's corporation over the 50-year period. Discussions on this topic are still ongoing. It should be noted that Jemena has only recently addressed the potential of a bespoke tariff for the battery system itself and is also a part of ongoing discussions.

The Village Power NBI project noted a similar experience in their engagement with Jemena and are currently engaging a consultant to investigate network barriers and potential regulatory pathways to support commercial viability. We hope to learn from their investigations and integrate any findings or solutions into this study. Additionally, after meeting with DELWP, we understand they are also looking at ways to work with Jemena to provide avenues for community battery viability.

Network engagement by other community battery projects have seen favourable outcomes from other Victorian network operators such as CitiPower/Powercor/United Energy and AusNet Services, with instances of bespoke network tariffs for battery operation being offered which allow for stronger business cases for implementation and community benefit passthrough.

It should be noted that at the time of writing, further consultations are being held between Jemena, APD and Flow Power, in which Jemena is showing willingness and interest in finding a path forward to facilitate community batteries in their network. The outcomes and objectives of these consultations are discussed in Section 7.1.

2.2 Macedon Ranges Shire Council

Feedback from the local council planning authority, Macedon Ranges Shire Council, was received via responses to the development application (DA) submitted for the suburb. These responses resulted in changes to the intended number of lots to be built in the first phase of the development.

The planning authority prefers lower density housing than was initially proposed in the DA. The consequence was a revision to the lot plan to reduce the number of individual dwellings from 407 to 350. The reduction in dwellings has not resulted in a reduced housing footprint of the development, as many of the proposed higher density 'attached townhouse' type dwellings were replaced with larger land area 'traditional detached' dwellings. However, the total installed capacity of rooftop solar PV and hence annual generation is reduced. The changes to the number of each housing type, and the resultant impact to annual rooftop solar PV generation, are summarised in Table 3 below.

Table 3: *housing numbers and annual rooftop solar PV generation for the previous and new lot plans*

	Previous lot plan		New lot plan	
Housing type	**Number**	**Annual PV generation (MWh)**	**Number**	**Annual PV generation (MWh)**
Detached	261	1,499	290	1,635
Attached	123	710	21	118
Multi-unit	23	132	39	220
Total	**407**	**2,341**	**350**	**1,973**

Note that the technical and commercial modelling in this report has been based on the new lot plan of 350 homes.

3 Technical approach

In this section we explore a community battery sub-model extension to the energy balance model for the suburb. Based on initial feedback from Jemena, the sub-model was designed to allow for two different scenarios: a centralised battery connected to the high-voltage feeder to the suburb or a series of distributed batteries on the low-voltage network located at kiosk substations.

The ideal technical solution was determined by considering impacts to:

- ADMD for import
- ADMD for export
- Viability for connection to the Jemena network

3.1 Battery technology and assumptions

For this project, lithium-ion technology was chosen as the preferred option for implementation as it is currently the prevalent technology for community-scale batteries. The assumptions used to model the battery solution are detailed in Table 4.

Table 4: *technical assumptions used to develop the neighbourhood battery design scenario*

Variable	Assumption
Technology	Lithium-Ion
Lifetime (at 1 cycle per day)	15 years
Round-trip efficiency	90%
C rating	0.25
Minimum state-of-charge (SOC)	20%
Network connection	Front-of-meter at HV feeder level or LV-side of kiosk substations

3.2 Battery sizing

Battery power output was sized such that the ADMD for the suburb, import or export, could potentially be entirely supplied or hosted by the battery system. In the case of the design scenario, the whole-of-suburb ADMD for import is 557kW while the ADMD for export is 954kW. As such, a battery power of 1MW – total power for a centralised battery and combined power for distributed batteries – was selected to account for the larger export ADMD. Setting this as a minimum and exploring larger battery sizes revealed diminishing returns against both technical and financial criteria; battery power was therefore fixed at 1MW.

Battery capacity was sized by assessing the typical residential load during network peak hours (typically 4pm to 9pm). The average residential load during this period was approximately 1.5MWh. We investigated a 2-hour aggregate battery capacity of 2MWh to match this load. We also considered a 4-hour aggregate capacity of 4MWh to account for diversity in peak consumption from the average.

Preliminary financial assessments revealed that the larger 4MWh capacity (i.e. C = 0.25) had the highest returns, because the revenue from our chosen control strategy (see following section) scales more rapidly than capital cost for higher battery capacities.

A neighbourhood battery design scenario was therefore created using a 1MW/4MWh battery aggregate, along with a simple control strategy predicated on charging during times of excess rooftop solar PV output and discharging during peak network hours.

3.3 Control strategy (put in graph showing export with charging regime overlaid)

The chosen control strategy for battery operation is predicated on providing solar soaking services and discharge during evening peak demand. The strategy involves a simplistic arbitrage regime of charging from the time of day when there is net export in the local network from solar generation (~8am – 10am depending on the season) until 4pm in the afternoon. The battery then discharges at a variable rate over the evening peak until the system reaches minimum SOC. Figure 2 below illustrates the control strategy in relation to the suburb solar export and peak evening load.

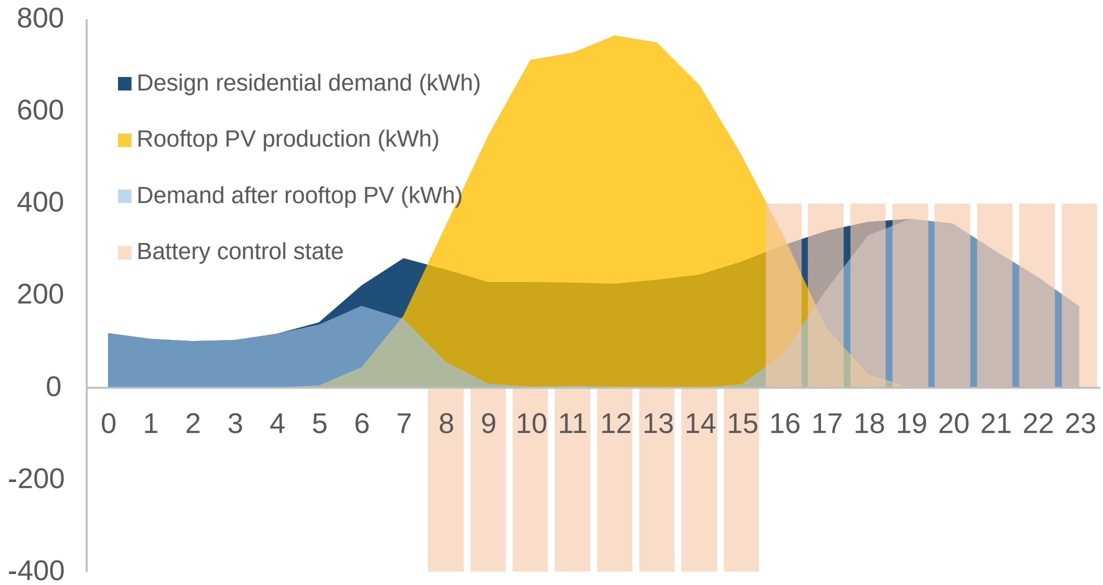


Figure 2: *graphical depiction of battery control strategy based on a simplfied arbitrage regime. Negative = charge, positive = discharge*

3.4 Centralised vs. distributed batteries

This study explores the implementation of either a single centralised battery on the HV network, or a series of distributed batteries connected to the LV side of kiosk substations. As the battery sub-model is based on the whole-of-suburb energy balance, it is assumed that the technical impacts to the suburb's energy balance are the same for either configuration. For example, a 1MW/4MWh battery would have the same net energy and demand impacts to the suburb as four 250kW/1MWh batteries.

The technical battery sub-model has been developed such that it sees no difference in the number of batteries to be deployed, but rather takes a total power and capacity as parameters to explore impacts to the suburb energy balance. The distinctions between the centralised and distributed scenarios are instead related to both network impacts and commercial viability.

In terms of network impacts, a centralised scenario with a battery located at the main feeder to the suburb would improve energy volumes and peak import/export demand from the reference point of the main substation. However, the suburb's local network infrastructure would still need to be sufficient to host the pre-battery suburb load as outlined in. With a distributed scenario where batteries located on the LV side of kiosk substations, only the LV infrastructure behind each kiosk substation would be required to host the full load of the homes connected. This could lead to a requirement for fewer kiosk substations and lowering the necessary hosting capabilities of the local HV network, which in turn could reduce the cost of network infrastructure for Jemena and APD as the developer. This reduced network cost could then result in cheaper homes or lower electricity bills for residents.

The additional network benefits of a distributed battery scenario may be offset however by the increased cost of multiple installations. In relation to commercial viability, a centralised scenario would likely be favourable to exploit economies of scale and would also avoid potential additional costs related to the connection, operation and maintenance of multiple batteries in place of a single battery.

As such, for the purposes of this study, the differences between the two scenarios are considered in terms of their commercial impacts rather than technical impacts to the suburb's ADMD. The commercial impacts are explored further in Section 5 of this report.

3.5 Modelling outcomes

This section presents the impacts to the energy balance of the community battery sub-model based on the input parameters for the battery described in Section 3.1 and the control strategy outlined in Section 3.3.

Table 5 details the key energy and demand metrics for the design scenario before and after battery implementation.

Table 5: *Per-dwelling energy and demand metrics with and without a community battery. These effects are on top of the ESD initiatives outlined in Section 1.1.*

Per-dwelling metrics	Without battery	With battery
Annual nominal demand (kWh)	5,802	5,802
Annual grid consumption[3] (kWh)	3,272	1,546
Annual solar export (kWh)	3,444	1,526
Import ADMD (kVA)	1.59	1.17
Export ADMD (kVA)	2.73	1.51

The impact of the community battery is to significantly reduce the energy volume and demand requirements of the suburb to be supplied by the grid and hosted by the distribution network upstream of the development. Importantly, a key parameter for network design – ADMD – is reduced for both import and export. This could allow for the installation of a lower rated network and avoid associated costs.

As well as reducing energy volumes and demand, the battery also changes the shape of the suburb demand. Figure 3 presents the change in median daily demand profile resulting from community battery operation.

3. Note that 'grid consumption' here refers to electricity supply that has come from the broader distribution network in front of the main feeder to the suburb.

