KPMG

Ausgrid Community Battery

Feasibility Study Report
A report for Ausgrid Operator Partnership.

February 2020
kpmg.com.au

Disclaimer and limitations

Purpose of advice

The purpose of our advice is to assist Ausgrid in their community battery feasibility study.

Scope of work

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Executive summary

Ausgrid Operator Partnership (Ausgrid), engaged KPMG and AECOM, to undertake a study to investigate the drivers that would make a Community Battery Initiative a cost-effective alternative to traditional network investment, now or in the future.

What were the key objectives of the study?

The study assessed a range of technical, commercial and regulatory factors impacting the feasibility of the business model for a shared community battery as an alternative to traditional network investment. The main question the study aimed to answer was the following:

> **Could a Community Battery Initiative be feasible, now or in the future, and if so, under which circumstances would this happen?**

1.
- Technical options for battery design and costs
- Expected change in network conditions in future
- Conditions where community battery is needed?

2.
- Potential contribution and use of local customers in the Community Battery
- Market revenue potential from wholesale and ancillary services

3.
- Regulatory changes required to support standardised roll out of Community Batteries as an alternative network solution

To evaluate this, the multiple services that a community battery could offer and the associated benefits that can be captured from sharing the use of the battery across the community needs to be properly understood. Therefore the study considered each aspect of the business model by focusing on questions related to three areas - technical, commercial and regulatory, as listed on the left.

What is a community battery?

A community battery is a locally-based shared battery (operating 'in front of the meter') through which customers are able to store excess solar PV energy which they can then access at a later time to offset their energy import. In parallel, the community battery can also be used to support network operations and potentially trade in the wholesale markets. The concept involves the installation of a battery that would be connected to local distribution centres. This has the potential to unlock the greatest value, providing much-needed low-voltage network support.

A community battery has the potential to provide a cost-effective energy storage solution for *all customers* ('society') by addressing local electricity network constraints, as well as a range of broader system level services and benefits (wholesale market arbitrage, FCAS (Frequency Control Ancillary Services), photovoltaic (PV) customer storage-as-a-service, and additional benefits to customers, in the form of avoided capital expenditure for participating customers and benefits to the wider customer base. To be consistent with the framework for identifying efficient network investment under the National Electricity Rules, the benefits that all customers receive under a Community Battery Initiative must outweigh the costs.

Solar PV Generators

Increased solar self consumption

Avoids risks and costs with home installation and maintenance

Expands access to batteries for more customers

Network Businesses

Efficient way through optimal location to address network limitations and peak demand

Flexibility to provide additional network support

Wider customer base

Increased network resilience and ability to accommodate higher PV uptake

Lower network tariffs through use of battery for other benefits compared to network augmentation

Energy market & environment

Downward pressure on wholesale prices

Support future increase in intermittent renewables

Positive impact on environment through lower battery disposal

By stacking multiple end use cases and revenue sources, the business model for a community battery offers:

- **Cost reductions** through economies of scale compared to 'behind the meter' batteries;
- **Capacity optimisation** through diversity of customers' energy usage patterns;
- **The opportunity to generate value from multiple revenue streams,** leading to a more economical solution; and
- **Dynamic use optimisation** through a 'dispatch hierarchy' to ensure available benefits are maximised at any given point in time.

What were the outcomes of the study?

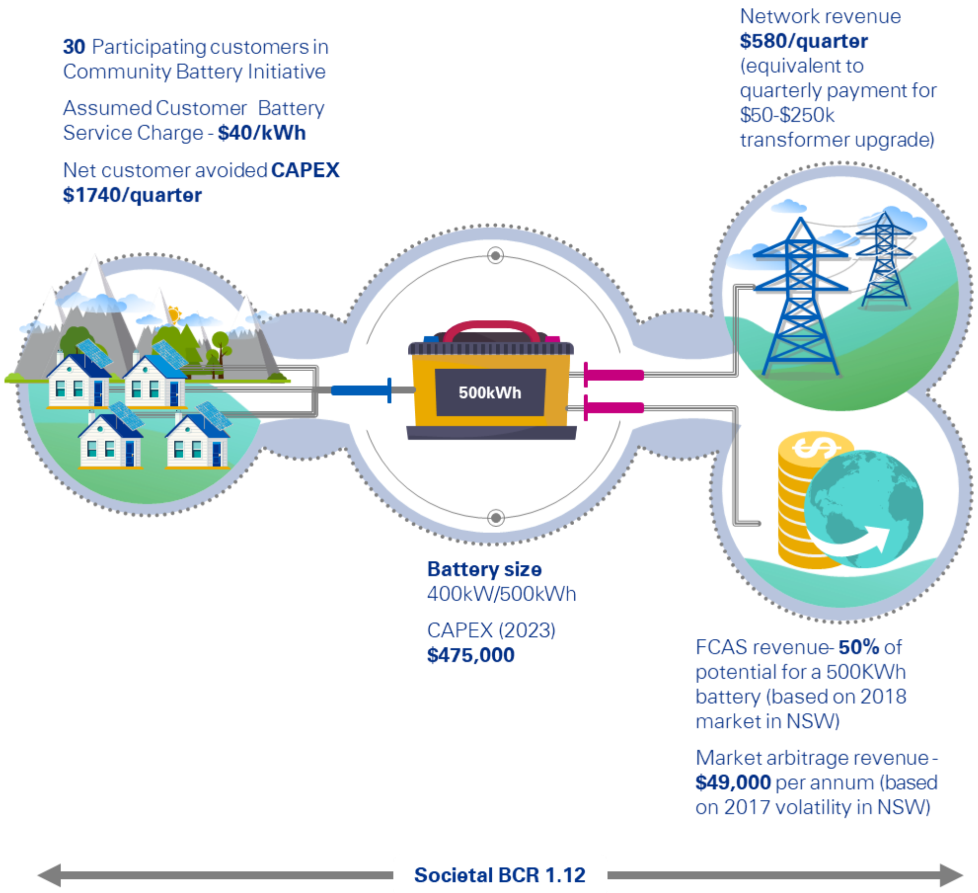
The study identified **three potential configurations** for battery installations that could be considered as alternative network solutions in local distribution centres, taking into consideration the following drivers:

- **Engineering specifications** and size constraints
- Expected **future uptake and size of solar PV** installations
- Potential future **network conditions**
- Projected future **cost curves for batteries**
- Potential future **energy market conditions**

Analysis of these configurations considered **a range of conditions under which a Community Battery Initiative could be feasible in the next 3-5 years.**

Among the cases tested, the optimal configuration could breakeven by 2023 achieving **an NPV of approximately $4,500** in 2023. It was found that the **Community Battery Initiative could present a positive societal Benefit to Cost Ratio of 1.12 under a base case scenario**, which could result in a much greater benefit to society compared to traditional network investments, where the use case for the infrastructure would not be able to capture the same wide range of benefits.

Community Battery Initiative Prospect



WHAT ARE THE KEY COMMERCIAL DRIVERS?

CONTRIBUTION OF ALL USE CASES AND REVENUE SOURCES

The optimum configuration was found to capture relatively higher revenue from customer payments and customer savings, accounting for more than 20% of the total revenue stack.

A community battery would be more feasible in larger Distribution Centres (DC) with higher potential for solar PV customer growth.

MARKET CONDITIONS

The market revenue contributes approximately 80% of total revenue in the optimum configuration.

Cases that considered smaller batteries (250kWh), were unable to break even by 2028 due to more limited market revenue capture.

The level of market volatility is a key driver for the overall economic feasibility.

What are the potential benefits and barriers for a community battery?

Potential Benefits

Networks	Potential to be more cost effective than traditional network investment.
Regulators	Potential to prevent market failure and wealth transfer.
Market Participants (investors and decision makers)	Development of new business and operating models generating new opportunities for market participants including investors and technology operators.
Customers	Lowers energy bills for participating customers while minimising risks related to over-purchasing capacity, complexity in operations, safety and integration with existing systems associated with home batteries. Additionally, avoidance of network events may provide benefits to the wider customer base.
Competition	Initiative will be available to all eligible customers regardless of retailer/plans.
Suppliers	Supports supplier development and refinement of standardised commercial off-the shelf technology.
Government	Opportunity to achieve storage at scale and ensure equitable access.
R&D	Encourage further research and development with respect to battery technology, regulation and commercial viability to optimise future projects.

Potential Barriers

Regulations	Rule changes required to support standardised roll-out across distribution networks.
Energy settlement	Process for settlement including metering, data collection and treatment of losses to be considered.
Market Volatility	Commercial outcomes are heavily dependent upon market conditions including spread, volatility and ancillary markets which currently are very uncertain.

Glossary

Term	Definition
AEMO	Australian Energy Market Operator
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
BCR	Benefit-cost Ratio
BESS	Battery Energy Storage System
BoP	Balance of Plant
CAM	Cost Allocation Methodology
CAPEX	Capital Expenditure
CARC	Cost of Acquiring Retail Customers
CB	Community Battery
CBO	Community Battery Operator
DER	Distributed Energy Resources
DC	Distribution Centre
DNSP	Distribution Network Service Provider
DMIS	Demand Management Incentive Scheme
DUOS	Distribution Use Of System
FCAS	Frequency Control Ancillary Services
FRMP	Financially Responsible Market Participant
FiT	Feed-in-tariff
kW	Kilowatt
kWh	Kilowatt-Hour
LV	Low Voltage
MASS	Market Ancillary Services Specification
MUA	Multi-Use Application
NECF	National Energy Customer Framework
NER	National Electricity Rules
NEO	National Energy Objectives
NEM	National Electricity Market
NPV	Net Present Value
NSW	New South Wales
TUOS	Transmission Use Of System
OPEX	Operational Expenditure
PV	Photovoltaic
RIT-D	Regulatory Investment Test for Distribution

Term	Definition
SCADA	Supervisory Control And Data Acquisition
SGA	Small Generation Aggregator

Contents

1. Introduction

The community battery feasibility study is an opportunity for Ausgrid to showcase an innovative technology application that is able to meet the network requirements for distribution networks, while maximising value to customers through a shared energy storage system

1.1. Overview of the Community Battery Initiative

With Australia's energy markets in a period of unprecedented change, the use of storage technology is gaining increasing interest for a wide a variety of applications, including deferring network upgrades. Distribution networks have the unique opportunity to integrate battery storage technology into their existing network infrastructure using an innovative business model, the **Community Battery Initiative.**

A community battery offers equitable access to an energy storage system allowing individual community members with excess electricity, generated by rooftop solar PV systems, to be shared with members in their community. The shared battery asset provides many benefits through different potential end uses. These include:

1	**Network:** An alternative, more efficient technological solution to conventional network assets to meet customer demand and maintain system security and resilience; Shorter asset life of a battery increasing option value compared to traditional assets;
2	**Customer:** Maximising the value of surplus solar PV energy and allowing solar and non-solar customers to take advantage of the shared distributed energy resources and save on electricity bills; and
3	**Market:** Maximising the utilisation of available energy storage capacity in the community battery by enabling energy market trading and ancillary services when the battery is available.

Integrating the above end uses and revenue streams leads to a business model which ultimately benefits PV customers as well as the wider customer base.

To investigate the viability of community batteries, Ausgrid Operator Partnership (**Ausgrid**) has approached KPMG and AECOM to assist in the preparation of a feasibility study for the Community Battery Initiative (the **Study)**. The feasibility study assessed a range of technical, commercial and regulatory issues associated with the introduction of a community battery program.

1.2. Motivation for the Community Battery Initiative

1.2.1 Background

The changes in the energy sector will have a significant impact on the network, facing challenges to deliver services to energy consumers to support e.g. electric vehicles, increased solar PV penetration, peer-to-peer (P2P) trading, etc. At the same time, the grid is expected to provide cheaper, safer and cleaner energy to all customers.

As at 31 October 2019, more than 2.23 million rooftop solar power systems have been installed across Australia, representing one of the highest uptake globally, equivalent to 21% of homes with rooftop PV. High growth is forecast to continue for the next three years, before gradually plateauing over the next decade[1]. There is an opportunity to optimally utilise this high penetration of behind the meter energy generation by integrating battery storage. This report aims to assess key questions related to the potential for a Community Battery Initiative, such as feasible locations of the battery, likely battery developer and the role of network operators that would lead required for the optimal implementation of such a strategy.

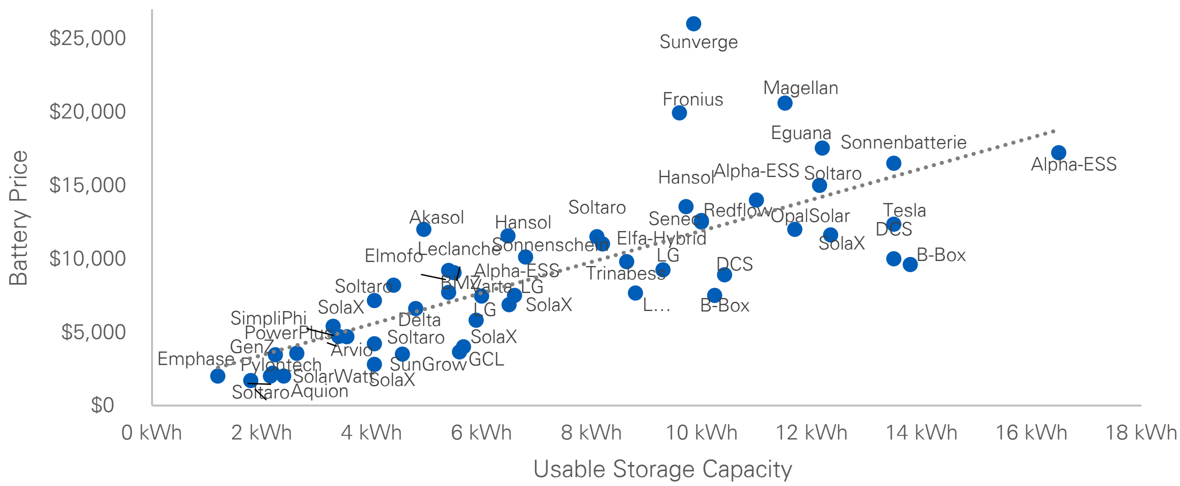
1.2.2 Individual battery economics

Currently, customers who own rooftop solar PV systems have an option of either continuing to pay their electricity bill as per usual, or investing in an energy storage system. Residents may consider several business models to invest in residential energy storage, such as home battery systems which include government rebate schemes, energy retailer battery products or investing in their own home battery systems.

A summary of current state-based battery and retailer schemes is included in Appendix A.

A customer intending to purchase an individual home battery needs to navigate the increasingly wide range of residential battery products, as illustrated in Figure 1 below. In selecting a home battery, the customer needs to decide how to size and operate the battery to maximise their return on investment.

Figure 1: Cost data for home battery systems in Australia – *KPMG market research*



The economic case for a home battery system is mainly dependent on the financial benefit associated with capturing the energy arbitrage value – or the difference between the feed-in-tariff and time-of-use tariff, plus any other additional market payments. This means that energy normally exported via the retailer at the feed-in-tariff can be used to offset energy imported from the grid during peak energy price periods using battery storage. This is the customer's behind the meter arbitrage value. Apart from financial benefit, home battery systems also pose risks like incorrect sizing of the battery

[1] AEMO, 2018 Annual Report, pg. 15

resulting in underutilization, recurring maintenance charges, high space requirements, relocation constraints, etc.

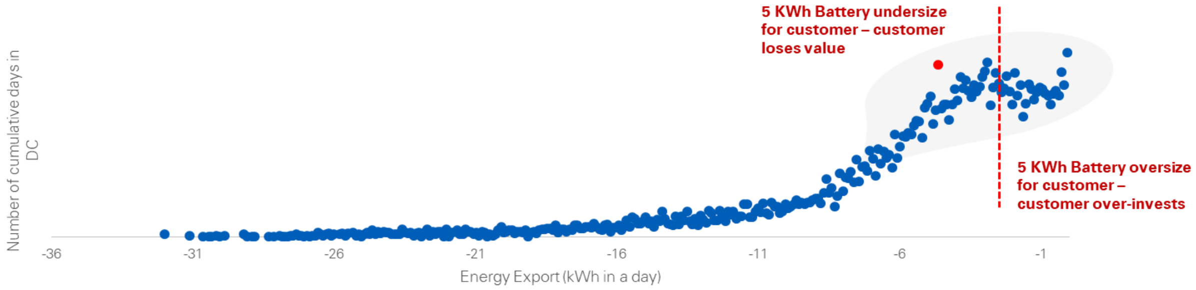
1.3. The benefit of customer diversity

Based on a sample of 2,800 PV customers in Ausgrid's network, we have estimated that, currently, the average household would require an individual battery of roughly 3-5kWh in energy storage capacity to maximise self-consumption, as illustrated in Figure 2.

The graph shows the frequency of daily energy storage requirements (kWh in a day) for individual customers in a sample Distribution Centre (DC), where the majority of daily storage requirement falls between 3 and 5kWh. However, there are some days when customers export as much as 31kWh. If each customer were to install a 5kWh system, this may correspond to an optimal use of the storage capacity by the majority of these customers, on the majority of days – but it would still be **undersized for some and oversized for others on some days of the year. A shared battery would enable multiple users to access the same storage capacity at different times, when they need it, and since these times don't overlap perfectly, the diversity in customers' energy profiles results in a smaller battery to meet most customers' storage needs**.

This is called the diversity benefit – a very important benefit that shared battery storage offers, compared to individual batteries.

Figure 2: Estimated daily battery storage requirement – Ausgrid solar PV customer sample[2]



[2] This analysis was based on customer export data for a sample DC (S018074). The horizontal axis shows the electricity export in a day (in kWh), and the vertical axis shows the times that a particular export volume appears in a year. For example, the red dot represents an export **between** 4.64 **and** 4.73 kWh, and there are 171 instances within that band per year

An overview of the potential advantages of a Community Battery Initiative versus a home battery is outlined in Figure 3 below:

Figure 3 Comparison of benefits of a community battery versus individual home battery

Home Battery

Inefficient sizing and low utilisation

Due to the high variability in an individual household's energy profile, customers are at a high risk of inefficiently sizing and/or operating their individual battery, leading to a lower return on investment. PV generation profiles vary greatly between winter and summer, and hence the battery would have to be oversized for winter, or undersized for summer.

Limited financial and environmental benefits

Home batteries have considerable financial and environmental challenges like limited economies of scale, recurring maintenance costs of batteries and issues with battery disposal.

High upfront cost

Based on a battery size of 5kWh, the average household would need to incur an upfront cost of $6,600 for a home battery, based on the data in Figure 1 – This is still prohibitive in many cases and incentive schemes to help fund the gap are currently limited.

Community Battery

More tailored/ incremental options

Currently batteries on the market are offered at standard incremental sizes, starting from 1.2kWh. A Community battery is not restricted by physical modularity of units and can offer a range of increments tailored to customer needs.
Greater economies of scale is also achieved by signing up for a community battery.

Providing greater value to the economy

Providing greater value to the economy Community batteries, like other valuable shared assets, provide greater economies of scale, benefiting a diverse customer base, with no installation and maintenance costs.

Flexibility

On average, assuming a life of 10 years, a community battery could deliver cost savings of $900 to $1,700 per customers after accounting for the Battery Service Charge. Also, customers would not be tied into the scheme for the life of the battery, and could opt out or switch packages as their needs change.

1.3.1 Multiple Value Streams of Battery Technology

An advantage of battery storage is its ability to capture multiple sources of value – often simultaneously. However, due to current market and regulatory barriers, customers and investors find it hard to capture all this value.

Battery technology lends itself to multiple services which enables different revenue streams to be captured, although split incentives and transaction costs can prevent the battery owner from realising the full economic value of the battery. Hence the cost-benefit analyses of energy storage systems are often focused on a single use case or service: demand charge reduction, network services, backup power, or increasing solar PV self-consumption.

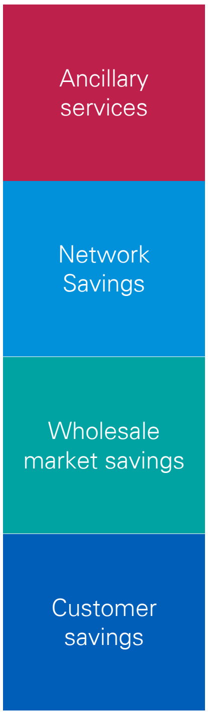
1.3.2 Benefits of the Community Battery

Community batteries are able to provide value and benefits to a range of stakeholders. The magnitude of the respective benefits lies in the design and operation of the battery initiative.

Front of the meter applications of storage such as the Community Battery can better enable stacking of benefits through:

- Solving co-ordination problems;
- Locating the battery for more efficient network and voltage management;
- Allowing for investment in more intelligent technology/programming through scale;
- Capturing diversity across multiple customers;
- Optimising battery systems under a single model to enable both longer lifetimes and improved performance within a storage resource's capabilities; and
- Maximising benefits from storage while ensuring network stability is maintained.

Benefit stacking under the community battery model



Capturing all the benefits will be key for the successful integration of distributed energy resources.

Understanding the complementary and conflicting drivers for the various value streams of a community battery is fundamental to structuring its design to co-optimise these values and maximise the benefits to customers – both to participating and non-participating customers. As the business model evolves, which can be facilitated by piloting of the concept, these drivers and their impacts on the magnitude of the respective benefits will be better understood and optimised. These benefits include:

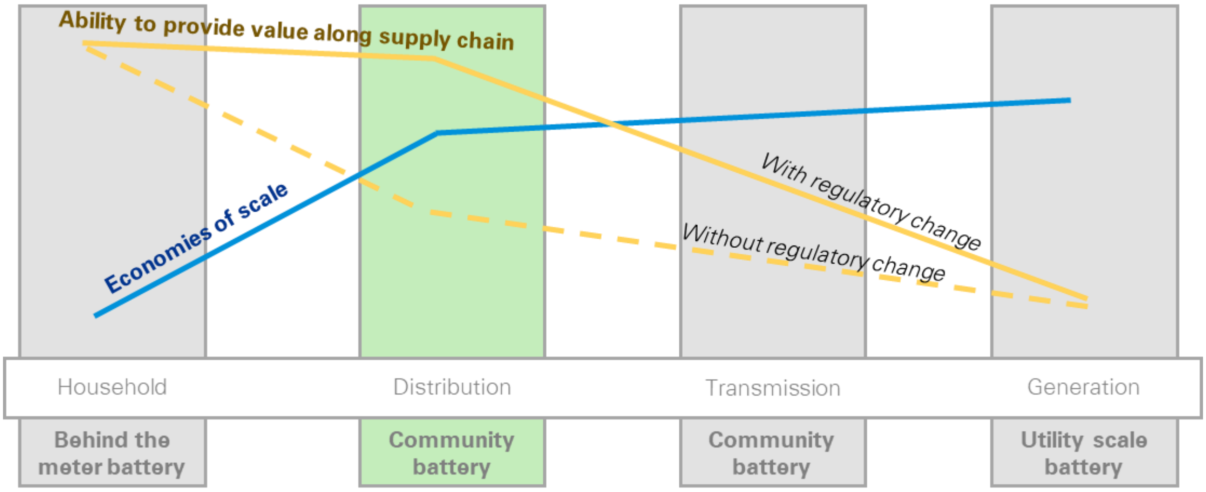
- **Supporting the network -** Providing battery storage capacity at specific local network locations to provide an efficient alternative to network investment required to provide greater network carrying capacity;
- **Reducing electricity bills for customers -** Enabling PV customers to capture the arbitrage benefit of their excess rooftop PV energy, allowing reduced electricity costs to both PV and non-PV customers;
- **Stimulating residential PV uptake** - By supporting the network to manage voltage issues and absorbing excess intermittent energy at a community level;
- **Reducing costs through aggregation** - Through sizing the battery, recognising the diversity of exports and consumption patterns, resulting in more efficient battery investments;
- **Environment and sustainability -** Consolidating energy storage limits the need for battery disposal while supporting increased use of renewables; and

- **Improving wholesale market outcomes -** Responding to price spikes, flattening price curves plus providing ancillary services to support integration of new renewable developments.

1.3.3 Benefits of a Community Battery delivered by Energy Distributors

Ausgrid is responsible for supplying electricity to over 1.7 million customers across Sydney, the Central Coast and Hunter Valley – resulting in substantial reach in their customer base. A community battery placed in the distribution network has the combined advantages of capturing economies of scale whilst providing maximum value along the energy value chain. Alternative providers along the energy value chain cannot fully capture this since:

- Individual batteries pose a high cost barrier for households, leading to slow uptake. In addition, capturing of all value benefits is limited in the absence of regulatory change.
- Network operators are able to leverage synergies with existing distribution assets to derive more value for customers as well as the network.



The key criteria for battery location selection by a generator or retailer would be optimal connection point and low cost of land – this is unlikely to be at the local distribution network level. However, under the current arrangements, such a solution may not take the impacts on network costs into account and does not allow for the full value to be captured and shared with customers.

2. Objectives of the study

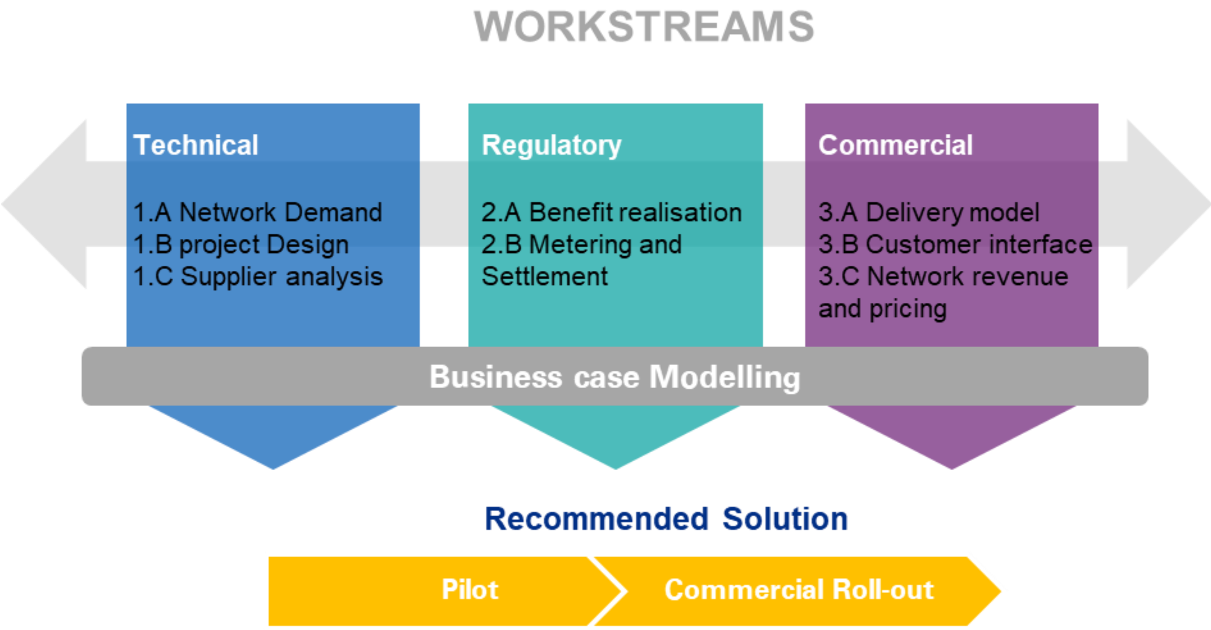
2.1. Key questions assessed in the study

The main objectives of this study were to answer a range of **key questions** in order to better understand the techno-economic considerations for a network community battery, as an alternative to network investment:

- **Will a community battery deliver benifits to solar and non-solar customers?**
- **What are the technical options for a community battery and what would the cost be?**
- **How do we expect the network conditions to change over time?**
- **Which future network conditions would be suitable for a community battery solution?**
- **What is the potential contribution and use of PV customers in the community battery?**
- **What is the market revenue potential of a community battery taking customer and network use into account?**
- **What regulatory changes would be required to support standardised roll out of community batteries as an alternative network solution?**

2.2. High level approach of the study

In order to answer the above questions, the study was conducted through three integrated workstreams; Technical, Regulatory and Commercial. To ensure alignment between these workstreams, an iterative process was adopted. The detailed approach to addressing each question is explained in further detail in the coming sections.

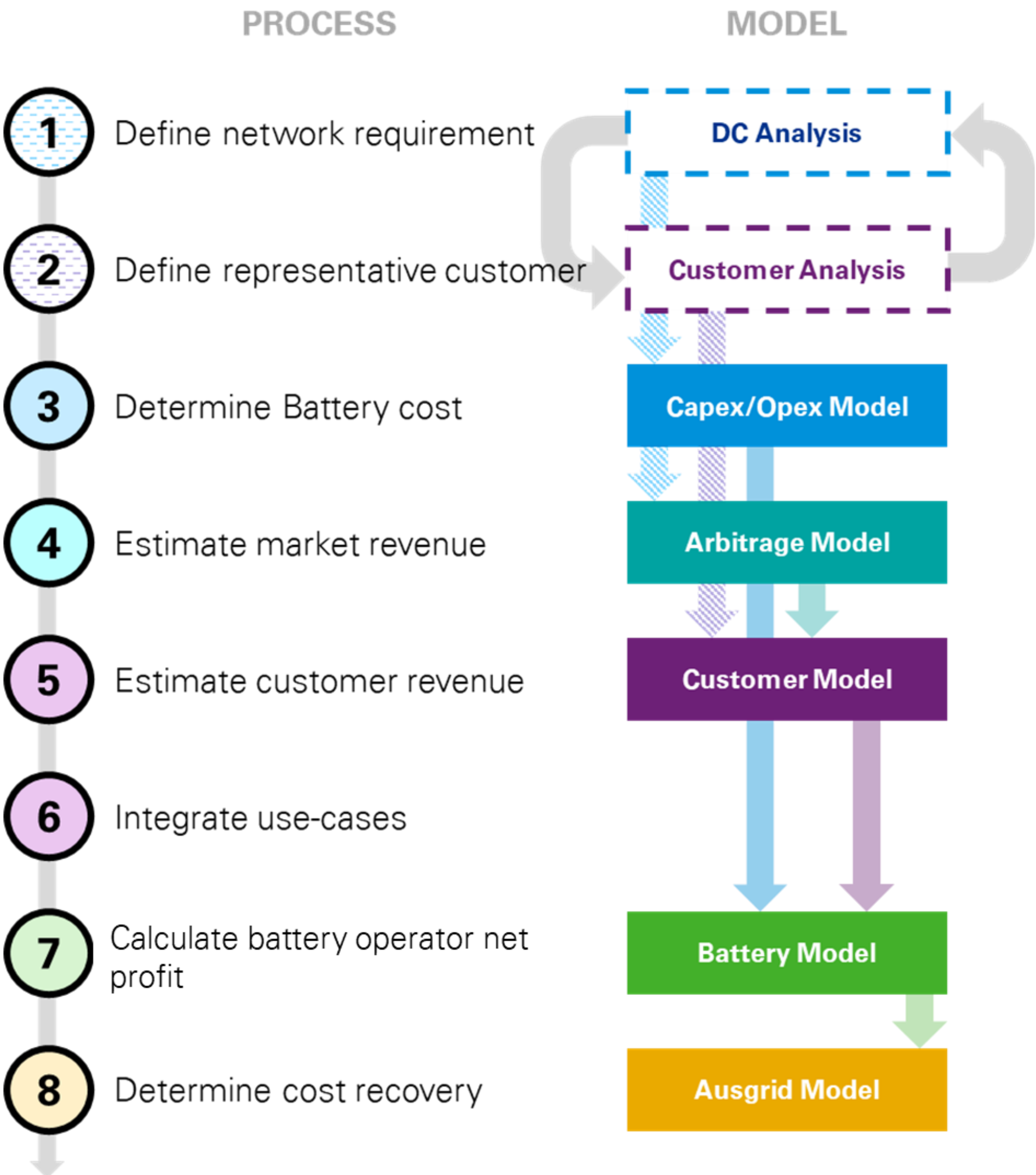


To assess the feasibility of the concept, several models were developed and analysis was undertaken iteratively taking technical, commercial and regulatory considerations into account to target an optimum outcome for all stakeholders. The process followed is depicted overleaf, and described below:

- A set of technical constraints and parameters was developed to establish the potential physical battery size and operational limitations **(Battery Solutions),** and the associated costs of various battery sizes and enclosures, in consultation with potential battery suppliers and Ausgrid network engineers.
- A selection of **data samples from DCs in Ausgrid's network and customer energy load data was analysed to develop generic DC and customer profiles.**
- DCs are localised electrical infrastructure at the end of the low voltage network serving a small number of customers**.** The customer composition in each DC profile was determined and used to forecast potential future overload conditions that may arise due to growth in customer numbers and/or changes in customer load profiles.
- This was used to assess those future **Network Conditions** where a battery could offer a feasible alternative to traditional network augmentation to manage overload at the DC transformer.
- **Battery sizes (in kW and kWh)** needed to meet the forecast Network Conditions were estimated for each DC, which resulted in a C-rating (power to energy ratio in kW/kWh) of each battery required to manage each overload condition. C ratings are important for feasibility of battery storage, as it is a measure of the rate at which the battery can discharge stored energy and is an important factor in optimising the value of the battery.
- The Network Conditions, represented by different DC sizes (in customer numbers) and overload conditions (between 10 and 40% overload in electrical demand at the DC transformer), were matched with the Battery Solutions established in the technical analysis to determine potential **Use Cases.** These Use Cases represent those future Network conditions where a community battery could be feasible within technical and physical constraints, for each DC**.**

- The **economics of different configurations combining Battery Solutions and Use Cases** were assessed using future battery cost curves, under a range of market assumptions. High, medium and low scenarios were tested to understand the key economic, cost and revenue drivers that determine whether a community battery would be a feasible solution for the network and for customers.
- The regulatory and market arrangements for batteries are key factors that drive the viability of this concept. Under this study we have focused on how the community battery could operate and be compensated under the current arrangements. This helped to identify a number of barriers and gaps which inhibit the efficiency of a Community Battery Initiative. To help resolve this, our study identifies a number of suggested regulatory changes to support the feasibility of the Community Battery Initiative and delivery of benefits to customers.

These **iterative steps** are presented below.



3. Overview of assessment and findings

This section aims to describe the key outcomes of the study and is essentially a detailed summary of the content covered in the Main Report Sections covered in Sections 4 – 13.

3.1. Market context

The use of storage technology to reduce costs for customers and improve security and resilience is becoming increasingly important.

There are now over 500,000 solar PV installations in NSW. With the rapid increase in rooftop solar generation, consumers are becoming more aware of their energy usage patterns and open to new technologies to further optimise their energy costs. While investment in home battery systems is still limited due to prohibitive upfront costs, it will be important to solve how to effectively combine solar PV with battery storage in order to lower costs for customers, and support customers in capturing the full value of their existing solar PV systems.

The changing landscape in the energy market and customer behaviour also means that energy networks will need to adapt – traditional modes of network investment and operations may no longer meet the requirements of the energy system as electricity production and consumption becomes more localised.

