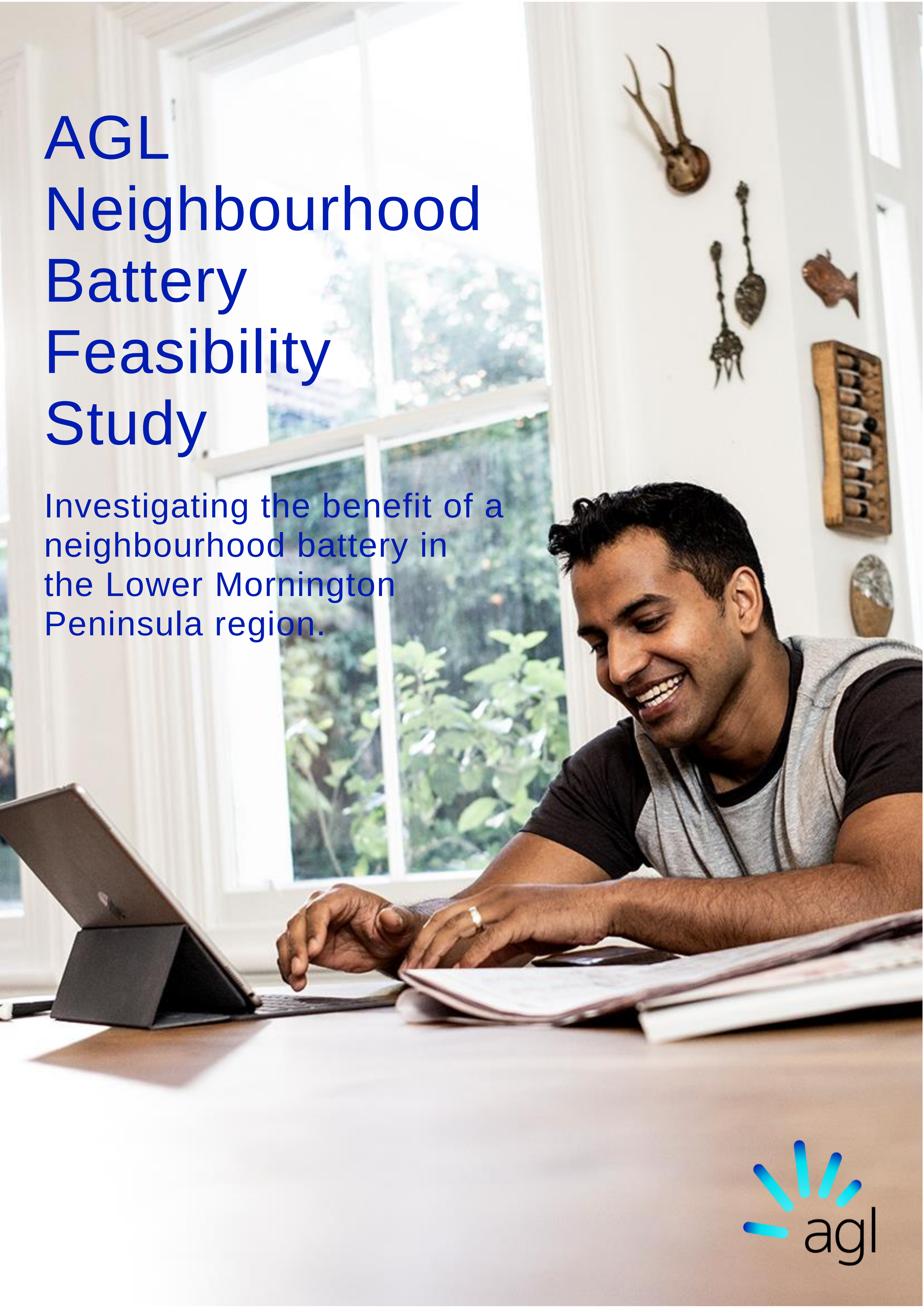
# AGL Neighbourhood Battery Feasibility Study

Investigating the benefit of a neighbourhood battery in the Lower Mornington Peninsula region.



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# 1. Executive Summary

Neighbourhood batteries have the potential to support Australia's energy transition by storing energy locally while benefiting from some economies of scale. The batteries, typically 100kW to 5MW, provide three key advantages over other forms of storage when connected locally to the distribution network:

- **Local grid stability**: By charging during off-peak periods and discharging during peak periods, batteries effectively smooth demand for electricity upstream of the network connection, reducing peak demand and potentially deferring the need for network upgrades. Batteries can also provide voltage support and support system frequency.
- **Solar enablement**: Neighbourhood batteries have the potential to absorb excess locally generated PV solar exports, reducing voltage regulation challenges and enabling customers to continue to export with less risk of constraints
- **Local use of energy**: Neighbourhood batteries increase the availability of local storage for household solar, increasing 'local' use of energy and contributing to lower energy losses

These advantages position neighbourhood batteries within a rapidly growing battery storage market, as evidenced by a number of emerging projects. Market participants and Network Service Providers (NSPs) are increasingly pursuing neighbourhood battery trials including:

- After two trials, Western Power and Synergy are rolling out a further nine 'PowerBank' batteries for network support. In this scheme, customers pay a subscription fee to 'virtually store' electricity, effectively smoothing demand to support network challenges
- After an initial trial, United Energy is rolling out a further 40 pole-mounted batteries to manage peak demand. The capacity will be shared with Simply Energy to improve commerciality
- A further four projects have recently been announced, two of which are in Victoria with support from Victoria's Neighbourhood Battery Initiative

Given their scale and noting that all projects received Federal or State Government support, it is unlikely that these trials have delivered a commercial return for NSPs or market participants. AGL and United Energy have collaborated to establish and deliver this Neighbourhood Battery Feasibility Study (the Study) to determine whether a battery, installed on the Lower Mornington Peninsula, (LMP) can:

- Meet an identified need for network services in a United Energy RIT-D
  - The LMP Region requires 13MW of demand response, or demand-side generation, to reduce peak demand and mitigate the risk of voltage collapse. The battery would form part of the 13MW non-network solution
- Enable greater production of distributed solar energy
- Produce a positive financial return for a market participant and asset owner

AGL engaged Aurecon to undertake power system modelling to identify the required storage duration and implications for the local power system. Aurecon identified, based on the LMP load profile and power system modelling, a storage system with up to 5MW (comprising multiple 1MW or 2MW systems) and up to 4-hours of duration would be satisfactory for network support. To support the network, the battery would be subject to network service requirements defining precisely how the battery must behave in summer during peak periods to support the network.

The Study tested how the battery behaved under different duration, network tariff, and network service requirement scenarios and found the battery could be effective at reducing peak demand. It also identified:

- A 1MW / 2MWh system is the preferred duration, effectively balancing network benefit with capital cost

- To encourage the desired behaviour, and enable profitability, network tariffs would need to be bespoke or entirely absent for distribution network connected batteries. For a 1MW/2MWh battery, introducing United Energy's low voltage grid tariff discouraged desired 'solar soaking' behaviour, as the battery charged less during the day, and reduced gross profit from $99K per year to -$8K per year (based on FY21 price data)
- Installing batteries without enforcing network service requirements risks worsening grid stability when the battery charges during shoulder periods (periods either side of peak demand)

Questions remain, however, over the commerciality of neighbourhood batteries in the current market environment. The Study assessed the net present value (NPV) of seven different scenarios and tested the sensitivity to various factors:

- All scenarios presented a negative NPV, ranging from -$1.5M to -$3.0M
- A pathway to positive NPV is identifiable, relying on:
  - Material reduction in battery capital costs
  - Identifying critical network needs and maximising the value of providing network services
  - Favourable market trading conditions
  - Accessing the full value-stack, such as avoiding cap contract premium costs (only available to market participants)
  - Improving forecasting capability
  - Installing multiple battery systems to realise economies of scale

Schemes offering 'virtual storage' subscriptions, or 'peer-to-peer trading' may reduce profitability and restrict the ability to scale distribution scale batteries across Australia's electricity networks, and reduce overall consumer benefits. Residential customers may receive benefits from distribution scale batteries without a direct participation scheme through lower wholesale electricity prices and lower cost of network services. Direct participation schemes can be costly to implement and tend to benefit a smaller group of customers than sharing of benefits in Australia's energy market regulatory framework. At this stage, AGL believes consumers overall will receive most benefit if distribution scale batteries can be implemented without a mandated direct participations scheme for consumers. Consumers benefit indirectly from reductions in network costs and the enablement of greater solar exports ('passive' scheme). Reductions in network costs are shared in line with the regulatory framework for electricity distribution networks while benefits from lower wholesale electricity prices are shared through the competitive market. Importantly, without a direct participation scheme which limits participants to those who sign up to the scheme, in a passive scheme the benefits are shared across all consumers

AGL believes that competitive market participants are the preferred owners of neighbourhood batteries, while recognising the critical role of NSPs, who have the best view of the nature, severity, and location of network issues. In a dual-participant model, cost efficient network solutions can best be achieved when roles are aligned with 'traditional' functions:

- NSPs understand network requirements, can identify future network issues, and can ensure cost efficient solutions by taking opportunities to the competitive market; and
- Competitive Market Participants can provide offers – as appropriate – to meet NSP's stated needs, informing the lowest cost solution

Ownership by a competitive market participant, versus NSPs, allows for:

- Efficient access to energy markets
- Ready access to customers if/when this becomes the preferred commercial model
- Transparency of opportunities to provide network services

For competitive benefits to be realised, it will be important that there be a level playing field for all battery service providers connected to the networks. By this we mean that the DNSP behaves in a non-discriminatory manner: the DNSP treats batteries the same regardless of the owner (e.g., by charging the same tariffs for the same services) and that all batteries are treated the same across the network (for example in times of constraint, the batteries controlled by DNSPs are not given preference).

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# 2. Context and Introduction

## 2.1. Project objectives

This feasibility study investigates the potential benefit of installing one or more neighbourhood batteries on the Lower Mornington Peninsula to enable greater production of solar energy by households and business and meet an identified need for network services.

The study is grounded in an existing network challenge – United Energy's Lower Mornington Peninsula ("LMP") Supply Area – Non-Network Proposal Request. United Energy has identified that in the absence of network or non-network solutions, the LMP area is at risk of voltage collapse which could lead to supply interruption to approximately 50,000 customers[1]. Network Service Providers (NSPs), including United Energy, are increasingly adopting neighbourhood batteries (typically 100kW – 5MW) as an alternative to traditional network investment. Batteries may offer the local community lower energy costs and a 'green' alternative, while market participants may earn a return in wholesale and Frequency Control Ancillary Services ("FCAS") markets when the battery is not required to provide network support.

This study seeks to determine if and how the LMP area could be serviced by a neighbourhood battery and considers five key questions.

- What are possible **battery design options**, considering both site selection and grid connection, that can support resolution of LMP network constraints?
- For each option, what is the potential **financial return** for a competitive market participant to own and operate the battery, and provide agreed network services to United Energy?
- What **incremental economic value** could the battery provide to the network and the community?
- How should **community members participate** with the battery scheme?
- Under different circumstances, who is/are the **preferred party/parties to own and operate** the battery?

## 2.2. Background

Neighbourhood battery projects are being implemented across the NEM; the LMP network challenges provide an opportunity to further test the potential of small-scale storage.

### 2.2.1. The value of neighbourhood batteries

It is important to consider how and when neighbourhood batteries can add value to the system. AGL has identified four primary pools through which neighbourhood batteries can add value.

- **Network support:** where the addition of storage to the network can be used to defer network investment and/or manage voltage
- **Market trading:** where the battery can buy and store electricity form the wholesale energy market to be later sold into the wholesale energy or FCAS markets
- **Customer:** residential and business customers can benefit from a local distribution-scale battery by sharing wholesale market trading value with competitive market participants or enabling a higher percentage of solar output to be fed back into the grid (and subject to a feed-in tariff)

[1] 2020, Untied Energy, Lower Mornington Peninsula Non-Network Proposal Request

- **Retail position:** where retailers may hold dispatchable energy to cover their customer load, or benefit from the ability to offer product to customers that support renewable energy

The extent to which value pools are able to be accessed depends on which entities are involved in battery ownership and operation (refer to *Section 7 Ownership Models*), where the battery is located (*Section 9.1 Industry Overview*), and AER rules and regulations (*Section 9.1 Industry Overview*). For more information on value pools, refer to *Section 9.1 Industry Overview*.

Neighbourhood batteries offer three key advantages over utility-scale storages:

- Localised peak demand reduction on the distribution network
- Localised excess solar absorption to alleviate solar constraints
- Potential for using more energy generated locally and lower distribution losses

While behind the meter batteries can offer similar advantages, distribution scale batteries promise to offer more economies of scale in their deployment and operation.

A key advantage of locating batteries within the distribution network, rather than connecting in the transmission network, is the ability to smooth local demand. High rooftop solar uptake has reduced operational demand[2], and created grid stability and voltage challenges[3]. At 14.7GW, rooftop solar has become the second largest generator by installed capacity across Australia[4], behind only coal-fired generation. While operational consumption and peak demand is forecast to decline in the next five years as distributed PV solar uptake continues, growth is forecast to return later in the decade, driven by the commercial and residential sectors, and an acceleration in the rate of electrification, particularly electric vehicles (EVs)[5]. Neighbourhood batteries can act as a 'solar sponge': soaking up excess solar during the day and discharging during the evening to reduce peak demand upstream of the connection point and, potentially, defer the need for network upgrades.

By absorbing excess local solar, neighbourhood batteries also reduce the likelihood of rooftop solar constraints. High network voltages can cause customers' solar inverters to trip and stop generating for both in-home consumption and for exports[6]. In March 2021, South Australian energy authorities remotely switched off thousands of household solar panel to stabilise the grid in response to a fall in demand - the first time this power has been used[7]. By connecting near to rooftop solar, either on the low voltage (LV) network or behind-the-meter (BTM), the battery can allow more distributed solar to continue to export.

Neighbourhood batteries can offer a value proposition to local community members, whether it be via a retail product (e.g. 'virtual storage') or provision of a 'green' alternative. Local shared batteries are put forward as alternatives to residential batteries for storage access. A 'virtual storage' payment model may not require upfront capital from participants, and provides access to a storage product to customers who could not previously benefit from storage, for example renters and apartment residents. Local shared batteries in a 'virtual storage' model do not however provide the same physical advantages of residential batteries but billing arrangements can be constructed to emulate similar behaviour.

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[2] Operational Demand - demand that is met by local scheduled generating units, semi-scheduled units and non-schedules units >=30MW
[3] AEMO, 2021, Solar PV curtailment initiative by SA Government supports the NEM
[4] PV Magazine, 2021, Australia's rooftop PV capacity reaches 14.7 GW
[5] 2021, AEMO, Electricity Statement of Opportunities
[6] United Energy, 2020, Solar Enablement Business Case
[7] ABC, 2021, Solar panels switched off by energy authorities to stabilise South Australian electricity grid

The Victorian Government is providing funding through the Neighbourhood Battery Initiative program to fund pilots and demonstrations that support identifying how neighbourhood batteries can play a role in Victoria's transitioning electricity system[8].

### 2.2.2. Neighbourhood battery projects in Australia

The NEM and South West Interconnected System (SWIS) are experiencing rapid growth in neighbourhood battery projects. Neighbourhood batteries are expected to form part of the rapidly growing small-scale storage mix: from ~0.6GW in FY22 to 10-17GW by FY40[9]. Projects are shifting from trials to operational as stakeholders begin to understand the potential value, and how it can be best accessed, as evidenced by:

- Energy Queensland Bohle Plains trial led to the implementation of five further 4MW batteries;
- United Energy Bayside Battery Project resulted in the announced implementation of 40 further pole-mounted batteries in inner Melbourne, with capacity to be shared with Simply Energy for trading; and
- Western Power and Synergy continue to roll out more 'PowerBank' batteries within WA.

Across Australia, the most mature projects involve partnerships between NSPs and competitive market participants, rather than NSPs or competitive market participants alone.

The largest, and most recent neighbourhood battery projects are provided in Table 1, including the stakeholders involved, stage, business model and objectives.

Across projects, we see common objectives include: managing peak demand (NSPs); access to trading markets, including the size of the opportunity; and reducing energy costs for customers.

[8] Victorian Government, DELWP, 2021, Victorian Neighbourhood Battery Initiative Application Guidelines
[9] 2021, AEMO, 2021 Inputs and Assumptions Workbook

*Table 1: Largest neighbourhood battery projects in Australia*

| Stakeholders | Project | Stage | Business Model | Stated Objectives |
|---|---|---|---|---|
| **NSP and Market Participant** | **United Energy Pole Mounted Batteries**[10] | Announced *(Based on trial)* | • 40 pole-mounted 30kW/66kWh batteries on LV network (result of Jun '20 trial)<br>• Capacity leased to Simply Energy for trading; United Energy controls during peak<br>• No customer offer; charged via excess local solar<br>• Funding: $4M from ARENA; $11M total project cost | • Manage peak demand, and in future minimum demand<br>• Access trading markets |
| | **PowerBanks**[11] | Operational | • Nine 116 kW community batteries across Perth and the South West<br>• Pay $1.20-$1.40/day to store 6/8kwh excess solar for use during peak periods<br>• Paid FiT for leftover stored energy at end of day | • Network support: minimum / peak demand<br>• Financial customer benefit<br>• Understand battery economics |
| | **Energy Queensland**[12] | 1 Operational, 5 Announced | • No customer offer<br>• Acts as a 'solar sponge' | • Reduce wholesale volatility<br>• Defer T&D auge; support rooftop solar |
| **NSP** | **PowerCor Tarneit battery**[13] | Announced (Sep '21) | • 150kW/400kWh 'solar sponge'; supply 150 homes during peak periods<br>• Local network tariff incentivises local generation and usage<br>• (Funding: $800K from Vic Neighbourhood Battery Initiative) | • Manage peak demand<br>• Trial bespoke network tariff |
| | **CitiPower and YEF Fitzroy community battery**[14] | Announced (Sep '21) | • Acts as a 'solar sponge'<br>• Customer offer undefined<br>• Funding from Yarra Council and Neighbourhood Battery Initiative Aug '21 | • Provide network support; increase hosting capacity<br>• Reduce cost of energy for participants |
| | **Ausgrid trial program**[15] | Trial | • Free to participate<br>• Customers store up to 10KWh excess solar daily<br>• Energy stored is credited against use; credits paid quarterly | • Test network support potential<br>• Test customer service offer |
| **Community** | **'Beehive' project**[16] | Announced (Feb '21) | • Peer-to-peer solar energy trading: 500 households (with or without solar) trade rooftop solar generation. Participants set their own price to trade electricity. Any participant can then purchase the stored solar.<br>• Supported by NSW Government grant | • Reduce FiT constraints<br>• Test whether battery can help small retailers manage fluctuating demand |
| **Model undefined** | **Ginninderry Battery Trial**[17] | Announced (Sep '21) | • Business model undefined<br>• Based in proposed new Canberra suburb with rooftop solar on every household | • Provide network support |

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10 ARENA, https://arena.gov.au/projects/united-energy-low-voltage-battery-trial/
11 Western Power, https://www.westernpower.com.au/our-energy-evolution/projects-and-trials/powerbank-community-battery-storage/
12 PV Magazine, 2021, Queensland to integrate large-scale community batteries into substations
13 Powercor, 2021, Media release: New battery to help Tarneit share the sun
14 PV Magazine, 2021, Victoria's first 'solar sponge' community battery network to be developed
15 Ausgrid, 2020, https://www.ausgrid.com.au/In-your-community/Community-Batteries
16 Enova Energy, 2021, https://www.enovaenergy.com.au/shared-community-battery
17 CWP Renewables, 2021, Ginninderry's First Community-Scale Battery Project

## 2.2.3. The need for investment in the Lower Mornington Peninsula

The LMP is supplied by a 66kV sub-transmission network supplying Dromana (DMA), Rosebud (RBD) and Sorrento (STO) 66/22 kV zone substations. United Energy has identified the need for both:

- Network support on the Lower Mornington Peninsula (LMP), per United Energy's Non-Network Proposal Request, to reduce peak demand
- Investment in the broader network, including LMP substations, to avoid constraining distributed solar generation

**Peak demand requirements**

The LMP sub-transmission network has been facing risk of voltage collapse since 2014 due to growing peak demand. United Energy has identified two key challenges related to this:

- Maintaining voltage levels within regulatory limits in the event of an outage of either the MTN-DMA 66kV line or the TBTS-DMA 66 kV line at maximum demand conditions; and
- Sub-transmission lines experiencing maximum demands that exceed their thermal ratings[18]

In November 2014, United Energy commenced the Regulatory Investment Test for Distribution (RIT-D) consultation process to seek alternative options to the proposed network option. United Energy received a proposal from each of GreenSync Pty Ltd and Aggreko Pty Ltd, for comparison against the network option. The assessment of the options is provided in Table 2: LMP RIT-D Option Assessment:

*Table 2: LMP RIT-D Option Assessment*

| Option | Title | Overview | Implementation Date | Capital Cost ($, 2015-16) | Annual O&M (% of capital) | Total Cost ($, 2015-16) |
|---|---|---|---|---|---|---|
| 1 | Network | Install new 66kV line between Hastings and Rosebud zone substations | 2020/21 | $29.5M | 0.5% | $32.5M[19] |
| 2 | GreenSync | Stage 1: Four year demand reduction via commercial, industrial, small businesses, utility and residences. | 2018/19 | $3.7M | - | $35.0M |
| | | Stage 2: Install new 66kV line between Hastings and Rosebud zone substations | 2022/23 | $29.5M | 0.5% | |
| 3 | Aggreko | Stage 1: Up to 18 embedded generators (1.4 MVA) support at RBD substation for five-year period | 2019/20 | $9.7M | - | $40.6M |
| | | Stage 2: Install new 66kV line between Hastings and Rosebud zone substations | 2024/25 | $29.5M | 0.5% | |

United Energy's analysis suggested Option 2 maximised net market benefit under the majority of scenarios, and therefore it proceeded with the GreenSync solution.

Subsequent to the RIT-D, United Energy revised its approach, implementing a combined solution consisting of GreenSync demand response and Aggreko embedded generation. Aggreko were contracted to provide 11 diesel generators, across a number of sites, each able to provide 1MW power if and when the network is at risk of exceeding the 120MVA voltage collapse limit. The generators are installed each December and dismantled at the end of February each year[20].