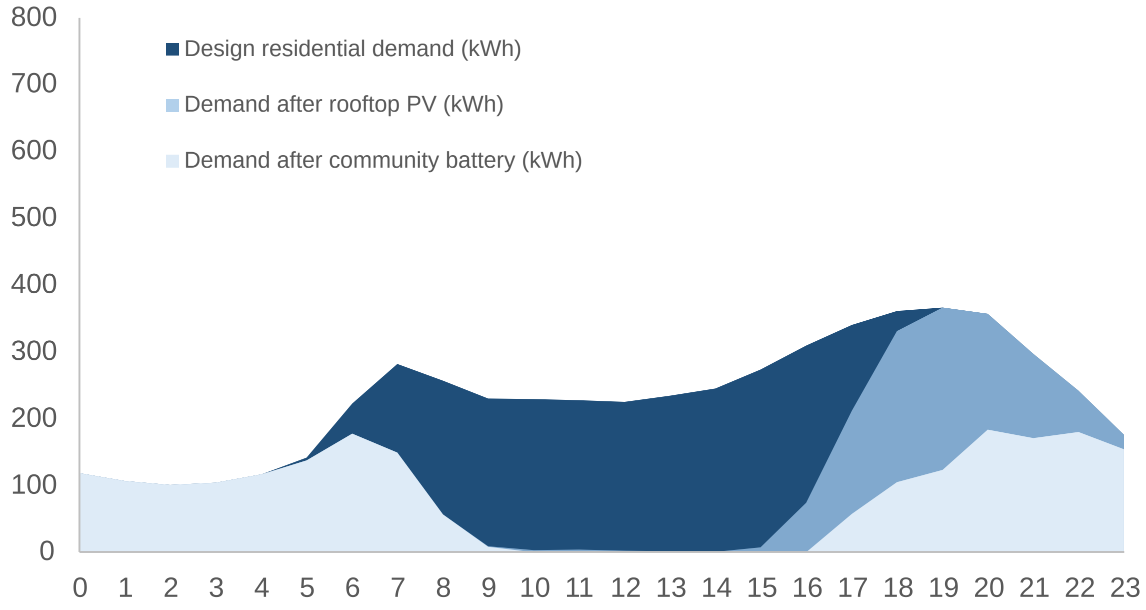


Figure 3: *daily demand curve for the suburb with a community battery*

The battery helps to alleviate demand on the network at the critical time of the evening peak, producing a demand profile that is less sharp in the evening and with a lower ramp rate, potentially reducing the strain on the network.

3.6 Technical barriers to the preferred approach

Barriers to the technical approach arise from the greenfield nature of the development, as well as an uncertainty of the potential impacts of contingency FCAS participation.

As the development is yet to be constructed, the exact configuration and intended layout of network infrastructure for the suburb is currently unknown. This makes it difficult to understand how the community battery or batteries will connect to the local network. As such, our study is precluded from detailed investigations into connection requirements and operating constraints that may apply to battery installations. For example, proposing distributed community batteries at kiosk substation level requires that we know the number of kiosk substations that will be installed in the network and their import/export ratings and constraints. Furthermore, introducing community batteries into the network for the purpose of reducing the level of required network infrastructure means that the two factors are co-dependent, and it will likely involve an iterative approach and/or scenario modelling in consultation with Jemena to determine the best network configuration and number of battery installations.

Participation in contingency FCAS markets could pose issues to the primary battery control strategy and counteract the positive impacts to network requirements that community batteries could provide. Firstly, to bid into contingency FCAS markets requires that a certain amount of battery capacity is reserved for FCAS response. This could interrupt the battery system's ability to follow the primary control strategy of solar soaking and wholesale arbitrage and potentially reduce revenue and benefits to the local network. Secondly, the nature of FCAS response – instantaneous charging or discharging at maximum capacity (1MW) – would require that the local network had the capacity to host this response. For example, if a contingency raise event were to occur during peak solar export, the network would need to host not only the export solar generation, but also an additional 1MW of export in response to the FCAS event. This works at odds to one of the primary objectives of a community battery system – to reduce the level of required network infrastructure – and may lead to a higher rated network being required for the suburb.

These barriers do not present a major hurdle for the implementation of a battery system, but rather are consequential for the commercial outcomes and viability of community batteries, which is explored further in Section 5. Further engagement with Jemena and the community will assist in determining a resolution to these barriers.

4 Regulatory pathway

This section provides an overview of the regulatory pathway necessary for the establishment of a battery or batteries, and those batteries' participation in various revenue raising activities. In the National Electricity Market (NEM), Battery Energy Storage Systems (BESS) can provide:

- Wholesale market participation and arbitrage
- Community energy services (defined below)
- Frequency management
- Network services.

The regulatory pathway to market is different for each of the revenue streams (noting that there is material overlap). Each pathway is detailed in following subsections.

4.1 Summary

There are multiple revenue streams available to storage projects connecting to the distribution network. There are also multiple options for battery proponents to take through the various regulatory instruments to access these markets. The proponent can either:

- Partner with parties who have already received the appropriate qualifications necessary to participate in wholesale and FCAS markets, as well as providing network support services
- Decide to register themselves and meet the necessary requirements.

If the proponent decides to register, the least complex option is to register as a Small Generation Aggregator. The downside of this approach is the inability to provide FCAS until April 2023. Registering as a Small Generation Aggregator would also limit options for the proponent to directly offer services to energy consumers, which may include some approaches to providing community energy services. For example, if the proponent registered as a Small Generation Aggregator, it would need to work with a separate energy retailer to offer energy exchanges between the battery and households.

Alternatively, the proponent could register as a Market Customer, which would allow participation in FCAS markets and the potential to sell services to other energy users, but this comes with far greater administrative and regulatory cost. If the proponent intended to provide retail electricity services, this would represent a material increase in the level of regulatory complexity and risk.

The proponent can also seek to reduce costs associated with use of the distribution network or receive payments for relieving congestion on the distribution network. These arrangements would need to be resolved through negotiation with Jemena.

The regulatory pathways available for the project proponent are set out in Figure 4 below, highlighting options for partnership with existing participants, or concurrently owning the asset and receiving appropriate registrations.

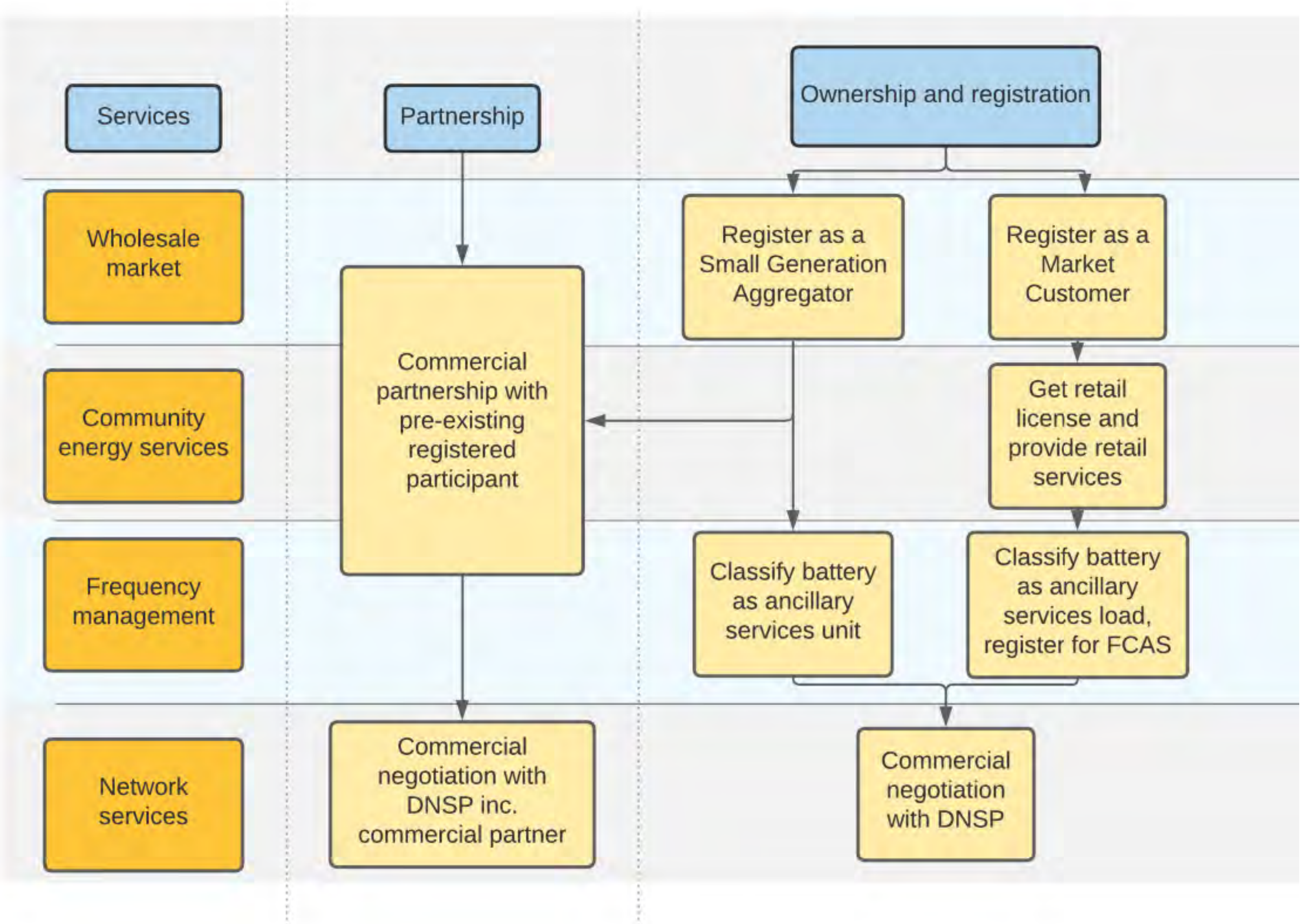


Figure 4: *Flow chart of possible regulatory pathways for battery connection, operation and benefit passthrough*

1. Registration as a Small Generation Aggregator does not permit retailing electricity. This would preclude direct electricity sales to energy consumers. Registration as a Small Generation Aggregator also does not permit participation in FCAS markets until April 2023. At this point, the registration will change to a registration as an Integrated Resource Provider, at which point FCAS market participation is permitted once necessary classification has been received from AEMO.

4.2 Wholesale market participation and arbitrage

Wholesale market participation and arbitrage refers to operating the BESS to maximise profitability in the wholesale electricity market. For example, charging the BESS at times of low (or even negative) wholesale prices, and discharging the battery at times of higher wholesale prices.

To access the wholesale market, there must be a registered participant allocated to a point at which the battery connects to the grid.[4] This registered participant is responsible for paying for (and receiving payment for) charging and discharging of the battery with the Australian Energy Market Operator (AEMO). For the battery at Clarkefield, the selected registered participant can be any party registered as a:

- Market Customer
- Small Generation Aggregator[5]

If the battery proponent is already registered in one of these participant categories, it can operate and settle the battery in the wholesale market. However, if the battery developer is not already registered, the path to participating the wholesale market requires either:

4. This is the case for all points where electricity is taken from, or supplied to the grid. For example, a residential property is required to have an electricity retailer allocated to its connection point. Electricity retailers are registered participants who are authorised to buy electricity from the wholesale market on behalf of energy consumers.

