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Economic Viability Assessment of Neighbourhood versus Residential Batteries: Insights from an Australian Case Study

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Abstract: Amidst the evolving paradigms of the contemporary energy landscape, marked by the imperative of sustainability and efficiency, the integration of energy storage has emerged as a transformative strategy that seeks to recalibrate the dynamics of electricity distribution and consumption. However, there remains a pressing need to determine the most economically viable approach for deploying energy storage solutions in residential low-voltage (LV) feeders, especially in rural areas. In this context, this paper presents the results of an economic evaluation of energy storage solutions for a residential LV feeder in a rural town in Australia. Specifically, the study compares the financial viability of a front-of-the-meter (FTM) battery installed on the feeder with that of a fleet of behind-the-meter (BTM) batteries. The FTM battery, with a size of 100 kW/200 kWh, is assumed to be operated by the retailer but owned by the community, with any profits assigned to the community. In this scenario, we studied a battery operating under standard network tariffs and three different trial tariffs that distribution network service providers currently offer in Australia. On the other hand, the fleet of BTM batteries (3 kW, 3.3 kWh) are individually owned by households with solar installations, and their cumulative capacity matches that of the FTM battery. The comparison is based on key economic parameters, including network charges, retail margins, frequency control ancillary service (FCAS) revenues, wholesale energy costs, technology costs associated with community batteries, and net profit or loss for the community, as well as considerations of utility grid arbitrage and solar photovoltaic (PV) self-consumption. The study also assumes different grant levels to assess the impact of subsidies on the economic feasibility for both battery configurations. The findings indicate that, while both require some form of subsidy for profitability, the BTM batteries outperform the FTM battery in terms of economic viability and so would require lower grant support. The FTM battery case finds a need for grants ranging from 75% to 95% to break even, while the BTM fleet requires approximately 50% in grants to achieve a similar outcome. In conclusion, this study highlights the importance of grant support in making energy storage solutions economically feasible. In particular, it highlights how the less mature segment of FTM batteries will need higher support initially if it is to compete with BTM. The outcomes of this study inform decision-making processes for implementing energy storage solutions in similar communities, fostering sustainable and cost-effective energy systems.

Keywords: community batteries; neighbourhood batteries; energy storage; solar photovoltaic; renewable energy; Australia

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1. Introduction

1.1. Motivation

The global energy landscape is undergoing a profound transformation driven by the imperatives of sustainability, efficiency, and resilience [1,2]. As societies grapple with escalating environmental concerns and the need for rapid decarbonisation, energy storage has emerged as critical in supporting the high levels of renewable energy penetration that are needed. The confluence of technological advancements and shifting energy policies has spurred the exploration of innovative strategies to optimise energy production, consumption, and distribution [3,4].

Battery energy storage is being deployed at various scales—residential, neighbourhood, and utility—to meet this need. However, there is uncertainty regarding the different consumer contexts in which individual household battery systems and communal neighbourhood battery systems perform best in terms of their economics.

In this paper, both battery configurations are compared using real data from an Australian rural town that underwent a detailed local energy solution feasibility study as part of a national grant program. The merits of both types of storage are then discussed, as well as the implications for future policy frameworks, which are essential to help consumers and communities use energy storage to access more reliable and affordable renewable energy.

1.2. Literature Review: Knowledge Gaps

The utilisation of battery energy storage in the decarbonisation efforts holds considerable significance within the scholarly discourse. This is underscored by its versatile applicability across a wide spectrum of sectors and applications [5,6]. Battery energy storage systems serve a pivotal role as a stabilising element in the context of variable renewable energy generation, exemplified by solar photovoltaic (PV) sources. In addition to addressing the variability challenge, these systems exhibit the potential to enhance the overall stability of electrical grids while simultaneously contributing to the energy market's value proposition. This contribution is manifested through services such as frequency and voltage regulation, as well as other ancillary services [7,8].

The market for individual household battery systems surpasses the maturity level of neighbourhood-scale batteries [9]. In Australia, around 180,000 homes have adopted household battery systems [10]. Nevertheless, there has been a discernible upswing in interest among various stakeholders, including industry, government bodies, energy market incumbents, newcomers, researchers, and local communities, in neighbourhood-scale batteries [11–14]. However, it is pertinent to note that the vast majority of such neighbourhood-scale installations currently consists of demonstrations, pre-commercial pilots, or projects heavily reliant on government subsidies [15]. Recent investigations and deployments suggest potential techno-economic advantages of batteries are contingent upon their optimal sizing and siting through appropriate methodologies [16–18].