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[18] United Energy, 2014, Draft Project Assessment Report RIT-D. UE-DOA-S-17-001
[19] $29.5M capital cost + 0.5% * $29.5M * 20 years
[20] Per discussion with United Energy, 27 Oct 2021

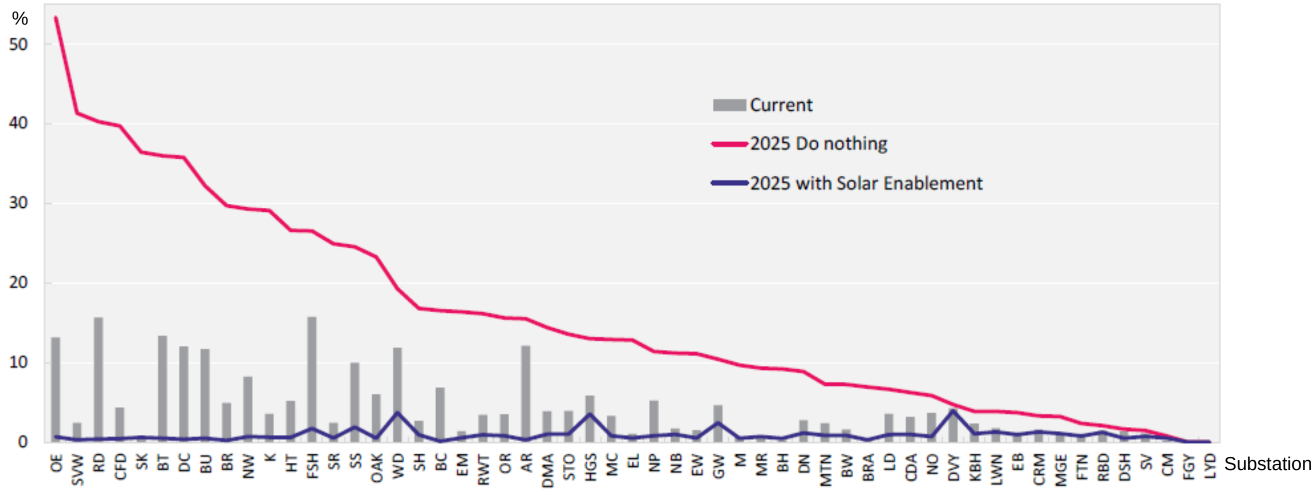
The current contract will run until the end of FY25, after which the need for the network upgrade will be reassessed, with the possibility of continuing to defer with support from a non-network solution[26].

Constraints on solar exports

Neighbourhood batteries have the potential to enable rooftop solar uptake in constrained areas. At the end of 2020, Australia had the largest solar power per person in the world (810W compared to Germany at 650W) with approximately two thirds of that solar on rooftops[21]. However, when solar exports rise sufficiently, high network voltages may cause customers' solar inverters to trip especially in areas where network voltage is already elevated. United Energy estimates if no action is taken, by 2025 the annual amount of constrained solar generation across United Energy's three networks will be equivalent to 272MW[22,23]. This level of export constraints does not meet customers' expectations or those of the Victorian Government, whose Solar Homes program is key to meeting the legislated 40% renewable energy target by 2025[24].

United Energy has launched a $41M Solar Enablement Program to alleviate rooftop solar constraints across its network. The program includes upgrades to many of United Energy's ~12,500 transformers, where it provides an economic benefit to do so, in a prioritised manner. The investment intends to unlock 95% of solar that would otherwise be constrained, as shown in Figure 1.

*Figure 1: Solar Constraints by Zone Substation. Source: United Energy*




The substations directly relevant to this feasibility study are DMA, STO, and RBD. Figure 1 shows that while these substations are not currently experiencing material constraints, the substations are expected to be experiencing constraints by 2025 of approximately 14%, 13% and 2% respectively. This is consistent with CitiPower's view of inner-Melbourne. CitiPower estimates rooftop solar in inner-Melbourne will grow from 5% to 24% by 2026. In response, CitiPower and Yarra Energy Foundation are creating a network of batteries, or 'solar sponges', located on the low-voltage electricity network across inner-Melbourne[25].

United Energy indicated they are witnessing an increase in solar penetration, particularly on the low voltage network, with constraints managed by tap changers at the zone substation transformer[26]. The transformer taps at RBD and STO are reaching the limit during minimum demand periods and alternative solutions to

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[21] RenewEconomy, 2021, noting that Australia now has nearly 1kW of solar per capita
[22] United Energy Solar Enablement Business Case suggests equivalent to the annual output of 2.4 Northern Victoria Karadoc solar farms
[23] SMA Australia, 2019, Karadoc Solar Farm – 112 MW
[24] Victorian Government, 2017, Renewable Energy (Jobs and Investment) Act 2017
[25] PV Magazine, 2021, Victoria's first 'solar sponge' community battery network to be developed
[26] Correspondence with United Energy, 16 November 2021

provide voltage support (to free up additional tapping range on transformers) is being considered in-lieu of undertaking localized augmentation works. United Energy indicated that batteries, if located appropriately, can support the network absorbing excess solar generation or by providing reactive support[27].

### 2.2.4. Storage as an alternative non-network solution

Storage is a potential alternative to Aggreko's diesel generation solution with benefits for networks, market participants, communities and the Victorian Government and can contribute to the resolution of both network and solar export challenges.

Specific to this study, AGL believes a battery solution on the LMP can offer opportunities for all stakeholders involved:

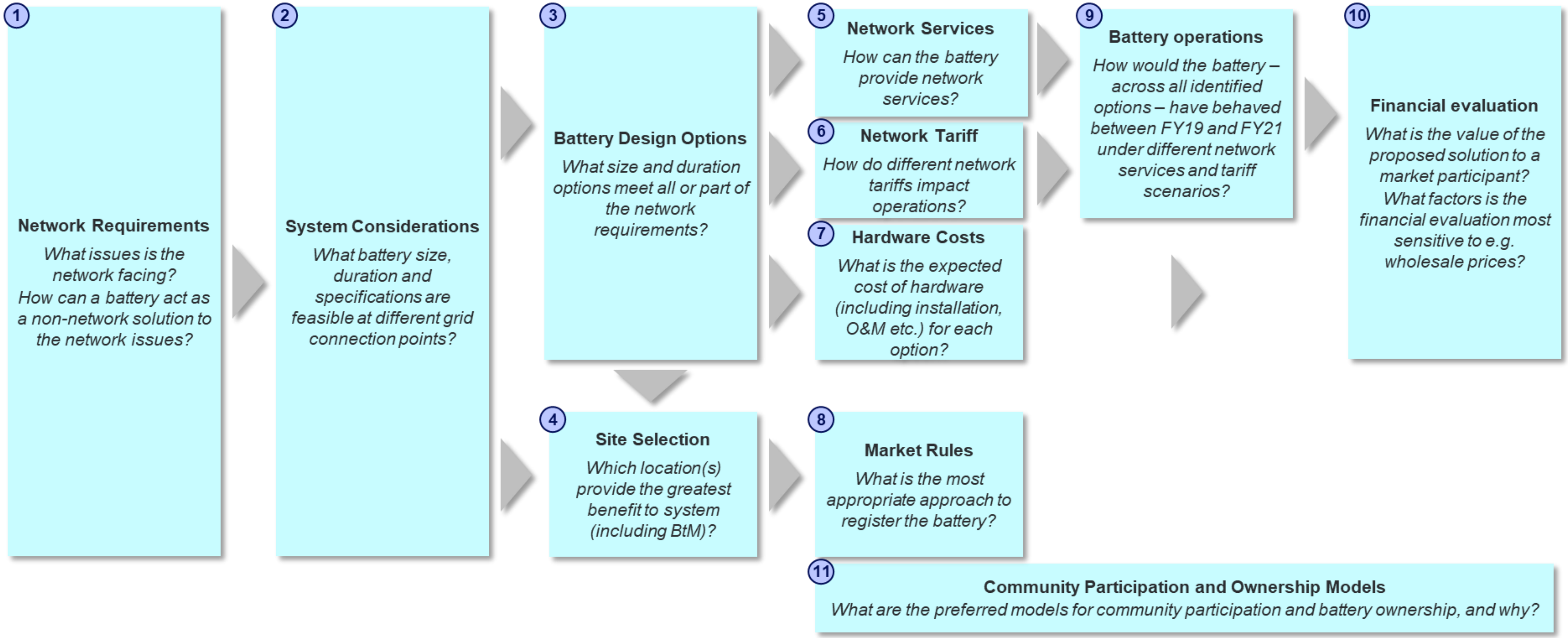
- For United Energy, the battery offers a potentially cheaper and 'greener' alternative to the existing Aggreko solution, that may offer incremental benefits such as solar enablement;
- For AGL, the battery offers a potential opportunity to generate value from providing a network service while using the battery in the wholesale energy market, using the opportunity to understand if and how AGL can utilise neighbourhood batteries broadly across the NEM;
- For the Victorian Government, the battery can encourage renewable energy uptake, support initiatives such as the Solar Homes Program, and may provide a blueprint for what is required to make neighbourhood batteries successful in future; and
- If successful, the battery may reduce energy costs for customers through lower network costs and reduced constraints on solar exports.

[27] Correspondence with United Energy, 16 November 2021

## 2.3. Structure of Study and Approach

In conducting this feasibility study, AGL first considered network needs and constraints, before overlaying locations considerations, and finally testing the system and financial impact of alternative options and scenarios including: battery size and duration; capital and operational costs; network tariffs; and market-based revenues. Figure 2 shows these key considerations and dependencies.

*Figure 2: Structure of Feasibility Study*




The approach taken to resolve the key questions for each section is provide in Table 3, below.

*Table 3: Feasibility study approach to resolving key questions*

| Section | Approach |
|---|---|
| 1 **Network Requirements** | • United Energy defined the problem in its 2014 RIT-D and updated in subsequent revisions:<br>– Risk of 120MVA demand leading to voltage collapse<br>– Risk demand exceeds N-1 thermal ratings<br>• AGL, in collaboration with Aurecon, analysed the load profile across DMA, MTN and RBD, using 2020 DAPR load trace data, to identify the duration required to deliver increasing levels of peak demand reduction |
| 2 **System Considerations** | • AGL and Aurecon[28] used United Energy sub-transmission PSS/E model to determine:<br>– Grid connection feasibility and voltage regulation benefit of locating the battery(s) at different site(s), connected to the different substations<br>– United Energy provided guidance as to what was feasible for the grid to handle at any one site |
| 3 **Site Selection** | • Based on analysis of the PSS/E model and discussion with United Energy, the study determined suitable locations for the battery(s) |
| 4 **Battery Design Options** | • Based on the network requirements, AGL defined five design options to test different size and duration combinations<br>• The study considered the critical specifications for the battery, as defined by United Energy<br>• AGL sourced indicative quotes from battery suppliers for likely battery types containing detailed specifications to test compliance |
| 5 **Network Services** | • The study modelled two network services scenarios: enforced; and not enforced<br>• Based on the current service provided by Aggreko, the study participants agreed the battery would be required to provide network services from December to February<br>• Based on the DMA, MTN and RBD load profile on the peak day in 2020, and across all days in 2020, the study defined battery operational constraints (for each duration) the operator must abide by to support the network.<br>• The constraints are not specifically designed to support solar enablement |
| 6 **Network Tariff** | • The study considered and discussed the impact of tariffs relevant to distribution grid connected batteries:<br>– United Energy's low voltage grid connected tariff (LVKVATOU)<br>– No network tariff (in line with DNSP's ability to negotiate tariffs with customers) |

[28] Aurecon were engaged by AGL, as part of the feasibility study, primarily to support with power system modelling, and to determine the impact on the network of introducing neighbourhood batteries

| | |
|---|---|
| | – ACT's DNSP EVO Energy's Large Scale Battery Trial tariff; a bespoke tariff designed to incentivise peak demand reduction from grid connected batteries<br>• The study modelled two tariff scenarios: zero tariff; and one based on an existing low voltage tariff within United Energy's network 'LVKVATOU' |
| **7 Hardware Costs** | • AGL sourced quotes from two battery suppliers and reviewed recent prior quotes from a third supplier<br>• Estimates used for financial modelling were developed for a range of likely battery configurations to create cost profiles for each option, including: battery hardware, engineering design, grid connection, civil works, and balance of plant items |
| **8 Market Rules** | • The study determined the most appropriate registration for wholesale and FCAS markets based on the size of the battery and grid connection (front of meter). |
| **9 Battery Operations** | • The study used AGL's internal battery optimisation modelling tool, Optigrid, to determine how the battery would participate in wholesale and FCAS markets<br>• Optigrid optimises the dispatch of a battery based on a given price forecast<br>• The study used FY19 – FY21 historical price data to estimate revenue and costs<br>• Optigrid defines the behaviour of the battery by 30-minute interval, enabling the study to assess the impact of battery operations on the network |
| **10 Financial Evaluation** | • The study defined the full value-stack available to batteries, but limited financial modelling to those value pools that are accessible to a competitive market participant<br>• Based on accessible value pools, the study evaluated the NPV of seven scenarios<br>– Five combinations of size and duration, with zero tariff and network services enforced<br>– A 1MW/2MWh battery with United Energy's LVKVATOU tariff<br>– A 1MW/2MWh battery with no network services enforced<br>• The NPV evaluation leveraged internal AGL and external forecasts to extrapolate revenue and costs<br>• For the preferred scenario, the study tested sensitivity to key financial and operational assumptions including:<br>– Wholesale and FCAS prices<br>– Up front capital expenditure<br>– Network payments<br>– Discount rate<br>– Incremental value pools<br>– Forecasting accuracy<br>– Battery degradation |

| | |
|---|---|
| 11<br>**Community participation and ownership models** | • The study conducted desktop research of community engagement schemes and ownership models, designed assessment criteria, and defined the preferred model based on the parameters of the feasibility study. |

# 3. Battery Design Options

## 3.1. Considerations

Key considerations in optimising battery design were ensuring the solutions would meet United Energy's network requirements, and maximising market-based returns relative to the capital cost of the battery. The design and evaluation of options considered a range of battery configuration, grid connection, network tariff, and network service scenarios, with a flexible set of financial assumptions.

### 3.1.1. Battery configuration

An initial view of battery specifications - size (MW) and duration (MWh) - were designed based on United Energy's network requirements, AEMO market rules and the current solution in place on the LMP (diesel gensets). The network requirements were determined based on publicly available information, including:

- United Energy 2020 Distribution Annual Planning Report (DAPR);
- United Energy Non Network Proposal Request, May 2020 (NNPR); and
- United Energy Embedded Generator Register.

**Battery Size and Specifications**

In order to add unique value to the system and attract network services revenue, a battery solution needs to be capable of replacing all or part of the current solutions (diesel gensets). Therefore, the study first considered different size options as replacements for on e or more diesel genset solutions.

United Energy indicated any proposed storage system should maintain the existing level of support provided by the diesel generation sets, and the number of diesel generation sets that can be replaced will be determined by the actual size of aggregated support that can be provided (both size and duration)[29]. Additionally, United Energy suggested an incremental approach could be taken, with the initial study considering replacing up to 5MW of the current 11MW solution. It was assumed that a 1MW battery would be a direct replacement for 1MW of diesel, as long as the battery duration was sufficient to meet network needs.

United Energy indicated the system characteristics to be considered in battery design are:

- Battery thermal characteristics i.e. it must be able to operate safely on a hot day (>35°C);
- System de-rating needs to be accounted for; and
- Fire safety risks must be considered as part of battery chemistry selection[29]

In the battery specifications provided by a leading battery OEM, a potential battery solution has an operating temperature range from -30°C to 60°C (>50°C derating), suggesting the battery should be able to operate safely, and to full capacity under all likely temperatures.

The study assumes a 15-year battery lifetime and degradation curve based on battery specifications provided by a leading Battery OEM. The study tested the impact of shorter or longer battery life on project financial performance in *Section 5.4 Sensitivity analysis*. Restricting parameters such as peak power, cycles per day, and the number of back-and-forth manoeuvres per day can increase battery life, but also has an impact on revenue and gross profit.

[29] Correspondence with United Energy, 16 November 2021

The modelling assumes:

- C-rating of 1 (i.e. a 1MW battery has equivalent power to 1MW of diesel generation) and 100% depth of discharge (i.e. so a 1MW/2MWh can discharge for a 2 hour duration). If the chosen battery has a different C-rating or depth-of-discharge, then the power and storage must be adjusted to be able to meet the network need, impacting battery capital costs.
- 85% round trip efficiency. Note this is conservative relative to specifications provided by a battery OEM ranging from 86% to 88% over the life of the battery

**Battery duration**

Battery duration is a key characteristic of the solution, with both ability to meet network needs and battery cost increasing as duration increases. AGL engaged Aurecon to analyse the required storage duration to meet the network needs on the LMP. Aurecon looked to design duration to cover network needs, but with a minimum amount of redundancy. To determine the duration required to decrease peak demand by up to 5MW on the 66kV sub-transmission line serving the LMP, Aurecon considered:

- Modelled duration required on a ‘peak day’;
- Modelled duration required across all days; and
- United Energy’s guidance on required battery duration.

Peak day analysis

The study used United Energy’s Load Trace Data 2020 DAPR[30] to determine the battery duration required to replace diesel gensets on a ‘peak day’. The peak demand day in the dataset was 30 December 2020.

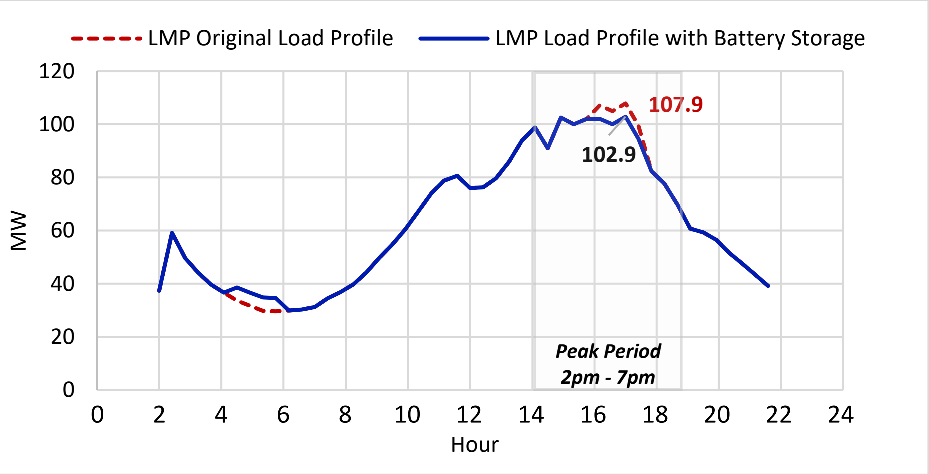
The analysis:

- Combined the load across the DMA, RBD and STO substations to determine the load on the single sub-transmission line serving the region
- Identified the peak (107.9MW) and new allowable peak (102.9)
- Identified, by 30 minute increment, how long the 5MW battery must run for to ensure the new peak demand was equal to 102.9MW

The results, depicted in Figure 3, show that a 1.5-hour duration is sufficient for 5MW of battery storage to reduce peak demand by the full 5MW on the modelled peak demand day.

[30] https://www.unitedenergy.com.au/industry/mdocuments-library/

*Figure 3: LMP load profile with and without 5MW battery (MW)*




The original load profile shows that demand remains high from 2pm – 7pm, suggesting the battery should not charge during this time to avoid the potential of creating a new peak.

<u>'All days' analysis</u>

Recognising that the profile for the 'peak day' may change year on year, the study also investigated the duration required to reduce the peak by 5MW across <u>all</u> days in 2020 for the LMP region.

The analysis, summarise in Table 4, shows that for 93% of days in 2020, a 1-hour or 2-hour duration is sufficient to reduce the peak demand by the required amount. The remaining 27 days required a 3-hour duration to reduce the peak by 5MW.

*Table 4: Number of days the peak 5MW is less than 1, 2 or 3 hours*

| Peak Duration | Days |
|---|---|
| 1 Hour | 138 |
| 2 Hour | 201 |
| 3 Hour | 27 |
| **Total** | **366** |

The equivalent analysis was undertaken for all 11MW provided by Aggreko's diesel generators, instead of 5MW. Noting that replacing more power requires a longer duration, the analysis determined that up to a 6-hour duration is required in some instances.

<u>United Energy guidance</u>

AGL discussed with United Energy the required battery duration to sufficiently reduce peak demand. United Energy indicated[31]:

- The diesel generation sets are currently enabled when the combined load across DMA, RBD and STO exceed 120MW under normal operating conditions. This is expected to occur on days when ambient temperature exceeds 35°C.
- Based on the typical load curve, peak demand across the region occurs between 5:00pm to 9:00pm.
- On days when ambient temperature is above 35°C, typical peak load is expected to last over a 3-hour period

[31] Correspondence with United Energy, 16 November 2021

- Note: This guidance is not consistent with this study's analysis of the LMP load profile. As such, a range of battery durations are assessed.

- Therefore, the requirement to displace 1MW of diesel generator is a 1MW/3MWh battery.

Based on the Aurecon analysis and United Energy guidance, the study participants agreed to investigate 1-to-4-hour duration batteries to provide coverage over a range of possible network requirements.

United Energy suggested there are a growing number of solar installations in the area[31]. AGL expects that, as solar penetration increases, demand during the afternoon will fall resulting in a shorter duration peak.

### 3.1.2. Location and grid connection

In designing the battery solution, the study considered the best location of batteries and any grid connection implications. AGL wanted to consider which location would be the most appropriate in terms of network services, and test that there were no adverse effects on the network if a battery were installed at those locations. Aurecon was engaged to undertake Power System modelling to investigate the capability of BESS to provide network support services to United Energy's network and likely impact on the system. Aurecon's work relied on a power system model and additional information provided by United Energy.

United Energy indicated[32]:

- Existing diesel genset sites are an attractive location for batteries, as there is physical space and network infrastructure already in place.
- Spreading the batteries across DMA, RBD and STO will assist in resolving network issues: installing all storage capacity in and around DMA (only) would not resolve the thermal capacity constraint on the sub transmission lines from DMA to RBD and RBD to STO

The current location of diesel gensets is:

- 5 x 1MVA generators in Boneo across 3 locations, connected to the Sorrento substation (STO)
- 4 x 1MVA generators in Dromana across 2 locations, connected to the Dromana substation (DMA)
- 2 x 1MVA generators in Rye at 1 location, connected to the Rosebud substation (RBD)

Aurecon's analysis of United Energy's PSS/E model suggested that any of the above sites would provide the ability to resolve the network issues raised in the RIT-D[33].