5. As detailed later in this document, recent changes to the National Electricity Rules will bring changes to this registered participant category.

- Partnering with an existing registered participant
- Registering with AEMO in one of the above categories.

Both are explored in more detail below.

4.2.1 Partnership

The owner of the battery can partner with any Market Customer or Small Generation Aggregator. Under this partnership, the registered participant would be responsible for interfacing with AEMO and settling the payments and revenue associated with the charging/discharging of the battery into the wholesale market.

The other aspects of the partnership, including how the battery is operated, and any services provided to customers, would be a matter for commercial negotiation between the battery owner and selected partner. The battery owner should be able to find a range of options available through partnership, offered by existing retailers and generators. For example, partners who only provide administrative settlement functions through to partners who settle, operate and maintain the asset. In addition, the developer could partner with a participant who is able to operate the battery to provide FCAS (discussed later).

4.2.2 Registration

If the battery owner decides to register, it must decide which category to register in. If the battery developer also intends to retail electricity, it should consider registering as a Market Customer. Alternatively, if the battery developer wishes to subsequently operate large generating assets, it would need to register as a Market Customer and as a Generator. However, if the developer's preference was to build and operate batteries sized like the Clarkefield battery, registering as a Small Generator Aggregator has the least administrative complexity.[6]

To register with AEMO, the developer should follow the steps outlined on AEMO's website. These steps include:

- Completing and submission an application
- Paying registration fees, which range from $11,760 to $24,401[7]
- Wait for AEMO's review, assessment and decision.

If the developer decides to register with AEMO, we advise early engagement with AEMO to assist the application process and provide AEMO to provide any necessary guidance to the developer.

4.3 Community energy services

Community energy services is an umbrella term for a range of services and products that could be developed that leverage the Clarkefield battery asset to provide benefits to local energy consumers. 'Community batteries' offer options including:

- A financial hedge for energy users against wholesale price spikes
- A 'solar sponge' to store energy from local distributed solar PV systems, and discharge stored energy and peak periods.
- Modular storage options, where portions of the battery capacity are rented to community members.
- Management of local network ADMD for import/export and voltage fluctuations preventing constraints on community owned assets such as distributed solar PV systems and home batteries

Directly facilitating these services would require a retail license. To get a retail license, the proponent would need to:

- Register as a Market Customer with AEMO
- Apply for a receive a retail license (from the Essential Services Commission in Victoria, and the Australian Energy Regulator in QLD, NSW, SA and Tasmania).

The regulatory obligations placed on electricity retailers are significant. Compliant, viable electricity retailers require significant resources to manage billing, settlement and financial risk management processes.

Alternatively, community energy services could be facilitated by partnering with one or more existing electricity retailers. These retailers would manage the billing and settlement functions, and may be able to offer community-style retail services.

6. As explained in later in the document, the registration category selected has implications for access to FCAS markets. Small generation aggregators are not able to participate in FCAS markets until March 2023.

7. See page 28 of AEMO's 2021-22 Budget and fees, available at: https://aemo.com.au/-/media/files/about_aemo/energy_market_budget_and_fees/2021/aemo-2021-22-budget-and-fees.pdf?la=en

4.4 Frequency management

Frequency management refers to the services procured by AEMO to help manage the power system frequency within acceptable bounds. Batteries are well suited to providing these services, and as such, most large batteries connected in the NEM intend to collect revenue from FCAS markets. However, there is significant regulatory complexity associated with gaining access to, and participating in FCAS markets. This section provides a brief overview of FCAS markets and explains the steps necessary to participate in FCAS markets.

4.4.1 FCAS markets

There are eight separate markets for FCAS. Four of these markets buy services to raise frequency, and four buy services to lower frequency. Within raise and lower, there are two sub-groups: regulating FCAS and contingency FCAS.

Regulating FCAS refers to two of the eight frequency control ancillary service markets. There is a paid regulating raise service, and a paid regulating lower service. Regulating services act to keep power system frequency close to 50Hz (the nominal power system frequency) by adjusting the dispatch targets for participating scheduled generators. To provide regulating raise, a generator would need to increase output in respond to an automated generator control (AGC) signal from the Australian Energy Market Operator. Providing regulating lower is the inverse – decreasing output in response to an AGC signal from AEMO.

There are six contingency FCAS markets. These markets procure services that intend to return the power system frequency to the normal operating frequency band following a frequency excursion. There are three contingency raise markets – fast, slow and delayed. These services act over various timeframes to arrest a fall in frequency and return it to at least 49.85Hz. The three contingency lower markets do the same thing, except return high frequencies to at least 50.15Hz.

4.4.2 Who can access FCAS markets

As FCAS markets serve to protect the power system from shocks and power quality issues, there is additional scrutiny and obligations placed on those providing FCAS. Proponents need to separately register and classify the assets that intend to provide FCAS as either ancillary services generating units or ancillary services loads.

Generators can classify their generating units as ancillary services generating units. Market customers can classify their market loads as ancillary services load. To provide regulating FCAS, you need to be connected to AEMO's AGC system, which normally means being a scheduled generator or scheduled load, requiring a minimum power output of 5MW. Small generation aggregators are not able to classify generating units as ancillary services generating units. This means small generator aggregators cannot provide FCAS.

This means, for a 1MW battery or aggregation of batteries:

- Participation in regulating FCAS markets is not achievable as an asset under 5MW cannot be registered as a scheduled asset.
- Small generation aggregators are unable to provide FCAS until April 2023, when upcoming regulatory changes occur and allow Small Generation Aggregators to provide FCAS.

4.4.3 Requirements for providing FCAS

FCAS providers need to comply with obligations including:[8]

- Requirements for remote control
- Ability to respond to locally measured frequency
- Power system event logging
- Compliant metering.

There are also additional droop setting requirements outlined by AEMO specifically for batteries. These requirements are available in a document published by AEMO.

8. These obligations are outlined in the Market Ancillary Services Specification (MASS). The MASS is published by AEMO, and is available here: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/primary-freq-resp-norm-op-conditions/market-ancillary-services-specification---v60.pdf?la=en

4.4.4 Options for accessing the market

To access FCAS markets, the proponent can either partner with an already registered FCAS provider, or follow the necessary steps to be able to provide FCAS themselves.

If partnering for FCAS, the proponent should seek market participants with experience operating batteries in FCAS markets.

If registering themselves, the proponent will need to:

- Classify the battery components as ancillary services load, including paying AEMO the required fees.
- Confirm they can meet the requirements for providing FCAS
- Establish a process for submitting bids and offers to AEMO for the provision of FCAS.

4.5 Network support services

Network service providers have obligations under the National Electricity Rules to provide network services. They are also incentivised to meet reliability standards on their networks. Network support services can be procured through bespoke agreements to assist in the network service provider's network services. For example, it may assist the network service provider in maintaining acceptable voltage levels on the network or it may defer investment in network assets.

In addition, network service providers are required to undertake investment tests when spending over $6M. These tests are called regulatory investment tests for distribution (RIT-D). A battery owner or proponent located close to the area where the network service provider is proposing an upgrade can offer services to help defer or reduce the size of any network augmentation needed.

Each network service provider will have their own approach to valuing network support and demand side engagement.

For projects connecting to the Jemena distribution network, proponents should:

- Register with Jemena to join their Demand-Side Engagement Register. This register stores the information of parties who wish to be notified of opportunities to help relieve network congestion.[9]
- Engage with Jemena to understand options for reduced network tariffs or network support payments available upon connection. This is likely to be bespoke commercial negotiation as there are no current pro forma approaches to valuing community batteries on Jemena's network. Jemena will most likely require particular operating conditions/ restrictions in exchange for any reduced tariff or network support agreements.
- Seek to understand from Jemena the potential for deferred/reduced network development costs, and determine the requisite burden of proof (we are working with Jemena to understand this now, see Sections 2.1 and 7.1)

4.6 Regulatory consequences of a distributed battery scenario

In terms of regulatory consequences for distributed battery installations compared to centralised installation, the key area for consideration relates to aggregation for contingency FCAS markets access and includes some additional steps in registration. The battery owner/operator should also note the risks associated with technical requirements imposed through connection agreements with Jemena limiting the ability of the batteries to provide FCAS.

To access FCAS markets with distributed batteries, the battery owner/operator can either partner with an already registered FCAS provider for aggregation or follow the necessary steps to be able to provide FCAS themselves. If partnering for FCAS, the owner/operator should seek market participants with experience operating batteries in FCAS markets. If registering themselves, they will need to:

- Apply to AEMO to aggregate the batteries into an Aggregated ancillary service facility.
- Have high speed metering in place for each individual battery
- Set up an approach for measuring state of charge and availability, and formulating bids to submit to AEMO
- Have infrastructure in place for receiving dispatch instructions from AEMO and responding to these instructions i.e. providing FCAS when successfully bid

9. This can be achieved by emailing DemandManagement@Jemena.com.au and providing the information listed on page 16 of Jemena's Demand side engagement, available at: https://jemena.com.au/documents/electricity/demand-side-engagement

In connecting the disaggregated batteries, the owner/operator will need to enter into connection agreements with the relevant local network service provider (Jemena in this case). There are additional risks that need to be managed in agreeing these connection agreements the proponent should be aware of.

Jemena have guidelines for connecting generators (including batteries) either between:

- 30kW – 200kW
- 200kW – 5MW

The appropriate guideline will vary depending on the preferred battery size. However, with respect to frequency management, it will be important to understand and negotiate limitations imposed under the respective guidelines that could limit the ability for the battery to rapidly increase power to or from the grid (as required when providing FCAS). For example:

- Export constraints could limit the ability of the batteries to provide raise FCAS.
- Ramp rate limitations following a fault, frequency deviation or voltage deviation may prevent batteries from responding under typical conditions where FCAS is required.

Furthermore, these connection agreement negotiations may entail further testing requirements and resultant costs, including testing and commissioning of the aggregated response. This would add to the already prohibitive costs of the distributed scenario.

4.7 Upcoming regulatory changes

Recent changes to the National Electricity Rules have partially streamlined the process for registration and classification of batteries. From April 2023, the most significant changes for this project include:[10]

- A new registration category will be available – the Integrated Resource Provider. Any small generation aggregators will automatically become Integrated Resource Providers.
- This new category will be able to classify integrated resource units (which would include batteries, hybrids etc.) as ancillary service units.

In addition, a new fast frequency response market is commencing in October 2023. This should create more opportunities for fast responding assets, including batteries.