An expanding body of scholarly literature also attests to the efficacy of community batteries in ameliorating challenges emanating from the escalating integration of distributed solar PV generation, predominantly through rooftop installations [19,20]. These batteries generate value by serving as providers of ancillary services to the larger utility network, mitigating load peaks on the distribution framework, enhancing power quality by tempering the variable output from distributed PV systems, ensuring operational continuity of the low-voltage (LV) grid during outages or maintenance, staving off the necessity for immediate network upgrades, and elevating hosting capacities for solar PV and electric vehicle (EV) technologies [21,22]. As shown in Figure 1, the schematic elucidates the fundamental concept underpinning a community battery.

On the other hand, the pervasive issue of current network tariffs has been widely acknowledged as a substantial impediment to the widespread adoption of community battery solutions. This conundrum emanates from the intricate interplay of tariff structures, often ill-aligned with the dynamic nature of emerging energy paradigms. This misalignment not only impedes the seamless integration of community batteries into the existing energy landscape but also undermines the potential economic benefits and operational efficiencies that such solutions could otherwise offer. This issue underscores the imperative for a comprehensive re-evaluation and recalibration of network tariff frameworks to foster a more conducive environment for the effective integration of community battery systems, thereby unlocking their considerable potential for enhancing energy resilience and sustainability [16–18].

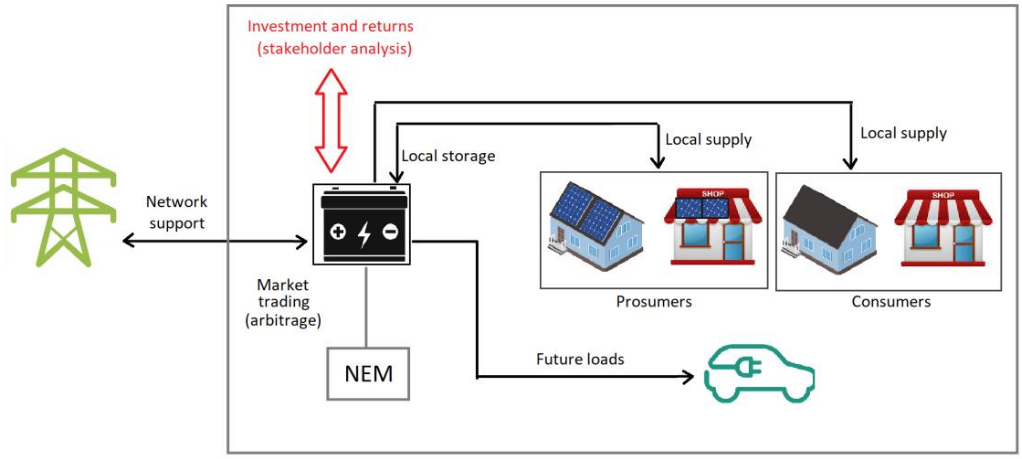


Figure 1. Illustration of community battery operation.

Within the discourse of communal energy solutions, the terminologies front of the meter (FTM) and behind the meter (BTM) delineate the spatial relationship of energy storage systems vis-à-vis the electricity network [23]. FTM battery storage systems are seamlessly connected to the grid and typically characterised by larger scales, whereas BTM counterparts are established on-site, encompassing residences or commercial premises [5,14].

While both configurations bear distinctive merits and complexities [5], the focal point of this study resides predominantly in scrutinising the economic feasibility of an FTM battery against a cluster of smaller-scale BTM batteries within households.

Adequately dimensioned BTM batteries emerge as enablers of augmented energy resilience, fostering cost savings through elevated self-consumption rates and peak shaving. Commercial entities, due to their higher energy consumption profiles compared to residential counterparts, stand to derive enhanced advantages from larger battery installations [24,25].