Additionally, United Energy suggested the LV network would not be capable of handling a single connection greater than 2MW[32] – if more than 2MW of diesel were to be replaced, it would require a separate connection and location. Aurecon tested replacing 5MW of diesel with 5MW of battery under three scenarios:

- 5MW connected to STO
- 3MW connected to STO, 2MW connected to RBD
- 4MW connected to DMA, 1MW connected to RBD

Note connections may be across multiple sites as to avoid exceeding the suggested 2MW limit.

Each scenario provided similar effectiveness for managing voltage and reducing the risk of each sub-transmission or distribution line falling below its N-1 thermal rating. Additionally, batteries are able to provide better voltage support when compared to diesel generators (MW for MW) by modulating their power factor. Based on the battery technology chosen, modelling indicated that this provides a small voltage benefit over

[32] Correspondence with United Energy, 16 November 2021
[33] Aurecon, 2021, AGL_Neighbourhood_BESS_Project_Update

the existing diesel generators due to the ability to provide reactive power support. Reactive power, however, comes at the expense of real power, and hence the potential to reduce peak demand by the full capacity of the battery is reduced if reactive power is required.

The study also considered the option of locating batteries behind-the-meter (BTM) to replace the diesel generators. AGL analysed its customer data to identify sites that may be suitable for larger battery installations and consulted with Mornington Peninsula Shire Council representatives[34]. Neither studies nor Council discussions identified sites with potential for behind the meter installations large enough to alleviate constraints on the distribution network. A large scale uptake of behind the meter battery storage could contribute to a potential solution but would be difficult to facilitate in a timely manner on the Mornington Peninsula The potential benefits and drawbacks of locating batteries BTM are discussed in *Section 5.5 Implications*.

[34] 19 October 2021. Mornington Peninsula Shire Council attendees included Chris Yorke, Jesse Caulfield, Stephanie Delaney, Melissa Burrage

### 3.1.3. Network tariff

The study considered both what tariffs the battery may be subject to, and how these would influence the behaviour, network impact and financial returns of a neighbourhood battery. In line with this, the study considered the following tariffs:

- No network tariff;
- United Energy's low voltage large kVA time of use tariff (LVKVATOU); and
- The possible implications of applying a tariff designed for grid batteries, such as EVO Energy's Large Scale Battery Tariff (refer to *Section 5.5 Implications* for further discussion on this tariff).

The LVKVATOU tariff consists of:

- Peak usage cost of 2.9c/kWh, with peak between 7am – 7pm on workdays;
- Off-peak usage cost of 1.4c/kWh, with off-peak is all times other than peak period; and
- Rolling peak of 24.43c/kVA/day. This is calculated based on a rolling 12-month maximum during peak period. For example, a 1MW battery that discharges at full power at any point during the peak period of the last 12 months would be charged at 24.43c x 1000kW / 100 = $244.3/day or $89K/year.

### 3.1.4. Network services

A critical capability of the proposed solution is the ability to provide network services to reduce peak demand in line with United Energy's needs, as published in the NNPR. We determined the constraints to be placed on battery operation (to support network services) by:

- Undertaking load profile analysis; and
- Through discussions with United Energy

The NNPR outlines high level requirements to support reducing peak demand, but does not specify precisely how a battery would be expected to operate. Through analysis of the load profile (refer to *Section 3.1.1 Battery configuration*), the NNPR, and discussion with United Energy, the study determined that:

- Peak demand occurs on a peak day between 5pm and 7pm
- In the daily peak load profile, as described in the NNPR, the peak can remain high between 2pm to 10pm. Importantly for distribution connected batteries, this implies that incremental load during this period has the potential to create a new peak
- Diesel generators are installed for summers only (start of December to end of February).

The load profile analysis returned guidance that was consistent with, and slightly conservative to, United Energy's guidance, which stated that:

- The desired operating period is between 5:00pm to 9:00pm on days when ambient temperature is above 35°C;
- Battery cannot charge between 3:00pm to 9:00pm during peak demand days; and
- Batteries should be fully charged and ready for discharge during the nominated time periods

Based on the above criteria, the study defined a conservative set of constraints within which the battery must operate in summer.

- All cases: Must not charge between 2pm and 10pm
- 1MW, 1MWh (1-hour duration): Discharge 5pm to 6pm
- 1MW, 2MWh: Discharge 5pm to 7pm

- 1MW, 3MWh: Discharge 5pm to 8pm
- 1MW, 4MWh: Discharge 4pm to 8pm

Considering the battery must fully discharge during the specified periods, this implies it must be fully charged prior to entering the peak period.

### 3.1.5. Wholesale electricity market participation

The study considered the implications of NEM wholesale energy and FCAS registration and participation requirements.

Regarding the wholesale market, batteries less than 5MW can engage in wholesale market trading without registering with AEMO[35] .This option was deemed this the most appropriate approach for this feasibility study. The load remains unscheduled and as such, the battery will purchase and supply electricity at the wholesale price but not participate in the scheduled dispatch process for energy.

For the provision of frequency ancillary services (FCAS), the battery would be registered as a Demand Response Service Provider (DRSP).

In order to provide FCAS services to AEMO, a participant is required to register as a wholesale demand response service provider, and the battery site considered in this study would have to be classified as an Ancillary Services Load (ASL), and either a new DUID created or aggregated into an existing DUID. Based on AEMO's fees schedule this comes at a cost of $10,609.

[35] AEMO, 2021, Guide to Generator Exemptions and Classification of Generating Units

## 3.2. Final design options

The study designed 7 options for investigation, defined in *Table 5* below.

*Table 5: Final design options for investigation*

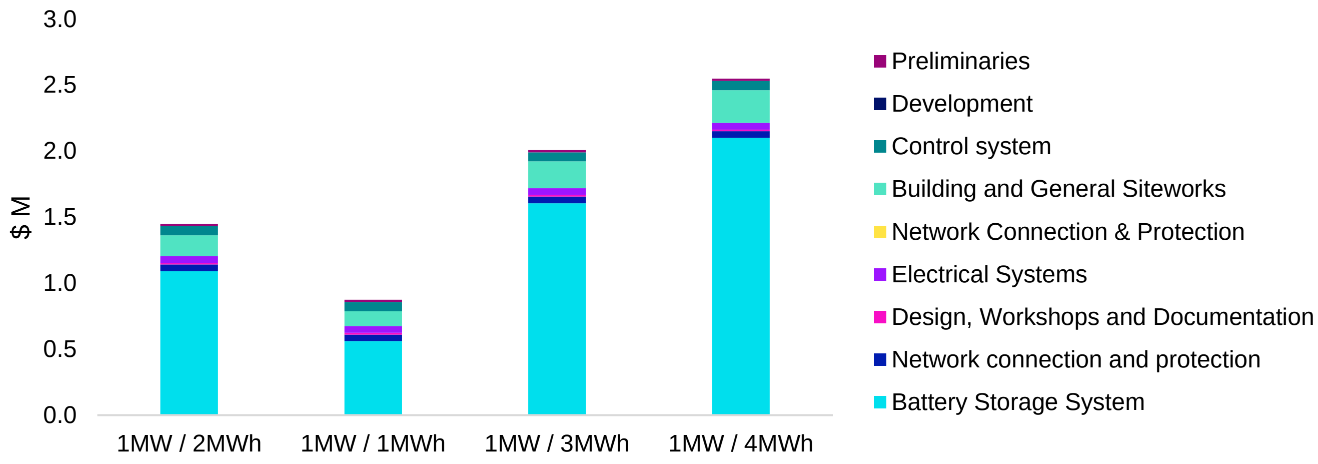
**Change from Base Case**

| | Option 1 (Base Case) | Option 2 | Option 3 | Option 4 | Option 5 | Option 6 | Option 7 |
|---|---|---|---|---|---|---|---|
| **Description** | *1MW/2MWh battery (to replace 1 diesel generator); no network tariff* | *Shorter duration than Base Case; potentially capable of only covering portion of peak demand* | *3-hour duration compared to 2; can be dispatched earlier to cover peak demand for longer period* | *4-hour duration compared to 2; can be dispatched earlier to cover peak demand for longer period* | *2 MW/4MWh battery to replace 2 diesel generators; realise economies of scale* | *Network tariff introduced to influence battery behaviour and economics* | *Network service requirements removed along with network service payments* |
| **Capacity (MW)** | 1 | 1 | 1 | 1 | 2 | 1 | 1 |
| **Storage (MWh)** | 2 | 1 | 3 | 4 | 4 | 2 | 2 |
| **Duration** | 2 | 1 | 3 | 4 | 2 | 2 | 2 |
| **Tariff** | Zero | Zero | Zero | Zero | Zero | LVKVATOU | Zero |
| **Network Requirements** | Yes | Yes | Yes | Yes | Yes | Yes | No |
| **Location** | *All options likely are less than or equal to 2MW – assumed to be located at the same site as the diesel generators used currently.* | | | | | | |
| **Connection** | *FOM – BTM options considered but not modelled in Optigrid* | | | | | | |

Figure 4 shows the estimated capital cost for the selected options. The capital costs are based on quotes from a battery manufacturer. These quotes have been compared against quotes from other providers and different providers are broadly in line with each other in terms of cost. The cost of system components other than the battery system itself has been estimated by AGL based on comparable projects. The capital cost for different design options are not firm due to not being set for a specific location. The items that could primarily be affected by this include the cost of building and siteworks and the cost of network connection and protection.[36] These items represent a relatively small share of the overall cost of the battery system, and we do not expect them to materially alter the outcome of this feasibility study.

We have not allowed for the cost of project development at this stage due to these costs to some extent being covered through this feasibility study. For a standalone project a competitive market participant would have to take these costs into account. We have assumed that the grid connection of the existing diesel generators could be reused for this project and have not allowed cost in relation to an application for network connection.

*Figure 4 Final design options capital cost estimates*




Source: Chinese battery manufacturer and AGL estimates of ancillary cost of storage

[36] It is theoretically possible that some of the network connection equipment used by the diesel generators currently in place could be reused for the connection of battery storage.

# 4. Findings: Impact of Storage

## 4.1. Battery operation

The study used AGL's proprietary battery optimisation and dispatch modelling tool, Optigrid, to determine how the proposed battery solutions would participate in wholesale and FCAS markets across the 7 scenarios as defined in *Section 3.2 Final design options.* Optigrid optimises the dispatch of a battery based on a given price forecast and used FY19 – FY21 historical price data to estimate baseline revenue and costs (detailed assumptions noted in *Section 9.4*. It defines the behaviour of the battery by 30-minute interval, enabling the study to assess the impact of battery operations on the network.

The key outputs of the modelling are:

- Operational profile: For each 30-minute period what is the battery doing: charging, discharging, neither?
- Cycles: How frequently is the battery charging and discharging?
- Gross Profit: How much revenue does the battery earn from wholesale and FCAS markets, and how much does it cost to charge the battery?
- How do battery operations and profitability differ when:
  - Duration increases or decreases?
  - A network tariff is put in place?
  - Network services are not enforced?

### 4.1.1. Battery operational profile

Based on the base case option[37], we investigated how the battery would operate on average, and also across high or low demand days.

Under base case conditions the battery – typically – discharges during the morning and evening peaks, with Figure 5 illustrating this behaviour on average during each season. Each season follows a similar profile, with summer influenced by the network service requirements imposed on the battery. Notable battery behaviours include that the battery:

- Charges during the early hours of the morning;
- Discharges during the morning peak, between 6am and 9am;
- Charges during the middle of the day, coinciding with period of low prices and high solar exports; and
- Discharges more quickly during the evening peak.

Network service requirements can be seen taking effect from 2pm to 10pm in summer, with forced discharge between 5pm and 7pm[38].

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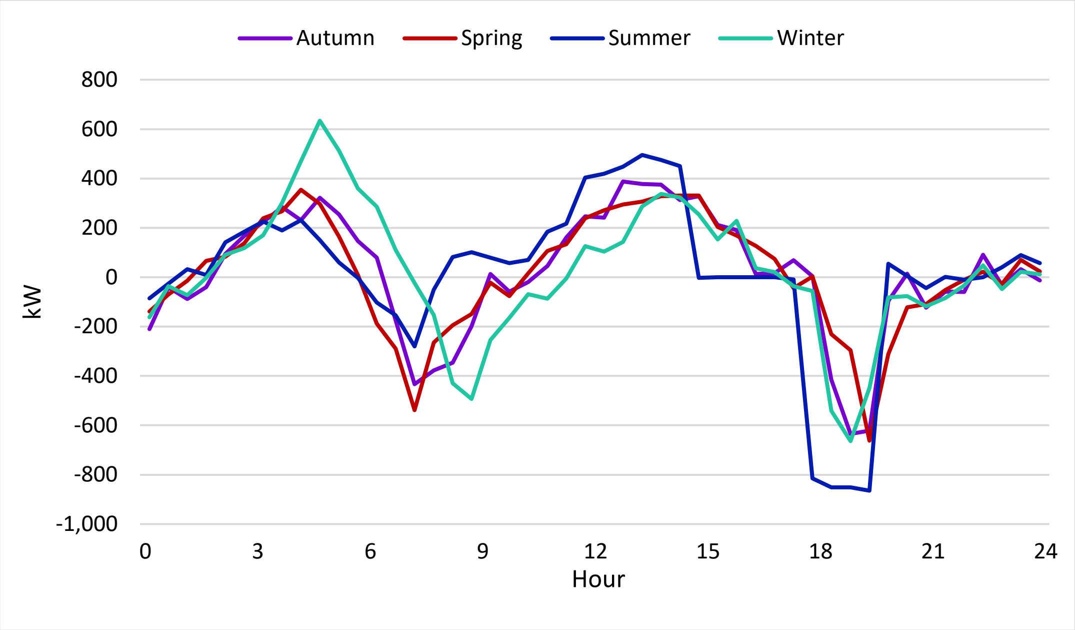
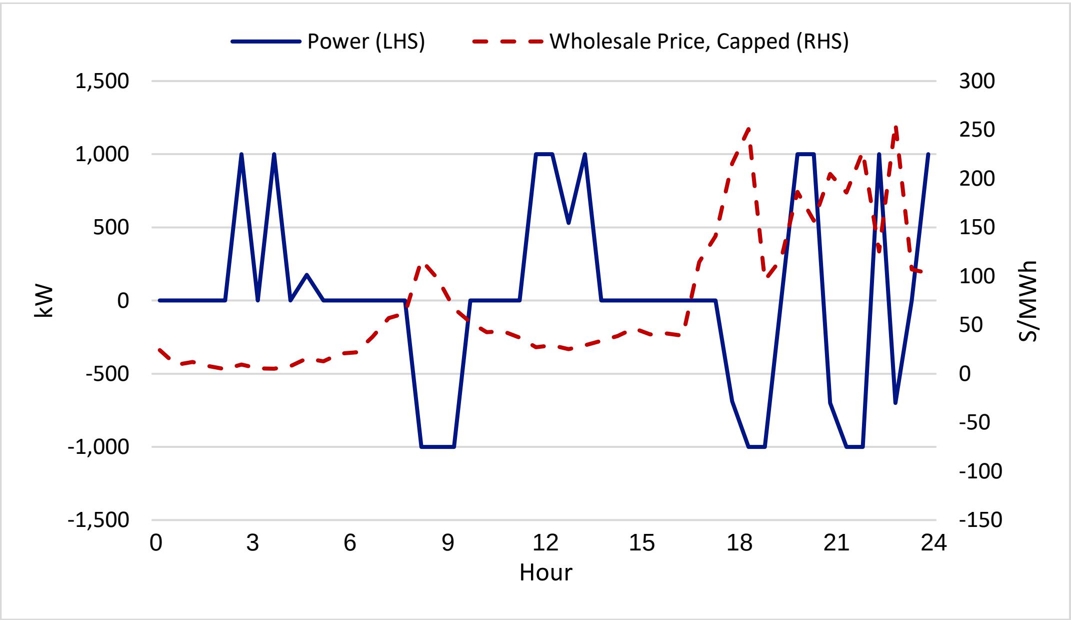
[37] Per Section 3.2 Final design options: 1MW/2MWh; zero tariff: network service requirements enforced
[38] Modelling limited export power to 850kW

Figure 5: 1MW/2MWh battery operational profile by season (FY21)



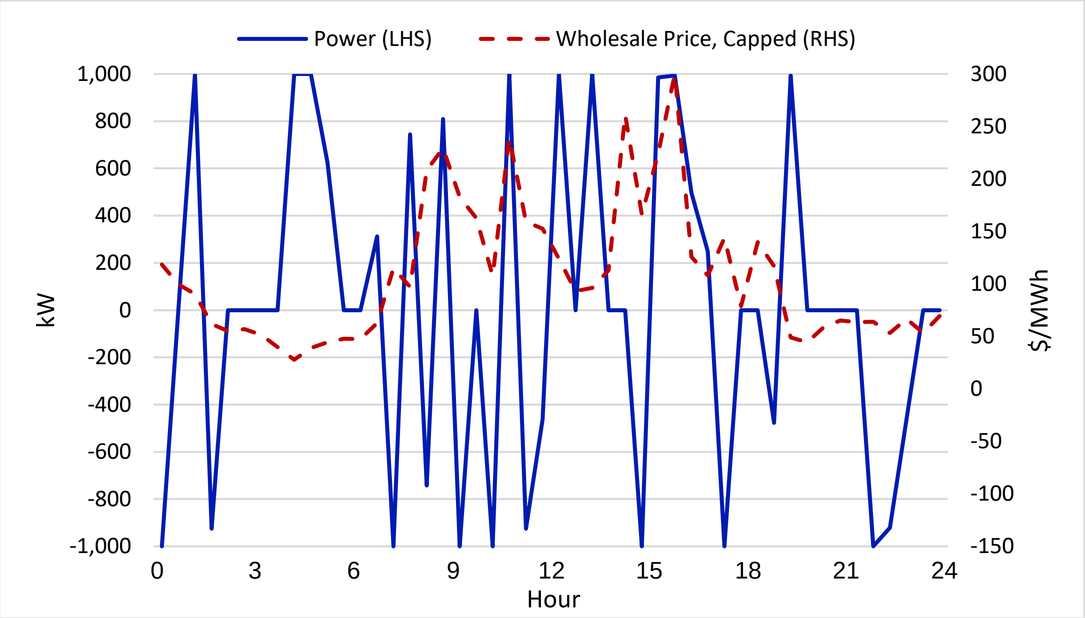

On an 'average' day – a day where imports, exports, wholesale revenue and the spot price are similar to the average – the battery is predictable. As seen in Figure 6, the battery follows a similar profile to the average (Figure 6), discharging at specific points of high prices during the morning and evening peaks.

Figure 6: Battery operational profile during 'average' day (4 June 2021)



Battery activity can vary materially by day. Figure 7 illustrates how the battery would have behaved during the ‘peak day’ in the 2020 DAPR data (30 December 2019) without network service requirements enforced. Power fluctuates frequently between discharging and charging in response to rapid changes in the wholesale electricity spot price. This behaviour is the result of the battery responding to price signal in the wholesale electricity market without constraints on ramp rates, cycling between charge and discharge cycles or the like. Power system modelling undertaken by Aurecon for this study did not indicate major issues with this type of behaviour but more detailed studies may be required. Competitive market participants are able to adjust the behaviour of battery storage to meet the needs of local distribution networks if requirements can be clearly formulated.

*Figure 7: Battery operational profile during 'peak day' (30 Dec 2019)*



### 4.1.2. Battery cycles

Based on the Optigrid modelling, on average, the battery is projected to perform 1.5 cycles per day[39], with a slight increase during winter and early spring months. We note that most manufacturers of battery systems do not warrant their battery operations for more than 1 cycle per day. For this study we have assumed that the number of cycles shown below could be achieved with the available technology, noting that this is likely to breach battery warranty. For a final investment decision a more conservative assessment of the number of cycles is likely to be required.

Figure 8 shows, from 2018 to 2020, the battery would have completed between 462 and 562 cycles each year, at an average per day of 1.3 to 1.5 respectively. In 2021, the average increases to 1.6, however, this excludes October, November and December data – November and December are generally below average (Figure 9).

*Figure 8: Battery cycles by calendar year*

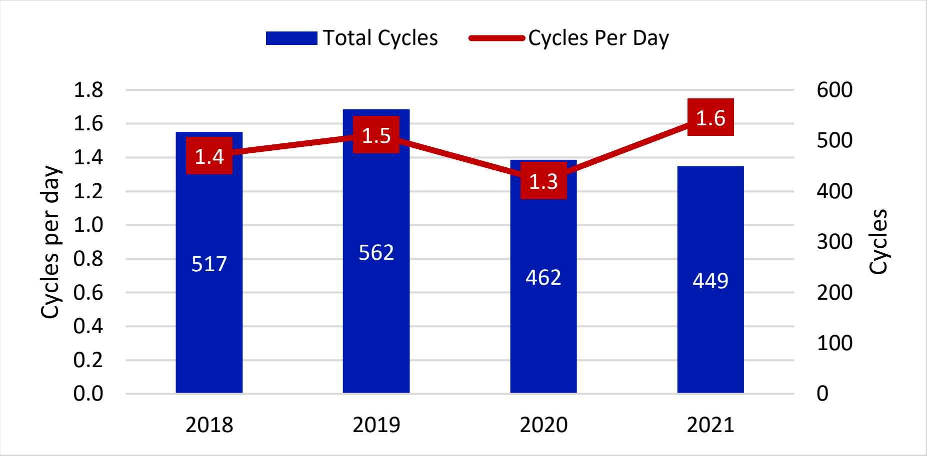



Figure 9 breaks down average cycles per day by month over the FY18 to FY21 period, showing that each month, except for March, sits within a +/- 20% range from the average. Early spring and winter see the most activity.