4.8 Key concepts

4.8.1 Registration

To participate in the NEM, you generally need to register in the appropriate category. For example, electricity retailers are registered as Market Customers to service electricity users. There are separate categories for operating generation assets. For example, anyone operating a large (>30MW) generator would need to register as a Generator. Alternatively, anyone operating a collection of smaller generation assets can register as a Small Generation Aggregator.

4.8.2 Classification

Following registration, the process of classification defines each connection point used by the registered participation. For large generators, these connection points are automatically classified as a generator, and customer connection points are by default classified as load connection points. For smaller assets (such as batteries smaller than 5MW), there is some optionality in how they are classified.

In addition, further classification is required for participation in ancillary services markets i.e. providing frequency control ancillary services.

4.8.3 Financially responsible market participant (FRMP)

Each connection point in the National Electricity Market has a financially responsible market participant allocated to it. The FRMP is the party responsible for settling the energy flows from that connection point in the wholesale market i.e. buying the electricity.

10. Australian Energy Market Commission, Integrating energy storage systems into the NEM – Final determination, December 2021, available at: https://www.aemc.gov.au/sites/default/files/2021-12/1._final_determination_-_integrating_energy_storage_systems_into_the_nem.pdf

5 Commercial approach

The commercial approach sets out to address the following over the lifetime of the battery system:

- Estimation of capital and operational costs
- Formulation and estimation of battery owner/operator benefits
- Formulation and estimation of benefits to homeowners/residents in the Clarkefield development

5.1 Preferred commercial model

Based on the available regulatory pathways for community battery implementation, our preferred commercial model is to have the battery owned and operated by a registered market participant, such as a retailer, that can participate in the wholesale and FCAS markets.

Other potential commercial models, such as third-party ownership by DNSP, community or other investment bodies, could also work for community battery implementation. However, the battery would still require a registered market participant or small generation aggregator as an operator to manage its participation in the wholesale and FCAS markets. In this study, retailer ownership is assumed as it would streamline the administrative processes required for battery connection and remove the potential complexity of partnership arrangements.

For any commercial investment, there will be an expectation for financial return. While this depends on the investing entity, for the purposes of this study we assume a minimum return on investment threshold (as an internal rate of return) of 8%.

As well as providing facilitated access to revenue streams, a retailer owned battery also allows for direct passthrough of community benefit via reduced retail electricity costs. The proposed model for this retail passthrough benefit is explored further in Section 5.8.1.

5.2 Modelling assumptions

Core assumptions for the modelling have been based on lithium-ion BESS characteristics specified by Aurora Energy Research[11] in their 2025 entry year central scenario. These include:

- 15-year project lifetime
- 2025 project completion
- 8% discount rate
- 2.5% inflation rate
- A single daily charge-discharge cycle
- 90% round trip efficiency
- Battery capex, OPEX and revenue forecasts by Aurora Energy Research

5.3 Capital costs

5.3.1 Centralised scenario

The capital cost for a single 1MW/4MWh battery at current technology prices has been estimated by Aurora to be AUD$1,492,000 in their 2025 Central scenario for Victorian installations.

5.3.2 Distributed scenario

Distributed batteries will result in higher capital costs of installation. The higher cost comes from losing the benefit of economies of scale, requiring additional connection infrastructure and more labour hours for installation. Furthermore, in this scenario the cost of distributed battery installations will depend greatly on the nature of the kiosk substations they are connected to, and whether the required switchgear and connection points will already be present or will need to be installed at the cost of the battery developer. Jemena has been approached to discuss this aspect but has not yet responded to our query.

11. See AUS Flexible Energy Market Outlook – Aurora Energy Research (March 2022)

12. https://www.solarchoice.net.au/blog/battery-storage-price/

There are very little published references to the specific cost for community-scale batteries under 1MW in size. However, the cost for small (16-20kWh), residential batteries is typically quoted at around $970/kWh[12]. Assuming a reasonable, diminishing economy of scale, we might expect mid-sized batteries to be in the region of $500 - $700/kWh of installed capacity, representing a capital cost increase of 40% - 100% compared to the preferred battery solution. At the time of writing, the battery industry is facing significant supply chain issues related to political tensions around trade and resource availability. Correspondences with other NBI project participants have indicated that current battery prices could be as high as $1,100/kWh even for mid-sized systems, representing a 210% increase to capital cost. Table 6 below outlines the effect to project capital over this range of potential prices.

***Table 6:** potential project capital costs for distributed battery installations vs. centralised installation*

Increased cost per kWh	Project capital cost ($m)
40%	$1.99
60%	$2.27
80%	$2.56
100%	$2.84
210%	$4.40

Capital costs for the distributed scenario have been assumed at the lower limit of potential increases compared to the centralised scenario, estimated at $1.99m.

5.4 Operational costs

Operational costs associated with battery installations are contributed by three main components:

- Annual OPEX
- Wholesale charging costs
- Network costs

5.4.1 Centralised scenario

The OPEX of a 1MW/4MWh battery has been estimated by Aurora as AUD$10,000 per year, or approximately 0.7% of capex. Wholesale charging costs are estimated by Aurora using wholesale market price forecasts and optimising average charge and discharge prices. The price averages inform an expected annual charging throughput for the battery corrected by a degradation factor (4% in the first 3 years, then 1.5% thereafter).

Network charges are based on the tariff offerings available to connected assets as published by Jemena. Considering available HV tariffs and the throughput and demand projections for a centralised battery asset (approximately 1.6GWh of throughput and a maximum of 1MW/1MVA demand), this leads to the assumption that tariff A40C would be applied according to published criteria (see Figure 5).

A40C	HV_{CR}		
Available to non-embedded or embedded network customers consuming < 55 GWh pa			
	Peak: 8 AM to 8 PM (local time) weekdays; Off peak all other times		
	Annual demand charging window is 8AM - 8PM weekdays (local time), Rolling 12 months		
	Summer Demand Incentive Charge charging window is 4PM - 7PM workdays (local time) each month in December to March, reset monthly		
	- Standing charge	$/customer pa	$19,766.312
	- Peak Unit rate	¢/kWh	4.082
	- Off Peak Unit rate	¢/kWh	0.956
	- Annual Demand charge	$/kVA pa	$52.054
	- Summer Demand Incentive Charge[f]	¢/kVA/day	35.493
	Minimum Chargeable Annual Demand	1,000 kVA	

***Figure 5:** assumed network tariff assignment for the centralised battery scenario based on expected throughput and demand of the system.*

The tariff charge structure is such that the battery would incur peak unit rate charges for all times that it is charging, other than weekends. Furthermore, with this tariff, the minimum chargeable demand is 1000kVA, so even if the battery is limited from charging at full capacity, a minimum annual demand charge of $52,054 would be applied. Combined with the standing charge of nearly $20,000 per annum and charging costs, this makes the network charges a significant proportion of total operational costs. Fortunately, given the battery control strategy avoids charging from 4pm, the summer demand incentive charge would not be incurred.

Figure 6 summarises the annual costs of the centralised scenario over its 15-year lifetime.

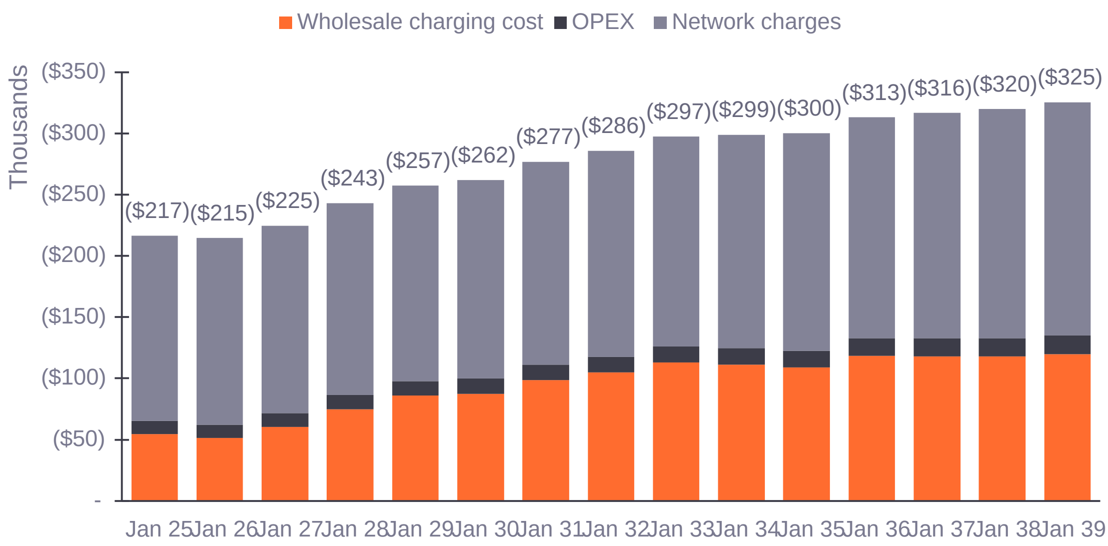


Figure 6: *annual battery costs by source for the centralised scenario ($'000 – nominal)*

What is evident is the disproportionate contribution to annual costs resulting from network connection, representing over two thirds of costs in the first few years and remaining consistently over 50% of total costs over the battery lifetime.

5.4.2 Distributed scenario

Further to the capital cost increase, it is also expected that multiple distributed batteries would entail larger operating costs related to servicing and maintenance. Even assuming the same proportional cost as with the preferred solution, 0.7% of capex per annum, this would be scaled by the same relative increases as the project capital. It is reasonable to expect it could be higher still, but again there are no published figures to corroborate this assumption.

Another significant impact to operating costs is a potential change to network tariff for the smaller batteries. Taking the example of four distributed batteries each of size 250kW/1MWh with annual throughput and maximum charging demand reduced to 25% for each battery, it is likely the batteries would be assigned a lower volume tariff. Furthermore, as the batteries would connect to the LV network, they would be designated a LV tariff.

To explore the impacts to network costs, we take the above example of four distributed batteries to assess the potential tariff assignment. With throughput and demand reduced to 25% (approximately 400MWh and 250kW respectively), this leads to the assumption that LV tariff A30C would be assigned (see Figure 7).