The extant literature comprises a plethora of studies investigating the influence of tariff structures on the feasibility of both FTM and BTM battery systems [26]. Notably, Parra and Patel [27] conducted a comparative analysis of BTM battery systems under three distinct tariff structures, encompassing a dynamic tariff, flat rate tariff, and time-of-use (TOU) tariff. Their findings indicate a substantial increase in the levelised cost of the battery installation when using the flat rate tariff compared to the dynamic and TOU tariffs. In a related study, Gautier and Jacqmin [28] explored the ramifications of network tariffs on PV adoption within the Wallonia region of Belgium. Their research revealed that specific network tariff structures can significantly influence the rate of PV adoption within the case study region. Notably, a favourable tariff structure tailored to incentivise distributed PV generation resulted in a significant uptick in PV installations, underscoring the pivotal role of tariff design in promoting renewable energy integration.

Moreover, Wang et al. [29] proposed a comprehensive operational strategy for battery storage within integrated energy systems governed by TOU tariffs. Their approach involved determining optimal charge and discharge patterns for the battery by juxtaposing the aggregate of electricity prices and energy storage operational costs against electricity sales prices during peak hours.

In a similar vein, Campana et al. [30] introduced a hybrid operational strategy that is tailored to BTM batteries, aimed at achieving peak load shifting and operational cost reduction across diverse scenarios. Zhang and Tang [31], in their investigation, delved into the influence of TOU tariffs and step tariffs, striving for enhanced economic optimisation of battery storage systems. Ouédraogo et al. [32] also explored an array of rule-based energy management strategies, varying in complexity, and evaluated their compatibility with different electricity tariffs—fixed, peak/off-peak, and dynamic tariffs—in the context of battery integration within microgrid settings. Additionally, Kong et al. [33] conducted an in-depth analysis of TOU tariffs, with the primary goal of minimising residential energy expenditures by formulating an optimal strategy for battery energy storage system charge and discharge sequences.

In another notable instance, Darghouth et al. [34] proposed a method for integrated solar PV and battery storage systems to reduce demand charges, whereas Bloch et al. [35] put forth a method to determine the optimal size of the battery energy storage coupled with PV systems, while minimising energy costs under dynamic tariffs for residential customers. There has also been a variety of other studies that have investigated the impact of demand charges and various tariffs for residential battery energy storage [36–39].

In this context, Gomes et al. [40] underscored the imperative need for further research in the domain of tariff design studies concerning battery storage systems integrated with PV installations. A research gap emerges in comprehending the intricacies of TOU tariffs in association with BTM and FTM battery storage systems [33,41]. While numerous studies accentuate the pivotal role of tailored tariff designs in improving the economic viability of solar PV-battery systems, there exists a noticeable dearth of scholarly efforts within the literature on the elements of such tariffs.

Significant works in the literature have also undertaken comprehensive assessments of the techno-economic viability of both FTM and BTM battery systems [41]. These assessments employed an array of key economic metrics, encompassing the payback period [42], net present value [43], levelised cost of energy storage, internal rate of return [44], and return on investment (ROI) [45]. For instance, Cardoso et al. [46] developed an advanced framework for elucidating battery cost dynamics and performance attributes within the domain of distributed energy resources. Their methodological approach exhibits a high degree of accuracy by integrating the multifaceted impacts of battery aging and degradation.

Similarly, Barbour et al. [47] investigated the feasibility of energy storage options at the individual household level, comparing it to a neighbourhood battery serving a community of 200 households and 4500 residents in Texas, USA. Parra and Patel [27] also studied the techno-economic implications of PV-coupled batteries within residential settings, delving into the essential prerequisites for achieving economic viability. These prerequisites encompass both initial capital outlays and the intricacies of retail tariffs and export prices. Several other studies [48–50] have also conducted techno-economic assessments of neighbourhood batteries. In another notable study, Kalkbrenner [51] compared the economics of residential and community batteries within a German community, while Dong et al. [52] embarked on a comparative analysis of the FTM and BTM batteries in the UK. However, a comprehensive comparative analysis of the economic viability of FTM and a fleet of BTM batteries, especially at the tariff level, is lacking in the Australian literature, which is part of the focus of this study.

Another prominent thematic thread within the extant literature pertains to economic analysis and methodologies for cost minimisation concerning FTM and BTM battery systems. For example, Sharma et al. [39] investigated the process of curtailing annual electricity expenses through optimal battery sizing, considering flat tariffs, while other studies [53–55] pursued strategies to reduce infrastructure costs associated with residential battery storage through optimal battery sizing, considering TOU tariffs. Furthermore, Tang et al. [56] contributed insights into the economics of battery energy storage and cost reduction methodologies, whereas Abdulla et al. [57] and Temene Hermann et al. [58] delved into diverse optimisation techniques for appropriately sizing battery energy storage systems.