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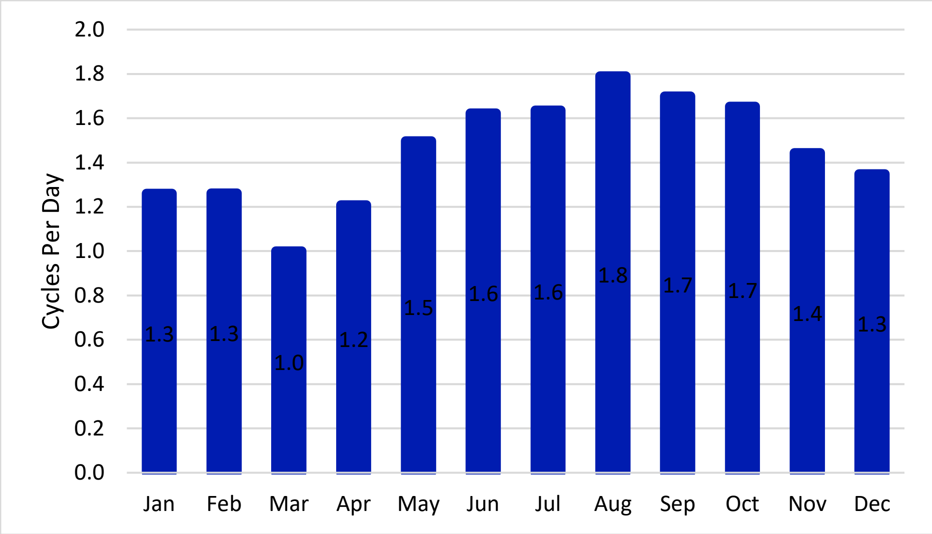
[39] Average cycles: sum of magnitude of all state of energy movements, divided by two, normalised by storage

*Figure 9: Average cycles per day by month (2018 – 2021; 2021 excludes October, November, December)*



### 4.1.3. Gross Profit

AGL's battery optimisation and dispatch model calculates expected market revenues and costs for each 30 minute interval[40], allowing a calculation of the expected market-based gross profit based on FY19 – FY21 pricing. Gross profit comprises four elements:

- Wholesale: Revenue achieved from selling electricity in the wholesale market at the spot price. Wholesale prices can be viewed in two ways:
  - Capped: Spot price is capped at $300. The capped price remains at $300 when the actual spot price moves above $300, and market participants access the cap contract market to hedge their portfolio for periods where the price spikes above $300. From FY19 to FY21, estimated gross profit from intervals when exporting at a price less than $300/MWh range from 68% to 81%
  - Uncapped: Spot price as achieved on a given day.
- FCAS: Revenue from providing FCAS enablement services in the 'raise' and 'lower' markets.
- Cost to charge: Cost of energy purchased from the wholesale market to charge the battery
- Network tariffs (noting zero tariff applied under base case conditions) including
  - Usage tariff: Network cost for each kWh of electricity imported from the grid; charges vary across peak and off-peak periods
  - Demand tariff: Network cost based on maximum power achieved during a specified time-period

The battery optimisation and dispatch model considers expected prices and costs for these four elements, and using 'imperfect foresight'[41], makes financially optimal decisions on how to charge and discharge the battery. In this section we consider Base Case gross profit, which includes FCAS and wholesale activity. The impact of network services on battery activity is explained in *Section 4.4 Provision of network services*. Based on wholesale revenue, FCAS revenue (raise and lower), and cost to charge (assuming no network tariff), a 1MW/2MWh battery is modelled to have earned $99K gross profit in FY21.

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[40] The modelling for this project was undertaken at a 30-minute resolution in line with the historical settlement periods. The switch to 5-minute settlement provides batteries with additional price arbitrage opportunities within the 30-minute intervals. The extent to which a battery could capture this additional volatility depends to some extent on the ability to forecast price spikes at the 5-minute level. On balance we believe that modelling battery operations on a 30 minute level is a sufficient approximation of the available revenues.

[41] Based on AEMO pre-dispatch price forecast published prior to each dispatch interval. Historical forecasts are loaded, and forecast price data for a range of years is replayed during the simulation of a given load year

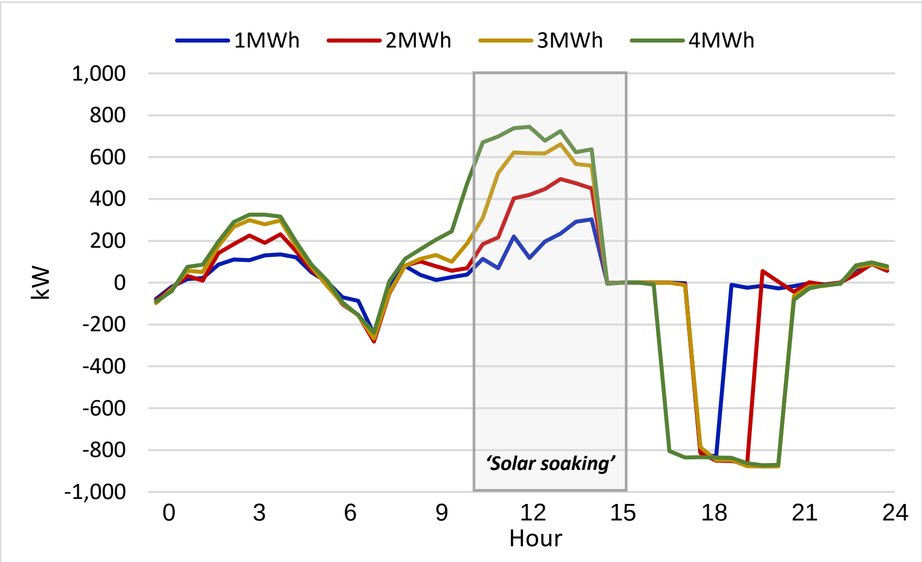
## 4.2. Impact of battery duration

The study considered the impact of changing battery duration. We found that increasing duration increases total gross profit, at the expense of profit per MWh, as the battery is forced to discharge over longer periods.

The operational profile for different durations over summer, when network service requirements apply, is provided in Figure 10. Figure 10 illustrates that increasing duration allows the battery to, on average, charge at a higher rate. The increase in power, however, does not increase in proportion to storage – decreasing unit returns can be seen after 2-hour duration. Considering storage is the key driver of capital cost (refer to *section 5.2 Option assessment*) this suggests a 1MW to 2MWh ratio is preferable.

Figure 10 shows an increase in imported energy during the 'solar soaking' period. 'Solar soaking' can be described as the act of consuming excess energy generated by distributed rooftop PV solar panels instead of energy generated by centralised large-scale energy sources. For the purposes of this report, AGL defined a 'solar soaking' period between 10am and 3pm: a period when rooftop PV solar is typically at its highest and household demand is typically low, resulting in high net exports of solar to the grid. By soaking excess solar, the battery helps to resolve the challenges discussed in *section 4.4*; the benefits are detailed further in *section 4.5 'Solar soaking' benefit*.

*Figure 10: Operational profile for different durations during summer (FY21)*



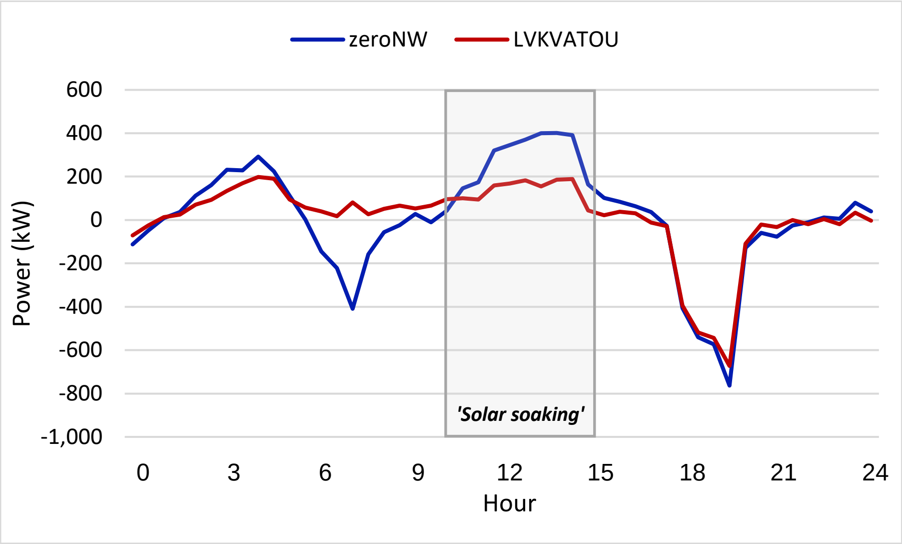

Total gross profit increases with duration, but at a diminishing rate per MWh.

## 4.3. Impact of network tariff

Overall, modelling indicates that introducing a network tariff reduces 'solar soaking' benefit and gross profit.

Figure 11 shows that implementing United Energy's LVKVATOU tariff would reduce peak power during the day to ~30-50% of the zero-tariff case. This reduction limits the 'solar soaking' benefit as the battery imports less excess solar. This finding suggests that if networks require batteries to act as a 'solar sponge' then new bespoke tariffs, or exemptions from network tariffs are required to incentivise the desired behaviour.

*Figure 11: Battery average operational profile with network tariff over spring and summer (FY21)*




This finding is consistent with the operational profile for the battery over a year, depicted in Figure 11.

## 4.4. Provision of network services

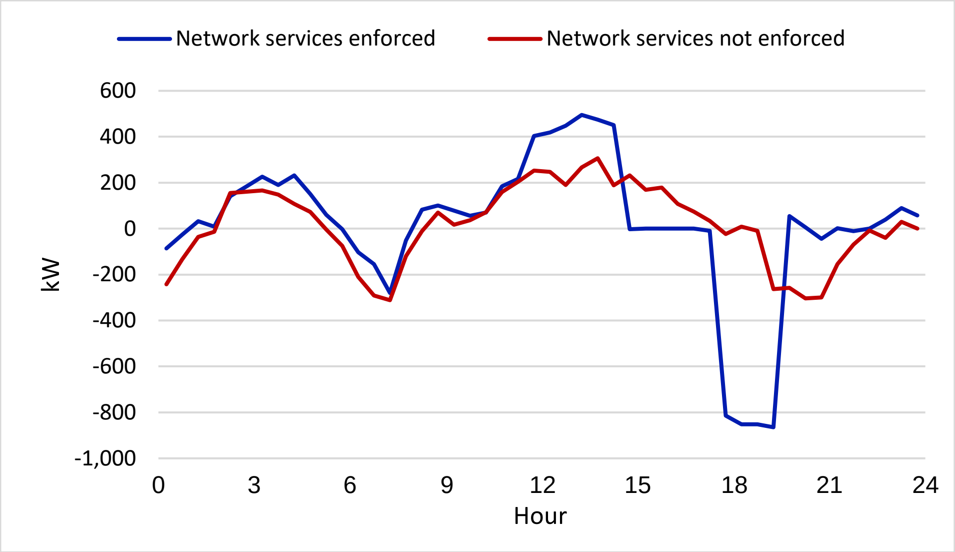
### 4.4.1. Network services impact on battery behaviour and gross profit

The study investigated the impact of enforcing constraints on battery operations to provide a network service.

The difference in battery operation while providing network services and when not providing network service is illustrated in Figure 12. Without constraints, the battery:

- Continues to charge from 2pm to ~5pm, risking potentially creating an even higher point of peak demand
- Discharges from 6:30pm – 10pm, potentially not aligned to peak demand on the LMP

*Figure 12: Battery average summer operational profile (FY21)*




The chart above suggests that providing a network service would change the operating profile of the battery. This change in operating profile may be more marked than the change in revenue earned. This suggests that implementing network support with batteries may be feasible where DNSPs are able to provide the precise requirements on the dispatch of a battery storage unit. The more timely and precise these requirements are and the more they overlap with the operation of the battery in response to wholesale electricity market price signals the lower the overall cost of providing a network service.

Figure 13 illustrates how the battery would behave on a representative summer day without material spikes in the spot price (February 8, 2020 selected). The impact of network services can be seen between 2pm and 10pm:

- Battery charges in the hours leading up to 2pm in preparation to fully discharge at 5pm;
- Battery cannot discharge during spike in price between 3pm and 4pm;
- Battery discharges at peak period from 5pm – 7pm, even though prices have not at their highest point

*Figure 13: Battery operational profile with network service requirements (FY19, December 20)*

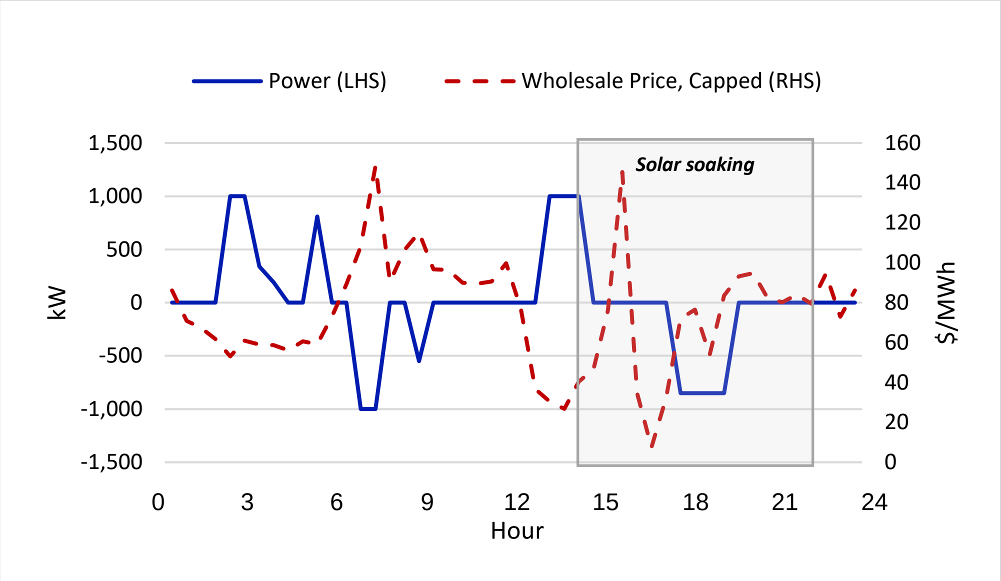



Figure 13 illustrates how improving the accuracy of forecasting and limiting the restrictions placed on the battery in the form of network service requirements can improve battery economics, effectively enabling battery uptake and reducing costs for consumers. Ideally, the agreement between the NSP and market participant should place as few constraints as possible on battery behaviour through active forecasting, allowing the market participant to maximise value generation during unconstrained periods, for example, the constraints applied in this study could be limited to only summers days where the temperature is expected to exceed a threshold, such as 35°C.

Overall, the study saw that – based on FY21 data – introducing network service requirements reduces profit per MWh exported as it forces activity during less profitable periods.

It is estimated that payment for network services would account for any decline in profitability. In this study, United Energy indicated the payment would be between $40K - $50K to replace a diesel generation (1MW), noting the current contract period is to the end of FY25[42]. We note that the reduction in opportunity and revenue is dependent on the exact network energy requirements in a given year and the outcomes in the wholesale electricity market. *Section 5.3.1 Value of deferred network investment* considers the potential value of providing network services to United Energy in the LMP region.

[42] Correspondence with Untied Energy, 16 November 2021

## 4.5. ‘Solar soaking’ benefit

Neighbourhood batteries can enable greater exports from rooftop solar installations and manage localised peak demand, particularly in shoulder months, by absorbing energy during times of high solar generation. By supporting solar exports, storage can provide incremental value to the community that the existing diesel generators cannot.

The solar soaking benefit provided by the battery is considerable even without an incentive on the battery to perform this service. Excluding network charges for the battery makes the solar soaking behaviour of the battery more effective. In the absence of appropriate incentives for solar soaking and/or voltage control the removing of network charges for distribution scale batteries may provide some incentive to perform a solar soaking service. Without network charges the wholesale electricity spot market price provides a direct incentive for the battery to charge at times of low price. Increasingly this occurs in the solar soaking window when generation from roof-top solar is highest.

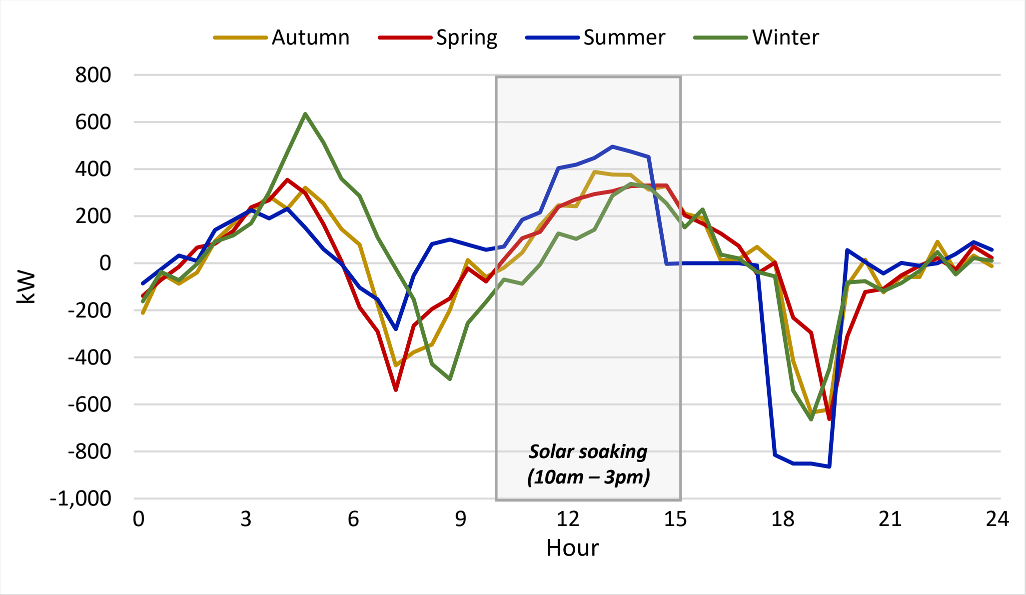
As discussed in *section 2.2*, when network voltage rise, high network voltages may cause customers' solar inverters to trip. As a result, solar exports cease and solar cannot be used for household consumption.

‘Solar soaking’ can provide value through three key value pools:

- For customers, alleviating constraints on exporting solar energy increases utilisation, and generates a higher return from feed-in-tariffs (FiT);
- NSPs may avoid or defer investment in infrastructure upgrades, such as United Energy’s Solar Enablement Program; and
- For communities, batteries increase the proportion of renewable generated electricity, which in the longer term leads to lower energy costs for consumers

AGL has estimated the potential value for customers and the community, using two different methods, in *Section 5.5.4 Solar enablement*.

*Figure 14: Battery operational profile during 'solar soaking' period (FY21, base case)*




The modelling assumes a solar soaking period of between 10am to 3pm in summer and spring. Figure 14 shows the average power over an average day for each season. The analysis shows that:

- The battery is typically charging during the required periods;

- The network requirement to be fully charged at 5pm encourages the battery to charge further in the leadup to peak, potentially absorbing more excess solar
- The network requirement to not charge from 2pm onwards in summer restricts the 'solar soaking'. The requirement was based on the peak day load profile, where from 2pm onwards if the battery charged it risked creating a new peak. As solar penetration increases, it is expected that the requirement may be relaxed, and the battery could continue to absorb excess solar during this time in summer

*Figure 15: Energy imported and wholesale prices during 'solar soaking' period*

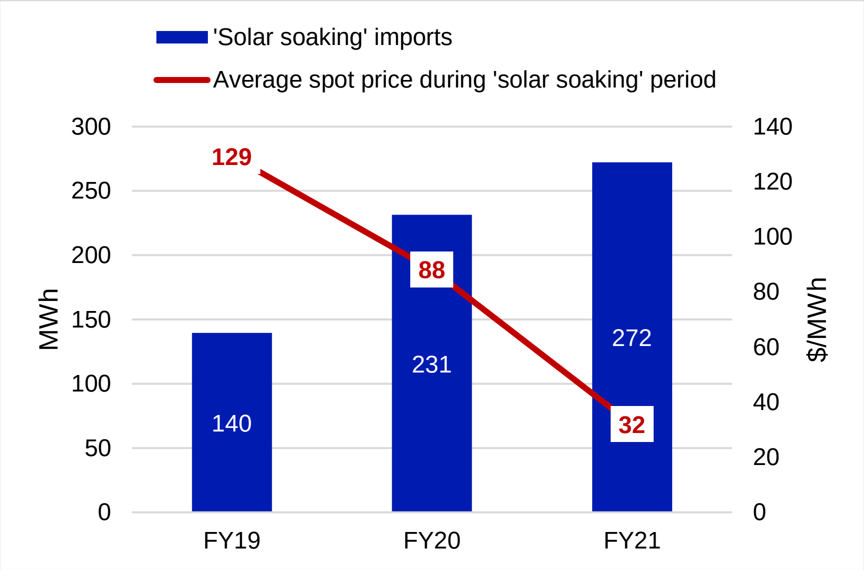



Figure 15 shows how much energy the battery would have absorbed during the solar soaking period under base case conditions. Over FY19 – FY21, it is estimated a 1MW neighbourhood battery would have imported 643MWh[43].

Given the 1MW capacity is only 1% of the 108MW peak (per United Energy DAPR 2020), it is reasonable to assume in future, once export constraints arise, each kWh imported originated from rooftop solar that would otherwise be constrained. Figure 15 also shows the battery is charging more during the solar soaking period in response to declining wholesale prices.

[43] Per Optigrid modelling

# 5. Project Financial Evaluation

The feasibility study defined the full value-stack available to batteries, but has focused financial modelling on those value pools that are currently quantifiable and accessible to a competitive market participant. Based on accessible value pools, the study evaluated the NPV (the present value of all cash flows over the life of the project) of seven scenarios:

- Five combinations of size and duration, with zero tariff and network services enforced;
- A 1MW/2MWh battery with United Energy's LVKVATOU tariff; and
- A 1MW/2MWh battery with no network services enforced.

The NPV evaluation leveraged internal AGL and external forecasts to extrapolate revenue and costs. For the Base Case, the study tested sensitivity to key financial and operational assumptions including: Wholesale and FCAS prices; upfront capital expenditure; network payments; discount rate; incremental value pools; forecasting accuracy; and battery degradation rate.

Key assumptions in the overall financial analysis include: 15-year battery life, commencing start of FY23; an assumed 6.7% post tax discount rate; and 2.5% inflation rate.

Detailed assumptions underpinning the financial analysis are provided in *Section 1.1*.

## 5.1. Value-stacking

In line with the feasibility study objectives, this financial evaluation was undertaken from the perspective of a market participant. The modelling assumes the market participant realises a share of the value from deferring network investment, and generates value in the wholesale and FCAS markets. Table 6 below outlines which, of the value pools considered, have been explicitly modelled in the financial evaluation.