A30C	LV$_{CR}$ 0.4 - 0.8 GWh		
Available to non-embedded network or embedded customers consuming ≤ 0.8 GWh pa			
	Peak: 8 AM to 8 PM (local time) weekdays; Off peak all other times		
	Annual demand charging window is 8AM - 8PM weekdays (local time), Rolling 12 months		
	Summer Demand Incentive Charge charging window is 4PM - 7PM workdays (local time) each month in December to March, reset monthly		
	- Standing charge	**$/customer pa**	**$2,908.991**
	- Peak Unit rate	**¢/kWh**	**4.928**
	- Off Peak Unit rate	**¢/kWh**	**1.411**
	- Annual Demand charge	**$/kVA pa**	**$72.059**
	- Summer Demand Incentive Charge[f]	**¢/kVA/day**	**48.664**
	Minimum Chargeable Annual Demand	**120 kVA**	

Figure 7: *assumed network tariff assignment for the distributed battery scenario based on expected throughput and demand of the individual battery systems.*

Figure 8 summarises the annual costs of the distributed scenario over its 15-year lifetime. Lifetime network charges are approximately 15% lower compared the centralised scenario, which derives from the cheaper standing charge and lower minimum annual demand charge for this network tariff. However, network charges remain the largest cost contribution in this scenario, further highlighting the issue of network connection under the current tariff offerings by Jemena. The issue of network charges and potential solutions are explored in Section 5.7.2.

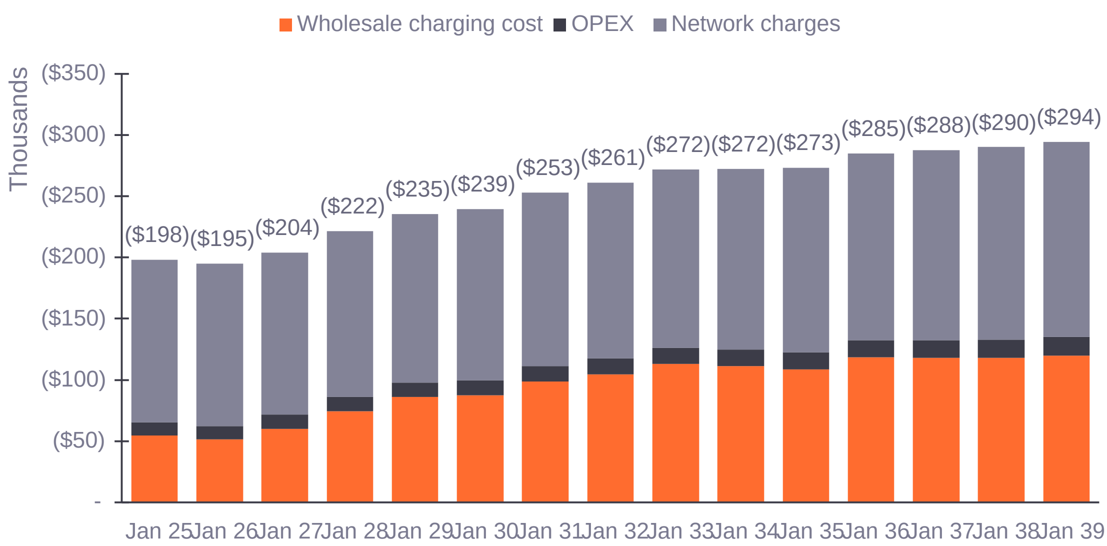


Figure 8: *annual battery costs by source for the distributed scenario ($'000 - nominal)*

5.5 Battery revenue

Financial returns to the owner/operator of the battery are derived from participation in the wholesale market and FCAS market revenue streams. Battery revenue can be considered independent of the number of batteries deployed, as the total amount of power and capacity participating in the markets is the same. Consequently, the revenue is assumed to be the same for both the centralised and distributed scenarios.

Wholesale market revenue derives from an arbitrage regime, being the difference in the average charge price (lower) and average discharge price (upper) multiplied by the annual battery throughput. The price averages vary each year depending on forecast market conditions. This is the largest component of battery revenue. A secondary revenue stream that is available to wholesale market participants is through responding to high price volatility. In this approach, this has been modelled for responding to price signals of over $300/MWh. This is a comparatively smaller revenue stream.

With the cost estimates outlined in the previous section, the operator of the battery will need to seek as many potential revenue streams as are available. This could derive from participation in contingency FCAS markets, although as discussed in Section .3.6, this could be counterproductive to the reduced network infrastructure objectives of battery implementation. It also has the potential to interfere with a solar soaking arbitrage control regime if battery capacity needs to be reserved for bidding into FCAS markets. Furthermore, it should be noted that the most recent modelling by Aurora Energy Research has downgraded the potential revenue from contingency FCAS due to saturation of the market with recent grid-scale battery installations.

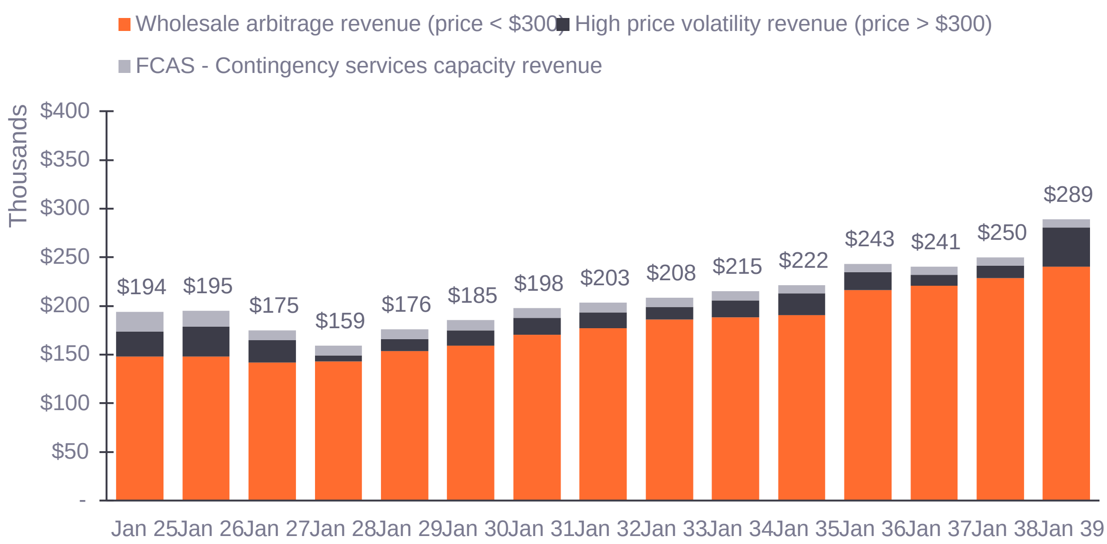


***Figure 9:** net annual battery revenue by source with contingency FCAS participation ($'000 - nominal)*

As can be seen in Figure 9, contingency FCAS revenue represents a modest value stream available to battery operators (making up less than 10% of total revenue). However, with the fine margins associated with ensuring commercial return at the same time as providing community benefit, it may be important to capture all potential revenue available to battery operation. Unfortunately, as the battery would not be a scheduled asset in the electricity market, it would be precluded from the higher value regulation FCAS markets.

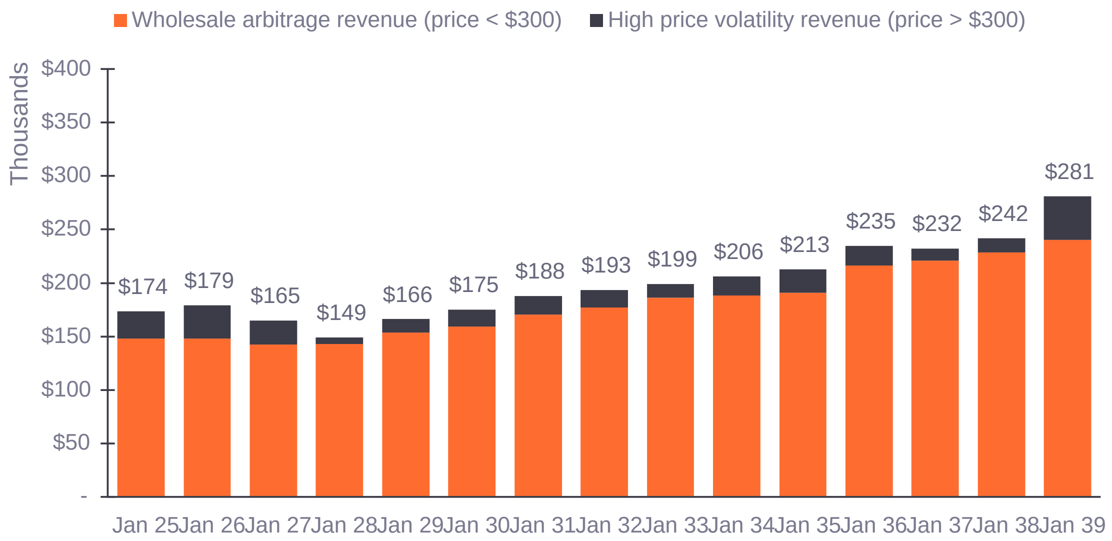


Figure 10: *net annual battery revenue by source without contingency FCAS participation ($'000 - nominal)*

Figure 10 shows battery revenue exclusively from arbitrage and high price volatility, showing a minor reduction to total revenue in the absence of contingency FCAS. As will be explored further in the next section, both the centralised and distributed scenarios are unlikely to be financially viable with the expected operational costs and available revenue streams.

5.6 Net cashflows

Cashflow assessments based on the costs and revenues modelled in previous sections highlight the financial difficulties a battery owner/operator would face in current market and network contexts.

5.6.1 Centralised scenario

Net cashflows for the centralised scenario are shown in Figure 11. With the potential issues linked to accessing FCAS markets, cashflows have been modelled assuming no revenue from contingency FCAS. As can be seen, from the first year of operation (2025) cashflows are negative, suggesting the wholesale market revenue streams available are insufficient to enable a commercially viable community battery installation.

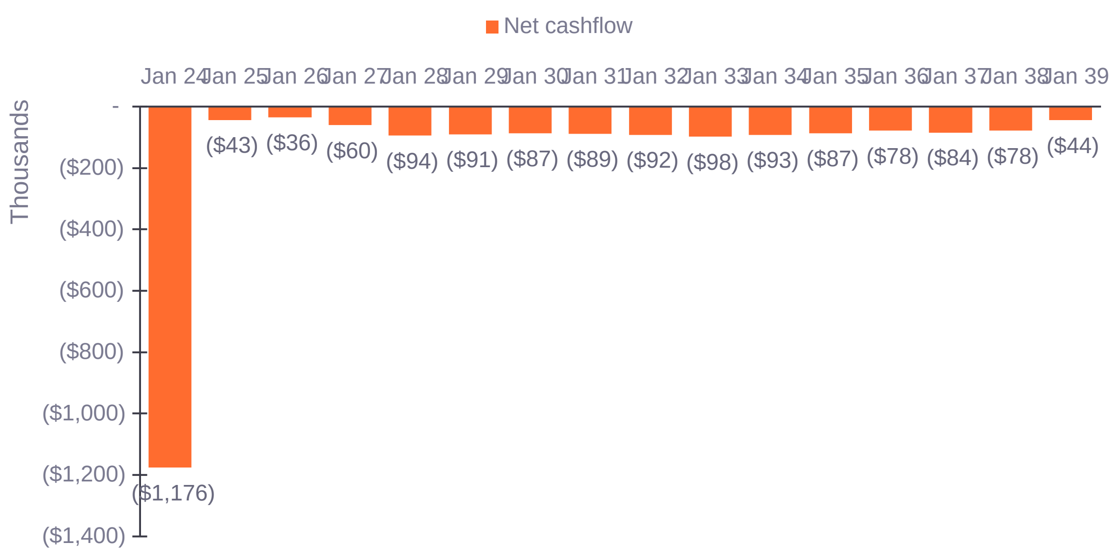


Figure 11: *net annual cashflow for the centralised scenario ($'000 - nominal)*

The NPV for this scenario at an 8% discount rate is -$1,812,273, suggesting there would need to be significant additional revenue streams or financial contributions available to make the project commercially viable.