The FTM and BTM battery systems present distinct business models and ownership structures, with prior research notably exploring the potential for communal energy sharing [51,59–61]. For example, Gjorgievski et al. [62] examined a business model within a German case study that facilitates community-driven power sharing independently of traditional energy suppliers. The research encompasses a spectrum of ownership structures, including “community-owned”, “partial ownership by the community”, and “owned and operated by a third party”. Also, in their comprehensive study of battery storage systems, Burlinson and Giulietti [63] identified pivotal elements within business models, encompassing key actors, ownership arrangements, core values, and consumer dynamics. They went further in [40] and demonstrated the critical role of willingness to pay and consumer acceptance as determining factors in shaping battery storage business models.

Various other studies have also delved into the potential of peer-to-peer energy trading and energy-sharing strategies facilitated by neighbourhood batteries [56,64–68]. For instance, Henni et al. [60] scrutinised peer-to-peer energy trading and energy sharing through battery energy storage systems, identifying the need for a revised regulatory framework to leverage such potentials. On a different note, Muller et al. [69] conducted investigations into the feasibility of energy sharing at the community level.

Table 1 serves as a thematic summary of the research findings derived from the extensive literature review and the identified knowledge gaps within each theme, aiming to position this research within the broader scholarly landscape.

Table 1. Synopsis of thematic prior work in the relevant literature.

Theme	Reference(s)	Description/Remark	Associated Research Gap(s)
Techno-economic analysis using tariff structures	[20]	Studying the impact of tariff structures on neighbourhood batteries	Lack of a comprehensive cost assessment framework for BTM and FTM neighbourhood batteries. Paucity of studies focused on evaluating the role of trial battery tariffs in improving the economics of community batteries.
	[26]	Studying the impact of tariff structures on neighbourhood batteries	
	[27]	Comparing different tariff structures for BTM batteries	
	[28]	Investigating the impact of network tariffs on the adoption of solar PV	
	[29]	Developing battery storage operating strategies based on time-of-use tariffs	
	[30]	Devising hybrid operational strategies for BTM batteries	
	[31]	Investigating the impacts of time-of-use and step tariffs on the performance of community batteries	
	[32]	Exploring the efficiency of various rule-based energy management strategies	
	[33]	Analysing the impact of time-of-use tariffs for reducing home energy costs	
	[34]	Optimising solar PV and battery coordination for minimum demand charges	
	[35]	Optimal sizing of the battery, minimising the costs for customers attached to time-of-use tariffs	
	[36–39]	Investigation of demand charges and various tariffs	
	[40]	Designing novel tariffs and evaluating their impacts on batteries coupled with PV	
	[41]	Studying the impact of time-of-use tariffs on the efficiency of community-scale batteries	
	[46]	Proposing an enhanced framework for reducing battery operation costs	
Comparison of community-scale and household-level batteries	[47]	Comparing the economic viability of FTM and BTM batteries	Lack of tariff-level comparative economic viability studies of FTM and equivalent fleet of BTM batteries, particularly within an Australian context. Underrepresented studies on the contribution of various value streams to the economic viability of BTM and FTM batteries.
	[48–50]	Economic viability assessment of community-scale batteries	
	[51]	Comparing economic aspects of residential and community batteries in Germany	
	[52]	Comparison of the economic viability of the FTM and BTM batteries in the UK	
	[53–55]	Cost reduction by optimal battery sizing for time-of-use tariffs	
	[56]	Developing methodologies for the operational cost reduction of battery storage systems	

Table 1. *Cont.*

Theme	Reference(s)	Description/Remark	Associated Research Gap(s)
Business models, ownership structures, and revenue streams	[51]	Energy sharing using neighbourhood battery storage systems	Lack of stakeholder-specific guidance in community battery integration, resulting in a deficiency of tailored insights and recommendations for different stakeholders.
	[56]	Investigating cost reduction strategies and potential revenue streams for community batteries	
	[59–61]	Developing novel energy sharing strategies for neighbourhood batteries	
	[62]	Review of business models and ownership structures for community batteries	
	[63]	Comprehensive review of business models and ownership structures for community batteries	
	[64–68]	Peer-to-peer energy trading using household-level BTM batteries	
	[69]	Comprehensive review of energy sharing mechanisms at the community scale	

1.3. Overall Aim and Objectives

This paper assesses the economic viability of neighbourhood batteries at the tariff level, using a case study from Australia. To better understand the economics of community batteries, the paper explores the value of their integration into an LV residential feeder and how it compares with an equivalent capacity of individual household BTM battery systems installed along the same feeder.