3.2. What is the potential role of a community battery?

A storage battery that can be shared across the community is potentially one innovative solution to these challenges.

This concept involves the installation of a small-scale battery located in the low voltage distribution network near customers. Customers are able to store excess solar PV energy which they can then access at a later time to offset their consumption or energy import. In parallel, the community battery can also be used to support network operations plus potentially be able to trade in the wholesale markets.

A community battery entails use of a flexible, standardized solution to important existing and emerging challenges faced by networks and customers in the new electricity marketplace. It offers a unique opportunity to integrate battery storage technology into existing network infrastructure while maximising the value of battery storage for customers and the electricity supply chain.

For customers, a community battery offers cheaper and reliable access to storage while avoiding the risks relating to over-purchasing capacity, complexity in operations, and safety and integration with existing systems associated with home batteries. Every household has its own energy usage pattern, and a home battery would inevitably have limited utilisation of the storage capacity at certain times. A community battery avoids this issue through optimising use of the capacity of the battery across the multiple value streams at all times.

A shared battery installed in the distribution network could provide a more reliable asset to avoid the need for network reinforcement plus be able to participate in the wholesale and ancillary services markets more effectively than an aggregation of home batteries installed on customer premises.

This concept represents a whole new way of looking at network infrastructure in a manner that leverages the inherent benefits of battery technology – its ability to support a range of different value propositions along the supply chain, or end use cases.

By taking advantage of this flexibility, a community battery is able to not only address the network requirements to avoid network events, but also provides an opportunity to store the growing excess rooftop solar energy in the local network, while capturing revenue from the energy market. This offers many **benefits to the market, the network, the wider customer base, as well as energy consumers participating in the community battery**, including:

- Reducing electricity bills by increasing self-consumption of excess rooftop solar energy enabling customers to capture more value from their existing PV installations;
- Reducing energy storage costs through aggregation and capturing diversity in customer profiles compared to individual purchases of home batteries;
- Stimulating residential PV uptake by providing cost effective storage to a greater number of customers;
- Supporting the network by enabling protection against network events;
- Improving wholesale market outcomes and flattening price curves to benefit all energy consumers; and
- Supporting the environment and sustainability by limiting battery disposal.

Effectively, the community battery is constantly delivering value across the electricity supply sector through delivering these multiple benefits.

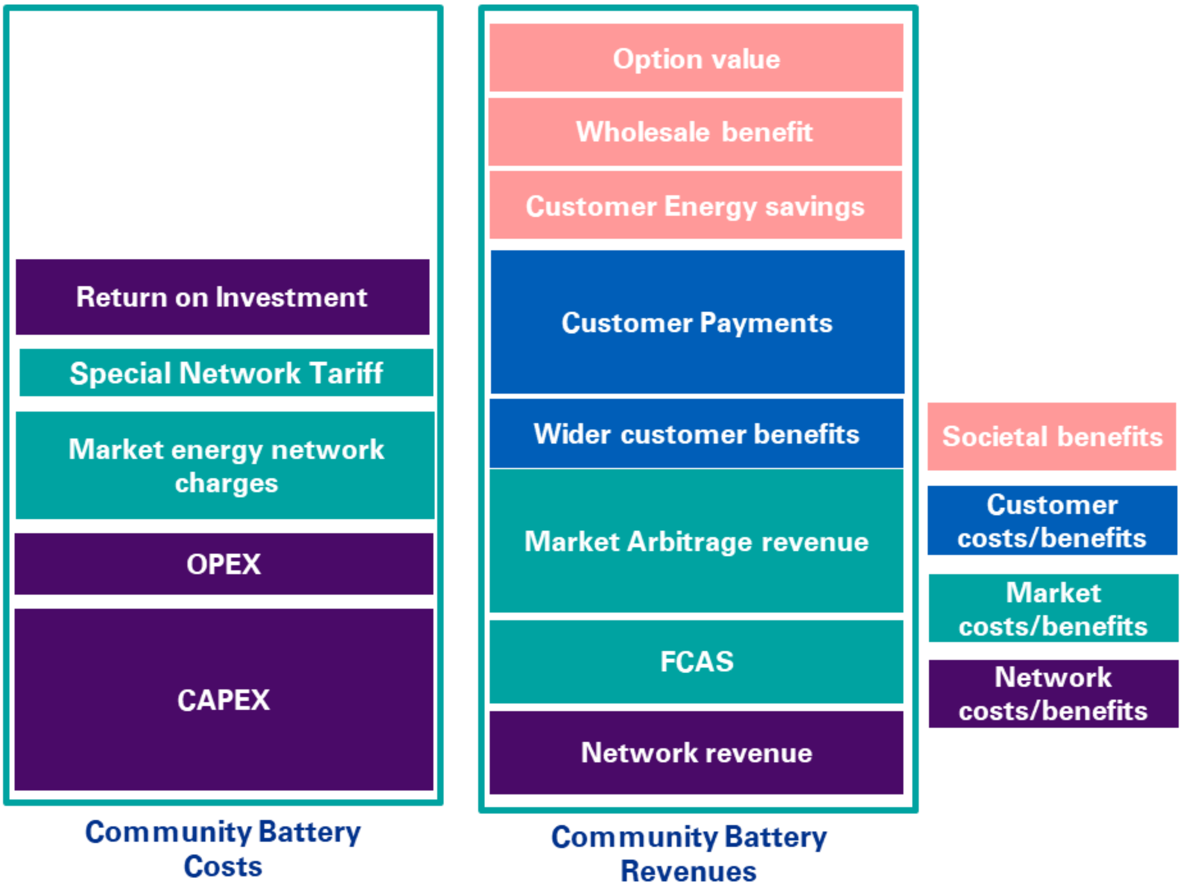
The key to making a community battery work lies in understanding **how these different end use cases contribute to the overall economics of the project, and what needs to be done in practice to ensure that maximum benefits can be derived** from the battery. Battery costs are expected to decline significantly over the coming decade due to the rate at which the technology and the market is developing. At the same time, the value potential for local energy storage will continue to increase. As these factors converge, it is foreseeable that the instances where a community battery would present an attractive alternative to traditional network investment will grow significantly.

3.3. How did we approach the feasibility study?

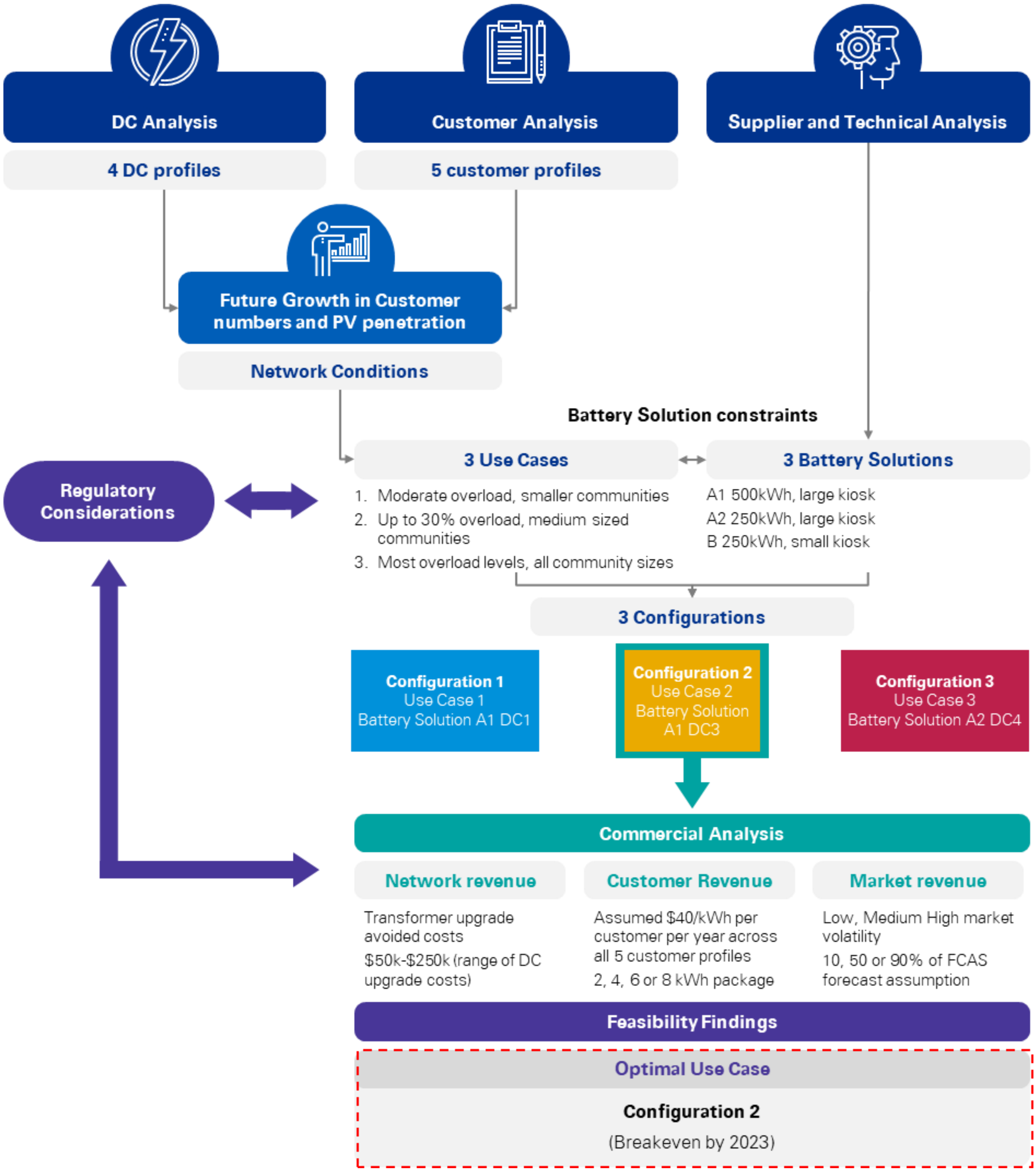
There are a few ways to define feasibility in this context. For the purpose of this study, the focus is on assessing the feasibility from an electricity customer perspective, in the sense of whether the costs to customers are offset by the benefits that all customers receive. This is consistent with the framework for identifying efficient network investment under the National Electricity Rules. To assess this, a list of specific questions were developed to enable each key driver for the business model to be analysed.

The core of any feasibility study is to compare the costs versus the expected benefits. Figure 4 below maps out the costs and benefits identified for the community battery and the nature of those benefits.

Figure 4 Costs and benefits of a Community Battery



A significant degree of modelling was undertaken, as depicted, at a high level, in the figure below.



The assumptions underpinning the study were supported by analysis of existing network and customer data. At the same time, a set of technical constraints and parameters were developed to establish the potential physical battery size and operational limitations **(Battery Solutions),** and the associated costs of various battery sizes and enclosures, in consultation with potential battery suppliers and Ausgrid network engineers.

A selection of data samples from DCs in Ausgrid's network and customer energy load data was analysed to develop generic DC and customer profiles.

DCs are localised electrical infrastructure at the end of the low voltage network serving a small number of customers. The customer composition in each DC profile was determined and used to forecast potential future overload conditions that may arise due to growth in customer numbers or uptake of rooftop PV. This was used to assess those future **Network Conditions** where a battery could offer a feasible alternative to traditional network augmentation to manage overload at the DC transformer.

Battery sizes (in kW and kWh) needed to meet the forecast Network Conditions were estimated for each DC, which resulted in a C-rating (power to energy ratio in kW/kWh) of each battery required to manage each overload condition. The C-rating is important for feasibility of battery storage, as it is a measure of the rate at which the battery can discharge stored energy and is an important factor in optimising the value of the battery.

The Network Conditions, represented by different DC sizes (in customer numbers) and overload conditions (between 10 and 40% overload in electrical demand at the transformer), were matched with the Battery Solutions established in the technical analysis to determine potential **Use Cases.** These Use Cases represent those future Network conditions where a community battery could be feasible within technical and physical constraints, for each DC**.**

Next, the **economics of different configurations of Battery Solutions and Use Cases** was assessed using future battery cost curves, under a range of market assumptions. High, medium and low scenarios were tested to understand the key economic, cost and revenue drivers that determine whether a community battery would be a feasible solution for the network and for customers. The assumed revenue from participating customers was based on the estimated potential energy cost savings for each individual load profile. The Battery Service Charge was set at a level that would result in customers retaining 30-40% of their energy savings, after paying the Battery Service Charge, which was deemed to be sufficient to incentivise uptake.

The regulatory and market arrangements for batteries will be a key factor driving the viability of this concept. Under this study we have focused on how the community battery could operate and be compensated under the current arrangements. This helped to identify a number of barriers and gaps which inhibit the efficiency of a Community Battery Initiative. To help resolve this, our study identifies a number of suggested regulatory changes to support the feasibility of the community battery and delivery of benefits to customers.

3.4. What were the key findings of the study?

The most notable findings of the study are highlighted below.

1. What are the technical options for a Community Battery and what would the cost be?

The study found that Community Batteries:

- Can offer an alternative network solution to address overloads at the DC level. Depending on the type of DC, the number of customers that a 500kWh battery could serve may be limited to 50-100, or in other cases it may be able to service up to 250 customers, which is considered the largest typical DC size;
- Can provide reliable access to battery storage to current and future customers with solar PV systems within the DC; and
- Can provide stored energy capacity to capture energy price differences and address peak demand events plus serve as an ancillary support service in FCAS markets.

It was found that, from a cost perspective, a larger battery would be preferred, due to economies of scale benefits especially related to installation and other indirect costs, as well as the capability to capture more revenue from the market.

A larger battery unit also provides a more robust solution over the long term through providing more capacity to serve an increase in the number of PV customers, as well as the size of PV installations. Also, it would provide more capability to capture wholesale market volatility if market conditions change.

With consideration to the battery sizes indicated from the customer and DC analysis and sizes of kiosks currently accepted in the community, the options available in the market were narrowed down.

Further criteria for the selection of the community batteries from suppliers were evaluated, which resulted in a manageable number of suppliers to consider.

The narrower field of suppliers provided differing solutions for the kiosk that the community batteries would be installed in. Some offered complete systems, while others required multiple enclosures for a single installation. Some were able to provide standard kiosks that met the criteria established, while others were able to provide bespoke solutions that could closely match the L-type and K-type kiosks, Ausgrid's standard kiosks that are routinely installed. Irrespective of bespoke or standard kiosk, inclusion of all of the components, including the low voltage cubicle within the enclosure or on a skid, was found to be most cost efficient.

Noting these points, the study was able to identify three potential Battery Solutions and the associated costs at different power to energy ratios were estimated based on consultations with a range of suppliers.

In cases where it is not possible to install a large kiosk in a community, the smaller kiosk with a smaller battery could be considered, which corresponds to one of the Battery Solutions. The study found that the **upper limit in battery capacity to fit into a typical DC enclosure would be 500kWh. Within these constraints, the 3 optimum value propositions were found to be:**

	Footprint	Capacity	Comment
Battery Solution A1	Large standard kiosk – Approx. 3.7 m x 1.8 m	Approx. 500 kWh	From an economic perspective a larger battery would be preferred, but Ausgrid's larger K-Type Kiosk size was deemed to be an appropriate maximum size. Discussions with suppliers indicated that with the K-Type footprint approximately 500kWh could be installed. For larger storage capacity needs, a second kiosk with battery would be required.
Battery Solution A1	Large standard kiosk – Approx. 3.7 m x 1.8 m	Approx. 250 kWh	Economics could be a limiting factor for installing a larger battery, but there could be scope for future expansion and hence a larger kiosk would still be used.
Battery Solution B	Medium standard kiosk – Approx. 2.7 m x 1.5 m	Approx. 250 kWh	In the event that a large, K-Type Kiosk cannot be installed due to size or community constraints, an enclosure that is approximately the same footprint as Ausgrid's L-Type Kiosk would be suitable, and could potentially comprise more than one unit side by side.

2. How do we expect the network conditions to change over time?

To understand the feasibility of a community battery at a local level, it is important to assess both the load profile of all customers' consumption in the DC, including the rate at which consumption ramps up to and down from maximum demand over the day, and the nature of those customers with solar PV installations who will participate in the Initiative. For those customers, we modelled the times of the day when the customer exports and imports electricity and the volume of those energy flows. The value of the battery will clearly be different for customers with a large PV size and low net consumption versus a customer whose PV system exports during the afternoon and has a high consumption in the evening.

To help model the optimal conditions needed to support the feasibility of the battery, we generated a number of sample DC profiles and customer profiles.

These **four DC categories** can be briefly described as follows:

DC1 has on average the smallest number of customers[3] (average 83), with the highest customer load and highest average solar penetration. Customers in this DC therefore have a relatively high demand per customer compared to other DCs.

DC2 has low to medium number of customers (average 100), with generally high customer load.

DC3 has medium to high number of customers (average 115), with lower load per customer.

DC4 has the highest average customer numbers (127), with the lowest load per customer.

The key factors that best represented the DC categories were found to be as follows:

1. Flex ratio (ratio between the maximum energy in kWh between 5pm-8pm and the average energy between 5pm-8pm for the rest of the year)
2. Maximum demand in kW per customer in a year

The customer analysis produced five generic customer profiles represented by the following key characteristics:

	% of Customer Base	Average PV system size	Energy profile
Customer 1	48%	1.4kW	Low energy user
Customer 2	22%	4.7kW	Average energy user with average PV system
Customer 3	21%	2.9kW	Average energy user with smaller PV system
Customer 4	7%	6.7kW	Average energy user with larger PV system
Customer 5	2%	10.5kW	High energy user with largest PV system

Combining the DC and customer profiles to project future network conditions showed that, **as the number of solar customers and PV sizes both increase, the forecast high demand shifts to later in the day while its duration decreases**. This implies that, over time, the hours of storage in the battery that would be needed to avoid overload decreases – hence the cost of the battery to fulfil the network need would decrease.

3. Which future network conditions would be suitable to create an identified need for a Community Battery solution?

The study identified **three Use Cases** where a Battery Solution could meet network requirements for various sizes of communities and at different overload levels:

Use Case 1 (a single battery can meet moderate overload for smaller communities)

A single battery of 500 kWh capacity can only service DCs with low customer numbers (smaller communities), and is unlikely to meet future network overload requirements for DCs with more than 50 customers. This was found to be applicable to DC1, which had the highest average customer load. Hence, the requirements for energy storage for these customers would be high and a 500kWh battery would only be able to meet limited customer numbers. Should the number of customers in the DC grow over time, the battery would become undersized. In this case, for DCs with larger customer numbers, a second/third battery would be required, or traditional network upgrades may prove to be a better long-term option.

Use Case 2 (a single battery can meet up to 30% overload for medium sized communities)

[3] Number of DC customers relate to the total number of customers in the DC, including PV and non-PV customers

A 500 kWh battery can service the majority of DC sizes over the longer term up to 30% overload. Hence, a battery may be a good alternative to traditional network upgrades for DCs where customer numbers are expected to remain below 100. These cases were found to be applicable to DC2 and DC3.

Use case 3 (a single battery can meet most overload conditions for all community sizes)

Although in many cases a smaller 250kWh battery (Battery Solution B) could be sufficient, there is an opportunity to oversize the battery for the future or to maximise market revenue (Battery Solution A1) or install a smaller battery early on and upgrade to a larger size in the future (Battery Solution A2). This was found to be applicable to DC4, which has the lowest load per customer.

4. What is the potential contribution and use of PV customers in the Community Battery?

Battery packages were tailored to each of the 5 sample customer profiles identified to result in the most cost efficient outcome for each customer type. The key variables modelled and decided upon for the Community Battery Initiative are:

- Whether customers can store energy over multiple days (i.e. when the energy is reset to zero);
- The sizes of community battery capacity that should be made available for customers to subscribe to; and
- The fee structure applicable for customer battery access to best reflect the sharing of the benefits with customers.

A common battery Service Charge of $40/kWh was determined on the basis that this would result in a balance between:

1. A revenue contribution to help cover costs of the battery (including capital and operating costs, customer handling costs and use of network costs);
2. Affordability for customers, ensuring that all customer profiles would be able to cover the Battery Service Charge, for their optimal package size, out of estimated energy savings whilst retaining at least 30-40% of their energy savings after paying the Battery Service Charge. It was assumed that this would offer sufficient incentive for customers to participate in the Initiative; and
3. Simplicity of the packages offered under the Initiative, especially for any pilots or initial programmes.

Based on a typical solar PV installation of around 5kW, we expect that a customer would need to purchase 6 kWh capacity at an estimated annual cost of $240. This is considerably cheaper compared to the customer purchasing its own home battery system and incurring the on-going maintenance and software costs.

Customers are assumed to store up to their energy storage limit in a day, and import their stored energy during the course of the same day. At midnight, the energy storage limit resets to zero. The package size that a customer signs up for determines their daily limit. On days where the customer exports more than their allocated storage package, surplus export energy would still be sold via the retailer.

Under this arrangement, it was found that a **Battery Service Charge of $40/kWh per year** would result in all customer profiles retaining 30-40% of the energy savings, apart from customer Profile 1 in 2018, whose solar PV systems and resulting energy savings would be too small to justify participation. However, assuming these customers would upgrade their systems to 5kW by 2023, their energy savings would increase significantly and they are therefore assumed to participate from this year onwards.

This proposed approach to customer access and fee is very simple and practical to aid the modelling plus to foster customer participation. There are obviously multiple variations which could add sophistication and greater choice for customer (for example, the option to purchase a holiday package when the customers are away) and these could be explored further in subsequent studies.

Overall, the outcomes of the feasibility study are not materially dependent on the revenue from customer access charges. The avoided network costs and revenue from the wholesale and ancillary services market are stronger drivers to the feasibility. The customers participating in the Initiative could receive substantial financial benefits both in terms of reducing net consumption in the evening and saving costs from avoiding installing home batteries. Further, these customers will also receive lifestyle benefits from not having to install and operate a battery at their home.

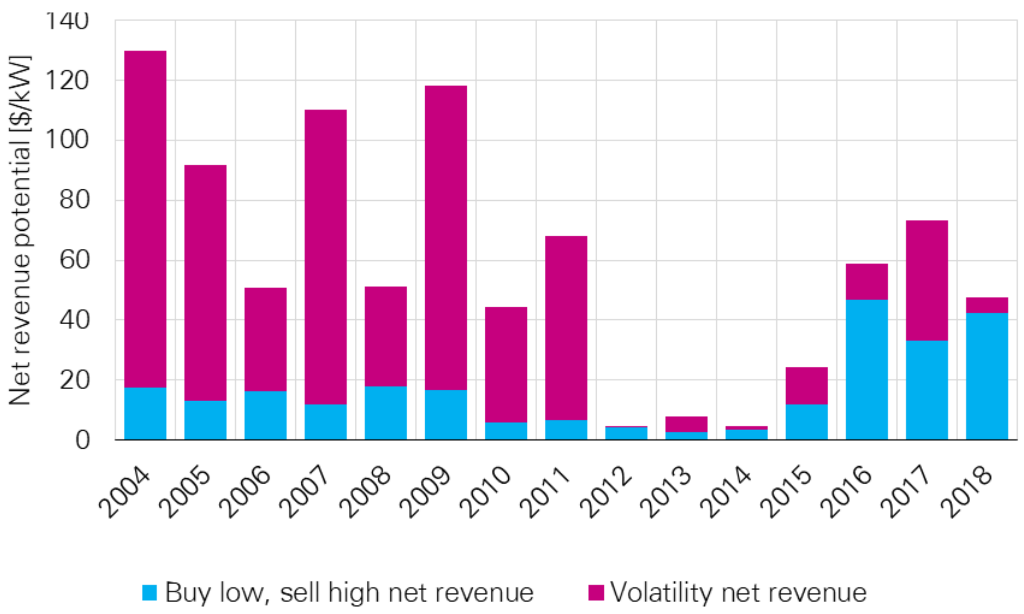
We advise that the customer Battery Service Charge be structured to encourage the greatest participation by customers to help this Initiative deliver the benefits to the community and to expand the use of batteries to a wider pool of customers.

5. What is the market revenue potential of a Community Battery from participating in wholesale and ancillary services (e.g. FCAS) markets, taking customer and network use into account?

At certain times of the day, the battery could also be used to trade energy from the wholesale market. Through buying electricity at low prices and then re-selling during high price periods, this arbitrage activity could deliver substantial revenue to help with the feasibility of the Initiative. This would have to be conducted in a manner which complements the battery's ability to serve network support and the requirements of participating customers. Further, the battery could also be used to provide ancillary services support such as FCAS. The access to these revenue streams have proved to be a key driver of value in other battery installations in Australia.

Our feasibility analysis included potential wholesale market revenue generated in the NSW market through the sale of surplus stored energy and FCAS revenue from the provision of ancillary services. Based on current market reforms under consideration and the extent of investment across the market, the wholesale market conditions (spread and volatility) and FCAS potential are very uncertain. The graph below represents the level of market arbitrage revenue that a 1-hour battery would have captured based on historical market prices in NSW.

Figure 5 Market revenue potential [1h battery 85% capture efficiency]



To this end a range of market conditions were tested to reflect the potential variability in market revenue potential. It was found that the feasibility of the community battery was subject to either of these conditions being met:

- relatively volatile market prices, or

- modest FCAS revenue capture

Under these conditions, the Initiative has the potential to achieve a breakeven point in the next 3-5 years.

6. What regulatory changes would be required to support standardised roll out of Community Batteries as an alternative network solution?

The Community Battery Initiative is an example of a Multi-Use Application (MUA) in the energy market. MUAs are those where a single energy resource or facility provides multiple services to several entities with compensation received through different revenue streams. While optimising and combining these various revenue streams improves the economics of the projects, this can lead to substantial challenges for the regulatory framework. This is especially the case for community batteries which will be providing both regulated and competitive services.

We have identified a number of regulatory changes which would support the operation and feasibility of the community battery. These changes are set out in detail in section 10 of the report and distinguish between what can be achieved in the short term for any pilot or standalone project and what is essential for a standardised roll out of this Initiative. The proposed changes have been identified to be consistent with the existing efficiency and customer considerations of current arrangements and therefore will promote the National Electricity Objective. This initiative may require material refinements in the current arrangements and the proposed changes are primarily to better account for benefit realisation plus also to reflect the nature of decentralised energy flows between the battery and participating customers.

Changes required are likely to relate not only to the National Electricity Rules but also to methodologies and procedures applied by both the AER and AEMO. There may also be a need to amend some aspects of the jurisdictional requirements.

The main required changes to note are:

- **Customer energy flows to and from the battery are treated separately to market energy flows, effectively netting out the community battery volumes from settlement in the wholesale market.** This would avoid double payment by customers for energy stored in the battery and imported back to the household via the same meter used to measure energy import via their existing retailer.

- **AEMO market specification to provide reasonable access of community batteries to FCAS market plus the wholesale market.** This would remove any barriers to capturing these revenue streams.

- **The development of an efficient and equitable network tariff to levy on flows to and from the community battery.** This avoids the application of inappropriate network tariffs which do not reflect the impact of such flows on the distribution network, or may not reflect the long run marginal costs of providing the service.

- **Compensation is provided through regulated revenues for any reasonable customer related benefits arising from the community battery.** This helps to recover the corresponding proportion of the battery initiative costs.

We note that some of the proposed changes would also help facilitate other models of DER and decentralised energy, as well as future market design changes such as peer to peer transactions.

The advantage of a community battery is that the total capital investment across the supply chain is significantly lower than installing single purpose battery storage (i.e. aggregation of home batteries, network support battery, or an energy arbitrage battery). The objective of the regulatory arrangements is to recognise and optimise this advantage in a manner which promotes efficiency, maintains network security and protects customers.

An effect of this advantage is that the direct network value from the community battery is likely not to cover the total costs of the project (as the battery will be over-sized for this sole purpose). The remaining costs can be off-set through the extra revenue recovered from participating customers' access fees and also revenue from the market and ancillary services. Our modelling has found that in the majority of cases, there would still be a funding gap to recover the total costs. **Consideration of the wider customer benefits from the community batteries in setting the regulated revenue allowance will resolve any remaining funding gaps and ensure that the benefits of the initiative is delivered to customers.**

While aspects of the current arrangements recognise the need to value and capture wider market benefits in network planning (such as the RIT-D) and revenue setting processes through incentive schemes (i.e. the AER Demand Management Incentive Scheme (DMIS)), an innovate new mechanism may be warranted in order better align incentives and certainty with the characteristics and nature of benefits arising from this Initiative.

Finally, access to reliable and real time data on participating customers' consumption and PV generation levels will be important for piloting the Initiative. Constraints in the current metering arrangements on participants' ability to access metering data could create additional costs during the pilot but will be important to fully understand the Community Battery's interface with customers.

7. Which configurations are expected to break even and when?

The economics of the following configurations were investigated, based on the outcomes of the technical and network analysis described above.

	Use Case 1 (Single battery can meet moderate overload levels for smaller communities only)	**Use Case 2** (Single battery can meet up to 30% for most medium sized communities)	**Use Case 3** (Single battery can meet up to 30% for the full range of community sizes)
Battery Solution A1 (K – Kiosk, 500kWh)	DC1 (<70 customers)	DC2 (< 120 customers) DC3 (< 160 customers)	DC4 (150 < 250 customers)
Battery Solution A2 (K – Kiosk, 250kWh)			DC4 (< 150 customers, future upgrade)
Battery Solution B (L – Kiosk, 250kWh)			DC4 (< 150 customers, space constraint)

Configuration 1	**Configuration 2**	**Configuration 3**
Use Case 1 Battery Solution A1 DC1	Use Case 2 Battery Solution A1 DC3	Use Case 3 Battery Solution A2 DC4

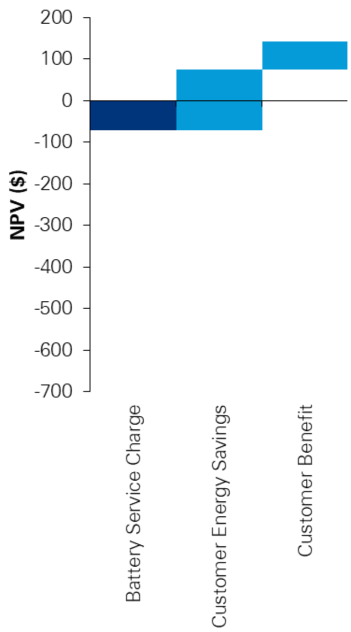
It was found that there are market conditions where **Configuration 1 and 2 (500kWh batteries) can break even on an NPV basis in 2023.** The optimal configuration was found to be Use Case 2 – a medium sized community where the capacity of a 500kWh system would be sufficient to meet 30% overload conditions, which corresponded to a Use Case tested for DC3. It was also found that:

- DC3 has the highest number of solar PV customers, a high number of total residential customers and a high proportion of Profile 1 customers. This implies that DC3 has a **high potential for customer revenue growth,** due to upgrade of PV systems and uptake of solar PV. The revenue breakdown showed the highest customer revenue in all cases was observed for this case - 6% higher than Configuration 3 and 54% higher than Configuration 1.

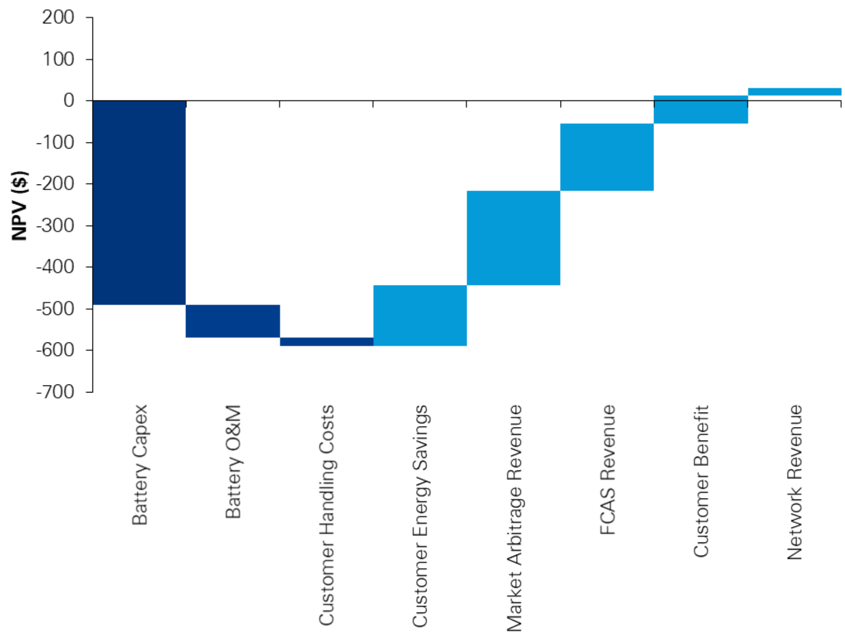
- Further, the **customer use of the battery is not detrimental to the ability to use storage capacity for market trading**, and since network revenues are largely the same for the same sized battery, the higher customer revenues have a notable impact on economics.

The cost benefit analysis of Configuration 2 is presented below from the perspective of the individual participating customers as well as society as a whole.

Customer Benefits and Costs
Benefit-cost ratio (BCR): 3.01



Societal benefits and Costs
Benefit-cost ratio (BCR): 1.12



3.5. Key drivers to the feasibility of community batteries

The effective development of the Community Battery Initiative requires addressing the technical, commercial and regulatory challenges in a coordinated and complementary manner. This report has identified the circumstances where this can be done in a way to deliver benefits to all customers. A community battery placed in the local network has the combined advantages of capturing economies of scale whilst providing maximum value along the energy value chain.

The economics depends on a wide range of factors which are explained in this report. Our modelling has identified the following factors as being key to the feasibility of the project:

- Solar PV installations at the residential level continue to increase in NSW, with the average size also increasing to at least 5kW;
- Ability of the community battery to have a reasonable ease of access to ancillary services markets;
- Regulatory reform to simplify settlement of flows between the participating customers and the battery in order to avoid any duplication of charges onto customers;
- Location of the battery and the nature of the network overload constraint issue which requires action; and
- Approval of the proportion of the community battery costs to be recovered through regulated network charges reflective of the societal and market benefits delivered through the project.

The feasibility study did not attempt to quantify all potential benefits from a community battery. For example, categories of benefits such as option benefit, dampening of wholesale prices and network reliability which are permitted to be included in any regulated network investment appraisal were not included in our analysis.

3.6. Future considerations

We understand that Ausgrid is considering whether to conduct a pilot program of the community battery. There are a number of aspects to the Community Battery Initiative that could be tested under a pilot to refine the feasibility approach and inform the best design to maximise the benefits for customers. These include:

- **Customer views** related to:
  - What information they would like to receive on their participation in the Community Battery Initiative;
  - Their preferred customer interface platform and associated customer handling costs;
  - Whether the community battery should be allowed to prioritise the capture of high price events in the market, and the potential to share profits with customers;
  - What subscription periods they would be willing to sign up for; and
  - The value they assign to safety and sustainability benefits of a community battery as opposed to home systems.
- How the battery imports and exports **impact on network operations and voltage;**
- The relative **use, timing and value of customer energy** exports and imports;
- How **often the battery would be used to protect against network events** and the impact on customers during these periods;
- The **preferred commercial model from the battery operator's perspective** and level of flexibility in the operating model to adequately manage risk;
- The **data requirements** for the Community Battery Initiative.