*Table 6: Financial model value-stack*

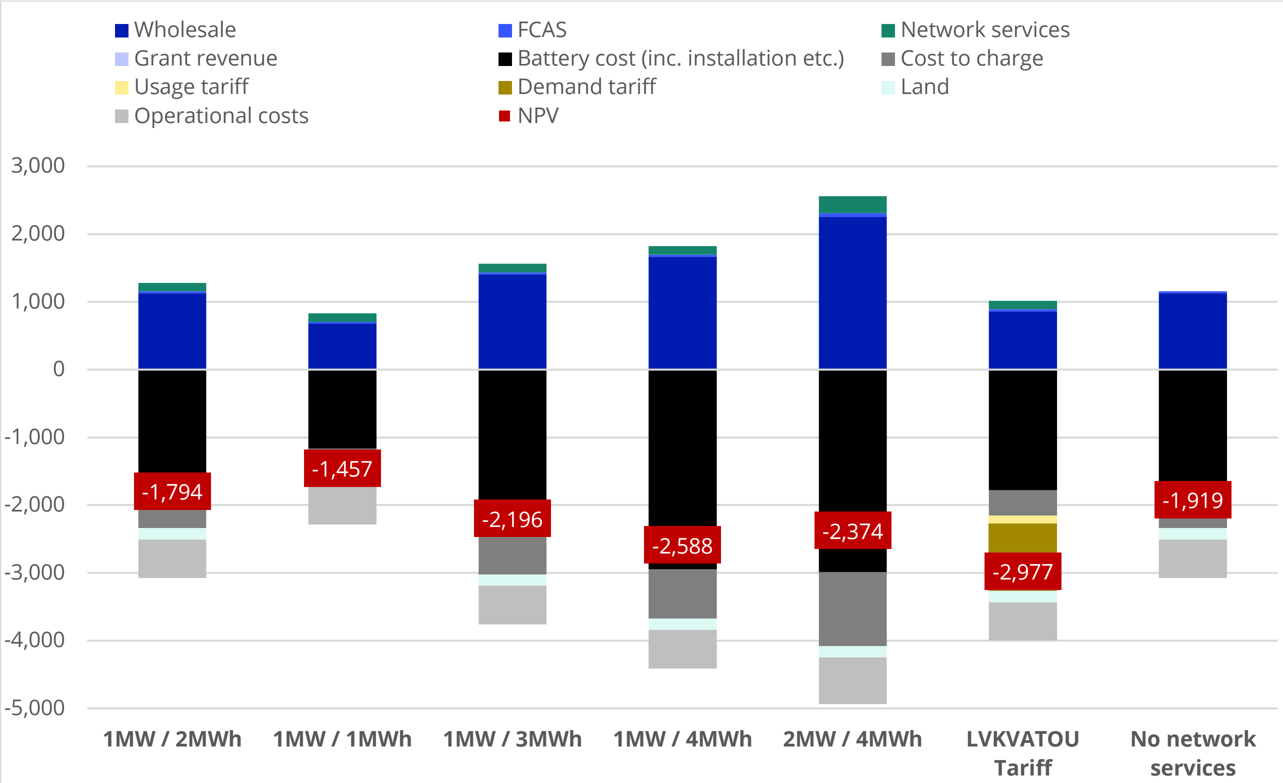
| Category | Value Pool | Assumptions | Included? |
|---|---|---|---|
| **Network support** | **Defer investment** | • NSP payment for provision of network services until deferred network upgrade implemented (base case assumes 3 years as review scheduled for end of FY25)<br>• Option to extend payment to full project life if upgrade continues to be deferred, or option to capture greater share of value from deferred investment | ✓ |
| | **Voltage regulation** | • Network receives benefits of voltage management for the purposes of deferring investment; no incremental payment received by market participant | *Not rewarded* |
| **Market trading** | **Wholesale** | • Base year determined using FY19 – FY21 observed prices<br>• Extrapolated using wholesale spread forecast capped to prices below $300/MWh<br>• Payout of $300/MWh cap contracts | ✓ |
| | **FCAS** | • Base year determined using FY19 – FY21 observed prices<br>• Extrapolate using FCAS price forecast | ✓ |
| **Retail position** | **Cap contract premium** | • No cap contract premium is assumed over spot market payouts. Contract premiums can fluctuate above and below spot market payout; the extent to which a battery can underwrite a derivative contract is not fully understood; revenue highly uncertain<br>– Potential upside tested in *section 5.4 Sensitivity analysis* | X |

| | | | |
|---|---|---|---|
| | **Customer** | • Ability for project to capture customer value dependent on Community Engagement Scheme (refer to section *9.2 Community Engagement Scheme: detailed assessment)* | *Scheme dependent* |
| **Customer benefit** | **Tariff arbitrage** | • Modelling focused on value available to competitive market participant. Community Engagement Schemes discussed in section 6, Community Engagement Schemes | *Not accessible* |
| | **Reduce FiT constraints** | • Modelling focused on value available to competitive market participant. Community Engagement Schemes discussed in section 6, Community Engagement Schemes<br>• Value of 'solar enablement' estimated (*section 4.5 'Solar soaking' benefit*) | *Not accessible* |

## 5.2. Option assessment

A comparison of the NPV for each option under base case conditions[44] shows all cases return a negative NPV, with the 1MW/1MWh option the least negative at -$1.4M. The other options ranged from -$1.8M to -$2.9M.

*Figure 16: Scenario NPV comparison ($K)*




While the 1MW/1MWh option returned the highest NPV, analysis of the load profile and guidance from United Energy suggested a 1-hour duration is too short to provide the required network services, hence this option was deemed infeasible. The study considered a 2-hour duration to be sufficient for the first MW of demand response, suggesting grant or other funding of $1.8M may be required to make up the shortfall.

The NPV comprises the combination of ten revenue and cost streams:

- Wholesale: Revenue achieved from selling electricity in the wholesale market at the spot price
- FCAS: Revenue from providing FCAS enablement services in the 'raise' and 'lower' markets
- Network services: NSP payments for delivering the agreed services to support the network
- Grant revenue: Funding provided to support project implementation (assumed 0)
- Battery cost: All costs associated with purchasing and installing the battery including grid connection and project labour overhead
- Cost to charge: Cost of energy purchased from the wholesale market to charge the battery, including green scheme costs and AEMO fees

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[44] Base conditions include zero tariff, network services enforced (3-year contract) and 15-year battery life. Financial assumptions detailed in *section 1.1 Modelling* assumptions.

- Usage tariff: Network cost for each kWh of electricity imported from the grid; charges vary across peak and off-peak periods
- Demand tariff: Network cost based on maximum power achieved during a specified time period
- Land: Estimated land lease payments; based on area required to install battery and cost per square metre estimate
- Operational costs: All costs associated with operating the battery including operations and maintenance, labour overhead, API access

The study determined negative NPV across cases even though:

- Key value streams are being accessed: wholesale and FCAS market trading, and network support; and
- No network charge applied.

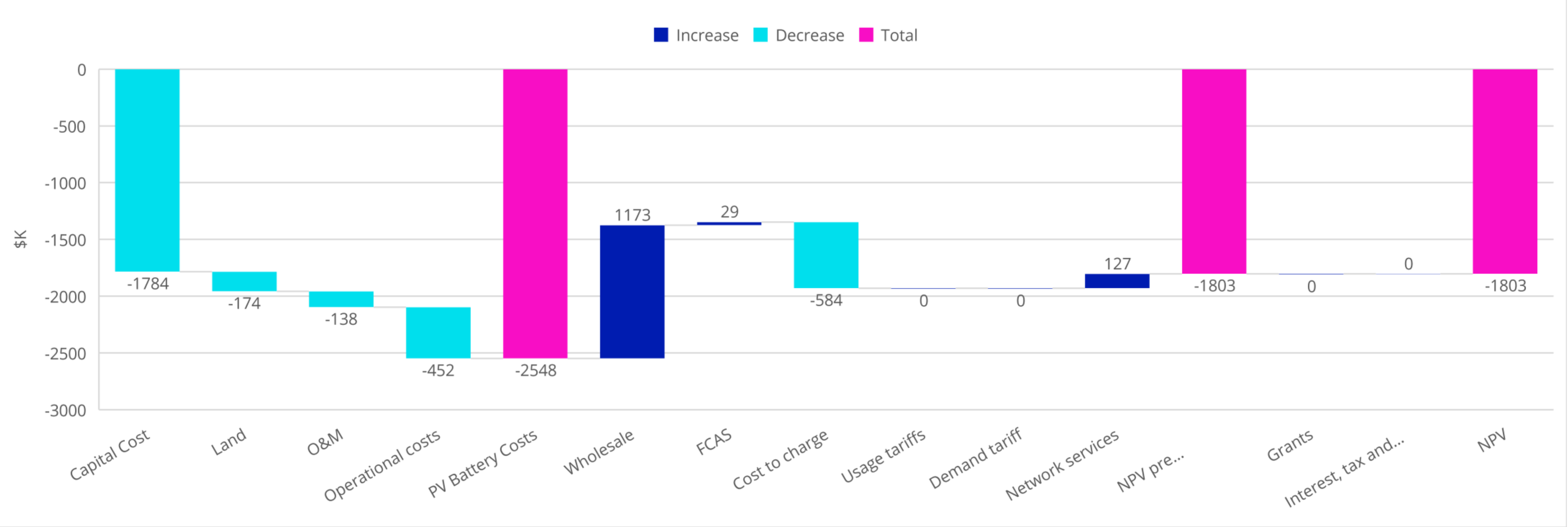
The comparison in Figure 16 suggest that:

- As duration increases, NPV declines because available market revenues do not offset the increase in battery costs.
- Increasing system size realises economies of scale, but alone it is not sufficient to recover NPV deficit
  - In isolation of the first battery, adding a second battery 1MW/2MWh battery (for a total of 2MW/4MWh) reduces NPV further by -$0.6M (compared to -$1.8M for the first battery)
  - This suggests the economies of scale are improving performance per MW, but will not be sufficient to recover the NPV deficit – adding further capacity will only continue to decrease NPV
- Introducing a network tariff reduces project NPV by $1.2M – approximately double net revenue from trading in wholesale and FCAS markets
- Removing network services reduces NPV by ~$0.1M, primarily due to no network payment revenue

## 5.3. Preferred solution

Figure 17 provides a detailed breakdown of project revenues and costs (present value over life of the project) for the base case, culminating in an NPV of -$1.8M.

*Figure 17: Present Value of Project Revenue Streams and Costs*




Key observations related to the base case are outlined below:

- Battery capital costs represent 71% of total costs
- Value streams represent a very small portion of total costs
  - $0.6M net wholesale revenue (‘Wholesale’ less ‘Cost to charge’) recovers just 24% of total battery costs and 34% of up-front battery capex
  - FCAS revenue is immaterial ($28K) as prices projected to decline rapidly post FY21. The sensitivity to FCAS prices is considered in *Section 5.4 Sensitivity analysis*
  - Network services revenue for replacing diesel generators represent only 5% of total battery costs and 7% of up-front battery capex

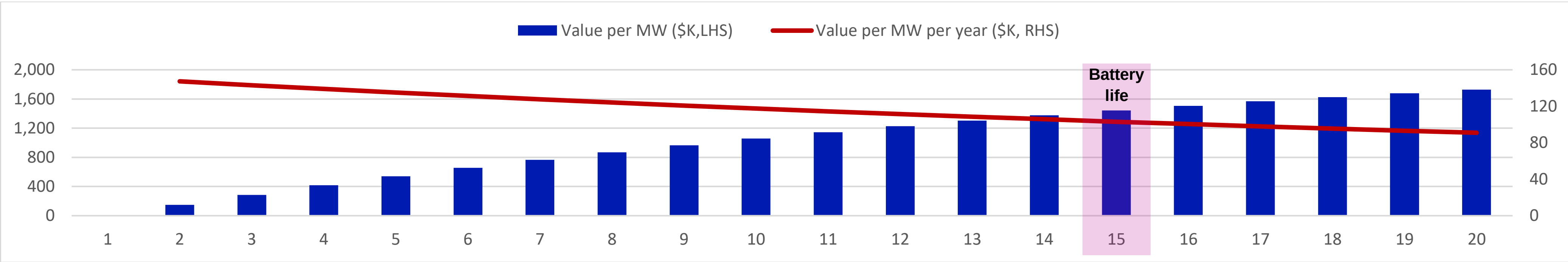
- Note: Network services modelled for 3 years only as the study assumes the ‘deferred’ network investment is implemented after the next review at the end of FY25 – value increases to 29% and 41% of costs respectively if payment continues for the life of the project, recovering an extra $375K

The 1MW/2MWh option delivers $26K EBITDA loss over the project (undiscounted).

### 5.3.1. Value of deferred network investment

The study sought to understand, indicatively, the total value of deferring the network investment, and whether there is a feasible 'value share' arrangement that could resolve the NPV deficit. According to United Energy Non-Network Proposal Request, the provision of network services is designed to reduce peak demand and defer installing a new 66kV line between Hastings and Rosebud zone substations. The capital cost of the new line was estimated at $29.5M (2015-16 AUD), and a discount rate of 6.1%. Figure 18 provides an indicative value from deferring network investment for up to 20 years; value is equivalent cost for the non-network solution to match the network solution.

*Figure 18: Indicative value of deferring network investment by year*




For the purposes of reducing peak demand, it is assumed 1MW of storage can replace 1MW of diesel generation (equivalent to one diesel genset) and therefore reduce the risk of voltage collapse to the same extent. United Energy's 2020 DAPR states the total cost of Aggreko's 11MW demand-side generation and 2MW of GreenSync's demand response is $4.3M across 5 years. If demand stays flat, the opportunity may arise to continue to defer the network investment. Hence, three options were considered:

- Network services payment of $45K/MW/year[45] for 5 years (base case)
- Network services payment of $45K/MW/year for 15 years
- Network services payment of $1.5M (present value) spread over the life of the battery (15 years)

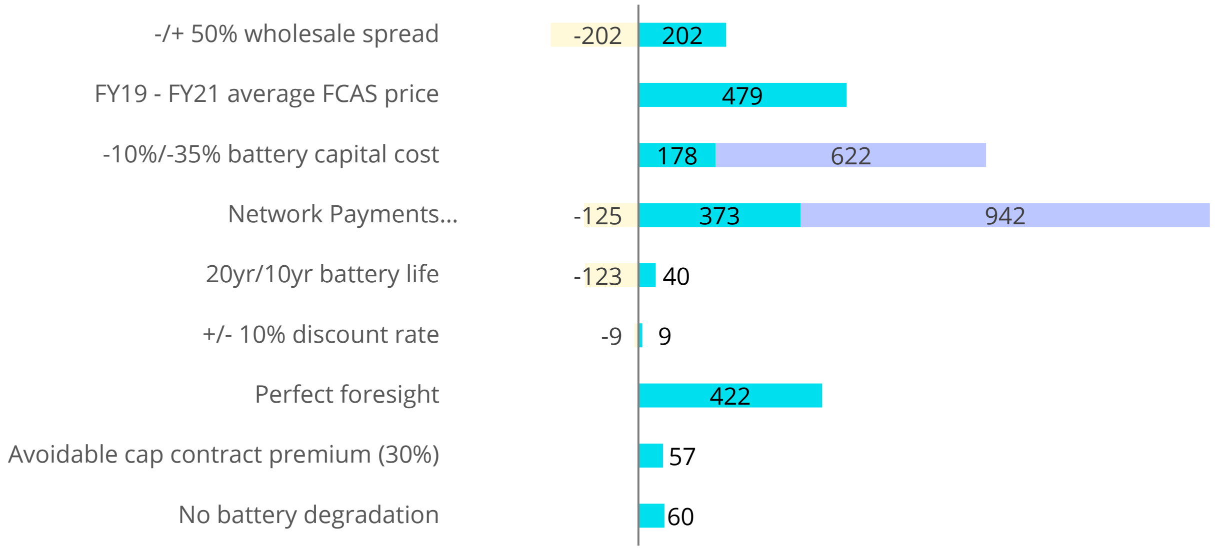
It is, however, considered unlikely the 13MW solution could defer network investment indefinitely. Demand for electricity is forecast to grow later in the 2020s, driven by the commercial and residential sectors, and an acceleration in the rate of electrification, particularly electric vehicles (EVs)[46].

[45] United Energy also suggested the offer to replace a diesel genset is $40K - $50K / year
[46] 2021, AEMO, Electricity Statement of Opportunities

## 5.4. Sensitivity analysis

The study assessed the NPV impact of a range of operational and financial sensitivities relative to the base case NPV of (-$1.8m). This is set out in Figure 19.

*Figure 19: Change in NPV from adjusted financial or operational assumption (base case)*




The parameters analysed include:

- **Wholesale spread** defined as the arbitrage opportunity arising from difference between peak 2-hour price and minimum 2-hour price daily. Sensitivity analysis suggests +/- 50% adjustment to wholesale spread alone cannot recover a material portion of deficits (~11% at the 50% upper bound)
- **FCAS price** is the price per MWh for FCAS raise and lower services. Holding FCAS prices constant at FY19 – FY21 values rather than basing it on projections, suggests NPV would increase by $479K
- According to National Renewable Energy Laboratory, **battery capital cost** of 4-hour duration utility scale storage will decrease 10% - 35% between 2021 and 2025[47]. Applying the same capex reduction for neighbourhood battery capex is equivalent to $178K to $800K saving
- The study modelled **network payments** for the replacement of the existing diesel generators for the first 3 years of the project until the current contract period ends. If the solution continued to defer the network investment, the contract length (years) and size ($/year) could increase:
  - At the current payment of $45K per year, this would deliver a $373K NPV uplift. The uplift would recover 21% of the NPV deficit suggesting battery economics rely on deferring network investment for a significant length of time as part of the value-stack
  - The total value of deferred investment for 15 years is $1.5M (*Section 465.3.1 Value of deferred network investment*) which is materially higher than the network services payment for the diesel generators. If the full deferral was available for the battery project, this would improve the NPV by $919K (NPV[48])

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[47] National Renewable Energy Laboratory, 2021, Cost Projections for Utility-Scale Battery Storage: 2021 Update

[48] Assumes either: $86.8K payment in year 1, increasing each year by the project discount rate (6.7%), or $135K per year for 15 years (real, not nominal)

- The proposed battery project could be able to provide a range of additional **network services** such as voltage support during non-outage conditions. AGL is not aware that such services are being sought in the Lower Mornington Peninsular or what payments would be available for such services and hence we have not included these services in our modelling.
- **Battery life** was shown to not have a material impact on NPV as the largest cash flows (both negative and positive) are during the early years of the project.
  - We note that the manufacturer of our chose battery warrants a battery life of 15 years where a battery is cycled for no more than 1 cycle per day. Increasing the battery cycles to more than 1 per day may result in a lifetime that is reduced to 10 years or less.
  - In the base case, after network payments ceased EBITDA trended downwards from -$1K in FY27 to -$23K in FY37, suggesting extending the life of the project continues to earn a negative EBITDA
- Analysis suggested the NPV is not particularly sensitive to the **discount rate** as the largest cash flows (both negative and positive) are during the early years of the project. This suggests that differences between the weighted average cost of capital (WACC) between different proponents are not the deciding factor for the viability of a battery project. Discount rates for project evaluation should take into account the nature of the project such as the predictability and reliability of the revenue stream for the project. The WACC of a regulated monopoly may not be the appropriate discount rate to evaluate projects that rely on revenue from the competitive market.
- Improving the ability to accurately **forecast** upcoming prices provides a material opportunity. The $422K improvement in NPV presented is achieved through perfect foresight of prices over the upcoming 36 intervals, which represents an upper bound for the opportunity. Capturing a portion of this value may be critical to improving commerciality.
- The **cap contract premium** is a potentially avoidable incremental cost paid to reduce exposure to high wholesale prices, replaced with increased dispatchable capacity. Additional value may be available for market participants from using the battery to hedge derivative contracts traded on the ASX and over the counter. Historical analysis suggests that contracts trade on average at a premium over the payout in the spot market. Assuming that an additional 30% premium is available would result in a ~$57K NPV uplift
  - Revenue is subject to being able to discharge as required. The ability to capture this value is limited by network service requirements and the availability of the battery.
- **Battery degradation**, the rate at which battery storage (e.g. MWh) declines over time, could improve through continued research and development. As battery durability improves, projects may be able to capture a portion of the $60K loss resulting from degradation

## 5.5. Implications

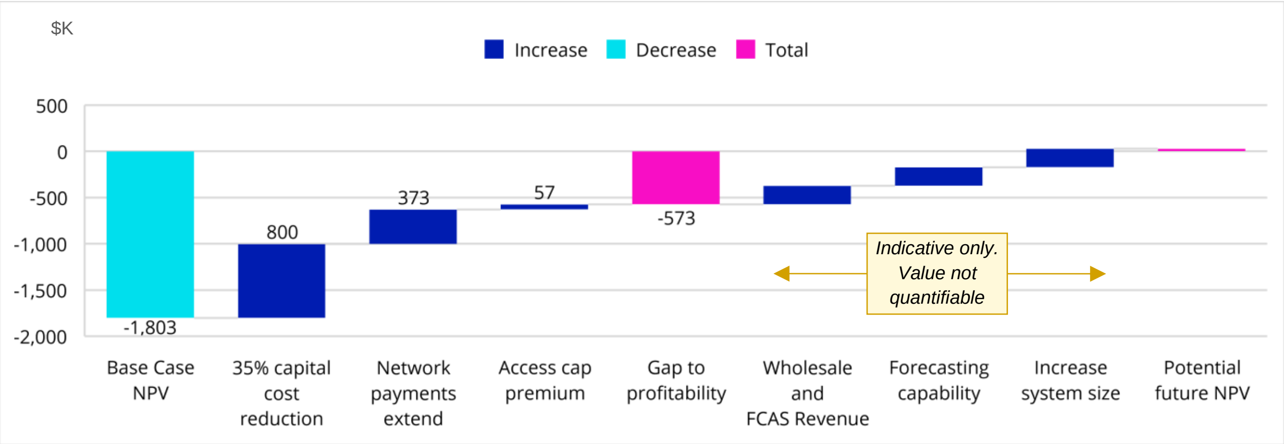
The study has considered the way in which a battery neighbourhood would operate, and the financial outcomes of the identified battery storage options. We have subsequently considered the implications for:

- Commerciality of neighbourhood batteries;
- Designing network tariffs to improve battery economics and performance;
- The importance of the value of deferred network investment;
- The value of solar enablement; and
- Benefits and drawbacks of behind-the-meter battery location.