Accordingly, this paper contributes significantly to the existing literature by making the following novel contributions, each addressing one of the identified knowledge gaps with insights from an Australian case study:

- Analysing potential value streams from a neighbourhood battery, with a comparison of the associated value streams in FTM and BTM configurations.
- Evaluating the economic impact of various network tariffs on a community battery, including the contribution of trial network tariffs to the economic viability of batteries.
- Comparing the ROI of a community battery to an equivalent capacity of BTM batteries considering different capital grant levels.
- Providing stakeholder-specific guidance in community battery integration, offering tailored insights and recommendations to different stakeholders.

1.4. Paper Organisation

The rest of this paper is organised as follows. Section 2 presents the materials and methods used for the economic evaluation of FTM and BTM battery energy storage solutions, detailing the scenarios, economic parameters, and evaluation frameworks employed. Section 3 outlines the results of the study, along with an in-depth discussion of the findings in the context of economic viability. Finally, Section 4 concludes the paper by summarising the key insights and implications drawn from the study's outcomes, while also outlining potential avenues for future research and exploration.

2. Materials and Methods

This section presents the materials employed and methods designed to assess the economic viability of FTM and BTM batteries on a feeder level, including (i) the scenarios, (ii) the data inputs and processing, (iii) the trial tariffs for the FTM battery assessment, (iv) the value sources, and (v) the value flow configurations.

2.1. The Scenarios

Situated within a strategically selected residential LV feeder in the rural town of Heyfield (GPS coordinates: 37.9785° S, 146.7845° E) (Victoria, Australia), this study encompasses two principal scenarios for examination:

1. Installation of an FTM battery on the residential feeder: A singular FTM battery energy storage system is positioned at an optimal location along the residential feeder. It is designed to provide energy storage and distribution services to those households served by the feeder.
2. Deployment of a fleet of BTM batteries across solar PV-equipped residences: Multiple individual household BTM battery energy storage systems equivalent to the total energy capacity of the FTM battery. All the households are also equipped with solar PV systems.

The study assesses the prospective advantages and challenges inherent to each delineated approach. This provides stakeholders with the required insights to help them make the most informed decisions regarding the strategic deployment of neighbourhood battery energy storage solutions.

The analysis was conducted using Gridcognition (the Gridcognition Simulation and Optimisation Engine incorporates meticulously validated parametric models, encompassing diverse energy resources [70]) software. It integrates a billing-grade pricing and rating engine, facilitating precise commercial calculations, alongside an advanced optimiser designed to simulate and optimise the management of energy resources.

2.2. Data Inputs and Processing

The analysis is based on two distinct case studies, each utilising time series data for generation and consumption from various sources. For the FTM battery on the residential feeder, aggregated smart meter data provided by the local electricity distribution company were utilised, encompassing the net load, controlled load consumption, and solar exports. The main and controlled load components were combined to calculate the underlying load, considering the negligible difference between controlled tariff and off-peak time-of-use (TOU) rates.

The fleet of BTM batteries on the same feeder relied on typical load and sub-load profiles obtained from typical residential load profiles for the subject town [71]. These profiles were used to construct representative scenarios of different solar household types, factoring in their heating systems and access to a controlled load tariff for the evaluation of comparative economics.

Furthermore, wholesale prices and contingency frequency control ancillary service (FCAS) datasets were obtained from the Australia National Electricity Market (NEM)'s data for the state (Victoria). The study focused on the time period spanning from July 2021 to June 2022 as the representative year, aligning with the available load data.