Further, it is important to note that this study could be further extended through analysis of the following:

- The impact of faster **uptake of solar PV**, or increased uptake of larger PV systems, on the identified Use Cases;
- The impact of **changes in customer composition** or energy profiles due to uptake of new technologies such as electric vehicles;
- The impact of **changes in retail and network tariffs** on customer savings and uptake;
- The impact of the **time of day settlement of customer stored and dispatched energy** on the market revenue capture and overall economics of the battery;
- The potential value of enabling **peer to peer trading** of solar exports between PV and non-PV customers in the same DC;
- The potential benefit of **option value for the network**, as well as the impact on **power quality,** voltage control and other grid support benefits;
- The impact of different **commercial models and risk sharing** between the network operator and battery operator on the overall feasibility of the Community Battery Initiative; and
- The potential contribution of community batteries to support the energy transition.

4. Guide to Detailed Report Sections

In the coming sections, the approach, analysis, and findings related to each of the key questions that were assessed in this study are discussed in more detail. The below outlines the key topics for each of the coming sections.

Section Description
Section 5- What are the technical options for a community battery and what would the cost be? This section covers a detailed supplier analysis, undertaken by AECOM, to understand the availability of battery technologies in the market, develop recommended battery solutions for installation of community batteries and estimate the high level CAPEX and OPEX associated with these.
Section 6- How do we expect the network conditions to change over time? This sections aims to understand the network conditions, driven by potential future changes in customer behaviour, through a detailed data and analytics study on selected samples of Distribution Centre (DC) and customer data.
Section 7- Which future network conditions would be suitable for a community battery solution? This section aims to provide an overview of which network conditions could be suitable for community batteries, and within which timeframes. Load curves for each DC cluster were taken into consideration to understand the limitations of battery solutions that could meet network conditions, and determine potential future battery sizes at different levels of overload and different community sizes.
Section 8- What is the potential contribution and use of PV customers in the community battery? This section aims to understand the use and contribution of customers to the business case for the community battery. This requires analysis of the retail tariff structures, affordability of the Battery Service Charge and other customer benefits to estimate the potential value to customers.
Section 9- What is the market revenue potential of a community battery, taking customer and network use into account? This sections analyses the potential contribution of market revenue to the business case of the community battery, including market arbitrage revenue and Frequency Control Ancillary Services (FCAS) revenue streams.
Section 10- What regulatory changes would be required to support standardised roll out of community batteries as an alternative network solution? This section provides an overview and assessment of the various aspects of the regulatory framework which impacts the realisation of benefits associated with the Community Battery Initiative. This section also aims to identify a number of regulatory changes required to support the commercial operation and feasibility of the proposed project.
Section 11- Which configurations are expected to break even and when? This section considers the commercial viability of each of the three specified configurations identified in line with the battery solutions and use case options. This analysis includes a detailed modelling exercise to determine the project NPVs of each configuration, in order to assess the optimal configuration which offers the earliest breakeven point. The economics of the optimal configuration is further stress tested, applying revenue and cost sensitivities under optimistic and conservative scenarios.

Section Description
Section 12- Considerations for Ausgrid to implement the Community Battery Scheme This section focuses on a range of additional factors that Ausgrid may consider in a potential pilot and future roll out of the Community Battery Initiative. Key considerations include general requirements such as project structure; regulatory changes that would be required to achieve maximum benefits; proposed delivery model; cost benefit analysis and a summary of stakeholder roles and responsibilities to help motivate the business case of a Community Battery as an alternate to network investment.

5. What are the technical options for a community battery and what would the cost be?

The technical inputs for the battery selection come from a number of sources and each DC will have an optimum design and specification to meet the use cases. The technology selection and design needs to be specified to meet the needs of the network, as well as the community, whilst being appropriate for a community environment.

5.1. Supplier Analysis

5.1.1 Supplier analysis overview

The purpose of the supplier analysis, which was undertaken by AECOM, was to determine the suppliers that were able to deliver a product suitable for Ausgrid’s requirements.

Consideration of the energy storage technology was based on previous studies undertaken, AECOM’s experience in the field, and the expected cost reduction in Lithium-Ion technology. Ultimately, a lithium-Ion battery energy storage system was deemed to be the most suitable technology to be placed in the community and only suppliers for Lithium-Ion technology were included in the analysis.

As part of the supplier engagement, a list of 44 suppliers were identified.

5.1.2 Supplier survey

AECOM developed question lists tailored to a set of selection criteria agreed with Ausgrid to shortlist suppliers for the purposes of the study. Details of the questions and selection criteria used can be found in Appendix B of the report.

Contact was made with a total of 40 suppliers, and based on their responses eight suppliers were given the “Go” for consideration in any pilot project, should one be chosen, and a longer term standardised option. For the purposes of this report the suppliers have been anonymised.

Prices were received from six suppliers for the commercial case; however, Supplier 8 priced well above the rest and was subsequently marked as for information, to be considered in future.

Supplier	Prices
Supplier 1	YES
Supplier 2	YES
Supplier 3	YES
Supplier 4	Not received
Supplier 5	Not received
Supplier 6	YES
Supplier 7	YES
Supplier 8	YES (information only - too expensive)

5.1.3 Battery designs and supplier responses

All suppliers responded that they did not undertake balance of plant design or installation, which is an important factor to consider given their proportion of the total cost of a community battery. All suppliers would support installation of the equipment to be undertaken by others, and the requirement for the supplier involvement in commissioning varied. If the supplier wanted to be involved in commissioning on site they tended to support training of others to do so.

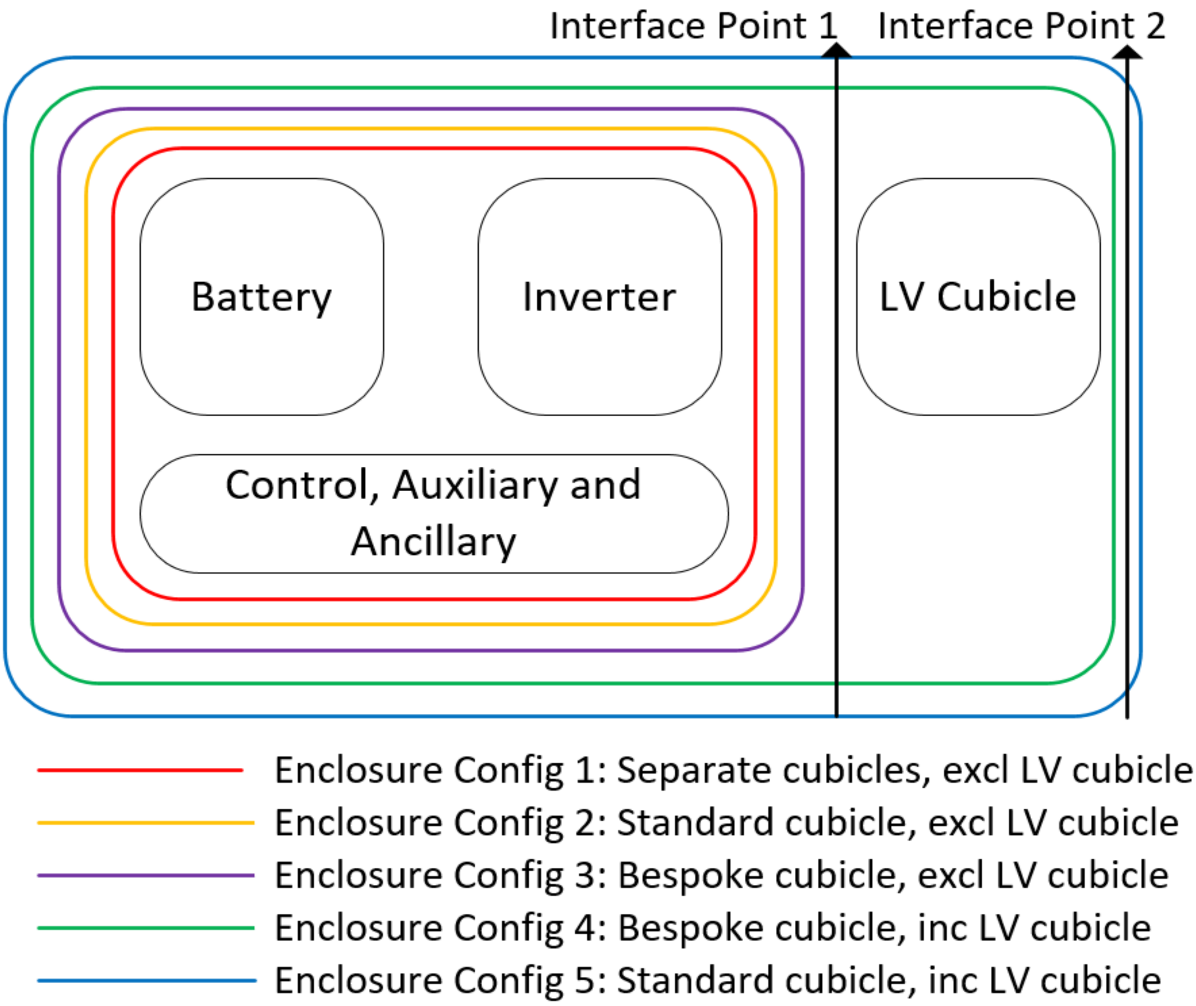
Among the suppliers, five different enclosure configurations were proposed. Figure 6 shows the Western Power Community Battery pilot. This configuration is "Enclosure Config 1", which is diagrammatically represented in Figure 7. It can be seen on the left of the image that there is an enclosure or kiosk separate to the battery equipment, in this case Tesla. This is a third-party Low Voltage (LV) kiosk that houses LV equipment such as isolators and circuit breakers.

Figure 6: Western Power Community Battery

Enclosures were considered an important factor in the feasibility study due to existing Ausgrid enclosure designs and the different offerings from each supplier. Figure 6 shows different system/enclosure configurations and the table below summarises the offers from the suppliers. Most suppliers fall into configurations 4 and 5, where Supplier 7 would not supply an LV cubicle, which they considered balance of plant (BoP), and Supplier 3 was reluctant to provide an LV cubicle.

Most of the enclosures required customisation, especially for larger sizes because the standard offering was a 10 foot container.

Figure 7: Enclosure configurations



Battery Supplier	Enclosure Config 1	Enclosure Config 2	Enclosure Config 3	Enclosure Config 4	Enclosure Config 5
Supplier 1				YES	
Supplier 2				YES	
Supplier 3		YES			
Supplier 4				YES	
Supplier 5				YES	
Supplier 6					YES
Supplier 7	YES				

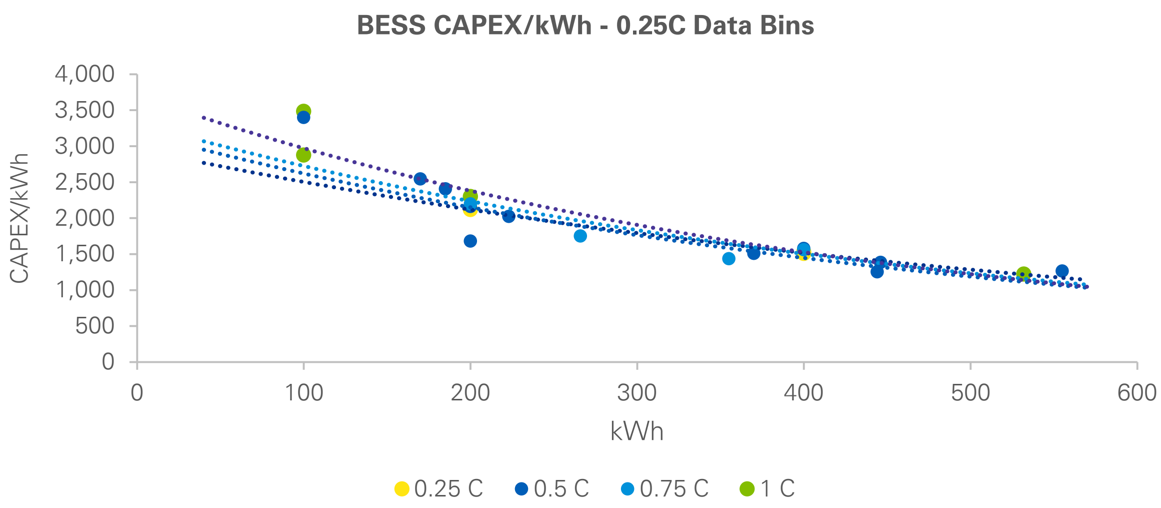
5.2. Battery capital and operating costs

5.2.1 Capital expenditure

Current cost curve from supplier analysis

The all-inclusive battery unit costs were plotted in $/kWh and are shown in 8. Cost curves were developed based on different ranges of C ratings – or Power to Energy ratios, where the power of the inverter (in kW) is divided by the energy storage capacity in the battery (in kWh). Some outliers were removed from the data set because they were well above the trend. The costs for C-ratings follow a trend that is expected, where the higher the C-rating the larger the inverter and therefore the higher the cost for any given battery capacity. Suppliers also indicated that the higher the C-Rating the higher the costs of the batteries themselves given the requirement to absorb more energy quickly.

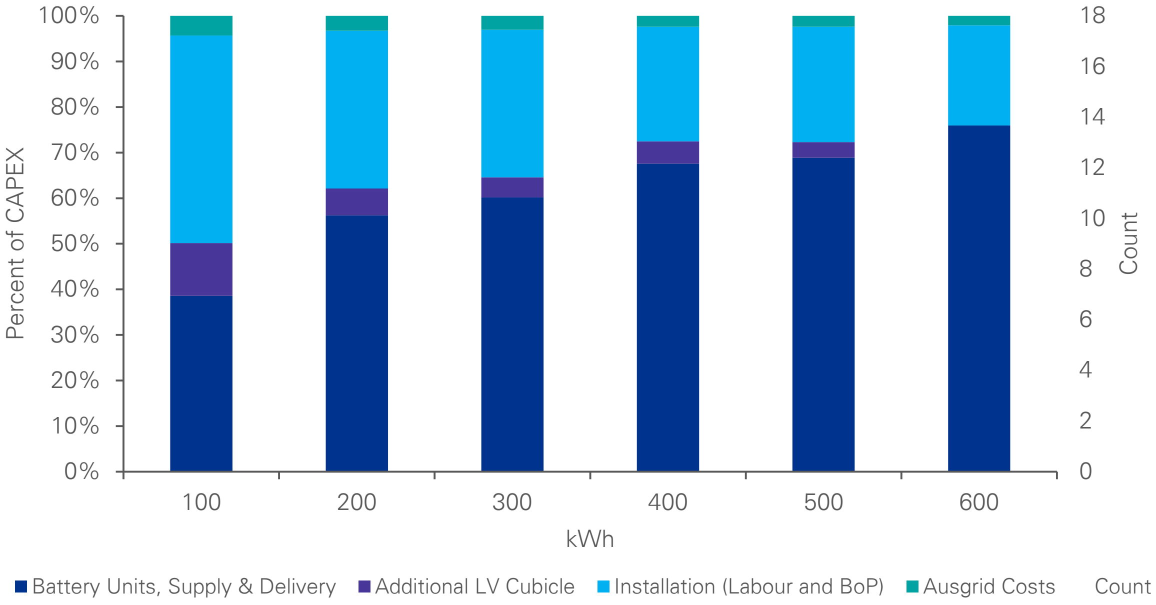
Figure 8: CAPEX/kWh



As seen in Figure 9 the larger the battery the larger the proportion of CAPEX and the two primary targets for cost reduction are the installation and the battery cost.

Discussions with suppliers have indicated that **an order of approximately 100 units over two years would yield a discount of between 5% and 13% on the batteries and slightly over 50% on enclosures**, if the enclosures are not part of their standard offering. Additionally, suppliers indicated that the most gains are to be made on installation and BoP where standardised processes and materials could be established, which would increase efficiency and reduce risk. Examples of this would be pre-cast concrete slabs that could be mass produced and installed at the battery location with less onsite work and consequently less installation weather risk.

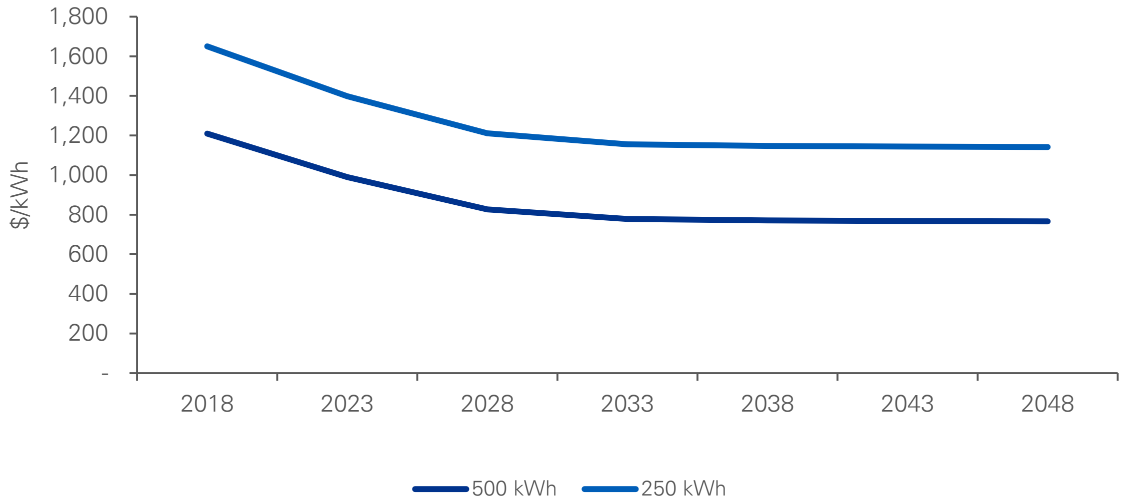
Figure 9: CAPEX Breakdown



5.3. Future cost curve projections

Using the above CAPEX cost curve to estimate the CAPEX for a 500kWh and 250kWh battery at a C-Rating of 0.8[4], and forecasting the future expected reduction in cost of the battery units while assuming a fixed value for the Ausgrid and installation costs (given the small proportion of the overall CAPEX as shown in Figure 10), results in a forecast CAPEX curve for those two batteries as shown below. These curves are used in the commercial modelling discussed in Chapter 0.

Figure 10 CAPEX - AECOM/CSIRO Forecast



[4] These sizes correspond to the Battery Solutions that were identified in Section 5.3.2 later in this Chapter.

5.3.1 Operational expenditure

OPEX is derived from the manner in which the battery is operated and maintained. Key operating characteristics include the:

Depth of discharge:	indicates the percentage of the battery that has been discharged relative to the overall capacity of the battery
Degradation rate:	the rate at which the battery asset degrades from cycling

We have assumed the following values for operational design of the battery.

Opex Assumption	Value	Units
Depth of Discharge	100	%
Degradation rate	2.5	% p.a.

Suppliers were offering between $2,000 and $4,000 p.a. for basic annual servicing. For modelling purposes we have conservatively assumed $10,000 p.a. ultimately, the operational expenditure is negligible when compared to the CAPEX of the batteries.

5.3.2 Recommended Battery Solutions

During the iterative process, preliminary commercial analysis indicated that the economics of larger batteries would be more favourable overall due to higher market revenue potential and irrespective of the overload condition. However, there are physical limits to the size of a battery that can be installed within an enclosure suitable for a community such that it is able to supply the required low voltage. It is therefore recommended that:

- Where possible, from a technical and cost perspective, a larger battery would be preferred; and
- Including the LV cubicle within the enclosure, or mounted on a frame (bespoke or standard) would be more cost efficient.

However, it is not always possible to install a large kiosk for various reasons and as such an option for a kiosk of a smaller size is also included. The reason for this could include size constraints at the preferred location or community objection to the larger size.

Additionally, the commercial analysis has indicated that a C-Rating of approximately 0.8C results in the optimum market revenue potential. This may imply that some suppliers would have suboptimal C-ratings, such as Supplier 7, who indicated they would not be able to satisfy this C-Rating at the capacities being considered and would not tailor the battery configuration to optimise the C-rating. With reference to Table 1, "K-Type" and "L-Type" are standardised Ausgrid kiosks and were chosen for the purposes of this study as they represent the most likely standardised solution that would be adopted.

Table 1 Recommended Battery Solutions

	Footprint	Capacity	Comment
Battery Solution A1	K-Type – Approx. 3.7 m x 1.8 m	Approx. 500 kWh	From a commercial perspective, within the limits described by the commercial analysis, the larger the battery the better, but the K-Type Kiosk size was deemed to be an appropriate maximum size. Discussions with suppliers indicated that with the K-Type footprint

	Footprint	Capacity	Comment
			approx. 500kWh could be installed.
Battery Solution A1	K-Type – Approx. 3.7 m x 1.8 m	Approx. 250 kWh	Economics could be a limiting factor for putting in a larger battery, but there could be scope for future expansion.
Battery Solution B	L-Type – Approx. 2.7 m x 1.5 m	Approx. 250 kWh	In the event that a K-Type Kiosk cannot be installed due to size or community constraints, an enclosure that is approximately the same footprint as the L-Type Kiosk would be suitable, and could potentially comprise more than one unit side by side.

6. How do we expect the network conditions to change over time?

With the forecast for growth in uptake of technologies such as solar rooftop systems, batteries and electric vehicles, the network is expected to see a significant degree of change over the coming years. Changes in the behaviour of energy customers will impact the conditions in the network and drive future requirements for network investment to keep the lights on, in a reliable and secure manner. In order to understand how these network conditions might manifest in the future, it is important to understand the customer profiles and how this impacts the resulting network profiles.

To investigate this, data analysis was performed on selected samples of Distribution Centre (DC) and customer data, and this was used to construct future DC profiles and identify network conditions that may occur in future.

6.1. Distribution Centre analysis

The purpose of the network analysis was to identify potential future overload conditions where a battery would be a feasible alternative to investing in expanding the network. To model future overload conditions, a theoretical framework was created to calculate potential future battery sizes, using projections based on historical demand data for a selected sample of DCs.

The DCs were provided by Ausgrid after selection from a total of approximately 34,000 based on a set of criteria, including number of customers over 40, low number of non-residential customers and significant representation of PV uptake. The 10 minute DC data was analysed in order to categorise the entire set of DCs into some representative categories to support different battery sizing for different communities.

Some of the data sources included in the analysis:

- 10 minute data from 146 DCs (12 DCs were filtered out as outliers); and
- DC characteristics such as number of customers, location, PV penetration.

6.1.1 Methodology

Theoretical overload conditions were calculated based on 10 minute demand data from 2018 following these steps:

1. Categorise **DCs in four clusters** based on theoretical overload curves
2. Determine **average load profile for non PV customers** in each DC using existing customer data
3. Construct **theoretical future DC demand profiles** based on growth in customers

6.1.2 DC profiles

The DC clusters that were identified have a relatively wide geographical spread. Out of the 129 DCs included in the analysis, 46 are in the regional areas and 83 are in the metro area. Regional DCs are relatively evenly spread between the 4 clusters, while the rest are predominantly in clusters 3 and 4. Each DC cluster has its own set of characteristics, however there is high variability between the underlying data points. The outcome of the DC clustering is shown in the table below:

Table 2 DC cluster characteristics

	Average DCs in cluster	Average residential customers	Total number of customers	Number SME customers	Max load / customer (kW)	Flex ratio (max demand day 5-8pm kWh vs average 5-8pm rest of the year)
DC1	15	82	83	0.5	4.7	2.96
DC2	30	99	100	1.3	3.8	2.57
DC3	37	114	115	1.4	3.0	2.27
DC4	47	125	127	2.3	2.4	1.85
Total	129	111	112	1.6	3.2	2.27

	Average Solar Generation Capacity (kW) - 2019	Average PV Size (kW)	Percentage of Solar Customers %	Average Income
DC1	82	4.1	24%	$110,431
DC2	79	3.7	24%	$112,296
DC3	69	3.3	22%	$104,586
DC4	68	3.1	19%	$102,653

By examining the summaries by DC cluster on a number of characteristics, there are some high level insights on the profile of each average cluster:

- **DC1 has on average the smallest number of customers (average 83), with the highest customer load** and highest average solar penetration. It is located mostly in regional NSW, has maximum demand days in summer and has the highest maximum peak demand 5-8pm compared to an average day 5-8pm.
- **DC2 has a low to medium number of customers (average 100), with generally high customer load** and the same solar penetration as DC1. The number of DCs is relatively evenly split between regional and metro areas and maximum demand days are all in summer as well.
- **DC3 has medium to high number of customers (average 115), with a lower load per customer** and slightly lower solar penetration. It covers locations in both regional and metro areas. The majority of maximum demand days are in summer, some in winter.
- **DC4 has the highest average customer numbers (127), the lowest load per customer** and average solar penetration (19%), and the majority are in metro areas. Maximum demand days are evenly split between summer and winter, and the ratio between the 5pm-8pm demand on maximum peak days compared to the average day, or the Flex Ratio, is the lowest.

These characteristics can be used to extend the analysis to include more details about the average residential customers. DC1 and DC2 have lower numbers of customers and higher maximum load. As the majority are in the regional areas this indicates they may represent larger dwellings.

Figure 11: DC Location Map

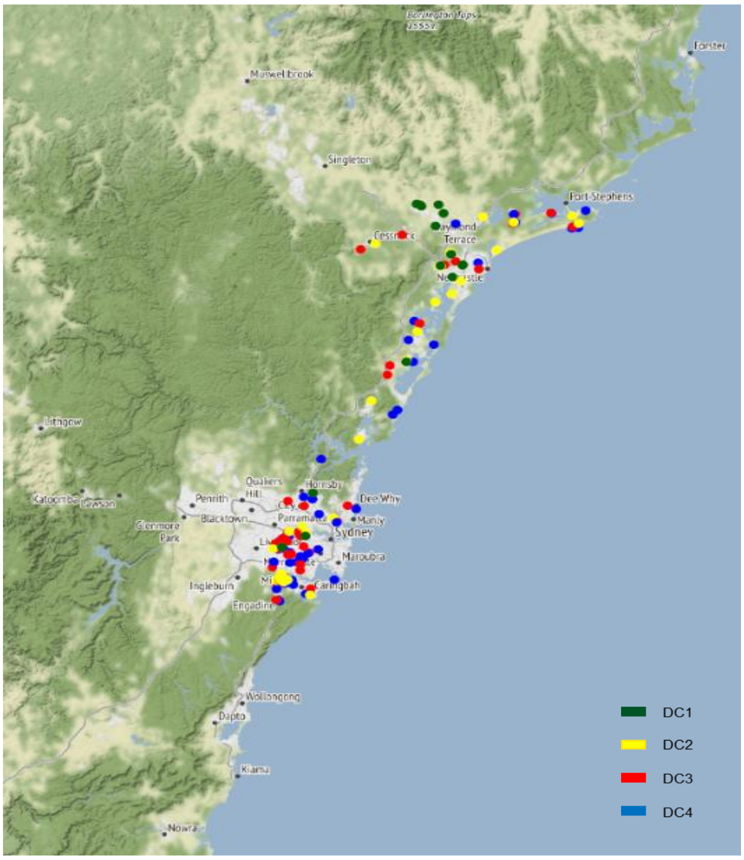
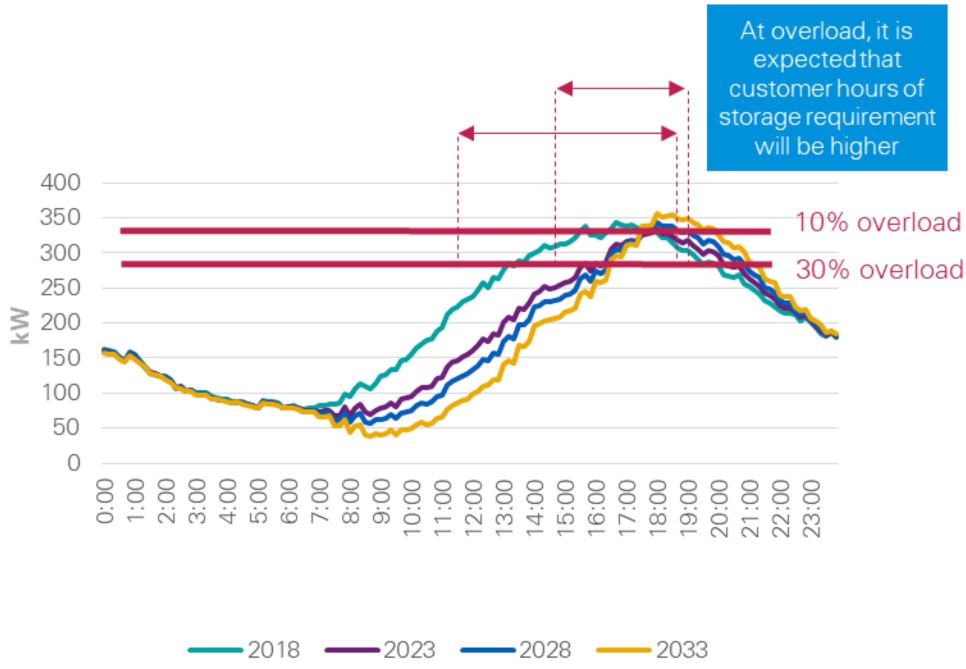


Figure 12 Regional vs Metropolitan

6.1.3 Categorisation of DCs based on overload curves

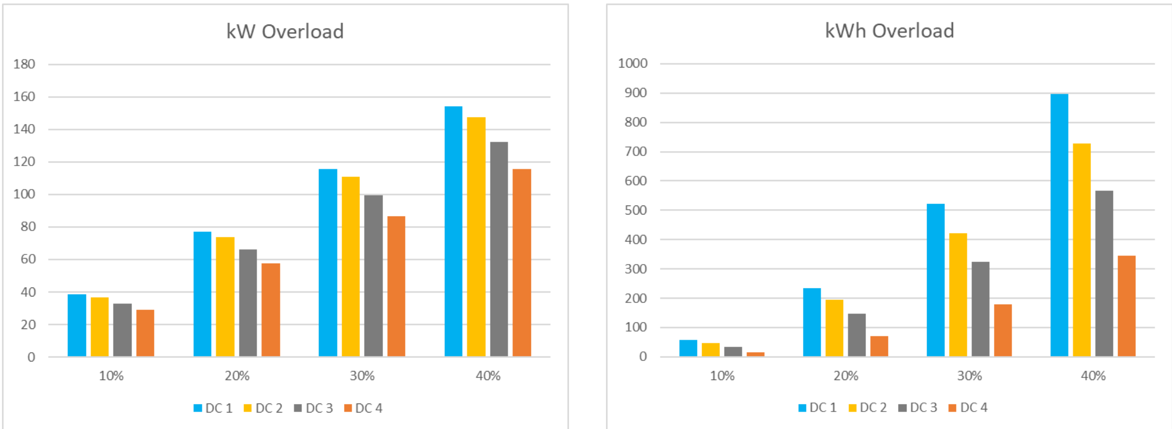
Calculated overload kW and kWh values were used to inform potential battery sizes for different levels of theoretical overload. As illustrated in Figure 13, the maximum kW overload was calculated at different percentages by assuming a different rated capacity of the DC transformer. By moving down in increments from the maximum demand day, the kW rating of the battery can be calculated at various percentage overloads. The duration of each level of overload determines the battery size in kWh – this is the hours over which we would need to be able to service the network at the specified level of overload (kW). This was done for 2018 data as well as for DC 10-minute forecast data for a changing customer mix, as further explained in Section 6.3.

Figure 13 Example of calculation of theoretical overload



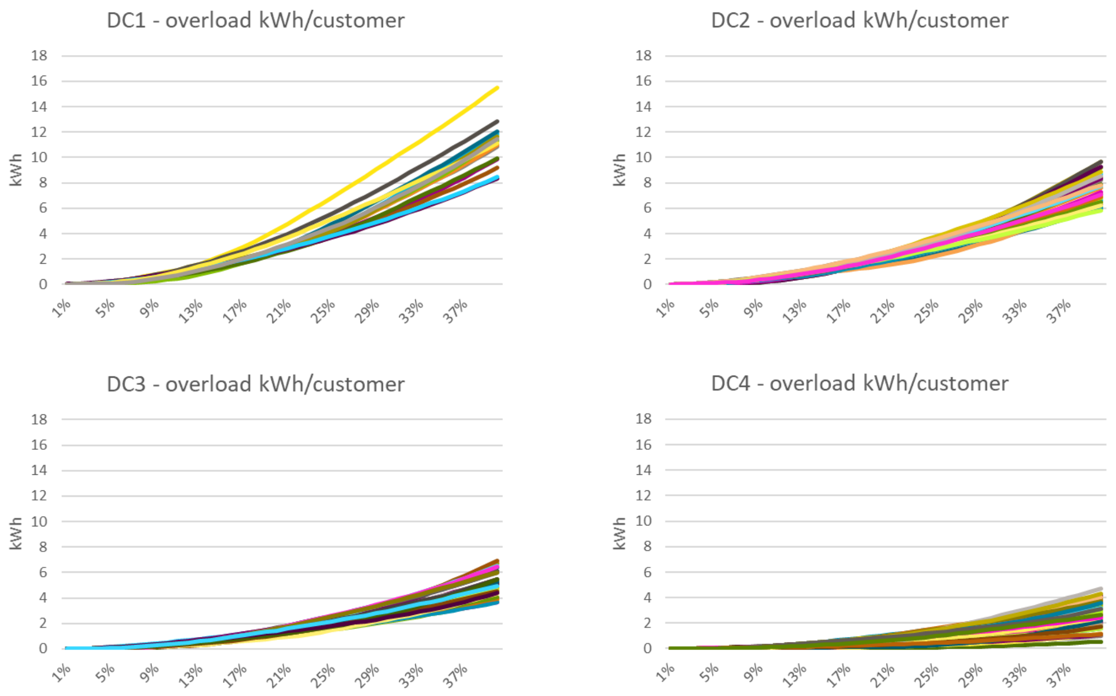
The resulting **kW and kWh battery sizes based on current demand curves for each DC** are presented below. This was used to calculate the C-rating (power to energy ratio in kW/kWh) of the battery required to manage overload. All numbers are calculated averages for each DC cluster.