5.6.2 Distributed Scenario

As with the centralised scenario, cashflows for the distributed scenario present a similarly poor outlook for a financially viable solution for implementing distributed community batteries. The distributed scenario cashflows have been modelled assuming a lower limit of a 40% increase to capital costs compared to the centralised scenario. The cashflows are shown in Figure 12.

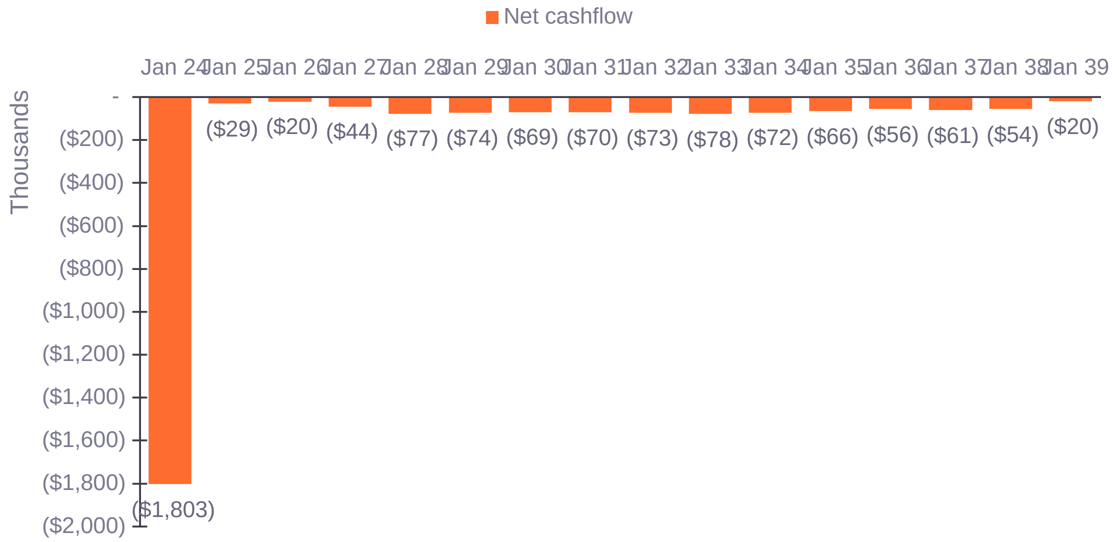


Figure 12: *net annual cashflow for the distributed scenario, assuming four 250kW/1MWh installations ($'000 - nominal)*

As with the centralised scenario, all annual cashflows are negative from the first year of operation, although slightly reduced in magnitude because of cheaper network tariff costs for the LV connections. However, the small improvement to annual cashflows is offset by the much larger initial capital outlay required for distributed installations. This impact is highlighted by a lower NPV of -$2,282,186 at 8% discount. This suggests that the distributed scenario would face even greater challenges to be commercially viable.

The poor cashflow outlook for both scenarios indicates that there would be a need for significant financial support to be a financially viable and commercially attractive investment for a battery proponent. Moreover, this is in the absence of community benefit passthrough, which would likely put more financial strain on the proponent. This issue and potential solutions are explored in Section 5.7.1.

5.7 Barriers to the commercial approach

5.7.1 Insufficient returns from market participation

Evident from the cashflow exploration in the previous section, both scenarios for community battery implementation are likely to struggle to make financial returns over their lifetime with expected costs and currently available revenue streams. Even if the battery system were to participate in contingency FCAS, it would have a very small impact, still yielding negative cashflows over the project lifetime.

In the absence of additional revenue streams, the project may require significant alternative funding to reach viability. This could be a capital grant, contributions from participating residents, or purchasing contracts for battery throughput.

A capital grant may help to relieve the initial financial burden, but with negative cashflows throughout the operational lifetime, even support equal to 100% of initial capital would not allow the system to reach financial viability. Many of the large-scale battery systems in Australia have been supported by capital grants, from either the Australian Renewable Energy Agency (ARENA) or the Clean Energy Finance Corporation (CEFC)[13]. However, it is unclear if the same opportunities for grant funding would be available to community-scale batteries. Upcoming policy changes from the new federal government may impact funding availability, as discussed further in Section 7.2.

13. See AUS Flexible Energy Market Outlook – Aurora Energy Research (March 2022)

Contributions from participating residents could take the form of up-front payments or subscription fees. Up-front payments could afford these residents a share in the battery installation and relieve some of the financial burden from the owner/operator but would face the same issues of negative cashflows throughout operation. Subscription payments could see cashflows improve, but the size of payments required to allow positive cashflows that produce a positive return for the battery would likely far outweigh any potential benefit received.

Battery revenues can also be supported by bespoke offtake contracts such as power purchasing agreements or government purchase contracts. These arrangements may allow for higher revenue from battery output than is available from wholesale arbitrage and could improve net cashflows. As with capital grants, purchasing contracts represent significant funding contributions to some of the large-scale batteries currently operating in the Australian market, and may be available to mid-scale installations as well.

Ultimately, even with alternative funding either as upfront support or annual revenue support, the main barrier to financial viability is the operating costs, in particular network charges. In the next section we explore this barrier and potential solutions further.

5.7.2 Network charges

As discussed in the previous section, the main barrier to financial viability for a community battery installation derives from the significant contribution of network charges to operating costs. Under the currently assumed network tariffs in the Jemena jurisdiction, it is very unlikely that any community-scale battery installation could provide sufficient returns to enable community benefit without various alternative funding contributions, which would need to comprise over 100% of project CAPEX.

Discussions are still ongoing with Jemena about the potential for alternative tariffs that could be applied to a community battery connection. However, other network operators in Victoria – namely Citipower, Powercor, United Energy – have already proposed a trial tariff for community-scale batterie[14]. The structure and charge specifics of this trial tariff are shown in Figure 13.

Non-distributor owned community battery

Retailers of a non-distributor owned community battery will incur the following network charges which exclude GST. There are no other network charges although metering charges may apply.

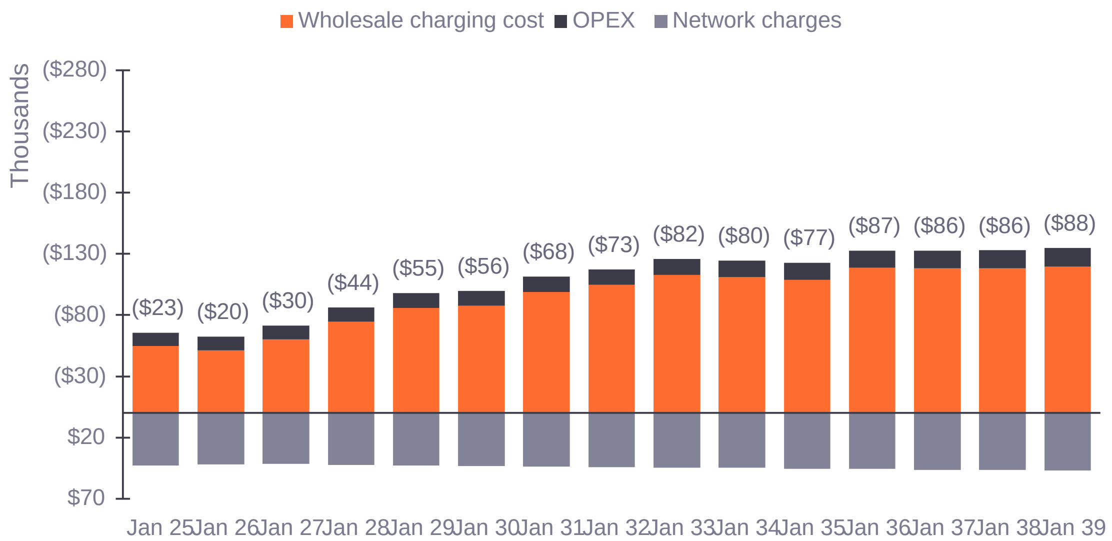
Time band	Fixed (cents/day)	Import rate (cents/kWh)	Export rate (cents/kWh)
10am – 3pm	45	-1.5	0
4pm – 9pm		25	-1.0
All other times		0	0

A positive rate is a charge, and a negative rate is a rebate

Figure 13: *proposed community battery network tariffs in the CitiPower, Powercor and United Energy networks from July 2022*

The trial tariff structure works as an incentive for batteries that operate on a solar-soaking control regime, providing a rebate for charging during peak solar hours and discharging during peak demand hours. To explore the impacts such a tariff could have on feasibility of a community battery installation, we modelled the annual costs for the centralised scenario using the above network charge structure, shown in Figure 14.

14. See Powercor's Community Battery Trial Tariff Factsheet: https://media.powercor.com.au/wp-content/uploads/2022/02/28084618/Community-Battery-Trial-Tariff-factsheet.pdf



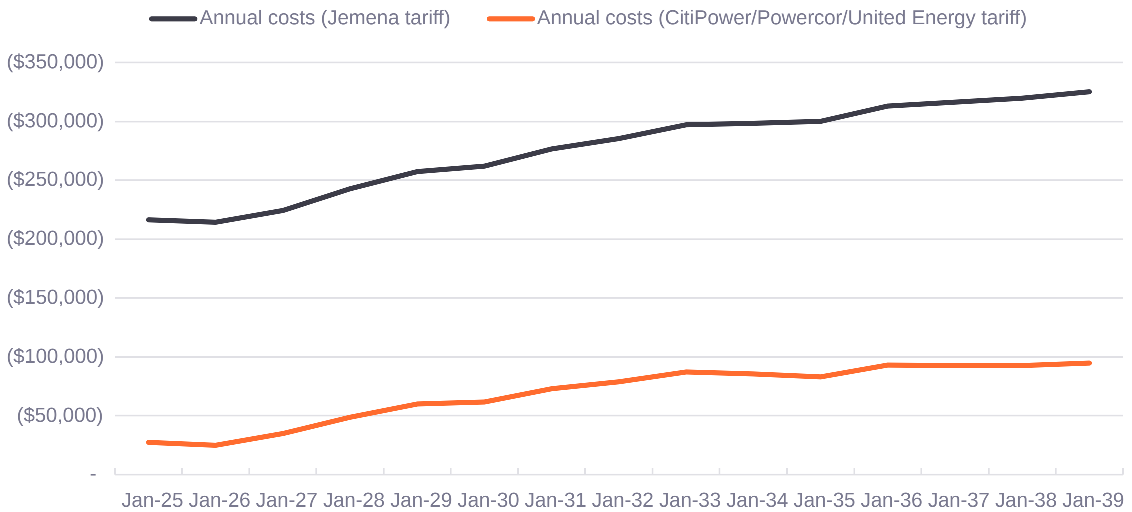


Figure 14: *annual battery costs for the centralised scenario with the CitiPower/Powercor/United Energy community battery network tariff (above) and comparison to annual costs on the Jemena tariff (below)*

The first chart clearly shows the effect of the trial battery tariff, with the cost of network connection becoming a rebate or additional revenue stream worth over $40,000 per annum. The difference between the two tariffs is nearly $200,000 per annum, as illustrated by the second chart.