### 5.5.1. Neighbourhood battery commerciality

The study determined that, at current costs, the benefits currently available to a neighbourhood battery on the Lower Mornington Peninsula do not recover the associated capital and operating expenditure. Each scenario returned a negative NPV, ranging from -$1.5M to $3.0M, suggesting grant funding would be required for the business case to be successful on the LMP. However, there is a potential pathway to profitability for neighbourhood battery projects as illustrated in Figure 20:

*Figure 20: Pathway to profitability*




The pathway relies on accessing the full value-stack under favourable conditions. In certain situations, in future, it may be reasonable:

- For capital costs to reduce by 35%; based on National Renewable Energy Laboratory high case[49]
- For network services to continue for the life of the project; and
- For the market participant to safely hedge their portfolio and access the cap premium

These changes deliver $1,194K NPV uplift, leaving a gap of $573K. Three further feasible improvements could support addressing the gap, however, their value remains unclear at this stage:

- Favourable wholesale and FCAS markets, including the ability for the market to participant to optimise participation in both markets simultaneously

[49] National Renewable Energy Laboratory, Cost Projections for Utility-Scale Battery Storage: 2021 Update

- Improving forecasting capability to inform battery operations; upper bound of $422K
- Capturing economies of scale for capital and operating costs by increasing the size of the system

While this path to profitability is feasible in the longer term, in the short term the commercial feasibility of neighbourhood batteries will depend on location-specific network challenges and the availability of grant funding

### 5.5.2. Network tariff design

On the basis of the modelling it appears that current network tariffs do not support the economics or preferred operational role of neighbourhood batteries.

- In this study, introducing the LVKVATOU usage tariff and rolling demand tariff reduced NPV by $1.2M, to -$3.0M.
- The rolling demand period of 7am – 7pm does not specifically encourage either peak demand reduction (~5pm – 7pm) or 'solar soaking' during the day.

The study found that network tariffs change the incentives and behaviour of neighbourhood batteries. In the absence of a network tariff, batteries respond to increasing solar exports by supporting network challenges and charging during the 'solar soaking' period, placing downward pressure on wholesale prices. Additionally, implementing network service requirements requiring the battery to discharge fully from 5pm, forced the battery to charge in the lead up period, inadvertently creating a 'solar soaking' benefit. This behaviour was not identified when the LVKVATOU tariff was applied (see Figure 11).

NSPs are trialing bespoke network tariffs to understand how they can best benefit the network. An example trial tariff is EVO Energy's Large Scale Battery Tariff[50], consisting of:

- 4.5c/kWh for net exports (imports less exports)
- 115c/kVah charge for imports or 77.6c/kVah rebate for exports during critical peak events
  - Up to 6 critical peak events per year, of up to 3 hours in duration. Operator notified 48 hours in advance
- Maximum demand tariff, for between 5pm and 8pm in residential areas, of 19.2c/kVa/day in winter and summer and 12.9 c/kVa/day in autumn and sprint
- 12.6c/kVA/day capacity charge based on maximum demand in previous 13 months

The implications of this style of tariff are:

- On a usage basis the battery operator is only charged for losses (net exports)
- Operator is prepared for spikes in demand, and can behave in a way that supports the network and be compensated accordingly
  - A 1MW / 3-hour duration battery could earn: 77.6c * 1000kW * 3hours * 6 events = $14K / year
  - Considering that critical peak events largely coincide with periods of high prices, the impact on the network is uncertain as it is likely the operator would attempt to be discharging during this period regardless
- The maximum demand tariff is targeting reducing peak demand by discouraging charging at a high rate. In cases where demand and prices are high, but expected to increase further, the tariff may stop batteries from contributing to the issue

[50] Evo Energy, 2021, Schedule of electricity network charges 2021/22

The EVO Energy tariff is focused on peak demand, but does not incentivise desired 'solar soaking' behaviour. As discussed in section 2.2.3 , many areas are not yet experiencing solar constraints, but will be by 2025. As such, the study expects to see bespoke tariffs encouraging 'solar soaking' to become more prominent over the coming years.

For competitive benefits to be realised, it will be important that there be a level playing field for all battery service providers connected to the networks. By this we mean that the DNSP behaves in a non-discriminatory manner: the DNSP treats batteries the same regardless of the owner (e.g., by charging the same tariffs for the same services) and that all batteries are treated the same across the network (for example in times of constraint, the batteries controlled by DNSPs are not given preference).

The potential harm associated with distribution networks directly investing in assets that provide contestable services or favouring their affiliated entities in the procurement of network services is well understood by industry and the Australian Energy Regulator. As the CEC recently observed in response to the AER's Ring-fencing Review: "it would be hypocritical and anti-competitive for DNSPs to advocate export charges for household distributed energy resources while also advocating that community-scale batteries they own should be exempt from network tariffs"[51]. This concern also extends to batteries owned by an affiliate of the DNSP, not just batteries owned by the DNSP itself[51]. Without further regulatory safeguards requiring affiliates to tender for services, there is a risk DNSP's favour affiliated entities.

### 5.5.3. Network benefit

The network payments included in this analysis are small (relative to the cost of the battery), for three reasons:

- Benefits are valued against the cost of a diesel solution;
- Short 3-year contract term until network investment review; and
- Network services such as voltage support in non-outage conditions is not rewarded.

Assuming the Aggreko solution is providing a positive financial return, the battery as modelled in this study, is not competitive without grant funding. The battery, however, provides incremental benefits to the grid, as compared to a diesel solution: low emissions technology; solar enablement; voltage regulation from reactive power; and reduced noise.

Currently, none of those relative advantages provide a financial return to market participants. If a cost were introduced for less desirable technology, or compensation provided, this may begin to reduce the deficit.

### 5.5.4. Solar enablement

Batteries have the potential to alleviate solar export constraints, effectively creating value for customers with rooftop solar. The study explored the potential financial benefit to customers of solar enablement.

In *Section 4.5 'Solar soaking' benefit*, *Figure 15* illustrated that over time, the battery is progressively charging more during the middle of the day as growing rooftop solar exports place downward pressure on wholesale prices. As solar penetration increases, it is expected that wholesale prices will continue to fall during the day as evidenced by the South Australian experience. South Australia has seen increased solar penetration, to the extent that from September 26 2021, South Australia generated more electricity from solar than it consumed for periods of time on five different days in the past five weeks[52].The impact can be

[51] AER, 2021, Electricity distribution Ring-fencing Guideline Explanatory statement – Version 3
[52] ABC News, 2021, South Australia sets world record in solar generated electricity

seen in the minimum daily 2 hour wholesale price, which has declined from approximately $50/MWh in 2018 to approximately -$25/MWh in 2021[53]

The study estimated the value to consumers based on missed feed-in-tariff (FiT) revenue. In Victoria, the minimum FiT from 7am to 3pm (shoulder period) is 6.1c/kWh, as set by the Essential Services Commission (ESC)[54]. We can conservatively assume the battery continues to import 272MWh/year during the solar soaking period that would otherwise be constrained; we would expect total imports to increase if wholesale prices continue to decline during this period as solar exports rise. 272MWh at 6.1c/kWh suggests a benefit of ~$17K/year across customers with rooftop solar in the LMP region.

Separately, United Energy's Solar Enablement Business Case suggests the overall economic value of solar to the community can be measured via wholesale fuel cost reduction and carbon emission reduction benefit. Jacobs, an international technical professional services firm engaged by United Energy as part of the Business Case, valued solar at $47/MWh. This was considered a conservative estimate as:

- It is lower than minimum FiT set by the ESC
- It is less than the $50/MWh average determined by HoustonKemp[55]
  - Note HoustonKemp forecast a relatively consistent value of avoided dispatch costs for solar PV exports from 2018 – 2035, ranging from $48.11 to $52.15
- It focusses on the fuel cost rather than the wholesale price change of generation, with the former being lower[56]

A $47/MWh suggests a solar enablement benefit of $13K/year.

Based on the two methodologies, it is estimated the neighbourhood battery could provide an ongoing benefit of up to $17K per year to the LMP region, with benefits primarily realised by residents with rooftop solar in the Dromana, Rosebud, and Mornington regions. This value is incremental to the financial evaluation as it is not accessible to the market participant.

### 5.5.5. Behind-the-meter

The study considered whether the battery could be positioned behind-the-meter (BTM), and the related benefits and drawbacks. BTM offers a number of important advantages over FOM.

- It does not incur network tariffs i.e. when charging from roof-top solar energy
- A BTM solution allows excess solar generated at the site to be used at the site. However, it does not absorb solar from multiple sources as a neighbourhood battery can and therefore if solar exports at the site cease for whatever reason, the battery could be idle unless it is orchestrated as part of a virtual power p
- There are no incremental land costs.

In addition to its own customer data AGL analysed consumption and solar generation data for sites operated by Mornington Peninsula Shire Council. The analysis found that the existing sites were not large enough to create a 1 MW+ BTM solution to meet the identified network need. This is somewhat driven by the fact that Mornington does not have many industrial sites. In place of installing one large battery, the option exists to install many residential batteries and leverage AGL's VPP capability to combine the storage and provide network services in the same manner as FOM It is challenging to achieve this scale of installations in time to

[53] AGL Analysis of half hourly AEMO price data
[54] DELWP, 2021, https://www.energy.vic.gov.au/renewable-energy/victorian-feed-in-tariff/current-feed-in-tariff
[55] HoustonKemp, 2019, Estimating avoided dispatch costs and the profile of VPP operation
[56] United Energy, 2020, Enabling residential rooftop solar

meet a network need that exists today. For example, a minimum of 200 Tesla Powerwall 2 batteries at 5kW and 13.5kWh would be required to match the same power output as a 1MW battery. These batteries would have to be located in the relevant network constrained area and be operated to provide the required network service.

Table 7 compares the cost of FOM and BTM:

*Table 7: High level comparison of FOM and BTM costs*

| FOM | | | BTM (Tesla Powerwall 2) | |
|---|---|---|---|---|
| Capacity | 1MW | | Capacity | 5kW |
| Storage | 2MWh | | Storage | 13.5kWh |
| **Capex** | **$1.09M** | | **Cost per unit** | **$12,938 (inc GST)[57]** |
| Capacity | 1MW | | Vic Gov Rebate | $3.5K[58] |
| Storage | 3MWh | | AGL Rebate | $1K *(for joining AGL VPP)* |
| **Capex** | **$1.61M** | | **Cost (subsidised)** | **$8,334 (inc GST)** |
| | | | Units required | 200 |
| | | | Capacity | 1MW |
| | | | Storage | 2.7MWh |
| **Capex[59]** *(Equivalent 2.7MWh)* | **$1.45M** | | **Total Cost** | **$1.67M** |
| **Land cost** *(PV, total project)* | **$167K** | | **Land cost** *(PV, total project)* | **-** |
| **Costs** | **$1.62M** | | **Total Cost** | **$1.67M** |

Table 7 demonstrates that the total cost of implementing 200 5kW residential battery units (1MW) is ~$50K more expensive than a 1MW FOM neighbourhood battery, or ~3%. Charging a BTM battery would not be subject to a network tariffs (~$1.1M over the life the project) if it is charged from solar energy. BTM could be a more beneficial solution than FOM as customers may derive additional benefits from a behind the meter solution e.g. protection from black outs and increased used of locally generated solar which creates bill savings.

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[57] AGL, 2021, www.agl.com.au/residential/energy/solar-and-batteries/solar-batteries/compare-solar-batteries
[58] Victorian Government, 2021, Rebate Changes Make Installing Solar Batteries Easier
[59] Assumes linear growth in capex cost between 2MWh and 3MWh battery options

# 6. Community Engagement Schemes

The Victorian Government considers delivering benefits to the local community as a key outcome for a successful distribution scale battery. In line with this, AGL considers distribution scale batteries as well positioned to enable benefits for local communities with options for community engagement, and aspires to deliver a sustainable model for customer and broader community engagement with neighbourhood batteries. Community engagement schemes are the additional component that may turn a distribution scale battery into a community battery. We aim to evaluate CES in their own right i.e. separately to distribution scale batteries and evaluate their costs and benefits.

## 6.1. Definition

We use the term Community Engagement Scheme (CES) to describe the way residential community members participate in and realise financial and non-financial benefit from distribution scale batteries.

A neighbourhood battery affects a range of stakeholders, including community members, customers, NSPs, IPPs and retailers, with research indicating that residential community members seek both financial and non-financial outcomes from distribution scale batteries[60],[61] including:

- Lower energy costs;
- Increased local energy use and solar export potential;
- Reduced emissions;
- Equitable access to DER for all community members; and
- Seamless integration with the existing environment (e.g. colour, noise, electric and magnetic fields).

We note that distribution scale batteries must deliver sufficient returns for owners if NSPs and/or competitive market participants are to scale the solution across the NEM, and therefore a CES must effectively manage both community benefits and account for return on investment.

In this report we have sought to assess the relative benefits of community engagement schemes, with a focus on their ability to sustainably deliver value to a wide group of community members.

## 6.2. Scheme types

There are a multitude of ways in which the community can be engaged in a distribution scale battery. We have categorised existing examples of schemes across four common models: group ownership; virtual storage; P2P trading; and passive models. Table 8 describes these four CES types, including the primary purpose, circumstances in which the scheme type is commonly employed ('key use case') and different characteristics of each CES type.

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[60] 2020, Energy Magazine, Batteries in the burbs: exploring the potential
[61] 2021, United Energy, Low-Voltage Grid Battery Energy Storage Systems Trial – Lessons Learnt Report No 1

*Table 8 - Community Engagement Scheme Types (CES)*

| | | Group Ownership | Virtual Storage | Peer-to-Peer Trading | Passive |
|---|---|---|---|---|---|
| **Overview** | **Description** | *Community group invests in a shared battery. Group members provide upfront capital to access storage, or to provide opportunity for members of a specific group to access storage (e.g. a housing development)* | *Battery provides storage access for community members to 'load shift' own energy usage in exchange for payment (e.g. subscription ($/day) or bespoke FiT). Operator may also access energy markets and provide network services.* | *Solar participants virtually store and use excess solar, plus an online marketplace enables engagement with other members to trade excess solar with solar and non-solar members. Intended return for owner likely to vary by case.* | *NSP and/or IPP provides network services and/or accesses energy trading markets; no direct customer offer, however, community members indirectly benefit* |
| | **Primary Purpose** | **Return value to owner and/or participants in form of energy cost savings** | **Reduce participants' energy costs, and provide positive return for owner** | **Reduce participants' energy costs and increase return of rooftop solar** | **Leverage value-stacking to maximise return for NSP, and/or IPP** |
| | **Key Use Cases** | Allowing community members to own a share of the battery | Engagement of customers with solar with a distribution scale battery installed in their area | Allowing community members to engage with distribution batteries by trading | Solving network constraints with battery storage for the benefit of all customers in a DNSP area |
| **Characteristics** | **Owner(s)** | Investors (e.g. community group, developer) | NSP and/or IPP | NSP and/or IPP | NSP and/or IPP |
| | **Access energy markets** | X unless a market participant is involved | ✓ | ✓ | ✓ |
| | **Customer offer** | ✓ | ✓ | ✓ | X |
| | **Customer payment type** | Upfront capital (direct or indirect) | Ongoing | Ongoing | X |
| | **Community participation** | ✓ | X | ✓ | X |
| | **Location driver** | Participant locations | Network requirements | Participant location | Network requirements |
| | ***Examples*** | ***Igloo Trent Basin Project (UK) (500kW)*** | ***WP & Synergy PowerBanks (100kWh \| 400kWh)*** | ***Enova Energy 'Beehive' Project (1MW \| 2MWh)*** | ***United Energy 40 Pole Mounted Batteries (30kW \| 66kWh)*** |

We examined recent distribution scale batteries to consider where they fit across the CES types. We found more recent installations are targeting network support and trading purposes (versus purely network or trading). More recent projects are more likely to employ 'Passive' CES compared to earlier projects that looked to employ Virtual or Peer to Peer models.

*Table 9: Recent Distribution Scale Battery Examples*

| CES | Project(s) | Location | Stage | Objectives | Customer participation and benefits |
|---|---|---|---|---|---|
| Group Ownership | Igloo Trent Basin Project[62] | Trent Basin, UK | Operational | • Offset energy cost<br>• Establish model for further developments | • Solar PV and DSB installed at new 500 home development in Trent Basin, UK<br>• DER cost included in overall home/land costs |
| Virtual Storage | 'PowerBanks'[63] | Multiple, WA | Operational | • Network support including managing peak demand<br>• Customer financial benefit | • Pay $1.20-$1.40/day to store 6/8kwh excess solar<br>• Paid FiT for remaining stored energy at end of day |
| Virtual Storage | Ausgrid trial program[64] | Multiple, VIC | Trial | • Test network support potential<br>• Test potential 'virtual storage' customer benefit | • Free: customers store up to 10KWh excess solar daily<br>• Stored energy credited against use; credits paid quarterly |
| Peer-to-Peer | 'Beehive Project'[65] | Kurri Kurri, NSW | Announced (Feb '21) | • Reduce FiT constraints<br>• Test managing fluctuating demand | • P2P: 500 households (with or without solar) trade rooftop solar generation. Participants set their own price to trade electricity. Any participant can then purchase stored solar. |
| Passive | UE & Simply Energy Battery Project[66] | Inner Melbourne, VIC | Announced (Sep '21) | • Manage peak demand<br>• Access trading markets | • No direct customer involvement<br>○ Customers indirectly benefit from increased hosting capacity and use of locally generated renewable electricity and (ultimately) lower network charges<br>○ LUOS tariff trial to reduce local network costs across community<br>• *Note: CitiPower and YEF community battery customer engagement scheme not fully defined at this stage; likely Passive* |
| Passive | Energy Queensland community batteries[67] | Multiple, QLD | 1 Operational, 5 Announced (Mar '21) | • Defer T&D investment<br>• Load shift excess solar into peak periods | |
| Passive | PowerCor DSB[68] | Tarneit, VIC | Announced (Sep '21) | • Manage peak demand<br>• Trial a 'LUOS style' tariff | |
| Passive | CitiPower and YEF community battery[69] | Fitzroy, VIC | Announced (Jan '21) | • Alleviate network constraints<br>• Share value with all users connected to the battery | |
| Passive | Remote distribution-scale batteries[70] | Primarily regional WA | Operational, announced | *Typically to:* Ensure reliable supply to 'fringe-of-grid' or increase hosting capacity in remote towns | |

[62] http://www.iglooregeneration.co.uk/2018/02/20/europes-largest-community-energy-battery-installed-at-trent-basin/
[63] https://www.westernpower.com.au/our-energy-evolution/projects-and-trials/powerbank-community-battery-storage/
[64] https://www.ausgrid.com.au/In-your-community/Community-Batteries/Trial-locations
[65] https://www.pv-magazine-australia.com/2021/02/11/tesla-gets-nod-for-enovas-shared-community-battery-project/
[66] https://www.unitedenergy.com.au/melbourne-to-host-australias-largest-community-battery-rollout/
[67] https://www.pv-magazine.com/2021/03/25/queensland-to-integrate-large-scale-community-batteries-into-substations/
[68] https://wyndham.starweekly.com.au/news/community-battery-to-harness-suns-power/
[69] https://www.pv-magazine-australia.com/2021/01/27/victorias-first-solar-sponge-community-battery-network-to-be-developed/
[70] 'Fringe-of-grid' examples include community batteries at Perenjori and Kalbarri. Horizon Power announced BESS to be installed at Carnarvon, Marble Bar, Wiluna, Yalgoo and Yungngora (https://www.horizonpower.com.au/our-community/news-events/news/more-customers-to-access-renewable-energy-through-bess/

## 6.3. Success factors

The feasibility study considers which type of community engagement scheme is most likely to succeed, based on each scheme's assessed ability to deliver value to all residents, and be widely-implemented to maximise welfare. Customer Engagement Schemes are assessed across 5 criteria: economic value; implementable; scalable; and equitable.

Table 11 describes each assessment criteria and scoring. The assessment criteria and scoring are based on: AGL's view of best practice community engagement schemes; its experience in delivering Peer to Peer schemes; and its Solar Sharing Market Review, conducted in 2021.

AGL has conducted trials, based on the solar sharing concept, of two different customer engagement models: Virtual Solar/Offsite Solar; and Solar Exchange. In none of these cases was AGL able to identify a scheme that could create value for both the customer and market participant. The table below provides more information on these schemes and how they ranked in terms of customer desirability, feasibility to implement and viability.

*Table 10: AGL Historical CES products with ranking against desirability, feasibility and viability*

| Product name | Offsite solar/ Virtual Solar | AGL Solar Exchange/P2P Trading for Solar Energy |
|---|---|---|
| Basic product construct | Give customer who can't install solar access to solar savings<br>Customer signs up and receives credits – commits to a period of time<br>Customer is matched to a C&I scale solar installation<br>Youtube link explaining product | Customers with solar can generate solar tokens for the energy they export to the grid<br>Customers without solar can chose to buy solar tokens<br>Youtube link explaining product |
| **Desirability** | **Low**<br>Product concept is difficult to understand<br>Customer interest was limited | **Medium**<br>AGL was able to generate customer interest by subsidising trading on the market place |
| **Feasibility** | **Medium**<br>Integration into a scaled retail product offering and compliance with all relevant rules and regulations is challenging | **Medium**<br>Integration into a scaled retail product offering and compliance with all relevant rules and regulations is challenging |
| **Viability** | **Medium**<br>Retailer may realise some customer retention value from implementing scheme<br>No additional value is created e.g. no additional solar is installed as a result of the CES | **Low**<br>Retailer may realise some customer retention value from implementing scheme<br>No increase in solar uptake is to be expected from the operation of the market place.<br>Incentivising trading required a contribution from AGL which is not long term sustainable |

Subsequently, AGL conducted a Solar Sharing Market Review which considered past and current solar sharing[71] propositions and trials (3 AGL, 5 other) and developed recommendations to increase the likelihood of future schemes being successful.

The recommendations from the review of these programs included the points below.

- Only pursue opportunities that create direct commercial value to all parties involved in the exchange. Exchanges that do not create value will not scale and won't be commercially viable.
- Technology-based trials in the solar sharing space require a clear value proposition otherwise they should not be pursued.
- Peer-to-Peer trading opportunities should not be pursued unless there is a clear pathway to deliver both customer value and commercial viability.
- Community solar opportunities should provide a clear pathway to deliver both customer value and commercial viability otherwise they will not scale and should not be pursued.
- Do explore and experiment with opportunities for providing solar customers with new value propositions, given the decline in feed-in tariffs, that may also bolster AGL energy plan and hardware propositions.
- Do keep scanning the market for opportunities in the solar sharing space, particularly those that provide opportunities for renters and apartment dwellers to access solar energy and save on their energy bills.