Figure 14: Overload kW vs kWh by DC Cluster



The overload kWh values were normalised by the number of customers in each DC for comparison. Theoretical overload per customer shows a high degree of variability from <1 kWh per customer to >10 kWh at 40% overload. Using four points on the **normalised overload curves** (at 10%, 20%, 30% and 40%) the overload curves were categorised using a K-means algorithm in four types to split the overload levels per customer in intervals with minimal overlap and provide a set of **DC clusters for future analysis.**

Figure 15: Overload Curves by DCs Category

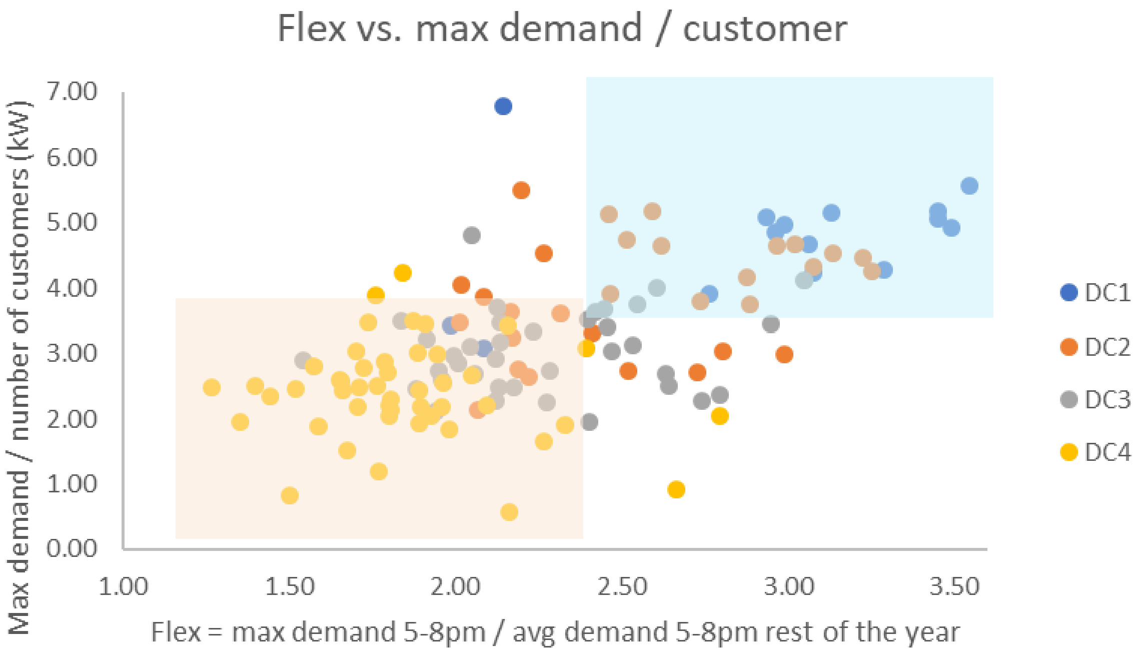


Various factors were investigated to identify those that correlate between the four DC clusters identified. The factors that seem best placed to explain the DC cluster allocation are:

- Flex ratio (ratio between maximum energy in kWh between 5pm-8pm and the average 5pm-8pm maximum energy for the rest of the year)
- Maximum demand in kW per customer

The majority of DC1 and DC2 fall into the upper right quadrant in Figure 16 below (flex > 2.25 and demand per customer > 3.5kW) while DC3 and DC4 fall into the lower left quadrant (low flex, low demand per customer).

Figure 16: Flex vs Max Demand per Customer



6.2. Customer Analysis

The DC analysis was combined with the customer profile analysis in order to develop future projections for DC demand profiles that would be driven by a change in the customer base.

6.2.1 Customer clustering methodology

A K-Means clustering algorithm was used to determine **five customer profiles** based on three key characteristics:

1. **Daily energy import**
2. **Daily energy export**
3. **PV capacity**

The diagram below presents the proportion of each clustering factor within each cluster or customer profile. The heat map indicates a measure of each standalone component (example % of total daily exports etc.), denoting highest to lowest levels across all the five clusters.

Figure 17: Overview of each customer Profile's contribution to clustering factors

Cluster	% of Total Daily Export	% of Total Daily Import	% of Total PV capacity (kW)
Cluster 1	18.70%	46.48%	24.65%
Cluster 2	37.43%	23.28%	34.24%
Cluster 3	21.96%	19.35%	19.85%
Cluster 4	15.14%	7.87%	14.57%
Cluster 5	6.77%	3.01%	6.69%

The dataset used was actual customer energy net loads from a sample of DCs in the Ausgrid network for the period between 1 January 2018 and 31 December 2018, and the customers' corresponding rooftop solar PV capacity. Customers who only imported energy (i.e. their consumption was always greater than their generation) were excluded from the analysis[5], as these would not form part of the target market of PV customers for the Community Battery Initiative. Both datasets were supplied by Ausgrid[6].

6.2.2 Customer profiles

The 5 customer profiles produced by the clustering algorithm can be summarized as below. As shown in Table 3 Customer profile characteristics, the majority of customers in the dataset analysed are represented by Customer Profile 1 – customers with small PV systems.

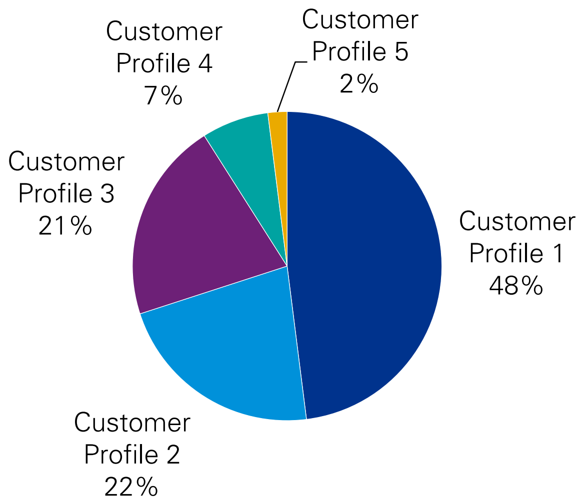
Table 3 Customer profile characteristics

	% of Customer Base	Average PV system size	Energy profile
Customer Profile 1	48%	1.4kW	Low energy user
Customer Profile 2	22%	4.7kW	Average energy user with average PV system
Customer Profile 3	21%	2.9kW	Average energy user with smaller PV system
Customer Profile 4	7%	6.7kW	Average energy user with larger PV system
Customer Profile 5	2%	10.5kW	High energy user with largest PV system

[5] This is because the import-only customers skew the average half hour load value for each profile such that cost savings for each profile are significantly reduced. During the analysis it was found that a small number of solar customers don't generate sufficient energy to export, e.g. Profile 1, where the inclusion of import-only customers would lead to Profile 1 having low exports and therefore would have no cost savings.

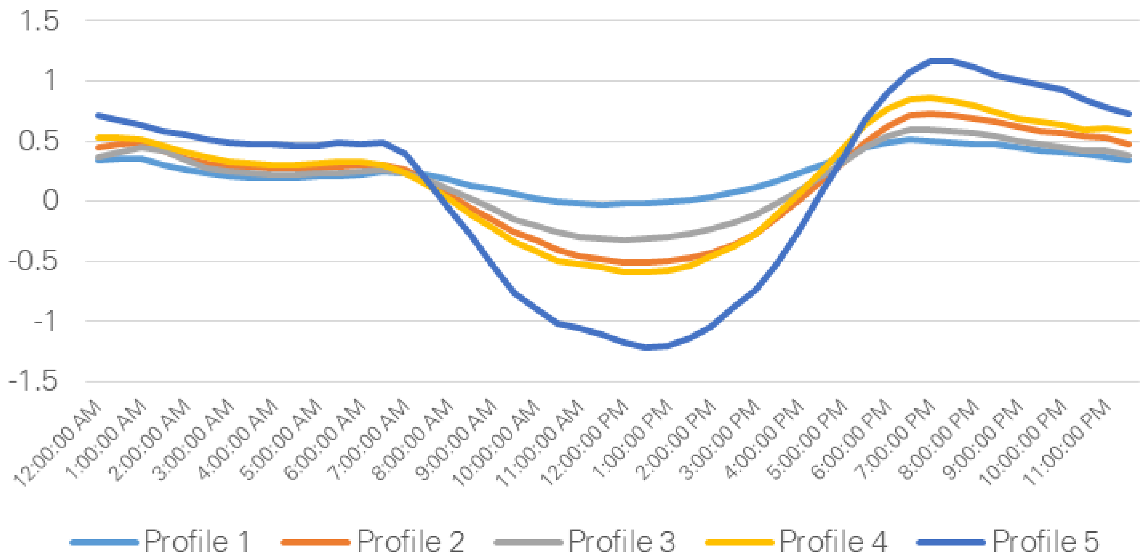
[6] Further details on Ausgrid's methodology to derive the DC dataset can be found in *Community Batteries: Methodology for identifying Distribution Centre use cases (7 June 2019).*

Figure 18 – Cluster customer composition in sampled dataset



The **average daily net energy profiles** for each customer are shown in Figure 19. It is clear that Profile 5 is the largest PV exporter – and also the largest importer during peak. This is an example of an ideal customer for a storage system since their requirement for energy import later in the day is significant.

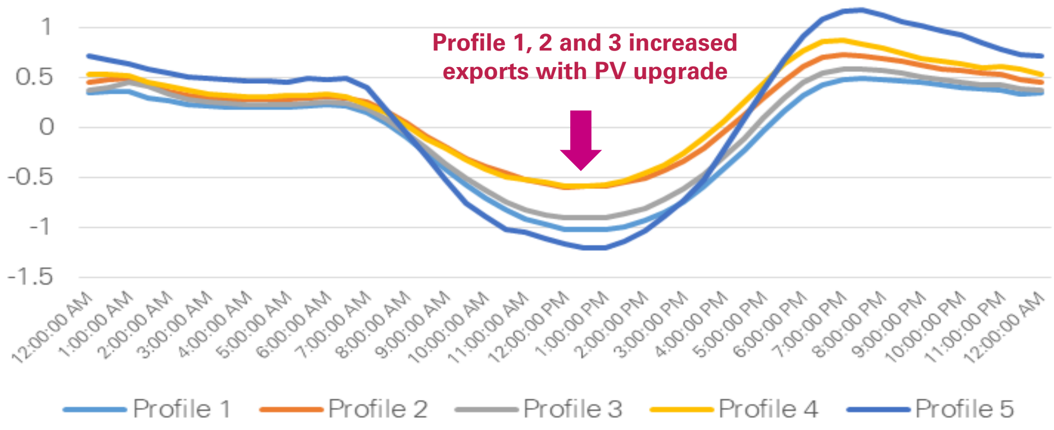
Figure 19 Average 30min customer profiles - current



Using the above customer energy profiles, we have assumed that customers with systems smaller than 5kW (Profiles 1, 2 and 3) are likely to upgrade their systems by 2023 and hence their energy load profiles would change due to an increase in their surplus energy. The resulting future average daily net energy profiles are shown below. It is evident from Figure 20 that e.g. Profile 1 exports an increased amount of energy, as the energy load doesn't change[7] while the solar PV generation increases, and hence the 'belly' of the duck curve moves downward.

[7] Note: It is assumed that generation will increase as customers increasingly adopt rooftop solar and that energy demand remains stable

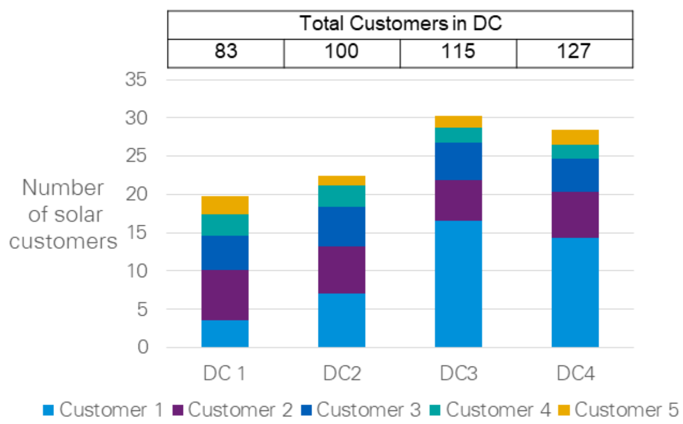
Figure 20 - Average 30 min customer load profiles (future adjusted)



6.3. Forecast of DC customer growth

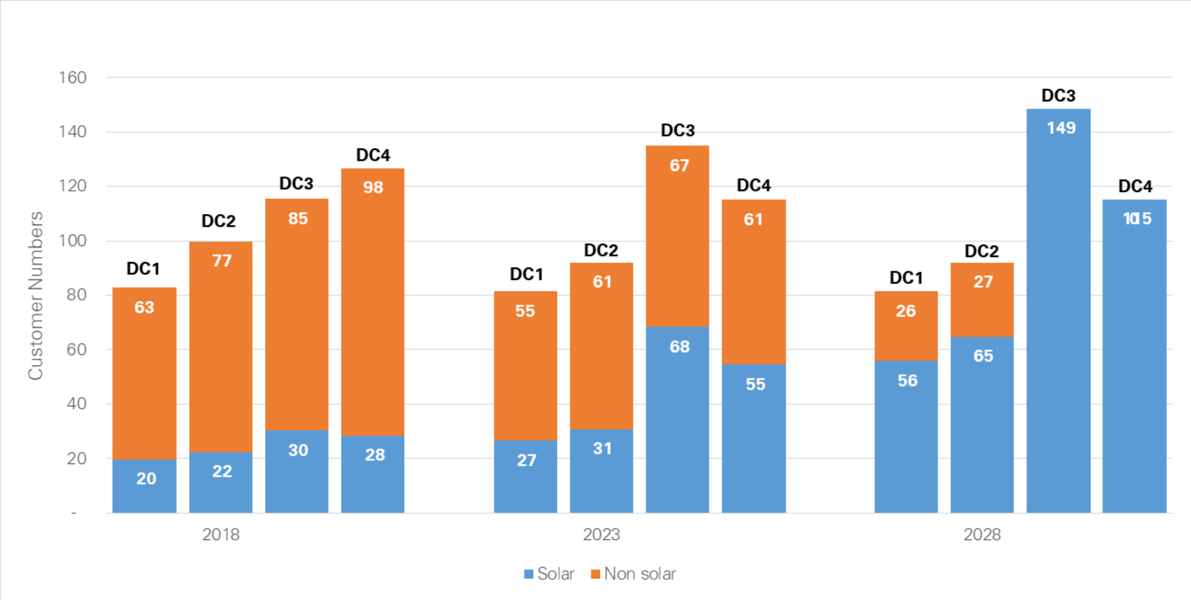
The customer profile analysis was combined with the DC analysis to develop a representative solar PV customer base for each DC, now and in the future. The graph below shows the current PV customer profile composition for each DC profile.

Figure 21 DC customer composition – current



In addition, the solar PV growth forecast for each DC profile was used to estimate the average solar PV growth rate, assuming a high growth scenario. DC profile 1 and DC profile 2 were assumed to have the same growth rates as insufficient data was available to match actual DC growth forecasts with this DC profile. This was considered reasonable as DC1 and DC2 are similar in size and current PV penetration.

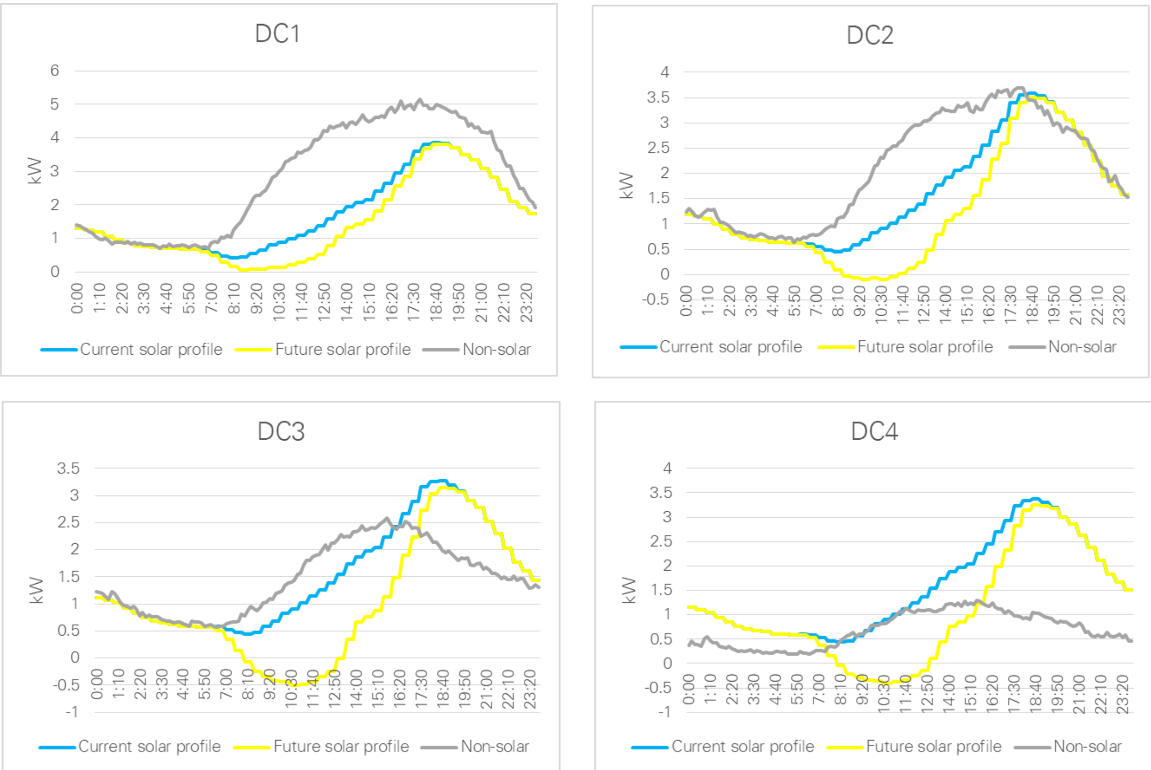
Figure 22 Solar and non solar customer forecast by DC



6.4. Forecast future overload conditions

Using the forecast growth in customers, the calculation of theoretical overload conditions described in Section 6.1.3 was repeated for future years. **Current and forecast average customer profiles** in the figure below were determined based on a weighted average of the 5 PV customer profiles which include projected changes in customer mix and PV size upgrade. The charts below are for illustration purposes, based on data for 7th of January 2018 which is one of the hottest days for most DCs. Non-solar customer profiles were estimated by subtracting the solar customer profiles from the average DC demand and dividing by the calculated difference in customer numbers, which is assumed to be non-solar customers.

Figure 23 Averaged Customer Profiles by DC Cluster



The results for DC4 appear counterintuitive due to a number of factors:

- DC4 has a larger average number of customers and a lower maximum demand compared to the others DCs
- DC4 has the lowest percentage of solar customers
- The average solar customer profile does not differ much in magnitude between DC clusters
- Only 30 DCs in total had customer information, and only 7 of those are DC4. Detailed customer information did not cover all customer, so there was not enough information to calculate an actual non-solar customer profile, so it had to be estimated using averages.

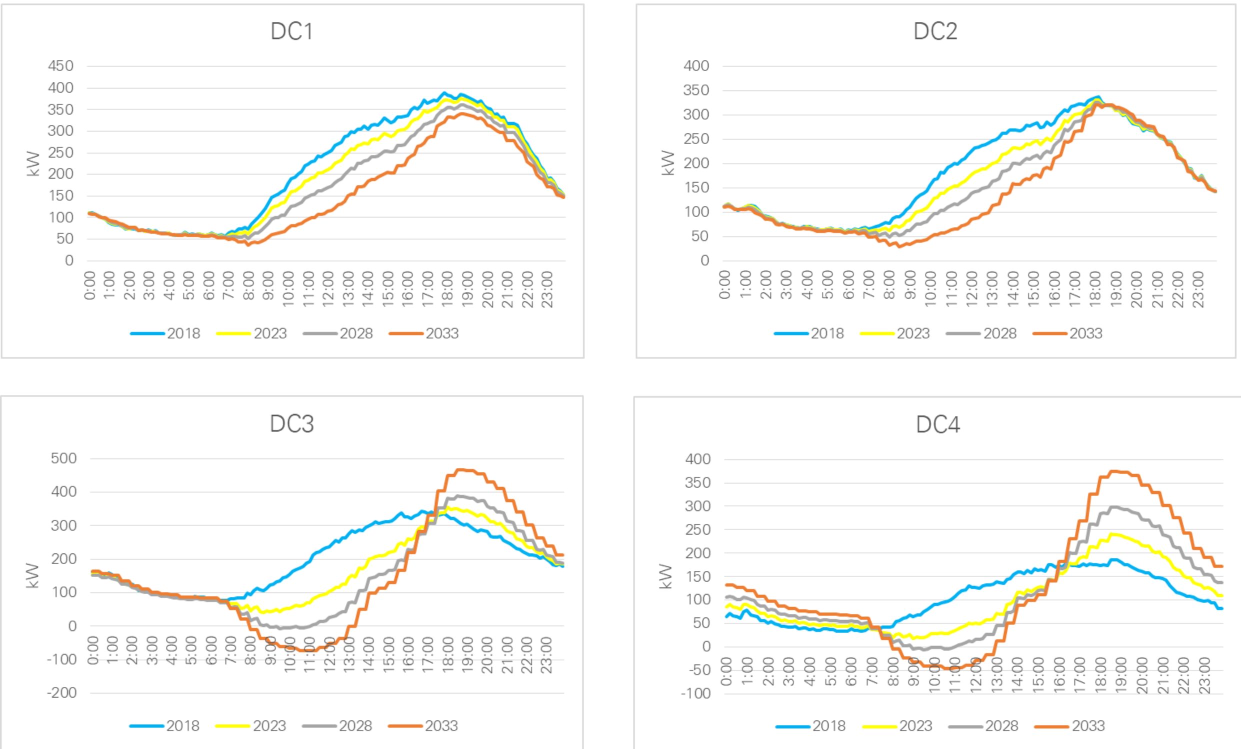
The analysis used 129 DCs with detailed interval data out of a total 1,000 DC and only 30 of them had detailed customer data so the total sample used for determining future profiles was small. An average DC profile was calculated and used together with the average solar customer profile to estimate an average non-solar customer profile. As the average demand for DC4 is a lot lower than the other DCs and the customer numbers are higher this resulted in a much flatter non-solar customer profile. This may prove to be unrealistic as the DC sample used is small and the analysis is based on averages. A more in depth analysis is recommended to look at a bigger sample of customer and demand data for DC4 to determine a more realistic non-solar customer profile.

Average DC demand profiles were built by using updated numbers of solar and non-solar customers and combining their future profiles. Depending on the difference between the maximum solar and non-solar daily demand having a forecast with a higher solar customer numbers can result in higher demand on peak days.

As shown in Figure 24 as the number of solar customers and PV sizes both increase in the future, the forecast high demand shifts to later in the day for all DC clusters, while its duration decreases.

DC clusters 3 and 4 have the largest number of customers and lowest overall demand, so when the numbers of solar customers increase this results in higher demand later in the day in future years, which impacts battery sizes.

Figure 24 Average DC Demand Profile – future years



This results in the need for less hours of battery storage to meet network needs for a set number of customers. The steps in the analysis result in a framework that shows how these sizes change over time, leading to improved economics of the battery.

The new calculated kW and kWh overload for 10% to 40% were used to inform future battery sizes at various levels of overload are presented in the next Chapter.

7. Which future network conditions would be suitable for a community battery solution?

As the profiles of the customers are varied, various use cases were analysed to determine suitable network conditions for a community battery. Load curves for each DC cluster were taken into consideration to understand the limitations of a 500KWh single battery and determine potential future battery sizes in cases required to meet different levels of overload.

7.1. Customer numbers and battery sizes

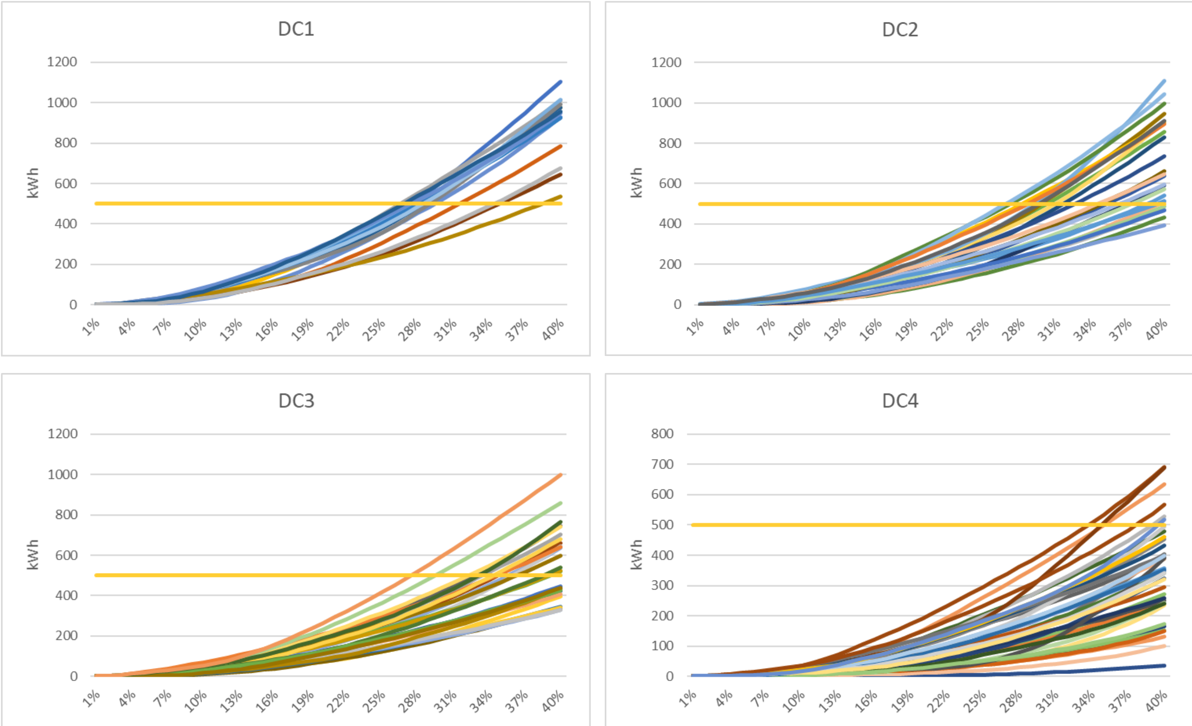
Using an average overload curve per customer for each DC cluster we tested how overload can change for different customer numbers. Comparing calculated overload at different customer numbers we can see what levels may be serviced by a theoretical 500kWh battery:

- **DC1 and DC2 types appear to have higher overload, hence a single battery can only service lower customer numbers and overload levels.**
- **DC3 and DC4 show lower levels of overload which can be met successfully by a 500kWh battery for most customer numbers and at most overload levels.**

Therefore, the approach to forecasting future network conditions that could be suitable for a Community Battery Initiative comprised of 3 main steps:

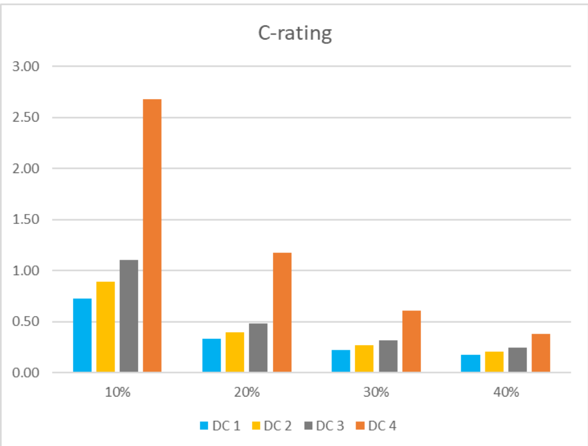
1. Calculate **size (kW and kWh) of battery to meet desired level of overload**, assuming a DC transformer rating at different levels below the theoretical demand curve, in each year
2. Develop a **framework of various battery sizes to service different customer numbers and overload levels in each DC**
3. **Rank battery use cases** as feasible or unfeasible taking size restriction of a 500kWh single battery into account, assuming there would only be sufficient space for a single installation

Figure 25 Overload vs Battery Size (500kWh)



The analysis indicates that batteries could service different DC clusters for different combinations of number of customers and overload percentage, as shown above. The resulting C-ratings required to meet those overload conditions are shown in Figure 26 below.

Figure 26: C-rating by DC Cluster



7.2. Determining network use cases

In order to rank the potential future battery sizes that would be required to meet different levels of overload as feasible or unfeasible, three factors were considered:

- A **feasible battery size** that can approximately fit in the footprint of a K-type or L-Type DC kiosk – depending on the type of enclosure the battery can be up to **500 kWh**;
- **Battery inverter size** that is economical (up to a C-rating of ~0.8) and can fit in the Ausgrid DC enclosure – in this case the inverter considered to be feasible is **250 kW**; and
- Total kWh and **C-rating calculated as kW/kWh** for different levels of overload and numbers of customers by DC.

The above assumes that only a single battery could be placed in the relevant DC, and that the upper limit for an individual battery to fit into an enclosure would be 500kWh. This is based on the capacity that could fit into a single enclosure, considering current technology. Depending on the location, it may be possible to install a second battery should sufficient space be available; however, for the purposes of simplification, only single installations in a DC were considered. Likewise, in the future, as battery technology develops, it may be possible to fit more than 500kWh into the same enclosure, but this was not taken into account for future scenarios as a part of this study.

The analysis was applied to different levels of overload and different customer numbers in increments of 50 from 50 to 250. An example of one case for DC1, based on 2018 results, is presented below. The **green cells represent feasible and economical battery options, while the orange ones are not deemed feasible**. As the maximum number of customers per DC can vary within a DC cluster, the grey cells represent cases where customer numbers were not found to be applicable to a particular DC cluster.

The study identified **three network Use Cases** where one of the three Battery Solutions could meet network requirements for various sizes of communities and at different overload levels:

Table 4 DC1 Feasible Battery Sizes vs Number of Customers

	50	100	150	200	250	
DC1	Number of customers					
2018	50	100	150	200	250	C-rating
10%	50	100	150	201	251	0.48
20%	178	355	533	711	889	0.27
30%	383	766	1149	1531	1914	0.19
40%	627	1255	1882	2510	3137	0.15
	kWh					

Use Case 1 (single battery can meet moderate overload, smaller communities): A battery of 500 kWh capacity can only service DCs with low customer numbers (smaller communities), which is unlikely to meet future network overload requirements (if the customer numbers grow over time, the battery would be undersized). In this case, for larger customer numbers, a second battery installation might be required, or in the absence of sufficient space traditional network upgrades may prove to be the best long-term option. This was found to be applicable to DC1.

Use Case 2 (single battery can meet up to 30% overload for medium sized communities): A 500 kWh battery can service the majority of DC sizes over the longer term up to 30% overload. This may be a good alternative to traditional network upgrades for DCs with lower numbers of customers where future growth is not expected to increase dramatically. These cases were found to be applicable to DC2 and DC3.

Use case 3 (single battery can meet most overload conditions for all community sizes): While in many cases a smaller 250kWh battery (Battery Solution B) could be sufficient, there is an opportunity to oversize the battery for the future or to maximise market revenue (Battery Solution A1) or install a smaller battery early on and upgrade to a larger size in the future (Battery Solution A2). This was found to be applicable to DC4.

For detailed DC uses cases refer to Appendix C:

> **Considering the three factors that were used to size the battery, it was found that the maximum kW output for the below network conditions result in an inverter capacity below 250 kW in all cases. Hence, the limiting factor in sizing the battery to meet network conditions is the size of the battery in kWh, with 500 kWh being the upper limit due to enclosure constraints (unless more than one enclosure can be placed within the same community).**
>
> **In addition, the optimum C-rating of the battery to maximise market revenue potential was found to be ~0.8 (refer to Section 9.1 and Figure 26). At this C-rating (up to a limit of 500kWh), the battery would always be able to meet network needs, since the inverter would always be oversized for the network.**

7.3. Conclusions on network analysis

The network analysis indicates there are some high-level DC clusters which show similar levels of overload per customer, however there is still high variability between the underlying data points.

Based on this, battery sizes at different levels of theoretical overload were calculated, which informed potential options for future network development.

> **Using this framework, another DC in Ausgrid's network can be categorised based on the cluster it fits into using the following 2 factors:**
>
> - **Flex ratio**
> - **Maximum demand in kW per customer**
>
> **In order to confirm its cluster allocation the theoretical overload per customer would need to be determined and tested against the cluster profile. Using the projected number of customers and level of overload expected, the network Use Case and an indicative battery size can be identified for further investigation.**

It is important to note that this analysis was based on a small selected number of DCs which have high average values (13%-40%) of PV penetration – and a more extensive analysis is recommended for future phases to validate the results and determine if they hold to different types of DCs.

The analysis was based on one year of data from 2018, which may not necessarily be representative of future years. Since the battery size is based on theoretical overload calculations further investigation is needed to determine how the theoretical overload conditions compare with practical conditions and whether a DC from a particular cluster is likely to experience overload in the near future. Forecast overload was calculated based on changing customer profiles. Overall customer numbers have been kept constant over time for all DCs, so increase in population may also need to be considered in the future.

Once a DC is identified and an indicative battery sizing has been determined, the feasibility of the Community Battery to meet future overload conditions would require further network analysis taking into account the equipment specifications and ratings, as well as operational parameters.

The outcomes of this analysis were used to inform the development of Configurations tested in the commercial analysis, which combined these network Use Cases with the results from the supplier analysis and cost projections discussed in Chapter 4.

8. What is the potential contribution and use of PV customers in the community battery?

As the profiles of the customer base change over time, the potential to derive revenue from participants in a Community Battery Initiative will increase. The purpose of this section is to understand what the contribution of customers would be to the overall economics of the battery, and the portion of the battery storage capacity that would need to be retained for customer use.

8.1. Customer model

The customer model calculates the savings in energy bills that each customer profile would derive from participating in a Community Battery Initiative. This allows the Battery Service Charge to be estimated as a proportion of these savings, to ensure that customers would still retain a net saving.

8.1.1 Battery Package design

In order to design the battery packages for customers, the impact of different approaches on estimated customer savings was analysed. This was driven by two key factors:

1. current retail tariff, and
2. how customers are able to store their energy exports (i.e. the *energy banking methodology*).

8.2. Retail tariff

We compare the cost savings of a customer under the Community Battery Initiative against their current retail offer. A list of current retail plans offered to customers in Ausgrid's network was compiled and filtered by the cheapest offer available by retailer and tariff type (Flat and Time-of-Use). We then took the weighted average price according to each retailer's market share in the NSW electricity retail market, as seen in Table 5. Therefore, the proxy retail tariff formed is largely driven by the three retailers with market share over 20%.