The impacts to commercial viability are significant, with cashflows becoming positive from the first year of operation and remaining strong throughout the battery lifetime, as shown in Figure 15.

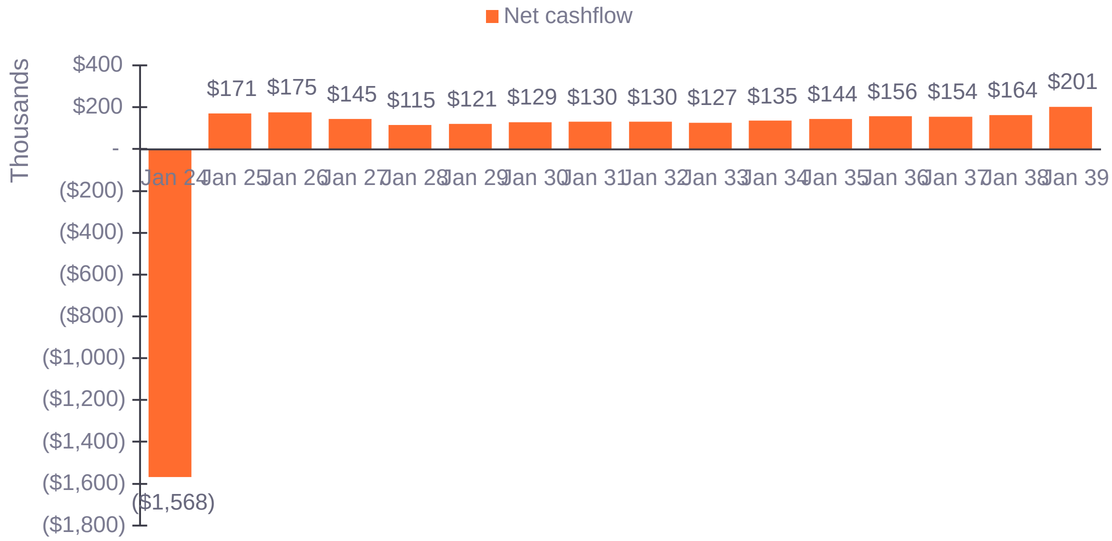


***Figure 15:** net annual cashflow for the centralised scenario applying the trial community battery network tariff ($'000 - nominal)*

Despite the improved cashflows from reduced network costs, the system would still need alternative capital funding equivalent to over 20% of CAPEX in order to reach an 8% threshold IRR. Without capital funding, the system has an NPV of -$323,822 and an IRR of 4.5%.

For the distributed scenario, the higher capital cost of implementation results in a less favourable outcome on the trial tariff, with an NPV of -$845,983 and IRR of 0.6% without alternative funding. To reach a 8% threshold IRR the system would require alternative funding equivalent to over 40% of CAPEX.

This presents a major hurdle for achieving the objective of providing community benefit to residents in Clarkefield, as financial benefits could only be passed through if there are sufficient returns for the battery system to surpass the investment return threshold. Additional returns beyond this threshold would form the basis on which community financial benefit can be enabled.

5.8 Community benefit

There are two main mechanisms proposed by this study for community benefit as a result of neighbourhood battery installation. The first is the offer of electricity discounts for participating residents, provided by the retailer that owns and operates the battery system. The second is, as discussed earlier in this report, the potential for reduced network infrastructure costs passing through to residents in the form of reduced cost of homes. Both are discussed at length in this section.

5.8.1 Electricity discounts

The model for direct community benefit passthrough works on the assumption that the battery owner/operator is an energy retailer. This assumption allows for benefit passthrough via the offering of a bespoke residential electricity tariff that incorporates a discount to electricity volume charges. This approach can be viewed as a "shared savings" mechanism, as the potential discount to customers would be based on the returns exceeding the battery owner's threshold rate of return. The premise of this approach is the designation of a c/kWh discount to energy rates, the net total of which can be considered as an additional annual cost to battery operation.

The retail model is predicated on residents becoming retail customers of the battery owner operator. Given that each resident has a choice in relation to their retailer, the total shared savings would be dependent on the uptake of retail offers by residents, as well as the value of the discount.

For the purpose of exploring this community benefit model in detail, modelling of shared savings has been performed using the cashflows based on the Citipower/Powercor/United Energy trial tariff, which are explored in the previous section. This is so the benefit model can be investigated and explained in the context of a battery system that can reach commercial viability, albeit with alternative funding support.

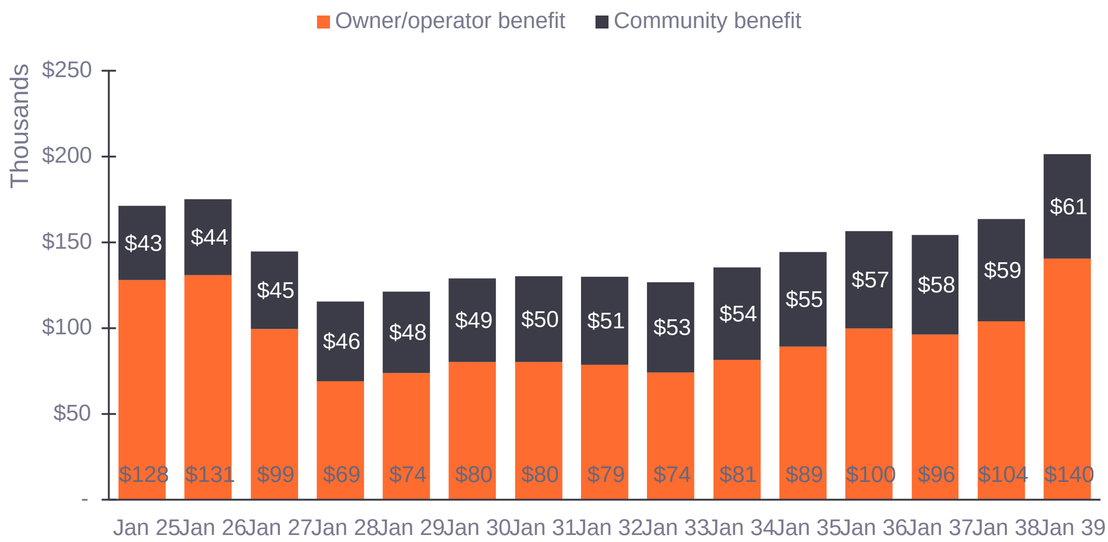


Figure 16: *net annual benefit share between battery owner/operator and the community, assuming 70% uptake and a 5c/kWh discount to electricity costs ($'000 - nominal)*

Figure 16 shows the share in net cashflows between the battery owner/operator and participating residents for an example scenario of 5c/kWh discount for 70% resident uptake of the retail offer. Based on the average annual energy use of each customer, the discount represents a proportion of battery revenue each year. This is assuming a single rate tariff but could be applied to time-of-use tariffs as well.

To explore the extent of this shared revenue, Figure 17 presents the proportion of net cashflow passed on as benefit to the residents, as well as the virtually contracted throughput.

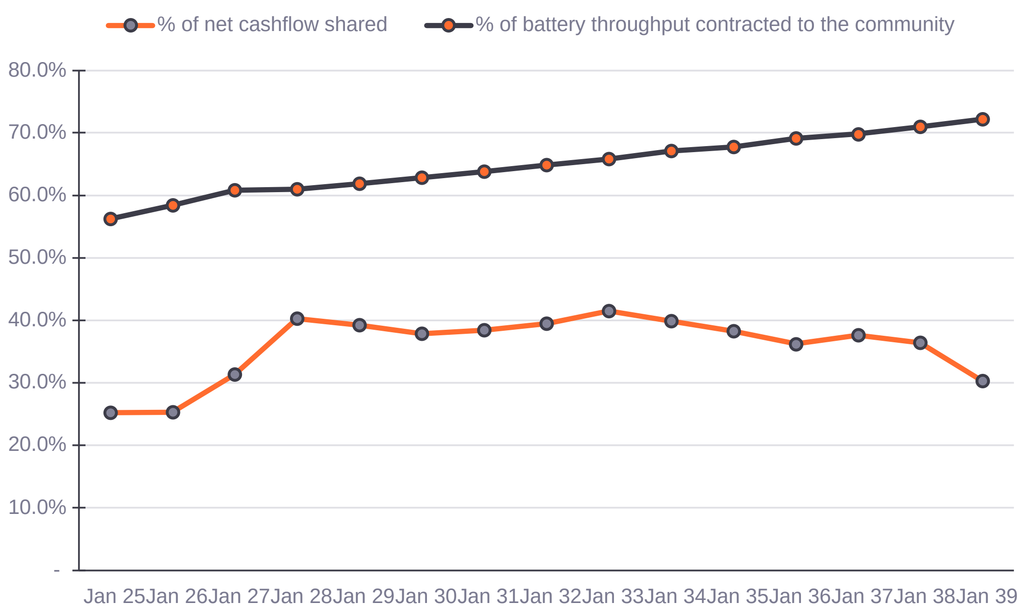


Figure 17: *proportion of battery cashflow and throughput providing benefit to the community, assuming 70% uptake and a 5c/kWh discount to electricity costs*

While the average annual energy use of customers is assumed to remain consistent over the battery lifetime, the proportion of contracted throughput increases as the battery capacity degrades annually.

As mentioned previously, the battery system would already require a source of alternative funding to allow it to reach the hurdle rate of return for the battery owner. This means that to allow for community benefit and for revenue to be shared, the battery would need further alternative funding. In Table 7, we explore the requirement for alternative funding (expressed as a percentage of total CAPEX) required to provide different levels of discount for the full range of potential uptake of the retail offer.