The assessment criteria for Community Engagement Schemes related to distribution scale batteries are below.

*Table 11: Community Engagement Scheme Assessment Criteria*

| Criteria[1] | Sub-Criteria | Assessment | Low | Medium | High |
|---|---|---|---|---|---|
| Deliver Economic Value | Scheme Participants | How effectively does the scheme reduce electricity costs for participants? | No impact | Increased solar exports (and FiT revenue) | Increased solar exports (and FiT revenue) + tariff arbitrage benefit |
| | NSP Customers | What is the impact on network tariffs for customers served by the NSP? | No impact | Indirect network benefit realised, eventually reducing tariffs | Specific services provided and augex avoided to reduce tariffs |
| | Network Benefit (Manage peak/min demand; hosting capacity) | To what extent does the scheme have the potential to encourage behaviour required to manage minimum operational and peak demand, or enable and encourage incremental PV solar uptake or output? | Encourages solar exports at undesired time periods; no expected change in PV uptake | Limited potential to influence solar export behaviour, but enables increased PV uptake | May effectively influence solar exports to support network issue resolution, and/or allows increased PV uptake in areas with known constraints |
| Ease of Implementation | | How easily is the scheme implemented? What barriers exist? | Regulatory constraints and stakeholder complexity | Regulatory constraints or stakeholder complexity | Low regulatory constraints and low stakeholder complexity |

[71] Solar sharing is the broad concept of a site with solar installed ('host site') exchanging value, typically financial, with a customer site related to the host site's solar generation or excess solar power. This exchange is facilitated by an intermediary, such as an energy retailer, technology platform provider, or marketplace operator. It is important to note that the 'consumer site' is not physically consuming the solar electricity produced by the host site and continues to use electricity from the grid.

| | | | | |
|---|---|---|---|---|
| **Scalable and sustainable** | What is the potential to scale the scheme across the NEM? | Relies on grant funding to be implemented | Positive business case location specific; requires specific set of conditions | Positive business case achievable in most geographies |
| **Allow Broad Access to Economic Benefits** | Is economic value easily accessible and fairly distributed across community members e.g. to households without access to PV solar? | Requires upfront capital; or benefits rooftop solar participants only | No capital required | No capital required; and value distributed fairly with non-participants |

Note that criteria that do not vary across community engagement schemes, for example battery safety and community appeal are not included in the assessment.

## 6.4. Preferred scheme

We applied the assessment criteria to the four scheme types outlined in Section 6.2, Scheme types with the summary results in Table 12 below. Detailed assessment can be found in *Section 9.2 Community Engagement Scheme: detailed assessment*.

Overall, while there is a strong level of perceived benefit to a community engagement scheme where participants are directly involved, either through ownership or 'buying in' to a virtual storage solution, these types of schemes incur significant additional cost when compared to passive community involvement without delivering significant additional economic value[72] from community participation.

As this feasibility study demonstrates, neighbourhood batteries are not always profitable in the current market conditions, so investment by community members into a community battery is subject to investment risk. To protect consumers, such investment schemes are regulated by the Australian Security and Investment Commission (ASIC) and require and Australian Financial Services License or exemption to operate.

Where customers are participating in a virtual storage scheme the benefit gained by the select group of customers who participate represents a transfer of value from battery owners and operators (or funding providers) to this group of customers. Furthermore, such schemes may reduce the value that is created from a neighbourhood battery. This is because virtual storage schemes can provide an incentive for consumers to consume energy during times of peak demand. Such consumption has a directionally opposite impact to the operation of battery storage and may negate some of the energy system benefits of battery storage.

AGL have found that peer to peer energy trading does not create value through the trades being conducted on the platform. For example, customer do not have incentive to shift consumption to times of high renewable generation. Regular participation may increase awareness about energy consumption and energy system needs (e.g. peak demand being reached, high amounts of renewable generation). Such engagement may encourage consumer behaviours that are beneficial for the transition to fully renewable energy system (e.g. shifting consumption during periods of high renewable energy generation). The value of such engagement must be compared to the cost of establishing and operating such trading schemes.

Schemes that primarily aim to create value from the operation of a battery can distribute this value broadly across the community for example by lowering the cost of network services to all consumers and by lowering the cost of wholesale electricity for all market participants. Such a value transfer is not as directly visible as that of an elaborate community participation scheme, but the amount of value created from such a scheme is higher due to lower administration cost. The value is also shared more equitably across the entire community

[72] Either accruing to community members or scheme proponents

rather than with a select group of customers who happen to live in an area where such a scheme is available or who are able to put capital at risk to participate in such a scheme .

To that end, the Passive scheme is assessed as likely to deliver the most community value as it can be effectively scaled across the NEM to solve network challenges, capture both network and trading value, and deliver value to customers equitably in the form of lower network tariffs. There is also value associated with other scheme types, but AGL does not believe these other types are sustainable, given current battery economics.

While the Group Ownership model maximises direct value to participants, it does not access full value-stack, and expected reliance on funding will limit implementation and scalability

A Virtual Storage model may access full value-stack, however, required customer acquisition and involvement is likely to create complexity that impacts ability to scale quickly. Additionally, the availability of value for scheme participants is variable and subject to the customer making a payment.

A Peer-to-peer model has similar advantages and disadvantages to the Virtual Storage model, with additional issues related to provision of a financial product, provision of 'trading' systems and the requirement for participants to remain actively involved to optimise benefits.

*Table 12: CES Assessment Summary*

| Criteria[1] | Sub-Criteria | Group Ownership | 'Virtual Storage' | Peer-to-Peer Trading | Passive |
|---|---|---|---|---|---|
| Direct Economic Value | Scheme Participants | High | Medium | Medium | Low – Medium *(subject to area solar constraints)* |
| | NSP Customers | Medium | Medium | Medium | High |
| | Network Benefit | Medium | Low | Medium *(subject to battery utilisation)* | High |
| Ease of Implementation | | Medium | Low | Low | Medium – High |
| Scalable and sustainable | | Medium | Low | Low | High |
| Allow Equitable Access to Economic Benefits | | Low | Medium | High | Medium – High |
| | | *Maximises value to participants, however, does not access full value-stack. Expected reliance on funding will limit implementation and scalability* | *Participant value subject to payment. Model may access full value-stack, however, customer acquisition and involvement likely to create complexity that impacts ability to scale quickly* | *Equitable peer-to-peer market, however, regulatory issues, and expected reliance on funding, will limit implementation and scalability* | ***Likely preferred under most scenarios.*** *Maximum network and trading value, and greatest potential for growth suggests scheme likely to maximise overall welfare* |

The detailed assessment and reasoning for each Scheme can be found in Appendix 9.2.

# 7. Ownership Models

We have considered the question of who is best positioned to own and operate a distribution-scale battery by considering it in two parts:

- What combination of participants allows access to the greatest level of benefits; and
- Which (of those) participants is best positioned to capture value from a distribution scale battery. The overall ownership options are informed by the relative value available across various participant models, with low-value participant models excluded from consideration of ownership options.

Our Industry Overview (Section 9.1) considers participant models and notes that:

- Distribution scale batteries can provide value across four broad categories: Network support, market trading, retailer energy position, and customer benefits; and
- Across these categories, distribution scale batteries in which NSP plus a Competitive Market Participant both participate can likely provide the most overall value to the network, customers and the asset owner(s). This is in comparison to NSP-only, Competitive Market Participant-only and Community-run models.

## 7.1. Ownership model options and preferred model

To assess a preferred ownership model, we considered five factors that allow the maximum value to be realised from battery ownership.

1. **Access to information**: Does the entity have access to information to inform battery design and maximise value to the system? For example, existing or expected network issues, market (energy and FCAS) outlook.
2. **Alignment with regulatory intent and operational expertise:** Does the proposed battery usage align with (intended) role of the owner in the marketplace?
3. **Cost of capital:** Does the entity have a competitive cost of capital?
4. **Access to wholesale markets:** Does the entity have ready access to wholesale trading markets?
5. **Access to customers:** Does the entity have ready access to customers (assuming DSB includes a Customer Engagement Scheme)?

We compared and rated NSP ownership and Competitive Market Participant ownership across these five factors, outlined in Table 13 below. Note: “Harvey ball” ratings represent the degree to which the NSP or competitive market participant is advantaged for that factor.

*Table 13: Distribution-Scale Battery Ownership Options*

| | NSP Ownership | | Competitive Market Participant Ownership | |
|---|---|---|---|---|
| **Access to information** | ● | DNSPs should have a clear view on the nature and severity of network constraints, which should drive the need for storage.<br>Note that NSPs or Competitive Market Participant may have the best view of how a DSB could best be operated to meet network needs and maximise market value | ◑ | Competitive Market Participants do not have direct access to network requirements, but arguably should have access to relevant data and forecasts for opportunities through NSPs (with opportunities put out to the market before investing in non-network solutions)<br>Strong view on forward market pricing<br>CMP should have the clearest view on the customer-side asset base including the size of the orchestration potential |
| **Alignment with regulatory intent and operational expertise** | ◑ | Use of battery for network services align with experience and intent<br>Use of RAB may lead to inefficient investment, but should be an option to NSPs where there is no non-network solution offered by Competitive Market Participants, or the solution is more expensive than that proposed by the NSP<br>Cross-subsidisation risk exists – and addressed in ring-fencing guidelines, but where batteries provide multiple services it is difficult to fully cost allocate to eliminate cross-subsidy issues: it is difficult to determine what proportion of the battery is used for network services; and margins earned on leasing remaining parts of the battery to others | ● | Competitive Market Participants are already set up to participate in energy and FCAS markets<br>Some mechanism to provide services to NSPs exist today (e.g. non-network proposal requests). Further improving these mechanisms should be the priority for reform such that:<br>• Opportunities to provide network services (e.g. “solar soaking”) are visible to the competitive market even where individual opportunities are small.<br>• Opportunities to provide network services are advertised in a manner that allows the competitive market to participate in these opportunities |
| **Cost of capital** | ◕ | NSPs in general have a lower cost of capital than CMPs<br>United Energy AER determination of WACC 4.76% (2021-26)[73] | ◑ | CMPs have a higher cost of capital than monopoly networks businesses (typically >6%), but these discount rates apply across the whole business. CMP can create project finance structure to finance specific projects. Where the offtake arrangements of such projects are favourable a low cost of capital can be achieved. |

[73] United Energy Distribution Determination 2021 to 2026 FINAL DECISION April 2021.

| | NSP Ownership | | Competitive Market Participant Ownership | |
|---|---|---|---|---|
| **Access to wholesale markets** | ◔ | Markets are not accessible to NSPs due to ring-fencing – but NPSs *can* contract with IPPs or Competitive Market Participants (subject to ring-fencing rules) | ● | CMPs have existing access to, and experience in, energy and FCAS markets |
| **Access to customers** | ◔ | NSPs do not 'own' customers: they have interactions as part of the network-retailer-customer relationship, but are not involved in customer acquisition and retention (nor have a good understanding of the costs and processes involved). NSPs are not subject to retailer consumer protections | ● | CMPs have existing relationship and experience providing retail offering and consumers protections to end users |

Overall, we believe that Competitive Market Participants are best positioned to own distribution-scale batteries, however, close collaboration with the NSP is required to maximise value to the network and improve commerciality.

- NSPs may have the best view of the nature, severity and location of network issues (potentially addressed by storage), which is integral to designing an efficient and effective storage solution. That said, adequate access to the relevant data would allow other entities to consider providing storage-based solutions. If Competitive Market Participants are reliant on NSPs to provide relevant information, this is potentially burdensome on all parties: where data does exist, NSPs may reasonably have staffing constraints that make timely responses difficult; and it can be the case that NSPs do not have up to date system forecasts for all parts of their network. The existing requirements on NSPs to provide information on emerging network constraints in their annual planning reports and through their non-network engagement strategies is in many cases not sufficient to put forward a business case for a distribution scale battery. United Energy has put forward a $41M business case for its Solar Enablement Program to alleviate rooftop solar constraints across its network. The information to assess whether this program could be delivered using distribution scale batteries is not publicly available.
- NSPs can participate in competitive markets but it requires leasing a portion of the battery to a market participant, which may be inefficient or risk cross-subsidisation with the network component added to the RAB. If implemented, this also risks network investments displacing other assets on an unfair basis as they have been financed through the RAB. If DNSPs procure services from batteries owned by the competitive market, this mitigates a risk of cross-subsidisation compared to a situation where batteries are added to DNSP's regulated asset base.
- Competitive market participants can provide network services while efficiently engaging in market trading at times when the battery is not required for network services, and are best positioned to develop and provide retail products and more broadly engage the community. For example, AGL manages customer relationships with over 4 million retail customers. AGL has created innovative consumer facing products such as its Virtual Power Plant which involve thousands of participants and are growing rapidly. Direct experience and license to interact with customers is required to create retail products.
- In the absence of a non-network proposal request, competitive market participants do not have ready visibility of network opportunities – there is the opportunity to facilitate provision of information through improved regulatory safeguards such as the requirement networks test the market for non-network solutions, as is proposed in the AER's updated ring-fencing guideline[74].

[74] AER, 2021, Ring Fencing Guideline Version 3

- In a dual-participant model, cost efficient network solutions can best be achieved when roles are aligned with ‘traditional’ functions:
    - NSPs understand network requirements, can identify future network issues, and ensure cost efficient solution by taking opportunities to the competitive market; and
    - Competitive Market Participants can provide offers – as appropriate – to meet NSP’s stated needs, informing the lowest cost solution

# 8. Next Steps

## 8.1. Key unknowns for further investigation

This report summarises the feasibility study for the LMP Neighbourhood Battery Project. The project may be progressed beyond this point if further funding for the project would become available or if market conditions become more favourable for battery storage. Outside the scope of this feasibility study, progressing the LMP Neighbourhood Battery Project would include further progressing two key items:

- Increasing the precision of capital and operational cost estimates
- Confirming the availability and amount of grant funding

For this study, the capital cost is estimated based on quotes from three separate suppliers and selecting a preferred supplier. Without a specific location and battery size it is difficult to get an accurate quote from suppliers. Once a final solution design, location and timing for the project is identified capital costs can be firmed up through binding quotes from suppliers. AGL will share the key results of this Study with United Energy, and pending the outcome of those discussions, collaborate to:

- Select a specific location;
- Agree final battery design specifications; and
- Source specific quotes for:
  - Battery cost
  - Battery design, installation, and network connection
  - Battery ongoing maintenance

AGL will share anonymised results with DELWP as part of a detailed cost breakdown.

The Feasibility Study has demonstrated that grant funding is essential to support neighbourhood battery projects while capability is being built and capital costs remain relatively high. AGL will engage DELWP to understand, indicatively, the opportunity for grant funding based on this Study. The grant funding opportunity is an important input for discussions with United Energy; it will inform the final capacity, duration and specifications of the system.

# 9. Appendices

## 9.1. Industry Overview

### 9.1.1. The case for neighbourhood batteries

Distribution scale batteries (DSBs) may become a key technology to manage distribution network challenges. The NEM is facing new challenges as increasing PV penetration is widening gaps between minimum demand and peak demand. The gap causes swings from high voltage during the day to low voltage in the evening, impacting asset lifetimes and constraining solar exports.

Neighbourhood batteries, with capacity less than ~5MW, may offer a solution. By limiting swings, it can defer network augmentation capital expenditure (4-14 years according to a United Energy trial)[75]and manage export constraints. LV-connected neighbourhood batteries may have the greatest potential to manage distribution network challenges with the technology to form part of the rapidly growing small-scale storage mix (7-18GW by FY40)[76].

Neighbourhood batteries may also offer an attractive value proposition to customers and retailers. Residential batteries have been the sole small-scale storage option for customers. Neighbourhood batteries may present a viable alternative, offering:

- Different addressable market: Capability to provide storage access to new customers (e.g. renters, apartment dwellers)
- Eliminates homeowners' upfront capital investment hurdles ($10k+)
- Opportunity to connect at a specific point to maximise network benefit
- Economies of scale for installation and management

Neighbourhood batteries also hold relative advantages over utility-scale storage:

- Benefits all upstream networks: Low, medium and high voltage
- Reducing distribution level voltage and reliability challenges
- Supports a value proposition to local customers and the community

[75] Management of Voltages in LV Networks, University of Wollongong
[76] AEMO, 2021, Inputs and Assumptions Workbook

## 9.1.2. Neighbourhood battery value pools

Distribution scale batteries can provide value across four broad categories: Network support, market trading, retailer energy position, and customer benefits.

*Table 14: Value pool definitions*

| | | |
|---|---|---|
| **Network Support** | **Network investment deferral** | • Defer or avoid investment in the transmission and distribution networks<br>• *DNSPs can own a battery but cannot use that battery to provide contestable services. However, DNSPs can procure network services from third-party operators' batteries[2]* |
| | **Voltage regulation** | • NSPs charge/discharge (or request owner to) in order to manage network voltages by providing or reducing active power or absorbing reactive power. |
| **Market Trading** | **Wholesale Energy** | • Market participants can achieve wholesale arbitrage by shifting electricity from periods of low market value to high value<br>• Increase value of PPAs by increasing dispatchability of contracted power to be bought/sold |
| | **FCAS** | • Market participants meet demand in the FCAS markets (lower and raise) for commercial return |
| **Retail Energy Position** | **Cap contract premium** | • Gentailers can avoid paying a premium on cap contracts for hedging. Instead, gentailers can dispatch additional generation to cover their short position when the spot price spikes and provide portfolio benefits.<br>• *Requires retail book to realise* |
| | **Customer** | • Market participants brand benefits from 'green' battery proposition; may see extended products/offers, increased share of wallet and customer loyalty |
| **Customer Benefits** | **Tariff arbitrage** | • Reduce customer bills by through charged 'virtual storage' – sees household solar energy stored during periods of excess generation and 'credited back' to accounts during higher price evening periods |
| | **FiT export constraint avoidance** | • Added storage capacity increases the extent to which solar power can be exported throughout the day |

The eight value pools defined are not equally accessible or monetisable. *Voltage regulation* is not yet an existing market – it can, however, be monetised as a non-network solution where it relieves a network constraint. *Dispatchable energy*, and *Customer* value pools are only accessible to gentailers and retailers respectively, while NSPs are ring-fenced from providing contestable Market Trading services.

Value pools are not equally accessed across existing projects. Typically, projects are focused on network support, and enabling solar exports. Increasingly, projects are accessing wholesale and FCAS markets.

*Table 15: Value pools accessed by major neighbourhood battery projects*

| Stakeholders | Project | Stage | Network Support | | Markets | | Retail position | | Customer | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Defer T&D investment | Voltage | Wholesale | FCAS | Cap contract premium | Customer | Tariff arbitrage | Avoid FiT constraints |
| NSP and Competitive Market Participant | United Energy Pole Mounted Batteries | Announced *(Based on trial)* | ✓ | ✓ | ✓ | ✓ | - | ✓ | X | ✓ |
| NSP and Competitive Market Participant | PowerBanks | Operational | ✓ | ✓ | X | X | X | ✓ | ✓ | ✓ |
| NSP and Competitive Market Participant | Energy Queensland | 1 Operational<br>5 Announced | ✓ | ✓ | ✓ | ✓ | - | ✓ | X | ✓ |
| NSP | PowerCor Tarneit battery | Announced (Sep '21) | ✓ | ✓ | X | X | X | X | - | ✓ |
| NSP | CitiPower and YEF Fitzroy community battery | Announced (Sep '21) | ✓ | ✓ | X | X | X | X | - | ✓ |
| NSP | Ausgrid trial program | Trial | ✓ | ✓ | X | X | X | X | X | ✓ |
| Community | 'Beehive' project | Announced (Feb '21) | X | X | X | X | X | ✓ | ✓ | ✓ |
| Model undefined | Ginninderry Battery Trial | Announced (Sep '21) | ✓ | ✓ | X | X | X | X | - | - |

LEGEND: Value pool being accessed | Value pool not accessed | Undefined

### 9.1.3. Preferred neighbourhood battery location

There are three options to locate a neighbourhood battery: high voltage (HV) network; low/medium (LV) voltage network; and behind-the-meter (BTM). The LV network may be an 'advantaged location' for storage due to access to network and customer value pools.

*Table 16: Preferred location for neighbourhood batteries*

| | Front of Meter: HV Network | Front of Meter: LV Network | Behind the Meter |
|---|---|---|---|
| ***Relative advantages supporting BESS location*** | • Manages transmission constraints<br>• Economies of scale | • Manages transmission and distribution constraints, voltage management[77]<br>• Opportunity to locate for maximum network benefit<br>• Benefits local customers ('virtual storage')<br>• Some economies of scale | • Potentially highest customer benefit over the life of the battery[78].<br>• Benefits individual customers<br>• Avoids double-charging of tariffs<br>• Falling feed in tariff makes storage more attractive<br>• Can provide some distribution/ voltage management benefit (need customers in the right location) |
| ***Relative disadvantages opposing BESS location*** | • Cannot address downstream network constraints<br>• High connection costs[77] and challenges | • Network tariffs limit benefit[3]<br>• High connection costs[77] and challenges<br>• Unproven DSB business model | • Storage not accessible to all customers (e.g. renters, apartment dwellers etc.)<br>• Homeowner upfront capex<br>• Requires orchestration to optimise network and wholesale value |

[77] AECOM, 2019, Grid vs Garage

[78] Assuming customer avoids paying a premium for DSB storage 'subscription' and accesses VPP value pools

### 9.1.4. Stakeholder models

There are four conceptual stakeholder models: NSP, NSP and Retailer, Retailer and Community. The stakeholders involved provide access to different value pools in different ways, for example, NSPs are ring-fenced from providing contestable services by the AER[79].