Table 5 Weighted-average retail tariffs

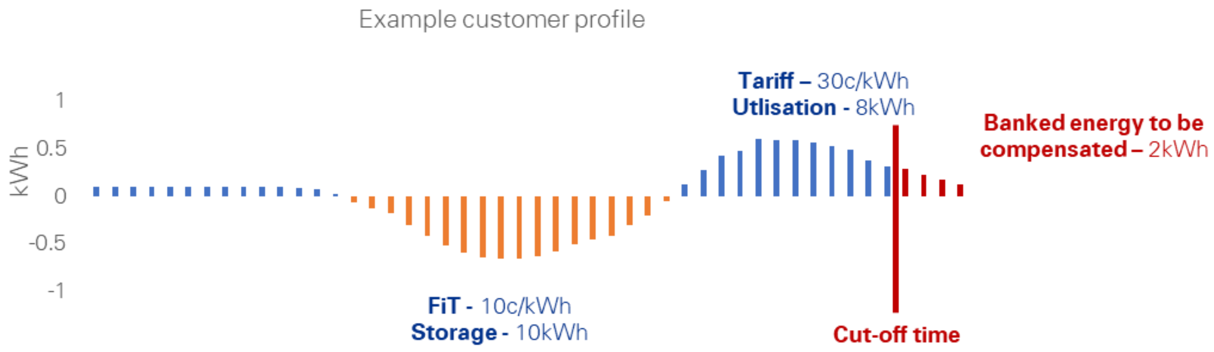
Tariff Type	Daily supply (c/day)	Flat Charge (c/kWh)	Peak (c/kWh)	Off-peak (c/kWh)	Shoulder (c/kWh)	FiT (c/kWh)
Time-of-Use Weighted	95.98	-	45.32	19.53	25.75	11.14
Flat Weighted	85.46	27.63	-	-	-	10.94

The estimate of savings is also highly sensitive to the Feed-in Tariff (FiT) – for the purposes of this study we assumed an average FiT. It should be noted that sensitivity of the analysis to FiT is significant and the actual FiT may impact the uptake of the Community Battery Initiative. This is an important aspect that should be further investigated and refined in future stages.

For the purposes of this study, we did not consider the potential impact of assuming a Demand Tariff versus a Time-of-Use Tariff. We note that although the introduction of a Demand Tariff is being investigated, there are currently no offers in the market and development of this is still in its infancy. It was therefore excluded from the analysis in this study.

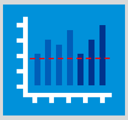
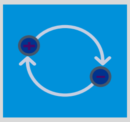
8.3. Energy banking methodology

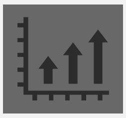
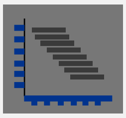
The energy banking methodology is also an important consideration in capturing the value of energy storage for customers. Depending on the amount of storage a customer signs up for, some customers might not consume all the energy they export on the same day. Therefore an appropriate compensation mechanism would need to be put into place to ensure that customers do not forfeit the FiT they would have received for any surplus energy exported and not used within the cut-off time.



There are various energy banking options, as shown below:

Table 6 Energy banking options

Methodology		Description
	**Energy Storage Cap**	• Customers are entitled to bank energy up to a certain limit (e.g. 5kWh) • Banked energy (up to the cap) carries forward indefinitely • Limits cost savings for customers with high net exports and low imports but maximises savings for customers with profiles that lag over some days
	**Reset**	• Banked energy is reset to zero at a designated time period, e.g. at midnight and customers need to be compensated for any surplus banked energy • Ultimately limits the value of the Community Battery Initiative to customers whose profile typically results in surplus banked energy at the end of the reset period – unless a higher FiT was offered to the customer compared to the retailer

Methodology		Description
	**Uncapped**	• Banked energy is carried forward indefinitely until there are sufficient imports to discharge • There is no limit on banked energy which may be carried forward – this is equivalent to the maximum potential energy savings
	**Rolling Reset**	• Banked energy must be discharged within a designated time from the time at which that energy is banked. • For example, 1kWh banked at 2pm, must be discharged within 24 hours (by 2pm the following day) otherwise the banked energy is lost

In order to access the different approaches to energy banking, the impact on customer savings was assessed assuming all customers can **sign up to a specified 'capped' amount of energy storage of 13.5 kWh (this was chosen as a reference home battery system currently available in the market)**, which is reset after a specified period of time. In order to establish the impact of varying the storage period offered under the Community Battery Initiative, the impacts on customer savings were tested for several reset periods. This provides an indication of the compensation that would have to be put in place to reimburse customers for any banked energy that is not used within the reset period. Table 7 Impact of different reset periods on customer savings in the absence of compensation for surplus banked energy below shows the range of reset periods and corresponding cost savings results.

Table 7 Impact of different reset periods on customer savings in the absence of compensation for surplus banked energy

Reset Period	Reduction in average savings **Shows the impact on average annual cost savings for an individual customer compared to unlimited storage period**
Capped, 24hr reset	↓58%
Capped 48hr reset	↓37%
Capped, weekly reset	↓19%

In general, the longer the reset period the higher the average customer savings, which is due to the fact that customers are allowed more time to import the stored energy and capture the value of their export energy in the absence of additional compensation for surplus banked energy.

Further, as discussed in Section 10, under the proposed AEMO settlement rule change, the battery would need to be able to charge and discharge in a manner to keep the energy system whole – and a timeframe would need to be agreed with AEMO/AEMC to settle the customer battery flows. It is proposed that a day would be ideal since the solution would need to be able to be incorporated easily into AEMO's current settlement process.

Therefore, a **daily reset on stored energy** was chosen since it would be aligned with the settlement timeframe.

Although it is possible for the Battery Operator to dispatch surplus banked energy received from customers into the market, this would pose a higher risk for the Battery Operator and complicates the battery's operational model and exposure to market price volatility.

It would therefore be beneficial to offer a range of tailored packages to suit different customer energy profiles that would match their daily profile and minimise surplus banked energy after 24 hours. It is anticipated that, as the business models for community batteries evolve over time, a range of models could emerge where the Battery Operator could trade customers' energy in the market on their behalf. However this would require a more thorough understanding of customer behaviour and its impact on the optimum operating model. For these reasons, it is envisaged that the first step in proving the concept for a community battery would be a simpler business model, where the energy is reset every 24 hours and customers are offered a range of battery packages to cater for different energy profiles.

8.3.1 Battery package offers

The approach to energy banking methodology was used to determine the ideal battery package (a hypothetical concept) for each customer profile as follows:

> **Customers are able to store up to their energy storage limit in a day, and import their stored energy during the course of the same day. At midnight, the energy storage limit will reset to zero. The package size that a customer signs up for determines their daily limit.**

Considering the optimal package sizes, future customer system upgrades and the need to limit the available packages to discrete, marketable sizes it has been assumed that that customers will be able to subscribe for package sizes of **2, 4, 6 and 8 kWh** of energy storage per day.

For each customer profile, the optimum package size that would achieve the optimum utilisation of the subscribed battery storage capacity was determined. **The Battery Service Charge applied is $40/kWh per year**. This was determined on the basis that all customer profiles will be able to cover the cost of battery charge for their optimal package size, out of estimated energy savings. This would mean that all customers signing up to the Community Battery Initiative would capture a net savings in their energy bill after paying the Battery Service Charge. Different customer profiles result in different levels of net energy savings, but it was found that all profiles would retain at least 30-40% of their estimated energy savings. This was assumed to offer sufficient incentive for customers to participate. The only exception is Profile 1 customers, who would initially see minimal benefit from participation in the Community Battery Initiative and are therefore not assumed to sign up before 2023. However, assuming that these customers would upgrade their systems to 5kW systems by 2023, their savings would increase significantly from 2023 onwards, from which point they are assumed to participate, and this increases the uptake of the Community Battery Initiative significantly from 2023.

Table 8 Customer package sizes, energy savings and Battery Service Charge - 2018

Customer Profile	Current system size	Package size	Battery as a service charge per customer	Energy bill saving per customer (net of Battery Service Charge)
Customer 1	1.4 kW	2 kWh	$0	$0
Customer 2	4.7 kW	4 kWh	$160	$107
Customer 3	2.9 kW	4 kWh	$160	$121
Customer 4	6.7 kW	6 kWh	$240	$103
Customer 5	10.5 kW	8 kWh	$320	$195

Table 9 Future customer package sizes, energy savings and Battery Service Charge – 2023 onwards

Customer Profile	Upgraded system size	Package size	Battery Service Charge per customer	Battery Service Charge % increase from 2018	Energy bill savings per customer (net of Battery Service Charge)	Energy bill savings % increase from 2018
Customer 1	5 kW	6 kWh	$240	N/A	$156	N/A
Customer 2	5 kW	6 kWh	$240	50%	$128	20%
Customer 3	5 kW	6 kWh	$240	50%	$132	9%
Customer 4	6.7 kW	6 kWh	$240	0%	$115	12%
Customer 5	10.5 kW	8 kWh	$320	0%	$216	11%

8.3.2 Battery Service Charge composition

The total fee charged to customers via the Battery Service Charge incorporates the following elements:

- Battery use charge
- Special network tariff
- Customer handling costs

Battery use charge

The battery use charge is essentially the net revenue component of the customer payments that is retained by the Battery Operator, after subtracting network charges and customer handling costs.

Special network tariff

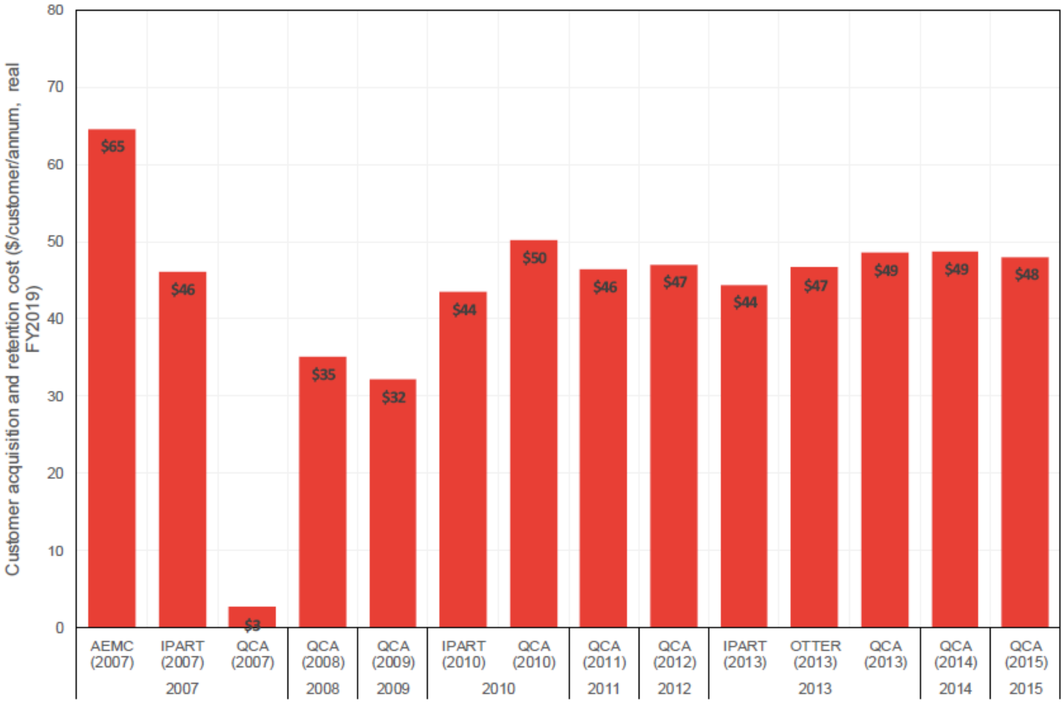
As outlined in the Regulatory recommended solution, for the purposes of this study, we have assumed that a special network tariff would need to be designed for Community Battery Initiative customers. The nature of the design of this tariff has not been explored in detail, but we have made a high level assumption for the purposes of the study to account for this cost. This would act in a similar manner to the Distribution Use of Network (DUOS) tariffs currently imposed on all customers in the network. However, taking into account that Community Battery customers would mostly be using network infrastructure at a localised, low voltage level, we have assumed a substantially lower tariff than the DUOS equivalent. Considerations for the DUOS charge have been further discussed in Section 10. Any energy that is exported via the retailer net of energy stored in the battery is still assumed to be subject to standard DUOS charges.

Customer handling costs

This portion of the total package cost accounts for services related to typical energy retailer activities such as customer handling and setup costs. For a typical energy retailer, the graph below provides an overview of the regulatory allowance for the cost of acquiring new retail customers and retaining new customers (CARC) by regulator. CARC includes:

- the costs of acquisition channels (such as third party comparison websites, telemarketing or door-to-door sales);
- the costs of retention teams; and
- marketing costs targeted at driving acquisition or retention.

Figure 27 Regulatory Allowances for CARC



Source: Frontier Economics analysis of regulatory decisions

As the figure indicates, most recent decisions have been the magnitude of $44 to $48 per customer per annum. However, retailer operating costs are typically higher, as it also includes customer handling costs, cost for billing, customer support centre and other general administration costs. However, given that we envisage the Community Battery Initiative to be largely digitized, and there would not be a need to establish a new call centre, compliance and administrative function, we have assumed a conservative cost of customer handling as below.

Table 10 Network and customer handling cost assumptions

Customer Handling costs	Value	Units
Special network tariff	2c per kWh	$43.8 per annum for a 6kWh package
Customer handling cost	10c per day	$36.5 per annum

8.4. Customer benefits

It is recognised that there are multiple benefits that could be realised for customers, through the Community Battery Initiative, as described further in Section 10.3. Many of these benefits are challenging to quantify. However, the avoided CAPEX for the total individual battery costs that would have been incurred by participating customers in the absence of the Community Battery Initiative can be estimated. Therefore, for the purposes of this study, we have estimated the potential savings in avoided customer CAPEX for investment in individual batteries and used this benefit as a proxy for the benefits to customers as a whole, which we deem to be conservative. In future stages, more work will be required to quantify and fully understand the whole of system benefit which will ultimately flow down to all customers.

For the purposes of the study, we have assumed the life span of a home battery to be 10 years taking into account that maintenance will be less optimal compared to larger scale batteries and therefore the home battery would degrade faster. Assuming this battery life and the corresponding total battery service charge costs over 10 years, the individual battery costs per customer for each DC profile were calculated to reflect assumed system sizes, based on the cost curve presented in Figure 1. The customer avoided CAPEX therefore changes in line with the increase in assumed system sizes in 2023. The battery service charge methodology is presented in Section 8.3.1 above. Due to the different customer compositions and system sizes for the four DC cluster profiles, the quarterly customer avoided CAPEX differs between the DC clusters. The table below presents the net quarterly customer avoided CAPEX for each DC cluster profile for 2018 calculations and 2023 onwards.

Table 11 Arbitrage Assumptions

Arbitrage Assumptions	Value	Units
Customer avoided CAPEX (DC Cluster 1) – 2018	815	$/Quarter
Customer avoided CAPEX (DC Cluster 2) – 2018	725	$/Quarter
Customer avoided CAPEX (DC Cluster 3) – 2018	709	$/Quarter
Customer avoided CAPEX (DC Cluster 4) – 2018	752	$/Quarter
Customer avoided CAPEX (DC Cluster 1) – 2023	766	$/Quarter
Customer avoided CAPEX (DC Cluster 2) – 2023	981	$/Quarter
Customer avoided CAPEX (DC Cluster 3) – 2023	1,742	$/Quarter
Customer avoided CAPEX (DC Cluster 4) – 2023	1,585	$/Quarter

9. What is the market revenue potential of a community battery, taking customer and network use into account?

A key revenue driver for the project is wholesale market revenue which can be generated through the use of the battery capacity when it is not utilised by customers. Based on current market reforms under consideration and the extent of investment across the market, forecast wholesale market conditions (spread and volatility) are very uncertain. To this end a range of market outcomes have been tested to reflect the potential variability in market revenue potential.

9.1. Market Arbitrage revenue

The arbitrage model was used to estimate the potential wholesale market revenue for the battery. Market revenue from arbitrage is a key driver for the commercial model and relies heavily on market volatility. At a high level, batteries are able to capture arbitrage by buying electricity at low prices and selling it at high prices. The extent to which this is possible depends on:

1. The spread between high and low prices on a daily basis – **daily spread.**
2. The frequency of market volatility, or very high prices – **high priced events.**

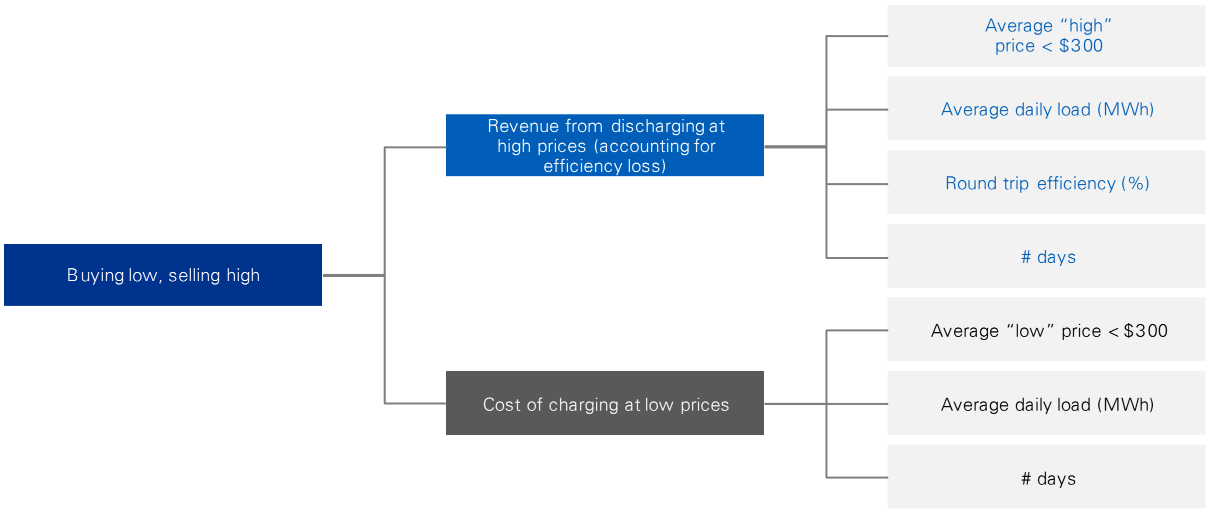
However, practical factors can diminish margins. These include:

- **Round Trip Efficiency:** Some energy will be lost between charge and discharge.
- **Duration and level of charge:** It takes time for the battery to charge, and the battery also needs to retain a minimum level of charge for other end use cases - this may limit the ability to generate during high prices.
- **Capture efficiency:** Even highly optimised dispatch algorithms will not capture all volatility events, or the optimum daily spread.
- **Degradation:** The efficiency of the battery degrades over time, impacting its effective capacity, or the cost to maintain this capacity. Manufacturers usually specify this as a maximum amount of cycles over the battery life to maintain a certain efficiency over time.

The aim of this model is to generate an estimate of the potential value stream from wholesale energy arbitrage. This is calculated as follows:

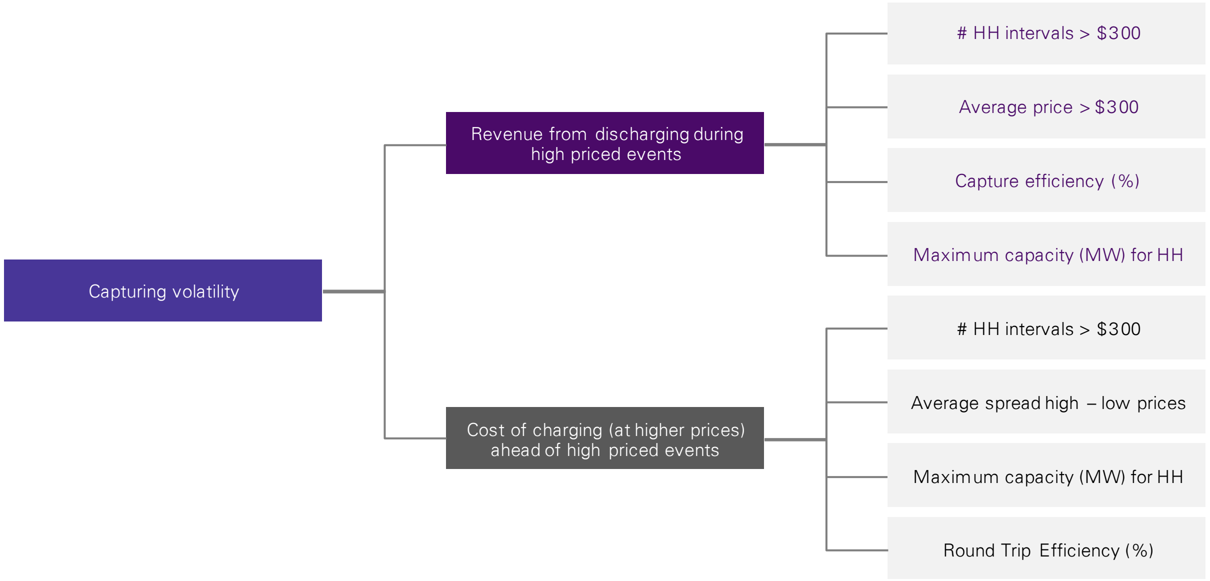
Approach 1: *Buying low, selling high (daily spread)* – Targeting prices under $300/MWh

A battery will be able to earn revenue from "buying low" and "selling high". The energy from the community battery will need to be replaced (for participants to use) by operator at low (off-peak) prices. This revenue depends on (i) the spread between high and low prices (where 'flatter' prices will mean less revenue), and (ii) how the battery operates.



Approach 2: *Capturing volatility (high priced events)* – Targeting prices above $300/MWh

A battery will also be able to earn revenue from volatility, or very high priced events. This revenue depends on (i) price volatility, and (ii) and how the battery operates (including the ability of the battery to capture price volatility).



9.1.1 Historical market overview

Revenue outcomes can be highly variable, depending on:

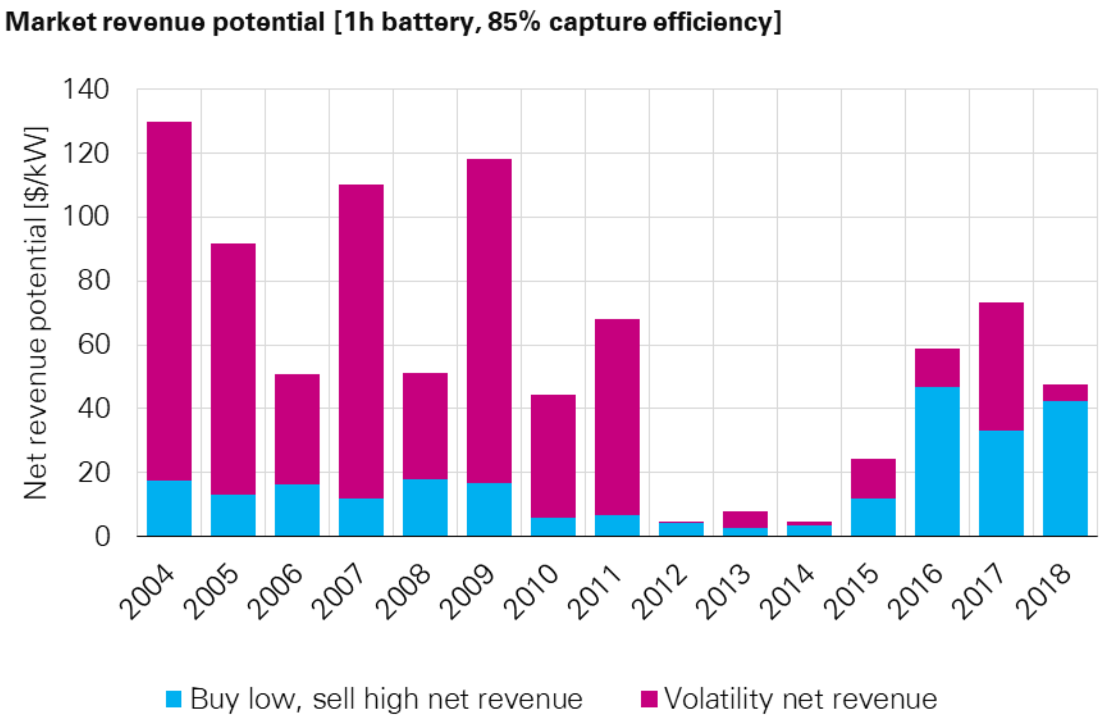
- How 'flat' the prices are on average, i.e. how much value can be derived from 'time shifting' electricity;
- The occurrence of volatility / high priced events; and
- Weather.

History shows that there can be several subsequent years with low price volatility. Both the spread between high and low prices and price volatility may change over time as the supply mix changes.

An increase in renewables and subsequent retirement of scheduled generation (coal) will likely increase the value of time shifting energy, and potentially also price volatility, but increased penetration of energy storage and other scheduled sources of supply will have the opposite effect.

The graph below shows the potential net revenue a 1h battery could have generated under different historical volatility assumptions in NSW. Between 2004 and 2011, NSW experienced the most volatility, especially in the year of 2007 which showed the highest net revenue potential largely from capturing high priced events. From 2012 to 2014, electricity prices were relatively flat and volatility was low, limiting net revenue. Between 2015 and 2018 the spread between high and low prices under $300/MWh is quite high, composing majority of the total net revenue potential.

Figure 28: Net revenue potential under historical wholesale electricity market volatility



9.1.2 Market arbitrage revenue assumptions

To generate revenue under the buy-low-sell-high approach, an assumption on how adept the battery can capture the peak and off peak prices must be made. In addition, this needs to be constrained to a maximum number of cycles to maintain the battery life. Similarly, to capture high-priced events, an assumption must be made on the percentage of market settlement intervals, priced above the 'high-price threshold' that the battery can capture at full capacity.

Based on the historical market pricing, we tested a range of market outcomes – 2007 being a flat, but very volatile year, 2018 having a higher average spread but lower volatility, and 2017 as the base case year, since the volatility and the spread are both in an average range:

2017 - Base Case - Average daily spread and average volatility

2007 – High - Flat daily spread and high volatility

2018 – Low - High daily spread and low volatility

We also tested various C ratings in the market arbitrage model for these years and the trend is similar – the highest possible market revenue coincides with a **C rating of just below 1**, or a battery with around 1.25h storage.

The maximum market revenue at an assumed capture efficiency of 85%, including daily spread and high priced events, and ignoring any adjustment for customer use of the battery, is as follows:

2017 - $79/kW @ C rating 0.8

2007 - $144/kW @ C rating 0.8

2018 - $55/kW @ C rating 0.8

Daily spread is based on running the battery for **1 full cycle (1.25h charge and 1.25h discharge) or 2 full cycles (2.5h charge and 2.5h discharge) per day**, such that the total number of cycles is capped at 400 per annum (6000 over 15 years), to maintain the life of the battery.

Table 12 Additional assumptions used in the market arbitrage model are presented below.

Arbitrage Assumptions	Value	Units
Peak/off peak capture efficiency	85	%
Minimum spread (2017)	39	$/MWh
Minimum spread (2007)	40	$/MWh
Minimum spread (2018)	51	$/MWh
High Price capture efficiency (cycle 1 & 2)	85	%
High price threshold (cycle 1)	300	$/MWh
High price threshold (cycle 2)	800	$/MWh

9.2. FCAS revenue

Additional ancillary service revenue can assist the business case, but is also difficult to forecast and not readily bankable under current Rules – FCAS is more seen as a potential opportunistic revenue stream.

9.2.1 Historical FCAS market overview

Batteries and demand side response (DR) are capturing significant FCAS market share despite relatively small capacity. Nevertheless, the ability to capture ancillary service revenue is uncertain going forward:

- Demand for FCAS may increase as non-synchronous renewable energy continues to displace synchronous fossil fuel generation. However, the markets are considered shallow and may become quickly saturated, that is, the profits from the FCAS markets may become eroded with growth in other utility scale batteries, demand response, qualifying renewable energy and more interconnection.
- The Rules make it hard to quantify "bankable" revenue from FCAS due to uncertainty in the current FCAS market. However, the Rules may change going forward to accommodate the

changing supply mix. We have included more details around the FCAS market rules in Appendix D:

The total value of the historical FCAS market is shown in the diagrams below. Further detail on the FCAS market is also provided in Appendix D:

Figure 29: NSW Regulation FCAS market historical data

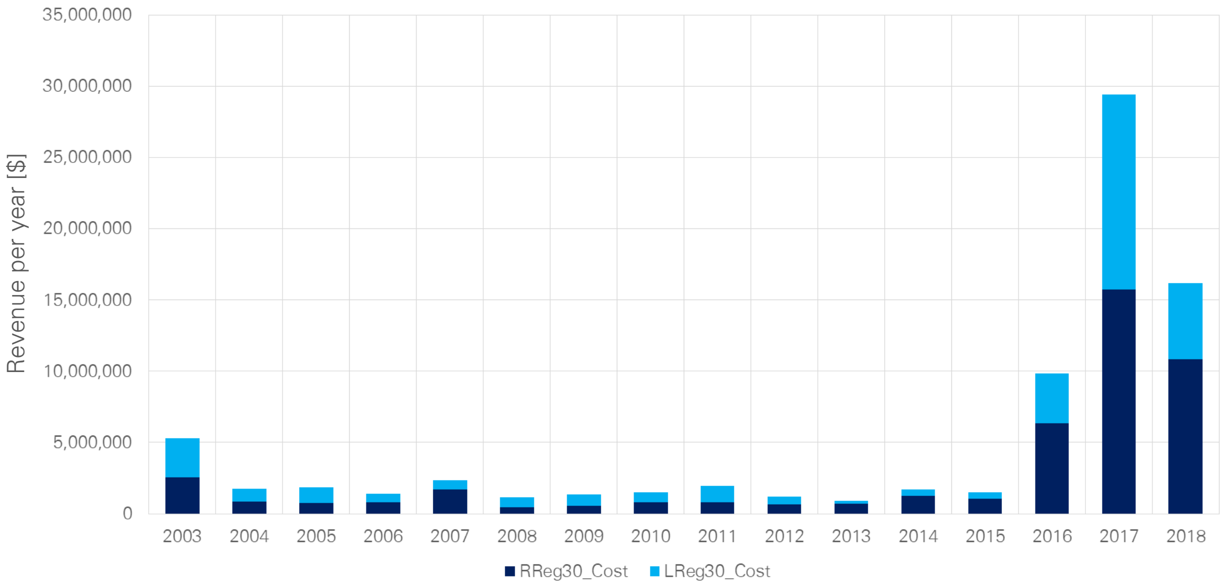
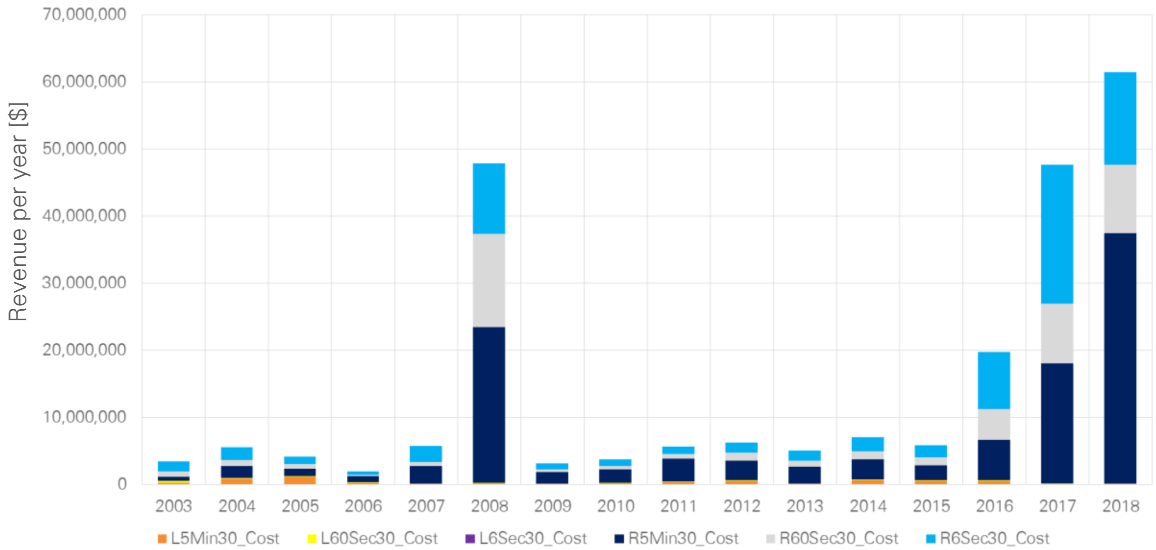


Figure 30 : NSW Contingency FCAS market historical data



9.2.2 FCAS requirements

The battery system must be able to meet the requirements of AEMO's published Market Ancillary Service Specification (MASS) and participate in central dispatch for FCAS. The two tests which may limit participation include the following[8]:

a. **The size of the battery installation (or aggregated batteries) -** the FCAS regime continues to discourage small capacity participants taking an active role in the market. Any aggregator of battery storage will need to wield a significant volume of storage before being permitted to participate in the market under the rules. The threshold for being classified as a Market Generator is 5 MW (for the aggregated batteries).

[8] Interim arrangements for utility scale battery technology- AEMO

b. **Whether the battery has sufficient real time metering -** with respect to virtual power plants (VPPs), currently AEMO requires high speed metering (sub second or micro second) for trading in the FCAS market and most smart meters (with capabilities largely limited to 1-minute metering) do not meet that requirement.

However AEMO has allowed different arrangements for the metering of aggregated, small FCAS services with VPP trials and relaxed some of the requirements. AEMO is currently investigating the establishment of a framework for the demonstrations in which participating VPPs submit operational data for their aggregated fleets on a 5-minute resolution, refreshing every five minutes[9].

Ausgrid would need to consult with AEMO about applying for exemptions if the total size of the potential pilot or future portfolio is less than 5 MW.

9.2.3 FCAS revenue assumptions

For our analysis we have considered two sources of historical FCAS market revenues in order to develop assumptions for annual FCAS revenue.

- Independent Energy Research - Independent energy market forecast estimates average annual FCAS revenue to be approximately $133/kW. This reflects an average across both contingency and regulation FCAS revenue.
- Historical FCAS market data - Historical data for the total annual FCAS market revenue (for each contingency and regulation services) and the corresponding available capacity in 2018 was extracted to calculate the average annual $/kW FCAS revenue.

Table 13 The revenue assumptions extracted from each source

FCAS Assumptions	Value	Units
Historical FCAS assumption	85	$/kW p.a.
Independent energy market forecast FCAS revenue assumption	133	$/kW p.a.

As part of our sensitivity analysis the following assumptions have been adopted in each case:

Base case scenario:	50% of Historical FCAS market value
Sensitivity (low):	10% of Historical FCAS value
Sensitivity (high):	90% of Independent energy market forecast value

[9] https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/VPP-Demonstrations/VPP-Demonstrations-Data-Specification.pdf https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/VPP-Demonstrations/VPP-Demonstrations-FCAS-Specification.pdf

10. What regulatory changes would be required to support standardised roll out of community batteries as an alternative network solution?

The Community Battery Initiative is an example of a MUA in the energy market. MUAs are those where a single energy resource or facility provides multiple services to several entities with compensation received through different revenue streams. While optimising and combining these various revenue streams improves the economics of the projects, this can lead to substantial challenges for the regulatory framework. This is especially the case for community batteries which will be providing both regulated and competitive services.