***Table 7:** required alternative funding (% of total capex) at an 8% hurdle IRR for a range of energy rate discount and uptake conditions*

Alternative Funding Required (%) at hurdle rate of return of 8%								
		Target Discount ($ / kWh)						
		$0.01	$0.02	$0.03	$0.04	$0.05	$0.06	$0.07
Customer uptake (%)	10%	21%	22%	23%	24%	25%	25%	26%
	20%	22%	24%	25%	27%	28%	30%	32%
	30%	23%	25%	28%	30%	32%	35%	37%
	40%	24%	27%	30%	33%	36%	39%	42%
	50%	25%	28%	32%	36%	40%	44%	48%
	60%	25%	30%	35%	39%	44%	49%	53%
	70%	26%	32%	37%	42%	48%	53%	59%
	80%	27%	33%	39%	45%	52%	58%	64%
	90%	28%	35%	42%	49%	56%	63%	70%
	100%	28%	36%	44%	52%	59%	67%	75%

What is evident is that the greater the shared revenue, the higher the need for alternative funding. The shared benefit is provided to the community out of a fixed pool of revenue that the battery can exploit with the currently available sources. In the absence of additional revenue streams, alternative funding could come from government subsidy, customer contributions, purchasing contracts or a combination of each. If this were to come from individual customer contributions, it would make sense that the scaling contributions from customers could account for this additional funding requirement. However, if funding were to come from a government grant or purchasing contracts, it would allow for customer benefit without the need for contributions.

There is also the potential to provide a bundled service accounting for rooftop solar PV, solar-following hot water and battery storage that is managed by the retailer and charged on a c/kWh basis. This could allow for each individual service to be integrated and commercially operated as a whole. For example, if the retailer owns the rooftop solar and community battery assets, solar production could be contracted directly for battery charging, avoiding the need to purchase energy at wholesale prices. Residents can then be charged for electricity based on the revenue and commercial outcomes of the resultant integrated system.

The retailer model distinguishes itself from other NBI project commercial models in that it establishes a revenue stream for participants separate from subscription fees and payments. There is a direct passthrough benefit that is related to an individual residence's energy use, providing a true sense of the impact of the battery installation on energy costs that does not depend on individual consumption behaviour. The retailer is incentivised to provide the service through contracting additional customer loads and the margin it receives as a result, as well as any additional contributions from participating residents

The leading alternative model for community benefit is a subscription model where participants pay a fee (upfront or annual) for a share of the community battery capacity, which is intended to defer the need for a home battery system. As well as involving complex metering and/or billing requirements to manage the virtual transactions under this model, an issue of equity arises due to the finite capacity of the community battery system and individual consumption behaviour. Participants who have greater solar export earlier in the day stand a better chance to maximise their virtual transaction volume prior to the battery reaching 100% state-of-charge, and similarly those who use energy earlier in the battery's discharge window stand to benefit more than those whose largest consumption occurs after the battery has fully discharged.

5.8.2 Reduced network costs

Another source of community benefit derives from the potential for neighbourhood batteries to reduce the required network infrastructure. The impacts of the battery system on ADMD for import and export could lead to the installation of lower rated cabling or a reduced number of HV-LV kiosk substations.

We are currently in ongoing discussions with Jemena regarding the potential for batteries to avoid network infrastructure, but as mentioned in Section 2.1, reducing the number of kiosk substations or capacity of cabling by implementing a distributed battery system could have significant cost reductions for network development. Given that the developer – in this case APD – is required to contribute to network installation for greenfield sites, a low-cost contribution by the developer could allow for discounted homes for prospective residents.

A distributed system may also add to these benefits through contributions to voltage management in the local network. As discussed previously, it is yet to be seen the extent to which voltage stability is a limiting factor in network infrastructure requirements, particularly with 100% penetration of rooftop solar. This has been flagged in ongoing discussions with Jemena.

This is a community benefit resulting from the network support capabilities of battery installations, potentially enabling lower cost, zero-carbon homes and setting a precedent for future developments. Other pathways for community benefit from network support may include reduced network tariff charges for participating customers, reflective of the lower cost network for the suburb.

In our continued discussions with Jemena, we hope to understand the extent of this potential cost reduction, to highlight a secondary benefit for neighbourhood batteries in greenfield developments.

6 Conclusion

This study has investigated the potential of neighbourhood batteries to provide community benefit, network support and pathways towards enabling zero-carbon greenfield developments.

The exploration suggests that there are two key technical solutions that are feasible for battery implementation – a single centralised battery connected to the local HV network, or multiple distributed batteries located next to kiosk substations on the LV network. The greenfield nature of the development allows for choice in this regard, and the key highlight of this study is the need to engage with the local network operator to understand the potential for network support benefits and avoided or deferred network augmentation. There is also a need for further work to understand the specific connection requirements for each battery scenario.

If policy makers intend to enable affordable, zero emission homes in new developments, there is a need to increase the transparency of the methods and processes used by network service providers to determine ADMD and other network constraints, and ultimately the design specifications for greenfield network infrastructure installations. Furthermore, with non-network solutions to demand management becoming increasingly prevalent, it is important to understand the burden of proof required to guarantee that these solutions will lower network hosting requirements over the lifetime of the network. In this way, developers can seek to implement sustainability solutions that align with network service providers' methods for designing network infrastructure and propose contractual arrangements that satisfy the requisite burden of proof.

With each scenario being technically feasible, the main barriers relate to the commercial operation of the battery systems and passthrough of community benefit. With the currently available revenue streams and operational costs, notably the network tariffs assumed to apply to battery connections in the Jemena network, the neighbourhood battery would not be a commercially viable investment for any proponent. This highlights the need for additional revenue sources, reduced capital expenditure through technology developments or new, battery-specific tariffs that acknowledge the network support benefits of neighbourhood batteries and apply charges – or rebates – accordingly.

Exploring the hypothetical scenario of applying the trial tariff proposed by Citipower, Powercor and United Energy reinforces this point, as this scenario could allow the battery to reach a level of commercial return that provides pathways for passthrough community benefit using a retail model, albeit with a necessity for significant alternative funding contributions. A secondary community benefit deriving from the potential for reduced network installation costs and consequent developer contributions is also possible, and could allow the offering of cheaper, zero-carbon homes by the developer to prospective residents.

7 Next steps and further work

In this section, we identify and briefly discuss potential extensions to work undertaken in this study.

7.1 Continued collaboration with Jemena

The central outcome of this study has been the engagement with the local network operator. At first, Jemena were hesitant to support investigations into enabling community batteries. However, as the study progressed, they have shown a greater interest and engagement in the project and discussions have been ongoing to explore pathways in greater detail.

The ongoing discussions are highlighting the need for an iterative investigation into the network benefits of battery installations, and the benefits or reduced costs that could be offered as a result. The key areas of further exploration include the structure and charge specifications for community battery network tariffs, forecasting methods and assumptions for ADMD reductions and voltage management, potential for installation of lower cost network infrastructure and the burden of proof or contracting requirements to guarantee the continued operation and maintenance of network services provided by community batteries.

7.2 Upcoming policy opportunities

With the recent federal election seeing a change in government, there is an expectation that significant government support will be allocated to community battery projects. In particular, Labor's 'Powering Australia' plan outlines an intention to install 400 community batteries across the country[15]. The policy includes $200m of investment to support battery installations, and could present an avenue for securing the alternative funding required to make the battery systems explored in this report commercially viable.

At the state government level, DELWP is also continuing its support for neighbourhood battery installations, with the launch of round two of the neighbourhood battery initiative in June seeing an additional $2.32m in grant funding made available for prospective projects[16].

7.3 Capital and revenue stream forecasts

The revenue streams available to community-scale batteries – wholesale market arbitrage and contingency FCAS – are highly dynamic in Australia. For wholesale arbitrage, projections by Aurora Market Research suggest that revenue is unlikely to increase in the near-term, with the average intra-day spread due to fall from 2025 to 2035. Similarly, FCAS markets are expected to decline in value due to market saturation, with total FCAS expenditure projected to fall from $400m in 2020 to less than $50m from 2027 onwards.

In terms of capital costs, technology developments and global manufacturing have seen steady reductions in the price of lithium-ion technologies and systems. However, recent global supply chain and lithium shortages have affected this downward trend, and costs have spiked as a result. Despite this recent price spike, it is expected that costs for mid-to-utility-scale lithium in batteries will continue to fall, with the National Renewable Energy Laboratory projecting system costs in their central scenario to fall from AUD520/kWh in 2020 to AUD300/kWh by 2030[17]. At this price, the centralised scenario in this study would cost AUD1.2m which, under the community battery trial tariff modelled in previous sections, would yield an IRR of 7.8%. This, however, is still below the threshold rate of return and insufficient to provide community benefit without alternative funding contributions.

To enable a community battery to provide benefits to residents with currently available revenue streams, application of the community battery trial tariff and no alternative funding contributions, assuming the same 5c/kWh discount at 70% uptake, would require battery costs to drop to approximately AUD$194/kWh for both the centralised and distributed scenarios.

Further work could be done to outline revenue and cost scenarios that would allow for favourable outcomes of community battery installations.

15. https://www.alp.org.au/policies/community-batteries-for-household-solar
16. https://www.energy.vic.gov.au/new-energy-technologies
17. See Cost Projections for Utility-Scale Battery Storage: 2021 Update NREL 2021

7.4 Community batteries vs. coordinated home batteries

The challenges and barriers associated with network considerations for community battery installations highlights the potential for an alternative approach to introducing battery storage in greenfield developments.

If the main contribution to battery operating costs derives from network tariffs, it may be worthwhile to explore the installation of individual, behind-the-meter battery systems in every home. The systems could then be coordinated and managed as an aggregate storage system to optimise solar soaking and demand management outcomes. Not only would this avoid network costs for battery charging, but would also manage solar export impacts before entering the local network, potentially reducing the hosting requirements of the network and consequent infrastructure costs.

Issues that could arise from this approach include the complexity of orchestrating a large number of battery assets, as well as a potential increase to total costs of storage implementation.

7.5 Grid-connected solar + battery plant

Another alternative to addressing network concerns of community battery implementation is to centralise both the battery and solar PV systems for the suburb. In place of having 100% penetration of rooftop solar, the suburb could be supported by a grid connected solar and battery plant connected to the HV network. This would allow for the battery to be fed directly by solar generation, avoiding network charges and preventing a large amount of solar export in the suburb's local network.

Essentially, this arrangement would require a power purchasing agreement between the suburb's residents and the solar plant, and goes against APD's objectives of developing zero-carbon sustainable residences. However, it may be important to understand if this is a lower cost option with greater network support and operational benefits.