*Table 17: Stakeholder models*

| Stakeholder(s) | Overview | Example |
| --- | --- | --- |
| **NSP** | • Operated for purpose of network support. Option for commercial agreement with customer | **Ausgrid trial program**<br>Customers paid quarterly for credits received from supplying rooftop solar |
| **NSP and Market Participant** | • Operated to maximise total value between the NSP and retailer through network support, market trading (FCAS and wholesale arbitrage) and possible customer proposition. Capacity either shared or network services procured by NSP | **Western Power & Synergy 'PowerBanks'**<br>Participants pay to receive benefits from tariff arbitrage and reduced rooftop solar export curtailment |
| **Market Participant** | • Operated for the purpose of maximizing profit across retail energy position, principally market trading value pools, option for customer proposition. | No Australian retailer-only examples; typically partnerships (NSPs) or community-focused |
| **Community** | • Operated for the purpose of providing largest possible benefit to customers while ensuring financial viability, suggesting secondary use in market trading value pools to support economics.<br>• Uptake and value realisation expected to be limited by lower capability relative to retailers and NSPs. | **Enova Energy 'Beehive Project'**<br>Peer-to-peer solar energy trading allowing up to 500 households (solar or not) to share and trade rooftop solar |

The NSP and Competitive Market Participant owned DSBs can likely provide the most overall value to the network, customers and the asset owner(s). By collaborating, the two parties can maximise network benefit and value from market trading, whilst still providing equivalent value to customers.

[79] AER, 2021, Ring-fencing Guideline Electricity Distribution Version 3

*Table 18: Stakeholder models access to value pools*

| Stakeholders | | Network Support | | Market Trading | | Retail Energy Position | | Customer Benefits |
|---|---|---|---|---|---|---|---|---|
| ***NSP*** | ● | • T&D investment deferral<br>• Voltage and inertia benefits<br>• RAB inclusion *(if for network support only)* | ○ | • Markets not accessible for NSP due to ring-fencing | ○ | • NSP without access to energy position | ◔ | • Reduces FiT constraints<br>• Potential to provide customer proposition, but "messy" given lack of customer relationship |
| ***NSP + Competitive Market Participant*** | ◕ | • T&D investment deferral<br>• Voltage and inertia benefits<br>*(Capacity dependent on leasing model / bilateral contract)* | ◕ | • Wholesale/FCAS trading<br>*(partially offset by use of capacity for network value pool)* | ◕ | • Support energy position<br>• Potential customer proposition for brand and loyalty benefits<br>*(partially offset by use of capacity for network value pool)* | ◕ | • Reduces FiT constraints<br>• Customer value proposition ('virtual storage')<br>*(partially offset by use of capacity for network value pool)* |
| ***Competitive Market Participant*** | ○ | | ● | • Wholesale/ FCAS trading | ● | • Competitive Market Participant use of battery to support energy position<br>• Potential customer proposition for brand and loyalty benefits | ◕ | • Reduces FiT constraints<br>• Customer value proposition ('virtual storage') |
| ***Community*** | ◕ | • T&D investment deferral<br>• Voltage and inertia benefits<br>*(Capacity dependent on leasing model / bilateral contract)* | ◑ | • Wholesale/FCAS trading assuming asset owner has access to markets<br>*(Optimised for customers first then wholesale/FCAS value if accessible)* | ○ | | ● | • Reduces FiT constraints<br>• Model optimised for customer benefit<br>• Potential share of net revenue as "owner" |

In a dual-participant model, cost efficient network solutions can best be achieved when roles are aligned with 'traditional' functions:

- NSPs understand network requirements, can identify future network issues, and ensure cost efficient solution by taking opportunities to the competitive market
- Competitive Market Participants provide offers – as appropriate – to meet NSP's stated needs, informing the lowest cost solution (even if the solution offered is not ultimately taken up)

### 9.1.5. Regulation

The neighbourhood battery regulatory environment is evolving. For example:

- NSP participation is limited due to being prevented from providing contestable services, however, rules regarding NSP ownership are becoming more lenient[80].
- AEMC released its Draft Rule Determination on Integrating Energy Storage into the NEM (July 2021). The proposed reforms suggest reducing network tariff costs for grid storage and simplifying registration, ultimately improving commerciality.

Table 19 outlines key recent or potential regulatory changes that could impact battery economics.

*Table 19: Neighbourhood battery evolving regulatory environment*

| | | | |
|---|---|---|---|
| Provision of contestable services | *Currently regulated* | • NSPs prevented from providing contestable services<br>• DSB can be included in regulated asset base (RAB) if only providing network support[81]<br>• New rules provide greater leeway for NSP ownership: if a project was ruled to be in the best interests of consumers, and is unlikely to be realised without the involvement of a DNSP, it is likely to get approved[82] | NSPs are increasingly able to own batteries as non-network solutions, where that solution would otherwise not be implemented |
| New participant category: Integrated Resource Provider (IRP)[83] | *AEMC proposed regulatory change* | • New 'IRP' registration category removes DSB barriers, reduces network costs:<br>• Facilitates simpler registration for participants with two-way energy flows (generation and load) as only required to register in one category<br>• Enables registered aggregators to provide market ancillary services from generation and load<br>• Grid storage will only incur DUOS, not TUOS | If made final, AEMC's draft determination may support DSB uptake |
| Local network tariffs (LUOS) | *Change requested* | • LUOS tariff would reduce network costs for local generation, applying to energy that originates and terminates within a local area<br>• Cost reflective, given transporting shorter distances[84]<br>• A rule change request has been submitted by the Australian Council of Social Services and the Total Environment Centre | A cheaper LUOS would incentivise local storage, charging from local solar[85]. NSPs are trialling other bespoke network tariffs. |
| Evolving & new markets | *New* | • Five-minute trading requires improved response/ orchestration capability as provider must forecast accurately and respond quickly | Accessing full value-stack may become challenging for less sophisticated providers |
| | *Evolving* | • Fast frequency response market will provide new FCAS value pool | |
| Other | *Potential future rules* | • Dispatchable capacity market mechanism to provide reliability services<br>• 'Solar tax' with customers potentially charged negative FiT for exports | Implication unclear; potential rules undefined |

[80] AER, 2021, Ring Fencing Guideline Version 3
[81] 2020, ITP, Project No. A0350 – Business Models and Regulatory Considerations for Storage on the Distribution Network
[82] One step off the grid, 2021, New rules pave way for community batteries and taking customers off the grid
[83] 2021, AEMC, Draft rule determination – Integrating energy storage
[84] ANU, 2020, Implementing community-scale batteries: regulatory, technical and logistical considerations
[85] Assuming the battery owner is paying a FiT more expensive than the wholesale price

## 9.2. Community Engagement Scheme: detailed assessment

Group Ownership maximises value to participants, however, may provide no network benefit and is likely to face implementation and scale challenges

*Table 20: Group ownership assessment*

| Criteria | Sub-Criteria | Rating | Description |
|---|---|---|---|
| **Direct Economic Value** | **Scheme Participants** | High | • Battery optimised to deliver maximum energy cost savings<br>• Reduces FiT constraints and provides load shifting benefits; may be offset by high upfront investment |
| | **NSP Customers** | Medium | • Unlikely to reduce network investment as location not intentionally within network constrained area, and network issues not intentionally addressed |
| | **Network Benefit (Manage peak/min demand; hosting capacity)** | Medium | • Battery likely to import during minimum demand and export at peak<br>• Lack of NSP or market participant ownership means broader network issues unlikely to be addressed<br>• May enable increased hosting capacity depending on network constraints, but likely to be located in areas with existing high PV penetration |
| **Ease of Implementation** | | Medium | • Potential issue with location except for greenfield sites<br>• Community groups may be exempt from being required to hold an AFSL license to implement the scheme |
| **Scalable and sustainable** | | Medium | • Likely to deliver low ROI (relative to other schemes), given less 'value stacking' |
| **Allow Equitable Access to Economic Benefits** | | Low | • Likely that benefit only accessible to community members with upfront capital and access to rooftop solar |

Virtual Storage shares value between participants and the battery owners/operators, however, the customer offer creates complexity that may impact implementation, commerciality and scalability

*Table 21: Virtual storage assessment*

| Criteria | Sub-Criteria | Rating | Description |
|---|---|---|---|
| **Direct Economic Value** | **Scheme Participants** | Medium | • Participants benefit from reduced FiT constraints and load shifting, however, benefit offset by customer payment<br>• Scheme only beneficial if customer payment less than equivalent cost of residential storage (where accessible). |
| | **NSP Customers** | Medium | • Likely to be located in network constrained areas to defer capex / augex<br>• Virtual storage operational requirements may limit the ability to manage network issues e.g. peak demand |
| | **Network Benefit (Manage peak/min demand; hosting capacity)** | Low *(subject to battery location and utilisation)* | • Encourages increased network usage during peak (as compared to BTM) but depending on where network issues are, may not significantly impact network performance<br>• Battery (or portion of) can be used by NSPs to manage load<br>• NSP incentivised to locate the battery in constrained area (dependent on ownership and ability to access constrained area) |
| **Ease of Implementation** | | Low | • Design of sustainable retail product somewhat complex (value trade off)<br>• Participants 'opt in' requirement introduces complexity |
| **Scalable and sustainable** | | Low | • Research suggests ROI unattractive without value-stacking1. Scheme may face value-stacking challenges, including: (i) deferring network investment as network constrained areas may not align with the area where customers can be efficiently acquired; (ii) ability to access trading subject to scheme participant service requirements<br>• Participant churn requires ongoing customer management (with decreasing BTM battery pricing necessitating frequent pricing reviews) |
| **Allow Equitable Access to Economic Benefits** | | Medium | • Benefit only accessible to community members with access to rooftop solar, but no upfront capital required |

The technical and commercial complexity of peer-to-peer trading is expected to limit uptake

*Table 22: Peer-to-peer trading assessment*

| Criteria | Sub-Criteria | Rating | Description |
|---|---|---|---|
| **Direct Economic Value** | **Scheme Participants** | Medium | • Online marketplace facilitates increased utilisation of rooftop solar and access to cheaper energy<br>• Level of benefit unclear; subject to trading dynamics |
| | **NSP Customers** | Medium | • Able to be located in network constrained areas to defer investment<br>• Virtual storage / P2P trading operational requirements may limit the ability to manage network issues e.g. peak demand |
| | **Network Benefit (Manage peak/min demand; hosting capacity)** | Medium *(subject to battery utilisation)* | • Encourages increased network usage during peak (as compared to BTM) but depending on where network issues are, may not significantly impact network performance<br>• Battery (or portion of) can be used by NSPs to manage load<br>• NSP incentivised to locate the battery in constrained area (dependent on ownership and ability to access constrained area) |
| **Ease of Implementation** | | Low | • Complex marketplace may limit customer acquisition<br>• Additional software, technical (metering) and process requirements create complexity<br>• AFSL may be required by scheme owners |
| **Scalable and sustainable** | | Low | • Sustainability challenged as marketplace requires ongoing active participation<br>• Ability to generate profit unclear; expected reliance on funding suggests unlikely to scale effectively across the NEM |
| **Allow Equitable Access to Economic Benefits** | | High | • Online marketplace provides non-rooftop solar participants with access to cheaper energy at an agreed price |

The Passive scheme maximises network value and has the potential to be implemented and scaled effectively across the NEM

*Table 23: Passive scheme assessment*

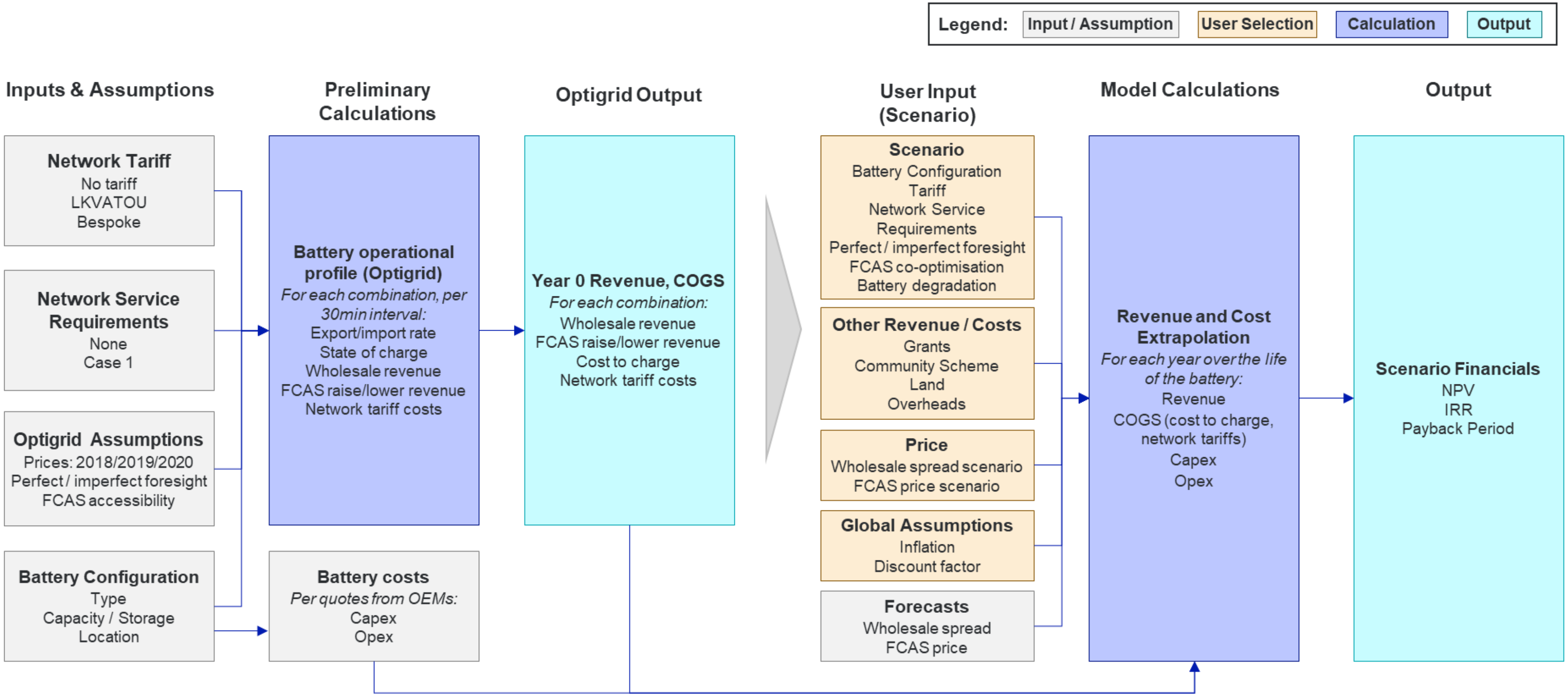
| Criteria | Sub-Criteria | Rating | Description |
|---|---|---|---|
| **Direct Economic Value** | **Scheme Participants** | Low – Medium *(subject to area solar constraints)* | • Participants receive benefits from reduced FiT constraints (if located in constrained area)<br>• No customer offer removes ability to access load shifting |
| | **NSP Customers** | High | • Battery likely operates as non-network solution to maximise value-stacking potential, delivering largest possible network investment deferral. |
| | **Network Benefit (Manage peak/min demand; hosting capacity)** | High | • Battery can be operated to manage min/max loading<br>• NSP incentivised to locate the battery in constrained area to optimise commercial business case<br>• With access to trading markets, there is the potential for the battery to be charged via sources other than local rooftop solar |
| **Ease of Implementation** | | Medium – High | • Assuming NSP and IPP actively collaborating to deliver project, barriers limited to ability to reach commercial arrangements<br>• Limited complexity with no retail product and limited community involvement |
| **Scalable and sustainable** | | High | • Market trading value accessible in all locations<br>• Value stacking increases likelihood of favourable commercial business case<br>• Location important for accessing network value |
| **Allow Equitable Access to Economic Benefits** | | Medium – High | • Scheme maximises network investment deferral; benefit shared across all NSP customers<br>• Relies on savings great enough to ‘trickle down’ to residential customers<br>• Load shifting benefit unavailable, limiting the advantaged position of households with rooftop solar access |

## 9.3. Modelling approach

Modelling for this study comprised two components:

- Operational battery modelling via AGL's Optigrid algorithm: Based on the network tariff, network service requirements, battery configuration and key assumptions, Optigrid defined how the battery would behave in each 30 minute interval, and as a result determine the gross profit from operations
- Financial modelling: Based on the scenario chosen, battery capital costs, and price forecasts, the financial model calculated return each year over the life of the project

*Figure 21: Modelling approach and functionality*



## 9.4. Modelling assumptions

The assumptions supporting each component are provided below.

### 9.4.1. Operational modelling

Operational modelling was based on historical price data and battery specifications.

| Category | Sub-category | Assumption |
|---|---|---|
| **Price** | Spot price | • FY19 to FY21 historical prices |
| | FCAS price | • FY19 to FY21 historical prices, Victoria |
| **Optimisation** | Approach | • Battery optimises profit in wholesale market; remaining capacity used for FCAS enablement services |
| | FCAS access | • Access FCAS raise and lower markets only; not regulation market |
| | Foresight | • Operations based on imperfect foresight. The imperfect forecast is based on the AEMO pre-dispatch price forecasts that are published by AEMO prior to every dispatch interval<br>• Perfect foresight option included for testing. Perfect foresight consists of full visibility of wholesale and FCAS prices for the next 36 intervals. |
| **Battery specifications** | Round-trip efficiency | • 85% |
| | C-Rating | • 0.5 to 1.0 |
| | FCAS availability | • Variable FCAS controller, resulting in application of 41.2% droop[86] |
| | Size | • *Variable* |
| | Duration | • *Variable* |
| **Other** | Tariff | • *Variable* |
| | Network service requirements | • *Variable* |

### 9.4.2. Financial modelling

Financial modelling was based on forecast prices, quotes from suppliers, AGL previous experiences and economic assumptions.

| Category | Sub-category | Assumption |
|---|---|---|
| **Forecast** | Wholesale spread | • AGL internal wholesale spread forecast (capped)<br>• ACIL Allen wholesale spread forecast (uncapped) |
| | FCAS price | • AGL internal FCAS price forecast (capped) |
| **Gross profit** | Wholesale approach | • Average profit over FY19 – FY21 calculated based on Optigrid output (wholesale revenue less cost to charge)<br>• Wholesale spread index created based on FY19 – FY21 wholesale spread, and wholesale spread forecast<br>• Wholesale profit (wholesale revenue less cost to charge) extrapolated in line with index |
| | Wholesale (capped) | • Revenue and cost to charge from prices below $300 indexed using AGL capped internal forecast<br>• Revenue and cost to charge from prices above $300 indexed using cap contract forward price |
| | Wholesale (uncapped) | • Revenue and cost to charge indexed using ACIL Allen wholesale spread forecast (uncapped) |
| | Wholesale (cap premium) | • No cap premium assumed due to volatility in cap contract payout |

[86] AEMO, 2019, Battery Energy Storage System Requirements for Contingency FCAS Registration

| | | |
|---|---|---|
| | FCAS | • Average revenue over FY19 – FY21 calculated based on Optigrid output<br>• FCAS price index created based on FY19 – FY21 prices, and FCAS price forecast<br>• FCAS revenue extrapolated in line with index |
| | Network payments | • $45K based on United Energy guidance (midpoint of $40K - $50K) |
| | Marginal loss factor (MLF) | • 100% factor applied. Assumes electricity transported locally on distribution network with minimal loss. |
| | Degradation | • Per Battery OEM specifications provided |
| | Green scheme costs | • Costs included for LGC, STC and VEEC certificates<br>• Costs paid on net imports |
| | AEMO fees | • $0.52 per MWh imported; increase with inflation |
| **Capital cost** | Capital cost quotes | • Quotes obtained from three battery OEMs for various battery sizes and durations ranging from 50kW to 3500kW.<br>• Quotes collated to estimate cost based on size and duration for each design option |
| | Capital cost breakdown | • Capital cost estimated for each design option based on cost of:<br>  • Battery storage system<br>  • Design and electrical systems<br>  • Network connection<br>  • Civils<br>  • Preliminaries<br>• Project operations estimate: 1 FTE full time for 6 months |
| | Contingency | • 10% contingency for capital costs |
| | DSRP registration | • $10,609 |
| **Operational costs** | O&M | • Indicative pricing based on quotes |
| | Other costs | • No data cost assumed<br>• $16.5K for FCAS Metering and MASS. Subscription Service for API based control services. Flat fixed cost<br>• Labour overhead: 0.4 FTE for first two years; 0.1 FTE afterwards |
| | Land | • Equivalent cost to current payment ($10k per site for 60 days) extrapolated to 3 months |
| | Community engagement scheme | • No community engagement scheme costs assumed; costs dependent on scheme type |
| **Financial and economic factors** | Inflation | • 2.5% |
| | Discount rate | • 6.70% |
| | Debt / equity | • Balance sheet funded i.e. no debt required |
| | Debtor/creditor days | • 30/30 |
| **Project** | Start date | • FY23 start |
| | Funding | • No funding provided |

## 9.5. Glossary

| Term | Description |
|---|---|
| Behind-the-meter | Battery located behind a residential, commercial or industrial meter - does not incur network charges; typically connected directly to solar generation |
| Cap premium | The premium paid to reduce exposure to spikes in wholesale prices; calculated as the difference between the cap contract payout and the cap contract price |
| Community engagement scheme (CES) | The way residential community members participate in and realise financial and non-financial benefit from distribution scale batteries |
| Competitive market participant | An entity capable of providing contestable market services such as engaging in wholesale market trading |
| Cost to charge | The cost of importing energy to charge the battery including green scheme costs (LGC, STC, VEEC) and AEMO fees |
| Degradation | The rate at which battery storage declines over time |
| Feed-in-tariff (FiT) | Amount paid for each kWh of solar exported to the grid |
| Front-of-meter | Battery connected directly to the network |
| IRR | Internal rate of return: A metric used to estimate the profitability of potential investments |
| LMP | Lower Mornington Peninsula |
| NEM | National Electricity Market |
| Network services | Network Service Provider payments for delivering agreed services to support the network |
| NPV | Net Present Value: Difference between the present value of cash inflows and the present value of cash outflows over a period of time |
| Solar soaking | The act of consuming excess energy generated by distributed rooftop PV solar panels instead of by centralised large-scale energy sources |
| Solar soaking period | Between 10am and 3pm, when rooftop PV solar is typically at its highest and household demand is typically low, resulting in high levels of excess solar exported to the grid |
| SWIS | South-West Interconnected System |
| Tariff (demand) | Network cost based on maximum power achieved during a specified time period |
| Tariff (usage) | Network cost for each kWh of electricity imported from the grid; varies with peak period |
| Tariff arbitrage | The process of buying electricity at low prices and selling at higher prices |
| Wholesale (capped) | The wholesale spot price is capped at $300/MWh – the capped price remains at $300 when the actual spot price moves above $300 |
| Wholesale (uncapped) | The wholesale spot price is not capped |
| Wholesale price | The spot price determined by AEMO every 5 minutes in the wholesale market |
| Wholesale spread | The difference between peak 2-hour price and minimum 2-hour price daily |