The regulatory framework applicable to the community battery is mainly governed by the provisions of the National Electricity Rules (NER). A number of Guidelines and methodologies from the AER plus procedures issued by the system operator, AEMO, are also relevant to the Community Battery Initiative. The AER and AEMO documents are made under the remit of the NER. Local jurisdictional arrangements (for example, arrangements for retailer feed in tariffs) have also been considered.

The aspects of the regulatory framework which impact on how the benefits from community batteries are realised for customers are:

- How flows to and from the community battery from the customer's premise are measured and settled in the market;
- The ability of the community battery to access and capture its value to wholesale and ancillary services markets;
- How the costs of the community battery are shared between regulated and contestable services and recovered from customers; and
- The applicable network tariff for flows to and from the battery.

Following our assessment of these issues, we have identified a number of regulatory changes which would support the operation and feasibility of the community battery. These changes are set out in detail in this section and distinguish between regulatory change that can be achieved in the short term for any pilot and what is essential for a standardised roll out of this Community Battery Initiative.

These proposed changes are considered to achieve the existing efficiency and customer considerations of current regulatory arrangements and therefore should promote the National Electricity Objective. Therefore, consideration of the impacts on both customers who participate in the Community Battery Initiative and others who do not have been taken into account.

Overall, we believe that Community Battery Initiative does not require significant deviations to the current arrangements, nor will it have any negative economic impacts to other participants or to end customers who do not participate. The proposed changes are primarily to better account for benefit realisation across the value streams and also to reflect the nature of decentralised energy flows between the battery and participating customers. We note that some of these proposed changes would also help facilitate other models of DER and decentralised energy such as peer to peer transactions and therefore would have a general benefit facilitating the transformation of the sector under increased DER.

10.1. Main barriers to the feasibility and benefit realisation of the Community Battery Initiative

The advantages of a community battery are that:

- The total capital investment across the supply chain is significantly lower than installing single purpose battery storage (i.e., aggregation of home batteries, network support battery, and an energy arbitrage battery); plus
- better enablement of benefits across the multiple value streams in the electricity sector due to the location of the battery.

The objective of the regulatory arrangements should therefore be to recognise and optimise this advantage in a manner which promotes efficiency, maintains network security and protects customers.

The following features of the current arrangements will act as a barrier to the feasibility of community batteries:

- **When a participating customer flows energy back from the community battery, this volume will be levied at the full retail tariff, even though the electricity is originally produced at the customer's premises through its solar PV installation.**

  When energy flows into the customer's premises, the energy is recorded in their meter and their retailer becomes liable for a number of costs, including wholesale costs, network charges and levies for environmental schemes. In addition the retailer needs to recover its own costs and a margin. Any flow from the battery will effectively be treated the same as if the customer was being supplied from the main wholesale market.

  We have assessed a number of potential solutions to this inefficient duplication of retail payment problem. The key challenge in each of these options is how to distinguish between energy that the customer draws from the grid and flows to and from the community battery.

  We consider a subtractive netting arrangement through AEMO settlements is the preferred option to address this as compared to installing separate meters or separate Financially Responsible Market Participants (FRMPs) at the customer connection point. Under this solution, customers flows to and from the battery would be separated out and treated differently for settlement purposes. This effectively nets out the community battery from the FRMP settlement liability in the wholesale market.

  Under such an option, the size of the battery needs to have regard to the customer volumes as it would need to be operated in a way to maintain balance in the system and keep the AEMO settlement whole. This is the most complicated part of this concept. As for the netting solution to be accepted it would need to be proved that there is no negative impact on the AEMO settlement and other market participants.

  However for the pilot, it is unlikely that this settlement change will be implemented in time. Therefore, Ausgrid would have to reimburse the customer to cancel out this effect. This would net off the feed in tariff which the participating customer would qualify for in relation to flows to the battery under current arrangements.

- **Application of current network tariffs to the Community Battery flow may lead to unreasonable charges being levied and result in a transfer from non-participating customers. There is a broader consideration of the appropriate network tariffs for local flows similar to the community battery project such as peer to peer transactions.**

  The application of network tariffs to the community battery needs to be viewed from the perspective of both:

  – The network tariff applicable to customer's flows to and from the battery; and

  – The network tariff levied on inflows to the community battery in relation to market flows (when the battery is charging from the market)

Under current arrangements, all inflows into the community battery are assumed to come from the wholesale market and therefore will be levied at the appropriate network tariff applicable to that connection point. This will add to the costs of the pilot project in the absence of any network tariff changes.

Going forward, it could be hard to justify any specific network charges for the market flows to the community battery and this should be treated as a normal load at the connection point, but this should be considered further.

There is more reasoning to have different network charges for flows between the battery and customer given the short distance. Any network tariff should reflect the long run marginal cost of providing the service to the customer. However, there are restrictions under the NER regarding the setting of network tariffs for the customer flows to and from the community battery[10]:

- Flows from the battery to the market are exempt from network DUOS under NER 6.1.4.
- Rule 6.18.4 of the NER prevents a DNSP from charging customers with similar connection and usage profiles differently. The question is whether this would constrain the ability to levy a lower tariff for flows from the battery back to the customer premises given the short distance.

- **Potential restrictions on the ability of the battery to access value in the wholesale and FCAS markets**

  The classification of the battery will impact on the settlement liability and risks for the project. The issue is the extent of the exposure of the battery to the spot prices. The size of the combined community battery units will determine how this is classified in the wholesale market and also how it is rewarded for any export to the market. The issues relate to:

  - whether the community battery units must be dispatched by AEMO (classified as non-scheduled, semi-scheduled or scheduled); and
  - if registered, whether the output of the community battery is sold into the wholesale market (classified as non-market or market). Non-market generation must be sold either to a customer that is co-located behind the same meter or (until 6 February 2022) to the Local Retailer.

  To participate in the NEM the battery must be registered as a Market Generator (for electricity being exported to the grid). It must also register as a Market Customer (for electricity being imported from the NEM if the battery is more than 5 MW. If less than 5 MW the battery could source electricity via a retail contract without being settled in the wholesale market).

  Multiple battery storage units are typically aggregated for dispatch under NER clause 3.8.3 subject to approval from AEMO consistent with the specified conditions. Appropriate Supervisory Control and Data Acquisition (SCADA) metering is required.

  We note that registration as a small generation aggregator (SGA) is not suitable for a number of reasons:

  - AEMO has previously advised that SGAs will need to have the solar systems gross metered (i.e. separate to the consumption load) and on its own NMI.
  - SGAs have been developed for standalone generation units and not net consumption sites.
  - Clause 2.3A.1 of the NER does not allow the SGA to participate to provide market ancillary services, it can only provide energy services.

[10] Another potential consideration is whether if there is going to be a specific customer tariff for community battery when should the participating customer be subject to two fixed charges under separate network tariffs (i.e. one for normal flows, and one for community battery flows).

Regarding access to FCAS revenue, the battery system must be able to meet the requirements of AEMO's published Market Ancillary Service Specification (MASS) and participate in central dispatch for FCAS. Market ancillary services are a part of the central dispatch operated by AEMO and participating in the central dispatch process requires telemetry and equipment for each generating unit. AEMO will specify the type of frequency controllers to be used and the allowable droop settings when delivering FCAS is also provided to help participants determine the maximum ancillary service capacity that can be registered, subject to a successful FCAS assessment by AEMO.

Further consideration of how AEMO market procedures will be managed and treatment of community batteries is needed and we would encourage Ausgrid to engage with AEMO on these matters. We note that AEMO has already allowed for different standards & telemetry/measurement requirements for the VPP demonstration trials[11] and similar treatment could be provided for the Community Battery Initiative.

10.2. Other regulatory considerations

10.2.1 Classification of services

There are 3 primary services a community battery enables which need to be assessed under the current AER electricity distribution ring-fencing guideline:

1. Customer Battery Access Service – we believe that this will be considered as a contestable electricity service.
2. Wholesale market trading/generation service – this will be considered as a contestable electricity service on the assumption that it would be viewed as "necessary to support the supply of electricity."
3. Network support service – when the battery is used to provide capacity or ancillary services for the provision of standard control services this will be classified as a distribution service.

Under the AER ring-fencing guidelines, Ausgrid as a DNSP will be prohibited from providing either services 1 (customer access) or 2 (wholesale trading). To capture these services the options are to:

- Seek a waiver from the AER; or
- Appoint a related party or third party provider to do either service.

For the pilot, there could be merit in seeking a waiver for the battery services from the AER given the temporary and limited scope of the demonstration project. This could be justified as it can be argued there is no negative impact on competition in electricity services.

The AER ring fencing guidelines operate through placing prohibition on the provision of services. It does not prevent ownership of assets.

The NER defines networks as "The apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity to customers (whether wholesale or retail) excluding any connection assets."

Therefore if the community battery is used for network services, then it could be considered to be a network asset. Overall in our view, there is no restriction on Ausgrid owning the community battery and operating the battery for regulated network services – the restriction is in using the battery to provide contestable services.

In summary, we consider that Ausgrid is able to own the assets but would have to engage other parties to perform the contestable services. Ausgrid could in theory operate the battery in relation to the contestable services but it cannot be the party providing the service to the customer. In such a

[11] see https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/VPP-Demonstrations/VPP-Demonstrations-FCAS-Specification.pdf

situation, the operation of the battery across regulated and contestable services will be subject to the cost allocation and ring fencing obligations.

10.2.2 Cost allocation and the AER shared asset guideline

As the community battery provides both regulated and contestable services in the market it will be considered as a shared asset. There are two mechanisms under the Rules for supporting efficient cost allocation for such assets:

- The Cost Allocation Methodology
- The Shared Asset Guideline

While the community battery is considered to be a shared asset the AER shared asset guideline (and the resulting 10% revenue sharing mechanism) only applies to existing assets where the expected use of the asset has now changed from being solely a regulated asset (see section 2.2 of AER Shared Asset Guideline). Therefore, as the community battery is being designed and constructed, its costs will be shared according to Ausgrid's Cost Allocation Methodology (CAM). We note that the CAM provides more protection to customers than the shared asset guideline as it provides a transparent and credible approach to sharing costs between regulated and contestable services.[12]

There are a number of potential approaches to consider for allocation of capital and operating costs which in turn will impact on how the costs of the battery are recovered:[13]

1. Only add that portion of the battery costs that can be directly attributed to the provision of network services to the regulated asset base and allowed operating expenditure. This could be based on the cost savings from avoiding other network investment. No other benefits associated with the battery are recognised in this approach.
2. Costs directly attributable to the provision of network services plus market benefits generated by the battery added to the RAB. The RIT-D provides a potential framework for considering and identifying market benefits associated with network investment.
3. Cost of the battery minus expected contestable revenue over the asset life added to the RAB.
4. No portion of battery capital costs added to the regulated revenue. Instead, Ausgrid procures the network services from the Community Battery operator for an agreed fee and the fee is then recovered through allowed operating expenditure.

There are a wide range of factors to consider in determining the appropriate cost allocation. KPMG's initial view is that method 2 could be the reasonable approach as this is consistent with the current arrangements including the Regulatory Investment Test and the AER expenditure assessment methodology.

[12] See section 6.6. of Ausgrid approved CAM
[13] Plus how the risks are shared

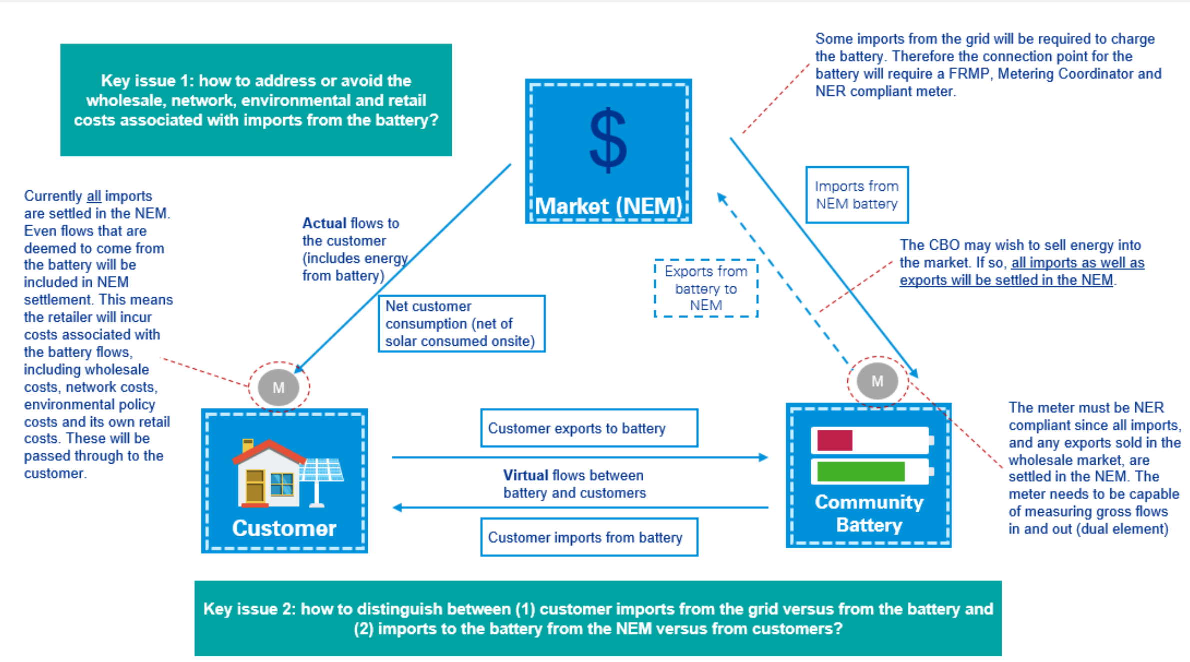
Box 10.1: Virtual settlement and data requirements

This section provides an initial assessment of how flows under the community battery model could be settled and measured under the proposed solution. This raises a number of issues for further assessment and discussion.

The NEM is a gross pool market operated by AEMO. All electricity supplied to the market and consumed by end users is transacted at the spot price for each trading interval in each region. The market settlement process ensures that for each trading interval market generators are paid for the energy they provide to the NEM and market customers pay for the energy they use. Market customers are mainly electricity retailers who purchase wholesale electricity to on-sell to their retail customers. Settlement occurs at the end of the day for retailers under AEMO MTAS process.

Effectively, solar PV customers' exported electricity is not stored in the battery in any physical sense. As there would be no dedicated link between a customer and the battery that is separate from the market settlement process managed by AEMO, the customer imports and exports need to be treated as a virtual flow. Overcoming this challenge of not being able to separate market flows and battery flows to the customer under current arrangements will be a key factor in viability of the Community Battery Initiative.

This diagram summarises the key issues under the current arrangements.



These issues can be resolved through changing the arrangements to allow the customer's flows to and from the battery to be separated out and treated differently for settlement purposes (effectively netting out the community battery). The diversity benefit transfers from the retailers to the community battery.

Under such an option, the size of the battery needs to have regard to the customer volumes as it would need to be operated in a way to maintain balance in the system and keep the AEMO settlement whole. This is the most complicated part of this concept. As for the netting solution to be accepted it would need to be proven that there is no negative impact on AEMO settlement and other market participants.

For this to be accepted:

- The data integrity of the metering arrangements for measuring customers' flows to and from the battery needs to be sufficient.
- The treatment of any losses/battery inefficiencies will be key. It would be easier for the community battery to agree to keep the flows whole and to supply sufficient energy for 1 to 1

flows. This avoids the complexity of considering how to manage battery losses within the global settlement arrangements for unaccounted energy.

- The battery would need to be able to charge and discharge in a manner to keep the system whole. Effectively, the battery absorbs the participating customer's net exports and discharges the net flows back to the customer to keep the settlement whole. Clearly this cannot be instantaneous and there would need to be an agreed time period for the battery to do this. This would need to be discussed with AEMO and AEMC – ideally a day would provide more flexibility to capture the energy arbitrage revenue stream.

This solution is dependent on obtaining real time flows and data for market settlement. Therefore, access to reliable and real time data on participating customers' consumption and PV generation levels will be important for the Community Battery Initiative. Constraints in the current metering arrangements on participants' ability to access metering data could create additional costs to the Community Battery Initiative.

10.3. Treating a portion of community batteries costs as a network expenditure

There are a number of potential funding mechanisms under the NER that Ausgrid could use to fund the capital costs of installing the battery, including any associated infrastructure required to house the battery. In considering the different funding options it is important to distinguish between the proportion of the battery that provides regulated distribution services and the proportion of the battery that provides contestable services, as the funding opportunities will differ. Where the community battery is used to provide regulated services, the related proportion of costs can be recovered through the regulated network tariffs in accordance with the current revenue determination.

A key driver of the feasibility of the community battery project is recognition and capturing of the wider externalities of the battery where there may not be a corresponding source of direct payment (i.e., impact on wholesale market outcomes). The issue to consider going forward is the ability of the NER current arrangements to recognise these benefits and whether new mechanisms would be needed.

As discussed above, there are a number of potential methods to identify the relevant proportions. It is important that the selected allocation method allows for all reasonable market benefits from the project to be identified and recognised into the portion recovered via the regulated revenue allowance.

Further consideration and discussion is needed on considering and identifying what types of market benefits from the community battery should be recognised and quantified through allowed network expenditures. While the RIT-D should provide a starting point for those considerations, there could be aspects of the type of DER model from the community battery which requires different treatment or new arrangements.

There are four categories of related costs and market benefits from the community battery to consider in this matter:

1 Direct network savings from installation of battery instead of other network assets

2 Indirect network savings from having a battery

3 Participating customer related benefits

4 Wider customer savings

1 **Direct network savings from installation of battery instead of other network assets**

- If the CB solves a network identified need (i.e. DC overload) and therefore avoids the need for investment in other network assets then Ausgrid could be allowed to recover the avoided network investment cost.

2 **Indirect network savings from having a battery**

- There are a number of potential indirect network benefits from installation of a community battery in the local network. This includes potential network support, emergency supply, option value and increased reliability. The value of the hosting capacity due to the installation of the battery in the local network is another example. We note that these indirect network benefits have not been accounted for in this feasibility study.

3 **Participating customer related benefits**

- For customers participating in the scheme, there are two types of benefits:
  - The savings from being able to utilise more of their solar PV generation to lower electricity bills; and
  - The savings to customers from avoiding the need to install batteries at the premises behind the meter.

As discussed in this report, there would be an access fee charged to customers participating in the Community Battery Initiative. For a wide number of reasons it is likely that the total amount of fee recovered will not be equal to the full value of these benefits. The question for consideration is whether there should be an adjustment made to the portion recovered through the regulated revenue given any shortfall between total customer contribution and the total customer value.

4 **Wider customer base related benefits**

- In addition to the network cost savings, the wider customer base (i.e. for customers not participating in the scheme) will receive other potential market benefits, including impact on wholesale market efficiency and outcomes from the community battery plus the contribution to lower FCAS costs. Such customers may get other benefits from the scheme, including a share in the revenue recovered from participating customers paying additional network tariffs for the flows from the battery to the customer.

The Community Battery project has been designed in a way to deliver benefits across the supply chain to optimise network savings and revenue. Our modelling has found that in the majority of cases, there would still be a funding gap to recover the total costs of the battery (net of payments from contestable services). As described in Section 8.4, for the purposes of the analysis in this study we have assumed a customer benefit equivalent to the avoided capital expenditure associated with individual batteries for participating customers, as a proxy for the total customer benefits. As further shown in a sensitivity tested in Appendix E.1, removal of this benefit would impact the economics of the Community Battery Initiative by moving the breakeven date out from 2023 to 2028.

Consideration of the wider market benefits from the community batteries in setting the regulated revenue allowance will help to resolve this and ensure that the benefits of the Community Battery Initiative are delivered to customers. We believe that recognising the broader market benefits of community batteries in calculating the percentage of battery costs recovered through AER regulated revenues is consistent with the long term interests of customers. This is because in the absence of community battery:

- Network costs (and hence prices) are higher;
- Societal investment costs are higher; and

- The value contribution of the battery to improving efficient outcomes in the wholesale market and ancillary service markets are not captured. The community battery has the potential to temporarily subdue wholesale price spikes and also to lower FCAS costs in NSW. [14]

Current aspects of the regulatory arrangements such as the regulatory investment test principles[15] and the AER DMIS could form a framework for considering these issues. In certain circumstances, these mechanisms allow for non-direct benefits from network projects to be internalised into the regulated revenue where there is a net benefit to customers.

However given the nature of the community battery with a high degree of direct customer participation, the shared nature of the asset and diverse range of market benefits, new innovative mechanisms may be warranted to treat this type of DER model. This issue would benefit from further consideration and options assessment including wide discussions with stakeholders to ensure consistency with NEO. It will be important to make sure that any mechanism must not create perverse incentives on the network or customers regarding the efficiency of the Community Battery Initiative. Further AER may also consider it appropriate to limit recovery of these customer benefits where there is an identified network need to be resolved.

In any event, any regulated allowance for the battery must not be more than the total costs of the battery minus any direct revenue earned through contestable services and customers should not be exposed to any commercial risk associate with the battery.

[14] While the operator will receive a direct benefit payment from energy arbitrage and FCAS participation, it will not be able to capture all the customer benefit from the actions of discharging the battery. This is the paradox for all forms of demand side participation – where the value is in the wholesale price spikes but the demand side action has the effect of reducing the value. The AEMC Demand Response Mechanism is an attempt to overcome this barrier to demand response.

[15] The RIT-D states the following as a market benefit is defined as "changes in costs for parties, other than the RIT–D proponent, due to differences in: the timing of new plant, capital costs, and operating and maintenance costs" The term "parties" is not defined in the NER nor the AER RIT-D application guidelines. KPMG do not see any credible argument to state that domestic batteries are not part of the NEM nor that all customer costs and benefits should be excluded from a RIT-D or expenditure assessment. This may need to be clarified by the AER.

10.4. Proposed regulatory amendments

In accordance with the regulatory issues identified above, the following table presents the options for Ausgrid with respect to regulatory exemptions/amendments.

			When is the exemption needed		
	Required Exemption	**Regulatory Instruments**	**Pilot**	**Commercial roll out**	**Reasons**
1	AER to approve waiver to Ring Fencing Guidelines to allow Ausgrid to provide customer battery services	NER Clause 6.17 & AER Ring Fencing Distribution Guidelines	Yes	Maybe not if Ausgrid decides to go via retailer under the mass roll out scenario	Under the AER ring-fencing guidelines, Ausgrid as a DNSP will be prohibited from providing either battery access services to customers as these are classified as contestable energy services by the AER. This could be justified as there is no negative impact on competition in electricity retail services under the pilot.
2	AER to exempt the flows from the battery back to customer premise from the operation of the revenue cap	NER Clause 6.4.3`	Yes	Yes	Under current arrangements, such flows will be treated as additional volumes and therefore the additional revenue paid by customers will be recognised as an over-recovery above the Maximum Allowed Revenue Cap in that year. This will be passed through to customers in the next year through lower network charges. This effectively means that the Community Battery Scheme will result in a subsidy to non-participating customers. In the absence of this derogation, the costs of the Pilot will be higher.
3	AEMO to provide clarification and appropriate treatment of Community Battery Access to FCAS market	AEMO Market Ancillary Service Specification (MASS)	Yes	Yes - and expect substantial changes to AEMO MASS. AEMO would need to change its Market procedures for community battery	Traditionally, FCAS in the NEM have been provided by utility-scale transmission connected plants that have high-speed data recorders in place as standard to confirm they are able to meet their registered Generator Performance Standard. AEMO has already allowed for different standards & telemetry/measurement requirements for the VPP demonstration trials (see https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/VPP-Demonstrations/VPP-Demonstrations-FCAS-Specification.pdf) and similar treatment should be provided for the community battery pilot.

	When is the exemption needed				
	Required Exemption	**Regulatory Instruments**	**Pilot**	**Commercial roll out**	**Reasons**
4	Exemption from 5 MW threshold for small generators to access and trade in the wholesale market and recognition by AEMO to treat the group of physical batteries as a single battery unit for wholesale market purposes	AEMO Market Registration and classification guides/AEMO system security procedures	Yes	Yes	AEMO's policy is that proponents of battery systems with an aggregate nameplate rating greater than or equal to 5 MW, whether directly connected to the network or integrated behind the meter with new or existing generation, are to be registered as both Generators and Market Customers. Their generating units should be classified as scheduled and market, and the load classified as scheduled load. To participate in the NEM the battery must be registered as a Market Generator (for electricity being exported to the grid). It must also register as a Market Customer (for electricity being imported from the NEM if the battery is more than 5 MW. If less than 5 MW the battery could source electricity via a retail contract without being settled in the wholesale market).
5	Ausgrid is not required to change its Cost Allocation Methodology to account for the battery asset costs allocation across regulated and contestable services	NER Clause 6.15 & AER Cost Allocation Methodology guidelines	Yes	Maybe, expect that under a wide roll out there would be a requirement for Ausgrid to adapt its CAM for community batteries	It is important to note that while the community battery is considered to be a shared asset (providing both regulated and unregulated contestable services) the AER shared asset guideline with the 10% revenue sharing mechanism only applies to existing assets. Therefore, the battery costs need to be shared according to Ausgrid's Cost Allocation Methodology (CAM). For a pilot or trial, the net costs of the battery would be funded under the AER distribution determination. Therefore we assume that there would be no need to consider whether to allocate remaining costs across regulated and contestable services.

	When is the exemption needed				
	Required Exemption	**Regulatory Instruments**	**Pilot**	**Commercial roll out**	**Reasons**
6	Customer flows to the battery are exempt from network tariffs	NER Clause 6.18 and AER approved Tariff Structure Statement	Not necessary but would increase the costs for the pilot	Yes, may require a special tariff for dual load/generation	Under current arrangements, all inflows into the community battery is assumed to flow from the wholesale market and therefore will be levied at the appropriate network tariff applicable to that connection point. This will add to the costs of a pilot project in the absence of any network tariff changes. However if the battery was installed at the premises, such costs would not be levied on the flows from the solar PV installation to the battery. Therefore in the absence of this exemption, the costs of the community battery will be higher.
7	Flows to the battery are exempt from retail environmental scheme costs	NECF and NSW legislation	Not necessary but would increase the costs for the pilot	Yes	Environmental policy costs account for approximately 6% of residential tariffs. This includes both Federal and NSW State schemes (Climate Change Fund, Energy Saving Schemes). If the battery was installed at the premises, such costs would not be levied on the flows. Therefore in the absence of this exemption, the costs of the community battery will be higher.
8	Ausgrid is able to introduce a new tariff for decentralised tariff flows from the battery to the household	NER Clause 6.18 and AER approved Tariff Structure Statement	Not necessary but would increase the costs for the pilot	Yes	Rule 6.18.4 of the NER prevents a DNSP from charging customers with a similar connection and usage profiles differently. Further, there are restrictions under the AER approved Tariff Structure Statement on introducing tariffs part-way through a regulatory period (2019 to 2024). AER has in the past rejected proposals from DNSP to assign special tariffs for solar PV customers due to NER clause 6.18.4. Therefore a rule change may be needed.

When is the exemption needed					
	Required Exemption	**Regulatory Instruments**	**Pilot**	**Commercial roll out**	**Reasons**
9	Ausgrid receives compensation in regulated revenues for customer related benefits from the CB in order for recover the corresponding proportion of the network battery costs	NER Chapter 6 expenditure objectives. AER RIT-D guidelines (and NER Chapter 5 provisions) and AER Demand Management Incentive Scheme Guideline	Don't believe this is necessary as Pilot can be funded under the 2019-2024 allowance	Yes, a new mechanism may be needed to recognise and capture the nature of market benefits from the battery	The question of the extent that the battery could qualify for a proportion of costs to be recovered through regulated revenue due to the wider community benefits needs to be further explored. While this would improve the viability of the project there are other aspects from the NEO perspective to consider.
10	Exempt battery flows to and from the participating customers from the AEMO wholesale Settlement rules and procedures	NER Chapter 3 and AEMO Settlement Guides	No - we are assuming that this change will not be able to be progressed	Yes - to avoid any double counting of retail energy costs onto the participating customers	To avoid double payment on customers participating in the Community Battery Initiative we advise that the AEMO wholesale market settlement to allow the customer energy flows to and from the battery is to be separated out and treated differently for settlement purposes (effectively netting out the community battery). This would be achieved under a subtractive metering arrangement.
11	Application of the Feed in tariffs for participating customers	NSW NECF rules on feed in tariffs	No - under the pilot participating customers would continue to receive FIT	Maybe subject to customers under roll-out scenario	The Feed in Tariff scheme is a voluntary mechanism in NSW so no exemptions or rule changes may be needed for a standardised roll out scenario as we assume that retailers would no longer provide this payment to participating customers on the grounds that exports are no longer recognised in the wholesale market (under proposed exemption #10). However an amendment/direction may be needed to clarify this.

11. Which configurations are expected to break even and when?

The overall commercial viability of the project will depend on optimising the revenue across the multiple value streams within the technical, regulatory and operational constraints of the potential configurations identified for each DC. This will depend on balancing the use of the battery for the network, customers and wholesale market, taking the network constraint and the nature of the service offered to the customers into account.

11.1. Definition of Configurations

Taking into consideration the Battery Solutions and Network Conditions that have been identified in this study, an end use case has been determined for each DC, and in the case of DC4, several end use case options.

	Use Case 1 (Battery can meet moderate overload levels for smaller communities only)	Use Case 2 (Battery can meet up to 30% for most medium sized communities)	Use Case 3 (Battery can meet up to 30% for the full range of community sizes)
Battery Solution A1 (K – Kiosk, 500kWh)	DC1 (<70 customers)	DC2 (< 120 customers) DC 3 (< 160 customers)	DC4 (150 < 250 customers)
Battery Solution A2 (K – Kiosk, 250kWh)			DC4 (< 150 customers, future upgrade)
Battery Solution B (L – Kiosk, 250kWh)			DC4 (< 150 customers, space constraint)

For the purposes of this report, the following Configurations were tested, combining the above Battery Solutions and network Use Cases:

Configuration 1	Configuration 2	Configuration 3
Use Case 1 Battery Solution A1 DC1	Use Case 2 Battery Solution A1 DC3	Use Case 3 Battery Solution A2 DC4

The cost difference between a K type kiosk and L type kiosk is estimated to be marginal (in the region of $10k-$20k). Hence, the costs of Battery Solution A2 and B are assumed to be the same and hence would have the same commercial outcome.

In terms of dispatch hierarchy for each of the above configurations, the following is assumed:

1. **Network Service:** It is assumed that the operation of the battery will be restricted in such a manner as to ensure that the battery is available to meet any network overload conditions, which is expected to occur on a limited amount of days per year. Weather forecasting will be used to predict likely network services that will be required and the Battery Operator would need to ensure that the battery is charged to meet those conditions.

2. **Customer Use:** The Battery Operator will need to ensure that any amount of energy stored in the battery by the participating customers is available for dispatch to customers within the assumed 24h reset period. For modelling purposes, it is assumed that this stored energy will be returned to customers during the peak price period, and hence on days when the battery would also potentially be used for market trading, the cycle with the highest price spread is adjusted down such that customers receive their stored energy first.
3. **Wholesale Market Trading:** The battery will be available to allow a market participant to take advantage of arbitrage and FCAS ancillary service opportunities in the NEM, while located in the Ausgrid network. Use of this device for this service will be constrained by the above requirements to mitigate network overload and obligations to customers participating in the Community Battery Initiative.

11.1.1 Network revenue

Network revenue has been calculated by determining the quarterly annuity value equivalent to the estimated transformer CAPEX at an implied cost of capital of 3.5% p.a. over its 45 year useful life. This annuity is then adopted as network revenue over the 15 year life of the battery. Different network avoided CAPEX scenarios have been applied depending upon the battery capacity for the specific battery solution. For the 500kWh use cases, we have assumed avoided network CAPEX of $250,000, while for the 250kWh use case, the network avoided CAPEX is assumed to be between $50,000 and $125,000 (for the purposes of modelling, we have assumed $125,000 as the standard for a 250kWh battery). The table below presents the assumptions on network avoided CAPEX.

Table 14 Network Assumptions

Network Assumptions	Value	Units
Pre-tax real Cost of Capital	3.5	%
Estimated transformer life	45	years
Transformer CAPEX (500kWh)	250,000	$
Transformer CAPEX (250kWh)	50,000-125,000	$
Network avoided CAPEX (500kWh)	582	$/quarter
Network avoided CAPEX (250kWh)	291	$/quarter

11.2. Battery model

This model combines all the quantified revenue streams and costs to assess the economics of each of the above configurations.

11.2.1 Battery model financial assumptions

The Community Battery Initiative is assumed to be funded by a mixture of Ausgrid's own balance sheet and grant funding. Ausgrid provided an assumed discount rate – due to this project's early stage of development, the rate provided is conservative and may be adjusted at a later stage in the project development.

Table 15 Financial assumptions for battery model

Financial Assumptions	Value	Units
Discount Rate (Project and Ausgrid)	~ 9%[16]	%
Discount Rate (Community Battery Operator)	12	%
Asset life	15	Years

[16] Assuming relatively high level of risk due to the early stage of development

Indexation rate	2.5	% p.a.
CAPEX (Base Case)	95% AECOM/CSIRO interpolated CAPEX	%
CAPEX (Conservative Case)	125% AECOM/CSIRO interpolated CAPEX	%
CAPEX (Optimistic Case)	70% AECOM/CSIRO interpolated CAPEX	%
FCAS Capture Rate (Base Case)	50% Historical FCAS data	%
FCAS Capture Rate (Conservative Case)	10% Historical FCAS data	%
FCAS Capture Rate (Optimistic Case)	90% Independent energy market forecast	%
Network revenue (500kWh)	582	$/quarter
Network revenue (250kWh)	291[17]	$/quarter
Net customer avoided CAPEX (2018)	DC Profile 1 - 815 DC Profile 2 - 725 DC Profile 3 – 709 DC Profile 4 - 752	$/quarter
Net customer avoided CAPEX (2023,2028)	DC Profile 1 – 766 DC Profile 2 – 981 DC Profile 3 – 1742 DC Profile 4 - 1585	$/quarter
O&M costs	10,000	$/year
Ongoing customer support costs	0.22	$/customer per day
Depth of discharge	95%	%
Degradation rate	2.5%	%
Round Trip efficiency	88%	%

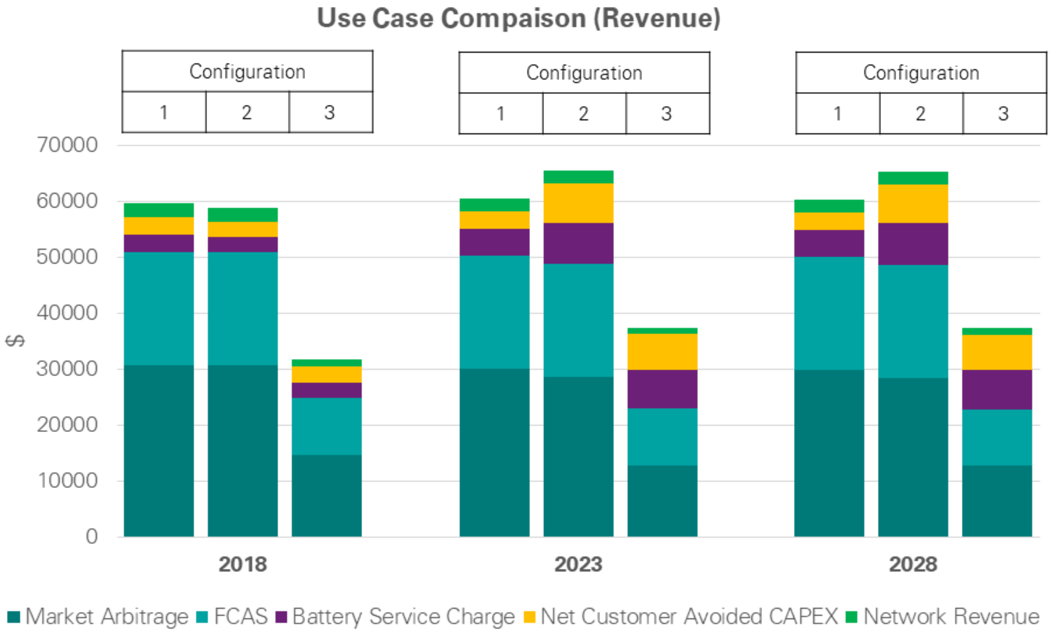
[17] Based on assumption of $125k network investment as a base case

11.3. Key findings

11.3.1 Comparison of revenue stack and NPV

The graph below represents the revenue profiles of Configurations 1, 2 and 3. On average, market revenue (FCAS and arbitrage) account for 80% of total revenue for Configurations 1 and 2 (500kW battery), with **network revenue only 4%** and the balance from customer's battery service charges and net avoided CAPEX.

Figure 31: Base Case, Revenue Breakdown ($/annum)



- **Revenue from customer payments and customer savings in Configurations 2 and 3 becomes more significant from 2023** where these sources account for more than 20% of the total revenue stack. Configuration 2 and 3 represent DC 3 and DC4, respectively – **larger DCs with higher potential for solar PV customer growth.**
- **DC4, with the lowest maximum load per customer, is able to meet the network need with a smaller, 250kWh battery,** and hence the balance between revenue streams is more evenly spread. On average, market revenue (FCAS and arbitrage) accounts for 61% from 2023, while customer's battery service charges and net avoided CAPEX account for 36%.
- **Configurations 1 (DC1) and 2 (DC3) have higher loads per customers and requires a 500kWh battery to meet network,** and hence revenue from the market is more pronounced.

The project NPVs are shown in the figure below:

Figure 32: Base Case, NPV Comparison

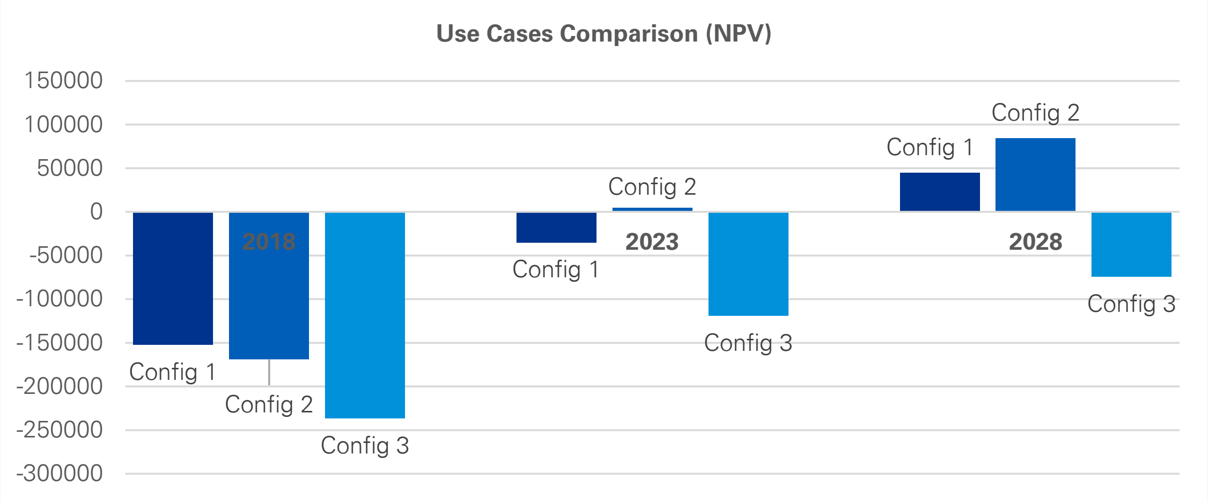
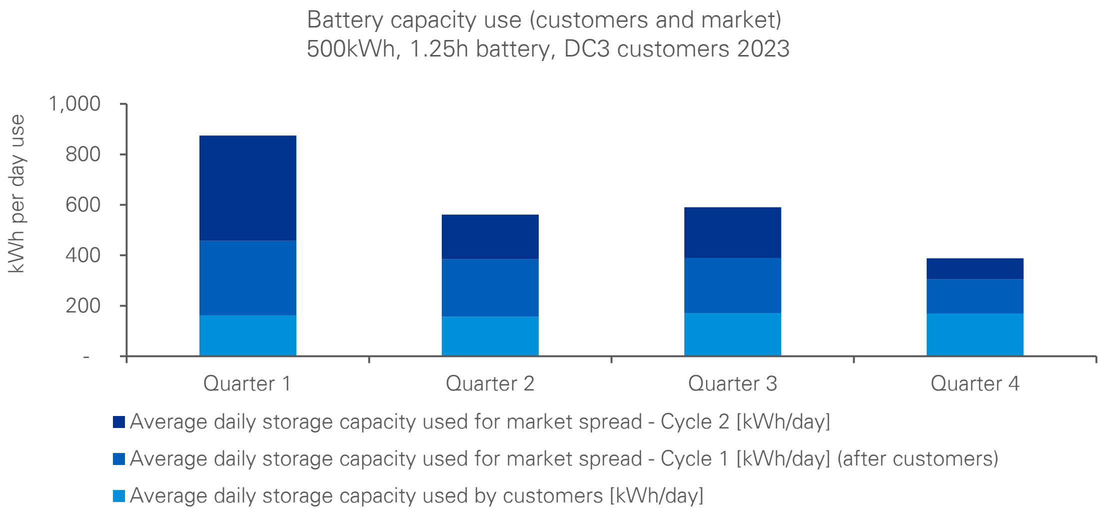


Figure 33: Customer and market use of battery capacity, Configuration 2



- **Configuration 2 (500kWh batteries) can break even on an NPV basis in 2023.**
- Configuration 2 corresponds to a 500kWh, 1.25h battery for DC3, up to an overload level of 30%. This represents the highest NPV and was found to be the **Optimum Configuration** from an economic perspective.
  - **DC 3 has the highest number of solar PV customers, a high number of total residential customers and a high proportion of Profile 1 customers. This implies that DC3 has a high potential for customer revenue growth, due to upgrade of PV systems and uptake of solar PV.**
- **This is confirmed by the revenue breakdown, where the highest customer revenue in all cases was observed for this case - 6% higher than Configuration 3 and 54% higher than Configuration 1.**
- **Further, the customer use of the battery is not detrimental to the ability to use storage capacity for market trading,** and since network revenues are largely the same for the same sized battery, **the difference in customer revenues translates into a higher NPV for Configuration 2.**
- Under the base case assumptions, **Configuration 3 doesn't break even in the medium term**. This is mainly due to the lower level of market revenue potential and hence the **larger revenue gap** that needs to be compensated by the network and customer contributions, which is insufficient. However, this does not account for other societal benefits, which is discussed further in Section 12.4. Also, the results would be far more positive under the High market assumptions and bulk purchase assumption.

11.3.2 Optimum Configuration Sensitivities

On the basis that Configuration 2 presents the optimum case among those analysed, we have applied optimistic and conservative sensitivities for CAPEX, FCAS and market arbitrage revenue.

As identified in section 11.2.1 above, our optimistic and conservative assumptions are as follows:

- **Optimistic case**
  - Market arbitrage revenue – 2007 market volatility and spread
  - FCAS assumptions – 90% capture rate applying Independent energy market forecast $/kWh assumption
  - CAPEX adjustment – 30% reduction in the interpolated AECOM/CSIRO for 2023
- **Conservative case**
  - Market arbitrage revenue – 2018 market volatility and spread
  - FCAS assumptions – 10% capture rate applying Historical FCAS data $/kWh assumption
  - CAPEX adjustment – 25% increase in the interpolated AECOM/CSIRO for 2023

The comparative revenue profiles and NPV results for these sensitivities as compared with the optimal base case are presented below.

Figure 34: Configuration 2 Sensitivity Revenue Breakdown ($/annum)

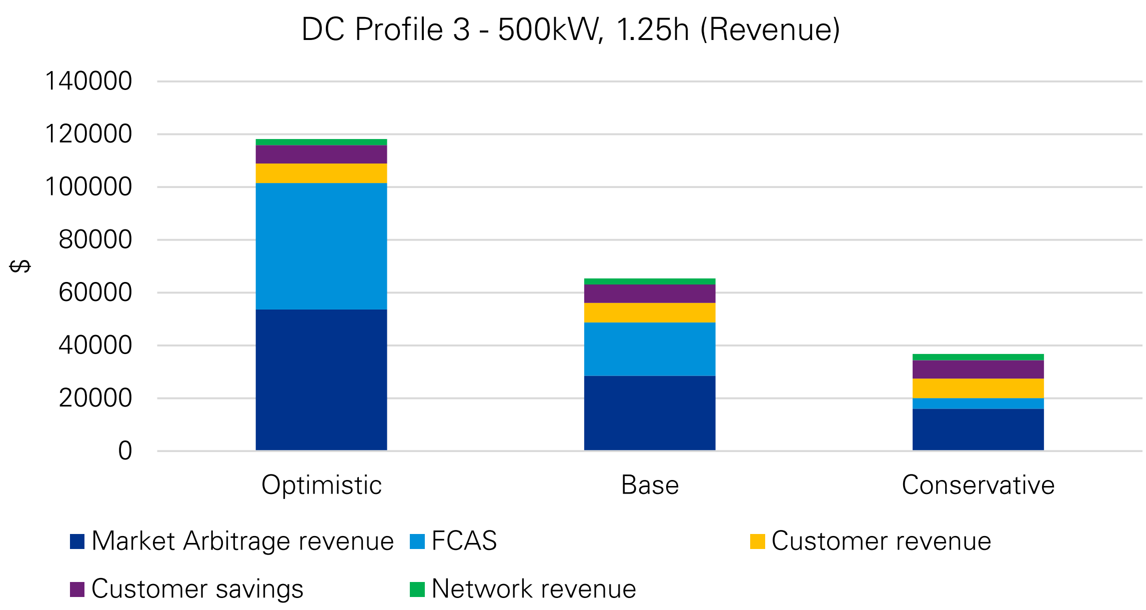
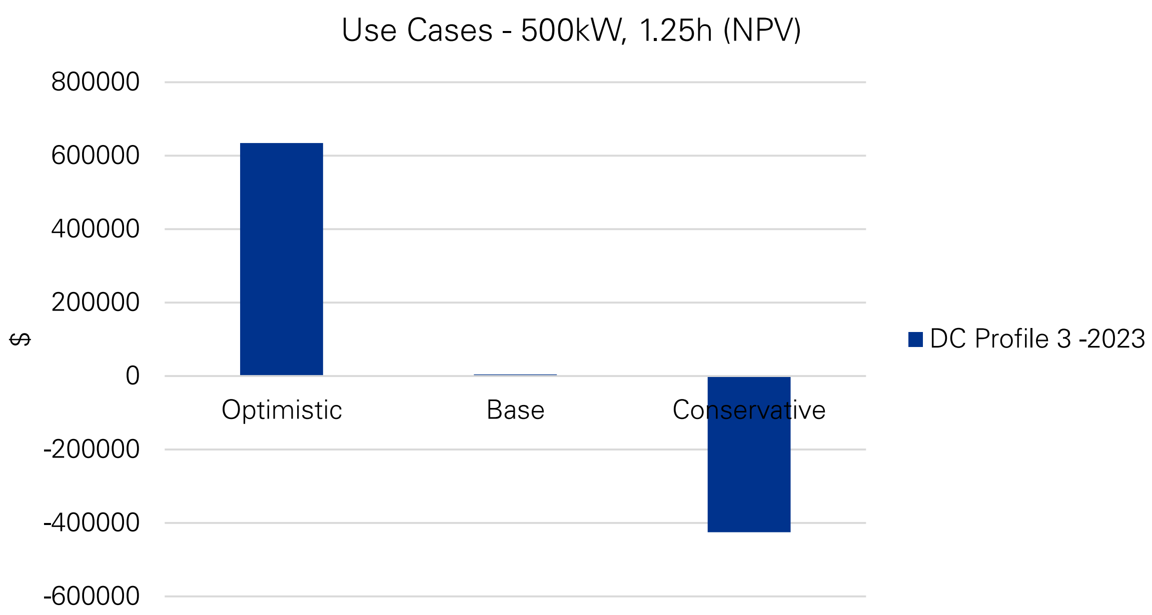


Figure 35: Configuration 2 NPV Comparison



- **Applying the sensitivities to FCAS capture and market volatility significantly affect the market arbitrage and FCAS revenue levels.** Under conservative assumptions, Configuration 2 would no longer break even the breakeven by 2023m but could break even by 2028.
- **These revenue adjustments along with the CAPEX adjustments leads to results which increase the project NPV of approximately $660,000 from the base case in the optimistic case and a reduction in the project NPV of approximately $370,000 from the base case in the conservative case.**
- The results indicate that the business case is highly sensitive to market assumptions, as well as assumptions in cost reductions over time.

12. Considerations for Ausgrid to implement the Community Battery Initiative

This study has identified a range of scenarios where the identified battery solutions and projected future network use cases could potentially be feasible. In order for Ausgrid to implement a proposed programme such as this, a range of additional factors would need to be investigated and further analysed. This Chapter describes the key considerations in designing the final Community Battery Initiative. We have analysed regulatory changes that would be required, and a cost benefit analysis of an example case that could help progress the business case of a Community Battery as an alternative network investment.

12.1. Key Community Battery Initiative design considerations

A number of key principles have been assumed for the purposes of this study. The pilot will enable Ausgrid to test a generic technical battery solution to enable selection of future potential sites and applications for standardised roll out. The pilot also serves the purpose of facilitating testing of various operating and commercial models. The ultimate commercial and regulatory plan will largely be driven by the requirements for widespread deployment.

Figure 36 Planning update

12.1.1 General assumptions

A number of simplifying assumptions have been made in the study. These include:

- Ausgrid (or its related party, unless classified as a market participant) would not be able (or permitted) to operate the battery for wholesale market trading and therefore a separate community battery operator (CBO) will be appointed.
- The CBO will have responsibility for operating the battery on a day to day basis and must comply with contractual obligations to meet network limitation needs plus any regulatory obligations. The CBO will decide how best to charge and discharge the battery subject to these constraints.
- Given the diverse range in size and time of customer exports within a DC, the Battery Service Charge has been structured in restricted unit sizes of kWh capacity, which is consistent with a simplified model for marketing purposes and customer acceptance.

- The tariff structure tested in this study has been simplified to this simple charge structure, as it would be easier to understand and communicate to customers. Although the intention is that customers would be compensated for unused energy, this was not modelled in this study as the package size was determined such that customers did not have any unused energy. However, more complex arrangements could be tested where customers could sign up for larger packages, that would result in excess stored energy on some days, which would increase customer revenue, and in this case the Battery FiT would also need to be established to compensate the customers for any unused exports (and enable peer to peer trading in future).
- Any potential profit sharing would be transferred to the customers via a lowering of the Battery Service Charge (hence an indirect profit share). This must be designed in a way to be compliant with the AER ring fencing guidelines. We believe that this is possible as long Ausgrid does not act in a discriminatory manner to charge or discharge the battery.
- Both residential and commercial & industrial customers will ultimately be able to participate in the Community Battery Initiative. For the purposes of this study, only residential customers have been considered.
- The incremental costs of enabling the battery to potentially participate in the FCAS markets are not material. This is subject to the technical assessment.
- There is a need to consider whether the commercial model needs to vary between seasons – i.e. summer versus winter given that the customer needs and the wholesale market value will materially differ across these periods.

12.1.2 Regulatory change assumptions

The regulatory framework should be amended to support innovative models such as the Community Battery Initiative to provide more value to customers and integrate storage into the existing network. We have assumed that the changes identified in Section 10 have been amended to support its feasibility.

The key assumptions to note:

Pilot

- The current regulatory arrangements add to the costs of the Community Battery Initiative which would need to be funded.
- Under the revenue cap formula, battery volumes back to the customer will be viewed as additional volumes. Seeking AER approval to treat such battery volumes differently for the revenue cap calculation would reduce costs.
- The project is able to reasonably access and participate in wholesale and FCAS markets.
- Potential waiver under AER ring fencing may be needed subject to further consideration on the classification of services.

Commercial

In the future, commercial application of the Community Battery Initiative would require the following:

- A mechanism to separate out and net off battery volumes away from market volumes. This could be best achieved through amendment to AEMO settlements.
- Potential design of a special network tariff for localised small distance flows to support decentralised transactions.
- Agreement with AER on treatment and separation of regulated services and costs from the commercial revenue streams.
- Metrology arrangements for calculating battery flows.

As noted earlier, these changes would also better facilitate other DER type services.

12.2. Customer Journey

A potential customer journey for the pilot is captured below for illustrative purposes – assuming customers have an existing, suitable PV installation. It is expected that this approach will be further tailored during the pilot and developed for the proposed commercial roll out.

The key difference is that during the pilot, no regulatory changes are assumed to be implemented and participating customers would still be liable for all energy imported via their retail contract. Hence, Ausgrid would need to compensate the customer via a credit or 'energy rebate' for stored energy that is virtually returned from the battery. Depending on the design, location and uptake of the pilot, Ausgrid would need to consider the trade-off of this rebate against revenue from this virtual customer energy that can be sold to the market.

Figure 37 Customer journey plan

Step 1: Receives the offer

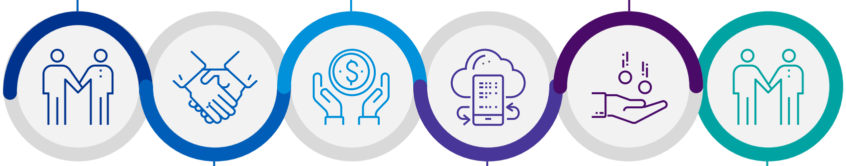
The PV customer receives a mail offer with Help Line details outlining the purpose of the pilot community battery scheme, the services and flexibility offered by the scheme, the timeframe for the trial and the pricing offer

Step 2b: Pay fee

The customer pays a nominal participation fee (battery service charge) for the duration of the trial, payable to the Battery Operator.

Step 4: Receive $XX back

The customer will receive an energy rebate [quarterly] which will be calculated based on their retail contract and their metering data.



Step 2a: Sign up

The customer signs up to the community battery pilot scheme, with the contract for the trial being between the customer and Ausgrid. As part of the contract the customer will provide their most recent retail bill* which displays their tariff to enable calculation of rebates to remove problem of imports from battery being charged at full retail price.

Step 3: See battery on App

The customer would download an App/sign on to a hosted website which enables a real time view of energy exported and imported from the battery and customer costing profile. This could provide an estimate of the customer savings under the scheme

Step 5: Trial end

Final rebate accompanied by feedback request on customer experience and advisement of anticipated next steps.

12.3. Ausgrid Proposed Model

This model estimates the potential lease to be paid to Ausgrid by the CBO.

12.3.1 Community Battery Operator Lease

There are various permutations for the lease arrangement with the CBO which Ausgrid may consider, depending on the risk allocation between parties. A simplified approach is presented below, which captures two main options.

In essence, the CBO has access to two value streams from the Battery - Customer and Market. The Customer stream has firm capacity and fixed revenue (i.e. customer pays fixed fee to CBO and there is a set capacity designated for customer use). The Market stream could either have a firm or conditional capacity[18], depending on which option is chosen.

Figure 38: Summary of two main options for lease structure

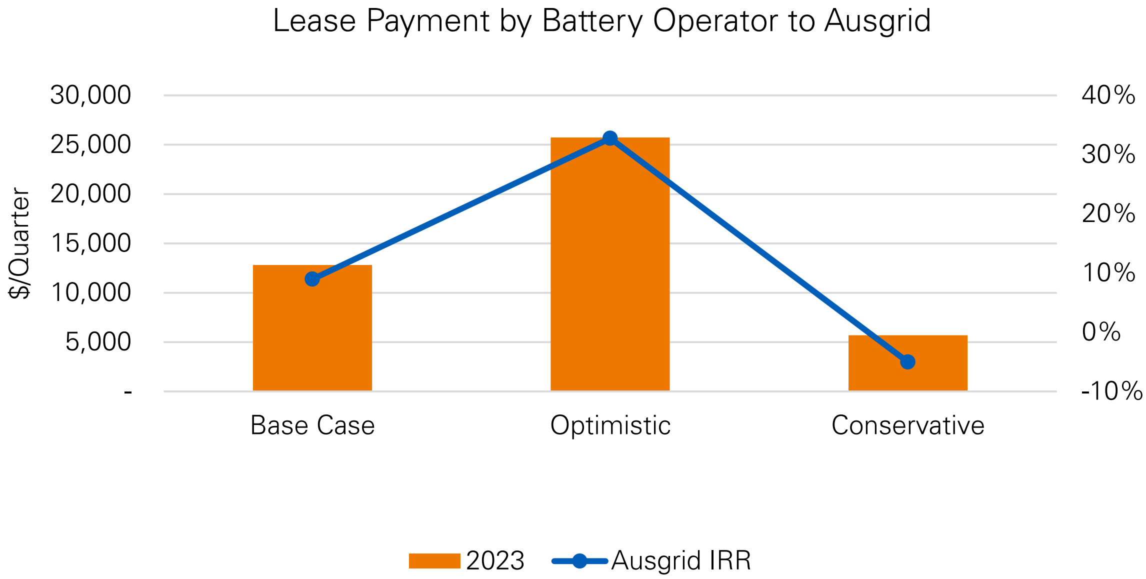
	Option 1	Option 2
Fee structure	• Both Customer and Market capacity are firm • Ausgrid charges the CBO a fixed lease fee for customer and market capacity	• Customer capacity is firm while the Market capacity is conditional • Ausgrid charges the CBO a fixed lease fee for customer capacity and variable profit share fee for market capacity • The fixed fee is smaller and linked to firm revenue (e.g Customer revenue) • Variable profit share is linked to realised market revenues at an agreed %
Risk profile	• The risk is taken on solely by the CBO • During years of low revenue opportunities ("bad year") the CBO must still pay a high fixed fee. The CBO risks unprofitable project economics.	• Market volatility risk is shared between Ausgrid and the CBO • Both share profits in 'good years' and share losses in 'bad years'

For the purposes of our analysis, **Option 1** was considered to estimate the potential lease amount and resulting returns for Ausgrid. For the purposes of the analysis we have assumed the minimum return of 12% to CBO. The lease payment to Ausgrid was solved by calculating the lease payment value which would still enable the **CBO to achieve a 12%** on battery income in the Optimum Configuration. We have also tested the lease payment and associated returns for Ausgrid in the base case and compared to optimistic and conservative cases. This assessment was done to understand the impact on Ausgrid's return, should the lease payment be set on different market and revenue assumptions, which would translate to the different lease structure options.

[18] *Firm Capacity: CBO always has access to set level of capacity. Conditional Capacity: Use-case hierarchy is imposed – network needs has first priority of capacity. CBO has access to variable capacity*

The results are presented below:

Figure 39: Lease Payment and Ausgrid IRR



In designing the lease structure and finalising the business case, Ausgrid would need to do further analysis to ensure that the Community Battery Initiative is sufficiently attractive to the Community Battery Operator, while balancing the potential risk and returns for both parties.

12.4. Cost-Benefit Analysis

12.4.1 Approach

A Cost-Benefit analysis (CBA) was undertaken for the Optimum Configuration. The CBA extended from the battery model and used the base case scenario assumptions and inputs for this case. The lease amount for the base case, discussed above, was used to inform the CBA for Ausgrid and the CBO. A description of all the cost and benefit components used in this analysis is outlined below.

Table 16 Project CBA elements

	CBA Element	Description
Net Project Costs	Customer Handling Costs	Cost incurred by the CBO due to retailer activities, such as customer installation and support costs.
	Battery O&M	Cost incurred by the CBO to operate and maintain the battery.
	Battery CAPEX	Cost incurred by Ausgrid to build the battery.
Internal Transfers	Battery Service Charge	Fee charged to customers by the CBO to recover Customer Handling Costs and the Special Network Tariff (see below).
	Lease Amount	Lease charged to the CBO by Ausgrid to recover the battery CAPEX.
	Special Network Tariff	Fee charged to the CBO by Ausgrid as compensation for use of the distribution network.
Net Project Benefits	Net Customer Avoided CAPEX	CAPEX cost avoided by customers through the use of the community battery
	Customer Energy Savings	Savings to customers through the use of the battery and reduced grid energy use.
	Market Arbitrage Revenue	Revenue derived by the CBO through arbitrage activities in the wholesale market.
	FCAS Revenue	Revenue derived by the CBO from trading ancillary services.
	Network Revenue	Revenue recovered from the network as part of the Regulated Asset Base
	Terminal Value	*Not modelled due to complexity*
	Option Value	*Not modelled due to complexity*

The allocation of cost and benefit components to each project stakeholder is shown below.

Table 17 Project CBA elements

	Customer	CBO	Ausgrid
Project Costs	• Battery Service Charge*	• Lease Amount*** • Special Network Tariff** • Customer Handling Costs • Battery O&M	• Battery CAPEX
Project Benefits	• Net Customer Avoided CAPEX • Customer Energy Savings	• Battery Service Charge* • Market Arbitrage Revenue • FCAS Revenue • Net Customer Avoided CAPEX*	• Lease Amount*** • Special Network Tariff** • Network Revenue • Terminal Value (unquantified) • Option Value (unquantified)

*The Battery Service Charge is compensation from Customers to the CBO, and as such, does not influence the overall project costs and benefits.

**The Special Network Tariff is compensation from the CBO to Ausgrid and does not influence the overall project costs and benefits.

***The Lease amount is compensation from the CBO to Ausgrid and does not influence the overall project costs and benefits.

12.4.2 Cost Benefit ratios

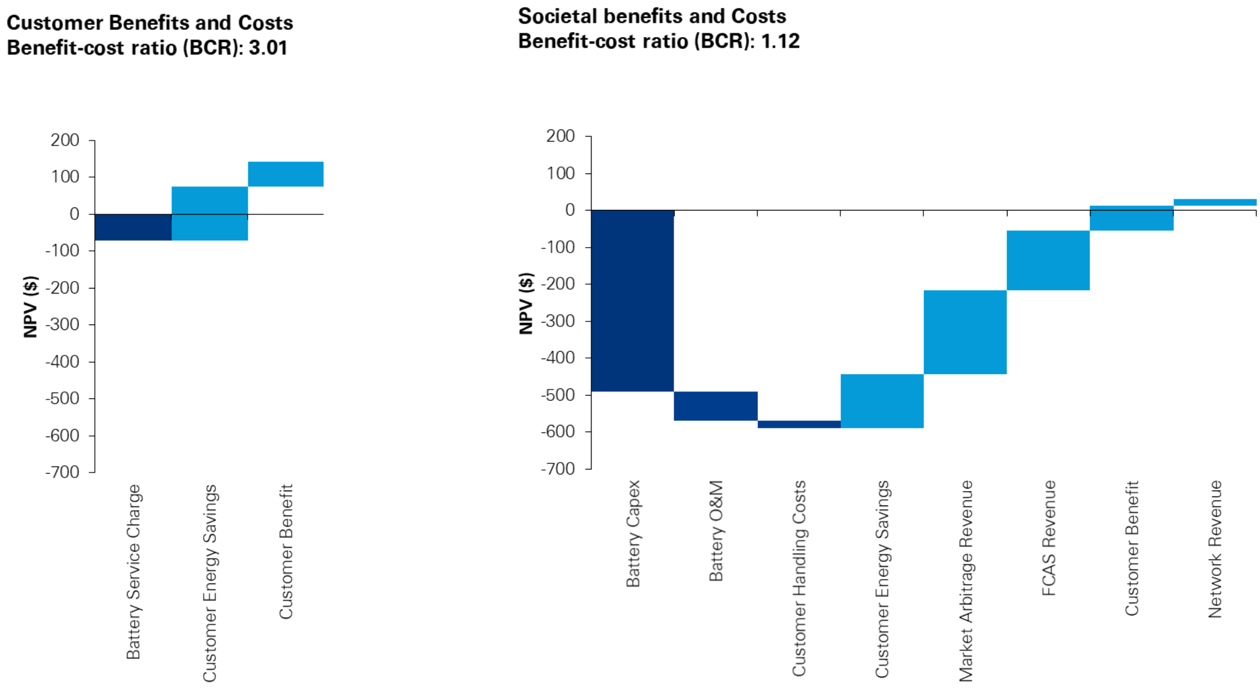
The ratio of overall project costs and benefits described in the above table is shown below, from the point of view of each project stakeholder. The overall project's benefit to cost ratio has also been calculated, and it ignores transfers amongst stakeholders (the Battery Service Charge, the Lease and the Special Network Tariff).

The resulting Benefit to Cost ratios (BCR's) and cost and benefit waterfalls for Configuration 2 are shown below by way of example.

Table 18 Project CBA elements

	Customer	CBO	Ausgrid	Project/Societal
BCR	3.01	1.00	1.01	**1.12**

Figure 40 Summary of NPV of costs and benefits to participating customers and wider societal benefits



Investment Test

The model also evaluates the net present value of undertaking a transformer upgrade, as a comparison to the community battery's present value – ignoring any revenue recovered from the network, i.e. network revenue is assumed to be zero. This is calculated by spreading the transformer upgrade cost over a 45-year period. The analysis considers $50,000, $125,000 and $250,000 upgrade costs, as the potential network investment levels (low, medium, high). The outcome of this analysis is summarised in the table below. Depending on the level of investment that is offset by the battery, it is clear that, for Configuration 2, the net present value of the battery would always exceed that of a transformer upgrade. This is due to the fact that while the transformer addresses a network need, it does not generate any additional revenue. The battery, on the other hand, is able to generate revenue from customers and the market, while serving the network need which only occurs on a few days of the year, and hence the benefit derived from the battery is far greater.

Table 19: Traditional network investment cost levels used to compare with battery investment cost

Community Battery NPV	Transformer Upgrade NPV	
NPV	*Upgrade Cost ($ thousands)*	*NPV*
$125k	$50k	-$18k
	$125k	-$46k
	$250k	-$91k

Note: NPV of the battery project excludes network revenue in this analysis

12.4.3 Secondary (unquantified) benefits

There are a number of additional benefits this project may bring, however, given the availability of data they are not included in the analysis. These include:

- Wider system benefits which may be recovered through regulated charges, such as wholesale benefits.
- Reduction in customer network charges due to lowering of network investment value.
- Extra reward/penalty through regulated incentives.
- Network voltage support and other operational benefits from the battery.

12.5. Summary of stakeholder roles and benefits

The potential roles and benefits to the network service provider, the battery operator, financially responsible market participant managing customer interface, participating customers and the wider customer base are summarised below:

	Role	Risk	Benefits	Trial outcomes
Network service provider	Asset Owner	*Commercial*: Financing a community battery could be challenging due to limited precedence on the application of the business model as well as energy market uncertainty. *Technical*: Incorporating battery storage into the grid requires development of a decision framework by network operators to determine where community batteries should be considered as alternative investments to traditional network infrastructure. *Regulatory:* The commercial viability of a community battery hinges on a regulatory framework that would need to be developed to enable all the benefits to be captured by all relevant parties.	Utility scale battery storage can reduce peak demand on network assets through load shifting from times of peak demand to times of lower demand. Battery storage can play a role in managing voltage on networks, during voltage rise and drop situations. Installation of a community battery could offset the need for high network investment costs and upgrades. Batteries offer access to more clean energy options for the network.	Raise community awareness and understand drivers for community acceptance of local network installations. Understand cost of installation in the local network. Test integration, use and performance of battery in local network. Understand customer uptake and actual value of customer energy savings. Understand requirements to support contracting and negotiation with battery operators. Depending on revenue share model, understand potential for market upside or downside risk.
Battery operator	Asset Operator and Maintenance provider	*Regulatory*: There are a number of regulatory challenges like Ring-Fencing Guidelines; requirement to pay network charges (DuoS/TuoS); ability to meet AEMO's FCAS rule of 5 minute dispatch, etc. that might impact the battery operator.	Generate revenue by participation in the Frequency Control Ancillary Services (FCAS) markets. Access to wholesale market trading. CBO can enter into the Corporate PPA market by firming or increasing the	Understand integration with network and impact on battery operation. Test market arbitrage and FCAS revenue capture rate. Understand customer use of battery and energy losses.

	Role	Risk	Benefits	Trial outcomes
		Commercial: Risks of wholesale market volatility, revenue uncertainty, over supply and saturation of the Frequency Control Ancillary Services (FCAS) market can have potential impact on commercial viability of battery projects.	dispatchability of the power that is contracted.	
Battery operator	FRMP managing customer interface	Risk of underestimating the cost of handling.	Ability to offer new service to retain customer base. Ability to capture additional revenue and support business sustainability.	Understand cost of handling, interface technology. Understand customer uptake and preferences.
Participating customers	Participator	The risks for participating customers are expected to be minimal. Potential risks could include cases where customers might oversize their package leading to higher costs during the contract period compared to their energy savings, leading to reduced realisation of energy savings.	No upfront CAPEX required for battery installation No maintenance costs No space constraint Potential to offer a range of different storage size options Flexibility to change storage sizes if PV system size increases, or consumption patterns change	Public perception and acceptance and level of interest in participating. Customer preferences in terms of battery package offers. Customer views on level if information that can be accessed and preferred interface. Future tendency to drive further PV uptake.
Wider customer base	Non-participator	The location of the community battery may not address the network need adequately, or the business model may not support sufficient use of the battery, resulting in additional investment required to protect against network failures.	Reduction in customer base network charges due to reduced network investment cost. Access to clean energy and improved sustainability outcomes. Reduction in wholesale market energy prices.	Public perception and acceptance, interest in participating and future tendency to drive PV uptake.

13. Conclusions

The study has identified multiple Configurations of Battery Solutions combined with network Use Cases that would represent a positive NPV and BCR for a Community Battery Initiative to be implemented as an alternative network investment.

1	**What are the technical options and constraints for a community battery and how much would it cost?** The study found that the upper limit in battery capacity to fit into a single community enclosure would be **500kWh – 3 Battery Solutions** were identified and costs were estimated with input from suppliers.
2	**How do we expect the network conditions to change over time?** As the number of solar customers and PV sizes both increase over time, the **forecast high demand shifts to later in the day and the duration becomes shorter.**
3	**Which future network conditions are ideal for a battery solution?** **3 network Use Cases** were identified where a Battery Solution could meet network requirements for **various sizes of communities and at different overload levels.**
4	**What is the potential contribution and use of PV customers to a community battery?** **Five customer profiles were developed** and battery packages were tailored to maximise customer energy bill savings. We assume the **Battery Service Charge would always be lower than the estimated customer savings.**
5	**What is the market revenue potential of a community battery?** Although market revenue is highly uncertain**, combining market arbitrage and FCAS revenue, the potential is still significant.**
6	**What regulatory exemptions or amendments are required?** In order to support the future standardised roll out of the Community Battery Initiative as an alternative network investment, **a Rule Change may be required to enable customer energy flows to be treated separate to market energy flows** – effectively netting out the community battery. This would avoid double payment by customers for energy stored in the battery and imported via the same meter used to measure energy import via their existing retailer.
7	**Which end use cases are expected to break even and when?** Configurations 2 was found to be attractive – one example is Use Case 2 – **a medium sized community where the capacity of a 500kWh would be sufficient to meet overload conditions of up to 30%.**

Appendix A: State-based battery and retailers schemes

Table 20 Current Australian State-based battery schemes

South Australia Home Battery Scheme	In late 2018, SA government launched a subsidy program for home battery installation. Customers can get up to $6,000 off a solar home battery.
Adelaide City Council Incentives	The Adelaide City Council offers up to $5,000 in grants for installing battery-based energy storage.
NSW Solar-Battery Interest Free Loans ("Empowering Homes")	The NSW Government has announced an initiative to support the installation of 300,000 battery or solar+battery systems over the next 10 years through the provision of interest-free loans.
Queensland Home Battery Scheme	Queensland government announced a budget of $21 million to provide households and small businesses access to interest-free loans and grants for solar and battery systems.
Victoria Home battery scheme	The Victorian government offers applicants either a rebate or interest-free loan for a solar or battery home installation.

Table 21 Current Battery retailer schemes

Origin Energy Battery Acquisition	Origin are offering a $500 discount on Tesla 2 batteries (RRP $12,749) that are purchased through them.
Origin Energy VPP Plan	Origin are offering a 6.4kWh battery for $4,790 (RRP $11,350) with a 24 month interest free loan, locking the customer into an Origin retail plan during a five year trial period.
Simply Energy – Simply Extra VPP	Simply Energy are offering up to $5,100 VPP Access credits (effective discount on full battery cost), locking the customer in for a three year trial period.
AGL – Power Advantage	Customers can earn up to $280 in bill credits in the first 12 months when they bring their own battery to AGL's Virtual Power Plant.

Appendix B: Supplier questions

B.1 Stage 1 Questions

The Go/No-Go criteria was based on Ausgrid's view regarding the primary engineering or community concerns if a battery were to be installed in a public space. The primary difference between the required Stage 1 answers for the Pilot and the Commercial Case was whether the supplier could deliver a pilot by June 2020.

Stage 1 Questions - Go/No -Go	Pilot	Commercial Case
Do they supply to Australia?	Yes	Yes
Battery Chemistry	Lithium-ion	Lithium-ion
Does the supplier have existing installations in Australia?	Yes	Yes
Are the units design to operate in a public space, if not can they be installed in an enclosure designed by the supplier or third party?	Order of preference 1. Yes, designed for operation in a public space 2. Supplier can design an enclosure to Ausgrid specifications 3. Supplier can source a third party enclosure to Ausgrid specifications	Order of preference 1. Yes, designed for operation in a public space 2. Supplier can design an enclosure to Ausgrid specifications 3. Supplier can source a third party enclosure to Ausgrid specifications
Is their BESS suitable for Utility Network Grade or only intended for single Domestic/Residential application	Utility, or non-residential	Utility, or non-residential
What are the energy capacity ranges offered?	At least one model in the 50 kWh to 500 kWh range, roughly, with one that provides the best per kWh value	At least one models in the 50 kWh to 500 kWh range, roughly, with one that provides the best per kWh value
What are the C-rating ranges offered?	At least one model in the 0.25 to 2 range	At least one model in the 0.25 to 2 range
Can the unit be delivered and installed by June 2020?	Yes	Maybe
Do the units have communication/remote capabilities, noting the distribution kiosks locations may not have any, or any capability for a wired connection?	Yes	Yes

B.2 Stage 2 Questions

The Stage 2 questions either had a requirement or preference for the response or was left open to the supplier to return with an answer. Sizing was a key element and ideally would be no larger than a K-Type Kiosk footprint but depending on the costs and other factors larger units may be acceptable. The height was discussed, as was whether the units could be made shorter or be recessed into the ground. Recessing into the ground was not deemed feasible from a servicing perspective and would likely driving the costs higher. Ultimately it was determined that what is on the market appears to be acceptable in terms of height.

Stage 2 Questions - Go/No -Go	Pilot	Commercial Case
Engineering		
Do any of the units fit in the foot print (of the K-Type kiosk): Max 3.65 m + 10% Max 1.77 m + 10% Max 1.82 m + 20%	Order of preference 1. Yes 2. No, but can be modified for delivery by June 2020	Order of preference 1. Yes 2. No, but can be modified (date required)
Are the inverters 4-Quadrant, multi-mode?	Yes	Yes
If the enclosure (standard, modified, or third party) doesn't comply with the requirements under "Enclosure Specification" and "Equipment Service Conditions", can it be made to?	Yes	Yes
What are the engineering costs associated with modifying the enclosure, or developing a new one to comply with the requirements under "Enclosure Specification" and "Equipment Service Conditions"? (if required)		
Does the equipment comply with Equipment Service Conditions?	Order of preference 1. Yes 2. No, but can be modified for delivery by June 2020 3. If no, then no-go	Order of preference 1. Yes 2. No, but can be modified 3. If no, then no-go
What are the engineering costs associated with modifying the equipment to be suitable for the "Equipment Service Conditions"? (if required)		
Approximately how many units are expected to be ordered for the additional engineering costs to be covered?		
What is the communication protocol?		
What is the remote & local monitoring & control hardware		

Stage 2 Questions - Go/No -Go	Pilot	Commercial Case
and software required and supplied?		
LV distribution board included?		
Revenue meter included?		
Control meter included?		
General		
Does the supplier have a local presence?	Preferred	Preferred
If no local presence, how are the units installed and commissioned?	Order of preference 1. Customer preference: according to manual by customer, or by technician sent for the job 2. According to manual by customer 3. By technician sent for the job	Order of preference 1. Customer preference: according to manual by customer, or by technician sent for the job 2. According to manual by customer 3. By technician sent for the job
Does the supplier require that they undertake the balance of plant design and construction	No	No
If a non-standard enclosure, where would assembly take place (supplier factory, enclosure factory, onsite)?	Order of preference 1. Whatever allows for installation by 2020, providing warranties are maintained	Order of preference 1. Supplier factory 2. Enclosure factory 3. onsite
Noting the questions above, if there are no models that fit the requirements above, are any new models expected to be available post 2020?	N/A	Yes

B.3 Stage 3 Questions

The Stage 3 questions related to the technical specification of the units the suppliers could provide along with costing. The table below lists the specification and costing queries. The equipment service conditions that the battery and associated enclosure needed to comply with, as provided by Ausgrid, are listed in the table below.

Description	Value
General Service Conditions	
Elevation above sea level	< 1000m
Environment	Rural/Urban
Ambient Conditions a. Extreme maximum temperature b. Average maximum over 24 hours c. Average minimum over 24 hours d. Extreme minimum temperature e. Maximum rate of temperature change outside f. Solar Radiation Level, maximum intensity	 + 45 °C + 35 °C + 15 °C - 5 °C 20 °C over 20 minutes 1 100 W/m2
Average relative humidity a. Winter at 15:00 hours b. Summer at 9:00 hours c. Maximum at sudden temperature drops	 57% 69% 100%
Isokeraunic Level (Days when thunderstorm activity is audible)	40 Days / Year
Seismic conditions a. Horizontal acceleration b. Vertical acceleration	 0.2 g 0.2 g
Additional Requirements for Outdoor Equipment	
Maximum wind velocity a. Steady b. Gusts	 110 km/hr 160 km/hr
Dust (Average)	50 mg/cu m (80% at 60 micron or larger)
Rainfall a. Maximum annual b. Average annual	 1370 mm (212 days) 890 mm (172 days)
Pollution Level	Heavy

Appendix C: DC Use Cases

DC1, Use Case 1 (single battery can meet moderate overload, smaller communities)

A single battery of 500 kWh capacity can only service DCs with low customer numbers (smaller communities), which is unlikely to meet future network overload requirements (if the customer numbers grow over time, the battery would be undersized).

In this case, for larger customer numbers traditional network upgrades or addition of a second battery may prove to be the best long-term option.

Table 22 DC1 Feasible Battery Sizes vs Number of Customers

	50	100	150	200	250	
DC1		**Number of customers**				
2018	**50**	**100**	**150**	**200**	**250**	**C-rating**
10%	50	100	150	201	251	0.48
20%	178	355	533	711	889	0.27
30%	383	766	1149	1531	1914	0.19
40%	627	1255	1882	2510	3137	0.15
			kWh			

		Number of customers				
2023	**50**	**100**	**150**	**200**	**250**	**C-rating**
10%	50	99	149	199	248	0.46
20%	159	317	476	635	793	0.29
30%	328	655	983	1310	1638	0.21
40%	544	1089	1633	2178	2722	0.17
			kWh			

		Number of customers				
2028	**50**	**100**	**150**	**200**	**250**	**C-rating**
10%	43	85	128	171	213	0.52
20%	136	271	407	543	679	0.33
30%	269	538	806	1075	1344	0.25
40%	451	901	1352	1803	2253	0.20
			kWh			

		Number of customers				
2033	**50**	**100**	**150**	**200**	**250**	**C-rating**
10%	38	77	115	154	192	0.54
20%	115	230	345	461	576	0.36
30%	226	451	677	902	1128	0.28
40%	362	724	1086	1448	1810	0.23
			kWh			

Table 23 DC2, Use Case 2 (single battery can meet up to 30% overload, medium sized communities)

> **A single 500 kWh battery can service DC sizes up to around 100 customers in the long term at up to 30% overload.**
>
> This may be a good alternative to traditional network upgrades for DCs with lower numbers of customers where future growth is not expected to increase the total numbers over 100.

DC2 Feasible Battery Sizes vs Number of Customers

	50	100	150	200	250	
DC2		**Number of customers**				
2018	**50**	**100**	**150**	**200**	**250**	**C-rating**
10%	28	56	84	111	139	0.66
20%	104	208	313	417	521	0.35
30%	251	502	753	1004	1255	0.22
40%	437	874	1312	1749	2186	0.17
		kWh				

		Number of customers				
2023	**50**	**100**	**150**	**200**	**250**	**C-rating**
10%	23	46	69	92	116	0.78
20%	88	177	265	353	442	0.41
30%	196	392	588	784	980	0.28
40%	350	701	1051	1402	1752	0.21
		kWh				

		Number of customers				
2028	**50**	**100**	**150**	**200**	**250**	**C-rating**
10%	25	51	76	101	126	0.70
20%	88	176	264	352	440	0.40
30%	182	365	547	729	911	0.29
40%	309	618	927	1236	1545	0.23
		kWh				

		Number of customers				
2033	**50**	**100**	**150**	**200**	**250**	**C-rating**
10%	31	62	94	125	156	0.56
20%	92	184	276	368	459	0.38
30%	179	359	538	717	897	0.29
40%	286	571	857	1142	1428	0.24
		kWh				

Table 24 DC3, Use Case 2 (single battery can meet up to 30% overload, medium sized communities)

> **A single 500 kWh battery capacity can service the majority of DC sizes over the longer term at up to 30% overload.**

DC3 Feasible Battery Sizes vs Number of Customers

	50	100	150	200	250	
DC3			**Number of customers**			
2018	**50**	**100**	**150**	**200**	**250**	**C-rating**
10%	27	54	81	109	136	0.47
20%	99	199	298	397	497	0.26
30%	204	408	612	816	1021	0.19
40%	336	673	1009	1345	1682	0.15
			kWh			

			Number of customers			
2023	**50**	**100**	**150**	**200**	**250**	**C-rating**
10%	21	43	64	85	107	0.62
20%	71	142	213	284	355	0.37
30%	140	281	421	562	702	0.28
40%	233	465	698	930	1163	0.23
			kWh			

			Number of customers			
2028	**50**	**100**	**150**	**200**	**250**	**C-rating**
10%	25	49	74	98	123	0.59
20%	73	147	220	293	367	0.39
30%	140	280	420	560	700	0.31
40%	223	447	670	894	1117	0.26
			kWh			

			Number of customers			
2033	**50**	**100**	**150**	**200**	**250**	**C-rating**
10%	18	37	55	73	91	0.97
20%	60	120	179	239	299	0.59
30%	117	233	350	466	583	0.45
40%	196	392	588	784	980	0.36
			kWh			

Table 25 DC4, Use case 3 (single battery can meet up to 30% overload and potentially 40%, all community sizes)

> **Batteries can meet most overload conditions for all customer numbers found in this DC.**
>
> **Although in many cases a smaller 250kWh battery (Battery Solution B) could be sufficient, there is an opportunity to oversize the battery for the future or to maximise market revenue (Battery Solution A1) or install a smaller battery early on and upgrade to a larger size in the future (Battery Solution A2).**

DC4 Feasible Battery Sizes vs Number of Customers

	50	100	150	200	250	
DC4		**Number of customers**				
2018	**50**	**100**	**150**	**200**	**250**	**C-rating**
10%	15	30	45	60	75	0.54
20%	62	124	186	247	309	0.26
30%	126	252	378	504	630	0.19
40%	208	415	623	831	1039	0.16
		kWh				

		Number of customers				
2023	**50**	**100**	**150**	**200**	**250**	**C-rating**
10%	13	27	40	54	67	0.78
20%	46	92	138	184	231	0.45
30%	94	188	281	375	469	0.33
40%	155	310	465	620	775	0.27
		kWh				

		Number of customers				
2028	**50**	**100**	**150**	**200**	**250**	**C-rating**
10%	14	28	42	55	69	0.94
20%	44	88	132	176	220	0.59
30%	87	174	261	348	435	0.45
40%	144	287	431	575	718	0.36
		kWh				

		Number of customers				
2033	**50**	**100**	**150**	**200**	**250**	**C-rating**
10%	17	34	51	68	85	0.97
20%	56	111	167	222	278	0.59
30%	109	218	327	436	544	0.45
40%	183	365	548	730	913	0.36
		kWh				

Appendix D: FCAS market information

D.1 Frequency ancillary services

A utility scale battery can generate revenue through participating in the Frequency Control Ancillary (FCAS) markets, which can be broadly broken down into three sub-categories:

- Frequency regulation
- Frequency contingency
- Fast frequency response

There are two FCAS regulation markets (raise and lower) and six FCAS contingency markets (raise and lower in 6 seconds, 60 seconds or 5 minutes).

Fast frequency response is in effect a faster version of FCAS contingency services. There is currently no formal market for FFR, and therefore no current potential revenue stream for providing this service. In July 2018, the AEMO published its Frequency Control Frameworks Review. In this review the AEMC said that it and AEMO will continue to assess the need for fast frequency response and, if there is a need, the more efficient means to procure that service.[19]

An FCAS provider that is also enabled in the wholesale energy market will be optimising its portfolio to ensure that it earns the maximum revenue between the markets.

D.1.1 How to participate and earn revenue in the FCAS markets

Frequency regulation ensures that supply and demand of electricity is balanced and that the frequency of the system is maintained. It is in effect a continuous correction of small frequency deviations. AEMO manages this by issuing signals to participants in the FCAS regulation market in how they need to respond to maintain the system frequency, via the Automatic Generation Control (AGC).

Frequency contingency ensures that the system has sufficient 'reserve' available to maintain system security after credible contingency events. There are six contingency markets, three for raising the system frequency and three for lowering the system frequency. The three markets are divided into 6 second response, 60 second response and 5 minute response.

To register to provide FCAS services the battery system needs to meet the requirements of AEMO's Market Ancillary Service Specification (MASS) and participate for central dispatch for FCAS. To provide FCAS as an ancillary service generating unit it is necessary to register as a Market Generator. To provide FCAS as an ancillary load unit it is necessary to register as a Market Consumer. AEMO advises that applicants contact them early in the design process to confirm latest registration and technical requirements for battery systems.[20]

Participants must register in each distinct FCAS market, and can participate in an FCAS market by submitting an FCAS offer or bid for that service to AEMO. An FCAS offer or bid for a "raise" service represents the amount of MWs that a participant can add to the system to raise the frequency. An FCAS offer or bid for a "lower" service represents the amount of MWs that a participant can take from the system in to lower the frequency.

[19] https://www.aemc.gov.au/sites/default/files/2018-07/Final%20report.pdf, p. vi
[20] https://aemo.com.au/-/media/Files/Electricity/NEM/Participant_Information/New-Participants/battery_fact_sheet_final.pdf

During each dispatch interval, AEMO must enable a sufficient amount of each of the eight FCAS markets for the FCAS bids submitted to meet the FCAS MW requirement. The MW FCAS offers are enabled in merit order of cost, with the highest cost offer to be enabled setting the marginal price for the FCAS market. FCAS service providers are only paid for enablement, not usage, and the revenue is resolved on a 5 minute basis. That is, the FCAS revenue = (FCAS 5 minute price x FCAS 5 minute enablement) / 12.

The FCAS costs are recovered from NEM participants according to recovery rules.

The costs / revenue is dependent upon the amount of service required at a particular time and can therefore vary significantly from time to time.

D.1.2 FCAS revenue is much higher in recent years than historically

The revenue that can be earned through the FCAS markets is, naturally, driven by demand and supply in the FCAS markets. Historically, the FCAS revenue has been low across the NEM, but it has increased substantially in recent years, as illustrated below.

Figure 41 FCAS regulation revenue in the NEM, 2003 - 2018

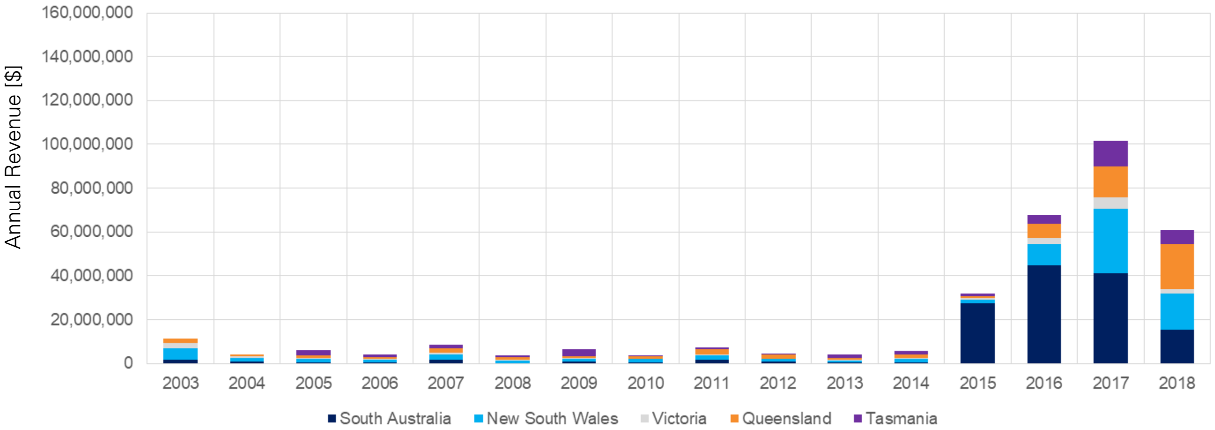
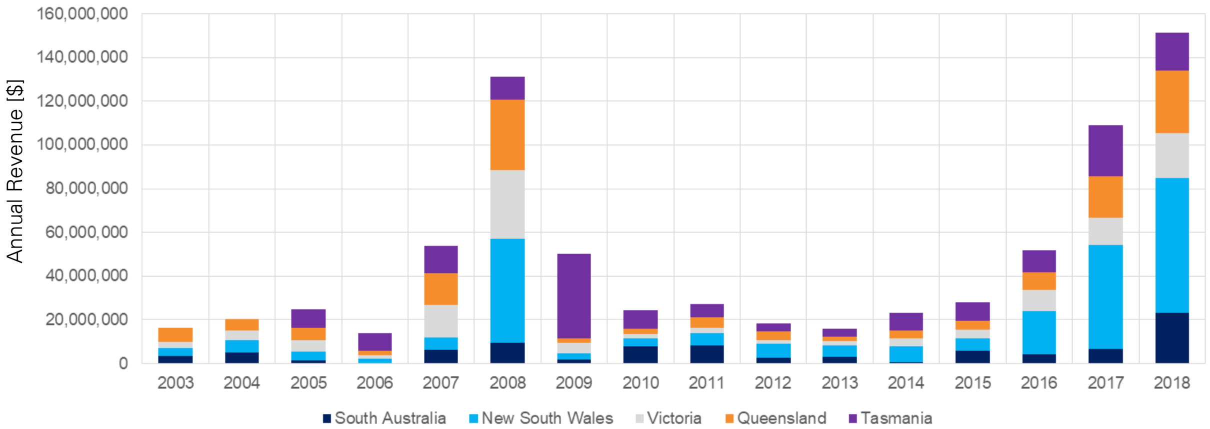


Figure 42 FCAS contingency revenue in the NEM, 2003 – 2018



South Australia has experienced particularly high levels of regulation FCAS in recent years, reflecting particular supply and demand dynamics.

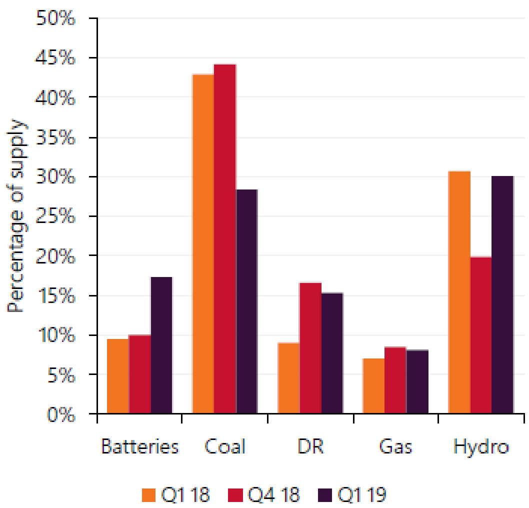
Since 2015, AEMO has required 35 MW of regulating FCAS in South Australia when a single credible contingency could result in South Australia being separated from the rest of the grid. This has been put into place for example during planned outages of the Heywood interconnector, in response of a risk that there would be insufficient regulating FCAS available locally to ensure an islanded system could operate adequately. Due to the limited number of participants registered to provide FCAS in South Australia, insufficient MW have been offered at lower price bands (despite significant capacity being available in the market). This has resulted in very high FCAS regulation costs during times when the constraint was imposed during 2016 and 2017.

When the Hornsdale Power Reserve entered the FCAS regulation market in December 2017, it was able to offer MW at lower price bands, taking a significant market share and reducing the overall FCAS regulation cost. For example, AEMO estimated that the additional FCAS regulation supply from HPR reduced the overall cost regulation services by about $3.5 million during a five hour period on 14 January 2018 when the 35 MW constraint was in place. Historically, during the times when the constraint has bound, the regulation FCAS prices in South Australia have exceeded $9,000/MWh due to the limited suppliers, but with HPR providing additional supply the average Raise and Lower regulation prices were $248/MWh instead.[21] In October 2018, AEMO removed the 35 MW pre-contingent regulation FCAS, as its analysis showed that with the SA system strength requirements met and the HPR in service, *"the SA power system will land in a satisfactory operating state following a credible contingency that results in separation of SA from the NEM."*[22]

The Hornsdale Power Reserve has been followed into the FCAS markets by the Ballarat and Gannawarra batteries in Victoria and the Dalrymple North Battery in South Australia. Following the commencement of the ancillary service unbundling rule in July 2017 new technologies have also entered. ActewAGL registered a 1 MW Virtual Power Plant in the Lower contingency FCAS market in New South Wales, and Enel X registered in the Raise contingency FCAS markets in four states using aggregated loads[23]. The Hornsdale Wind Farm has also registered in the FCAS markets following an initial trial in with ARENA, NEOEN and Siemens-Gamesa Australia. This is the first time a wind farm has been registered to provide FCAS in Australia.[24]

In its latest energy dynamics report on Q1 2019, AEMO noted that batteries have increased the share of the Raise FCAS markets from 10% in Q4 2018 to 17% in Q1 2019, with the increases coming from Dalrymple North (30 MW - 5% market share) and Ballarat (30 MW - 3% market share). The batteries are displacing higher priced supply, such as coal. Demand response has also taken a significant market share (15%).[25]

Figure 43 FCAS supply mix



[21] https://www.aemo.com.au/-/media/Files/Media_Centre/2018/QED-Q1-2018.pdf p. 14
[22] https://www.aemo.com.au/Market-Notices?searchString=64716
[23] NEM registration and exemption list
[24] http://energylive.aemo.com.au/Innovation-and-Tech/Wind-Farm-trial-shows-promising-results-for-system-security
[25] https://www.aemo.com.au/-/media/Files/Media_Centre/2019/QED-Q1-2019.pdf

D.1.3 Going forward

Demand for FCAS may increase as the penetration of (non-synchronous) renewable energy in the NEM grows, and displaces conventional (synchronous) fossil-fuelled generation, the overall system inertia will be reduced, which will increase the risk of frequency disturbances. A reduction in system inertia means that the need for frequency control services may increase.

Analysis from AEMO's Integrated Systems Plans suggests that projected major increases in utility-scale solar are expected to drive significant increases in the required amount of FCAS, especially when clustered in renewable energy zones. This is especially the case during the peak sunlight hours, when there is likely to be a significant reduction in the number of synchronous units online. This is highlighted by AEMO as an opportunity for non-traditional providers, such as battery storage. AEMO also highlights the role of transmission augmentation, as FCAS is usually sourced globally. Challenges are projected to emerge locally in South Australia and Queensland without interconnector upgrades.[26]

The markets are considered shallow and may become quickly saturated

However, whilst utility scale batteries are technically very well suited to providing FCAS services, and demand for FCAS is likely to grow, these markets are likely to become saturated as they are inherently shallow. That is, the profitability in the FCAS markets could be eroded. Competition from other utility scale batteries, demand response, qualifying renewable energy and new interconnectors will all impact the revenue potential from FCAS.

Under the current rules it is hard to quantify "bankable" revenue from FCAS

Further, it is difficult to quantify potential "bankable" revenue from FCAS markets. The Frequency Control Frameworks Review noted that, *"as conventional generators retire, and newer technologies take their place, there is likely to be a greater focus on FCAS income as a bankable revenue stream. In this case, the current market framework may not be ideal in that it does not readily facilitate secondary contracting of the kind used by wholesale electricity market participants to create revenue certainty and underwrite investments".*[27]

A report from Hydro Tasmania on the Battery of the Nation notes that *"attempts to assign direct value to storage in Australia typically only recognise energy arbitrage value (since frequency control ancillary services (FCAS) are not presently considered bankable)."*[28]

The rules may change to accommodate the changing supply mix

In the future, the market will need to be designed in such a way that it provides investment signals to recognise the value of inertia, flexibility and the ability to rapidly change output, alongside the values that are currently recognised such as energy and ancillary services.

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[26] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Integrated-System-Plan-2018_final.pdf
[27] https://www.aemc.gov.au/sites/default/files/2018-03/Draft%20report.pdf
[28] https://arena.gov.au/assets/2018/06/battery-of-the-nation-analysis-of-the-future-national-enlectricity-market.pdf p. 19

Appendix E: Further NPV Sensitivities

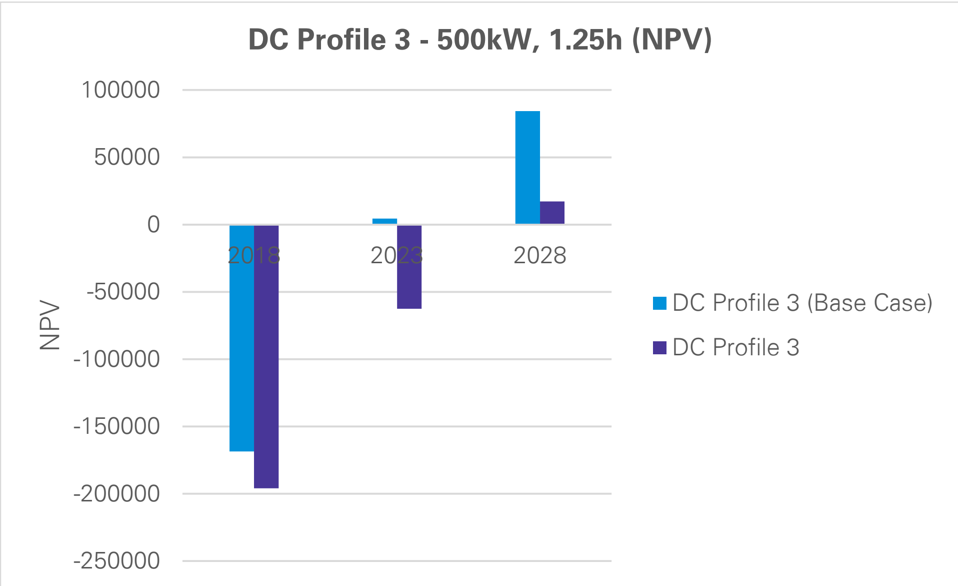
In addition to the sensitivities considered in section 11.3.2, we have separately considered the impact on the Optimum Configuration NPV and breakeven years under three further scenarios. These scenarios include:

- Customer avoided CAPEX (as a proxy for captured customer benefits and other benefits such as network frequency/voltage, islanding and reliability/resilience benefits) cannot be recognised.
- Network revenue sensitivities with transformer capital costs at three levels ($50,000, $100,000 and $250,000)
- Customer avoided CAPEX is not recognised **and** Network revenue sensitivities with transformer capital costs at three levels ($50,000, $100,000 and $250,000)

E.1 Customer avoided CAPEX cannot be recognized

In the event that customer avoided CAPEX revenue cannot be recognised, this revenue reduction results in a lower NPV for the Optimum Configuration. This NPV reduction means under this sensitivity, the project will not achieve a positive NPV until 2028, whereas the base case Optimal Configuration achieves a positive NPV in 2023. This is presented in Figure 44 below.

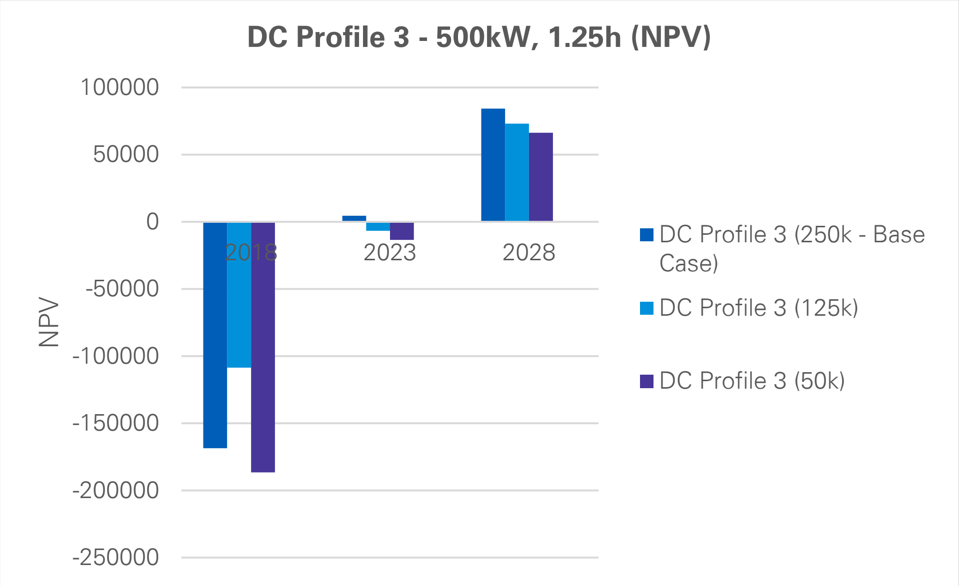
Figure 44 NPV comparison – no customer avoided CAPEX



E.2 Network revenue sensitivities

On the basis that cost offset applicable to transformer upgraded is lower (either $125,000 or $50,000) than the assumption under the base case Optimal Configuration, the NPV of the Optimal Configuration will be reduced. Under both the $125,000 and $50,000 scenarios, the project will not achieve a positive NPV until 2028 whereas the base case Optimal Configuration achieves a positive NPV in 2023. This is presented in Figure 45 below.

Figure 45 Network revenue sensitivity

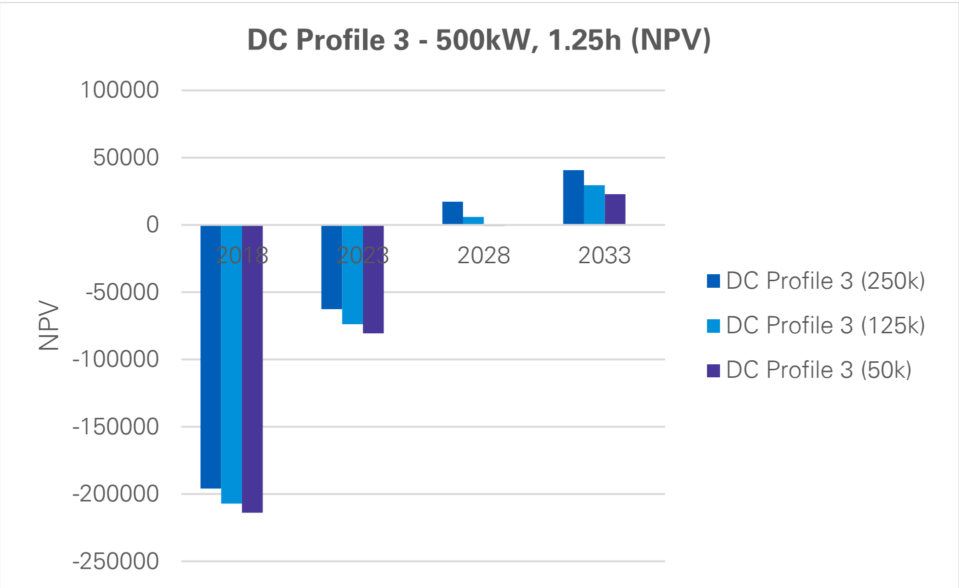


E.3 Customer avoided CAPEX cannot be recognised and network revenue sensitivities

If CAPEX revenue cannot be recognised and the sensitivities to the network revenue are applied the NPV reduction will not achieve a positive NPV (see Figure 46 below) until:

- **2028** with a transformer upgrade cost of $125,000 and $250,000; and
- **2033** with a transformer upgrade cost of $50,000.

Figure 46 No customer avoided CAPEX and network revenue sensitivity



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