2.3. Trial Tariffs for FTM Battery Assessment

The study considered three distinct trial tariffs for the battery assessment in addition to the standard network tariffs to evaluate their impact on the economic viability of the FTM battery case. These trial tariffs, offered by other electricity network service providers were examined since AusNet Services (AusNet Services serves as the Distribution Network Service Provider (DNSP) for the case study site of interest (Heyfield, Victoria)) was in the process of developing its own trial tariff during the study period. Table 2 provides a comprehensive overview of the standard network tariff, the TOU energy community battery trial tariffs, and the peak demand-based community battery trial tariff that were subjected to evaluation. Notably, all of these trial tariffs incorporate a local use of system (LUOS)-based tariff regime during off-peak hours. This structure enables cost-free consumption and export when utilising the local system, specifically the network downstream of the 415 V transformer. Conversely, consumption during other time periods incurs an off-peak charge.

Table 2. Network tariffs employed in the evaluation of the FTM battery scenario.

<table>
<tr><th>Network Tariff</th><th>Fixed Charge</th><th colspan="2">Off Peak/Solar Soaker (Essential Energy Only)</th><th colspan="2">Peak</th><th colspan="2">Shoulder</th><th>Critical Times</th><th>Ref.</th></tr>
<tr><td rowspan="2">AusNet Services Standard tariff (NAST12)</td><td rowspan="2">34.2658 cents per day</td><td colspan="2">10 p.m.–8 a.m. weekdays
The entire weekends</td><td colspan="2">9 a.m.–9 p.m. weekdays</td><td colspan="2" rowspan="2">Not applicable</td><td rowspan="2">Not applicable</td><td rowspan="2">[72]</td></tr>
<tr><td>4.7115 c/kWh import</td><td>0 c/kWh export</td><td>19.3182 c/kWh import</td><td>0 c/kWh export</td></tr>
<tr><td rowspan="2">Essential Energy Community Battery Tariff</td><td rowspan="2">AUD 15.8085 per day</td><td>9 a.m.–3 p.m.
9 p.m.–7 a.m.</td><td>10 a.m.–2 p.m.</td><td colspan="2">5 p.m.–7 p.m.</td><td colspan="2">7 a.m.–9 a.m.
3 p.m.–4 p.m.
8 p.m.–9 p.m.</td><td rowspan="2">Not applicable</td><td rowspan="2">[73]</td></tr>
<tr><td>2.7850 c/kWh import

AUD 2.3064/kVA/month demand charge

0 c/kWh export</td><td>0 c/kWh import or export

AUD 0.65/kW/month 0 kW to 3 kW export capacity, AUD 1.45/kW/month above 3 kW</td><td colspan="2">5.0624 c/kWh import

AUD 10.2257/kVA/month demand charge

10.8012 c/kWh export</td><td colspan="2">4.1956 c/kWh import

AUD 9.2519/kVA/month demand charge

0 c/kWh export</td></tr>
<tr><td rowspan="2">Powercor/CitiPower/United Energy Community Battery Tariff</td><td rowspan="2">45 cents per day</td><td colspan="2">10 a.m.–3 p.m.</td><td colspan="2">4 p.m.–9 p.m.</td><td colspan="2">All other times</td><td rowspan="2">Not applicable</td><td rowspan="2">[74]</td></tr>
<tr><td>−1.5 c/kWh import</td><td>0 c/kWh export</td><td>25 c/kWh import</td><td>−1 c/kWh export</td><td>0 c/kWh import</td><td>0 c/kWh export</td></tr>
<tr><td rowspan="2">Ausgrid Community Battery Tariff (EA962/EA963)</td><td rowspan="2">AUD 1.72/kW/month (Balancing charge paid to the network to make battery revenue neutral if supporting network)</td><td colspan="6">Anytime (other than critical peaks) when adding load to the transformer *</td><td>Up to 10 4-h events per year</td><td rowspan="2">[75]</td></tr>
<tr><td colspan="6">1.6 c/kWh import

0 c/kWh export</td><td>Peak demand
141 c/kWh import
−141 c/kWh export

Peak solar export
−75 c/kWh import
75 c/kWh export</td></tr>
</table>

* This does not apply when local PV exports are greater than the local load, as, in this situation, the load on the transformer will not increase.

2.4. Values Sources for the FTM and BTM Batteries

To gain deeper insights into the economic performance of FTM and BTM batteries, it proves valuable to compare the energy flows that contribute to their respective sources of value. Figure 2 exhibits two graphs that illustrate the key distinctions in energy flows between BTM and FTM batteries.

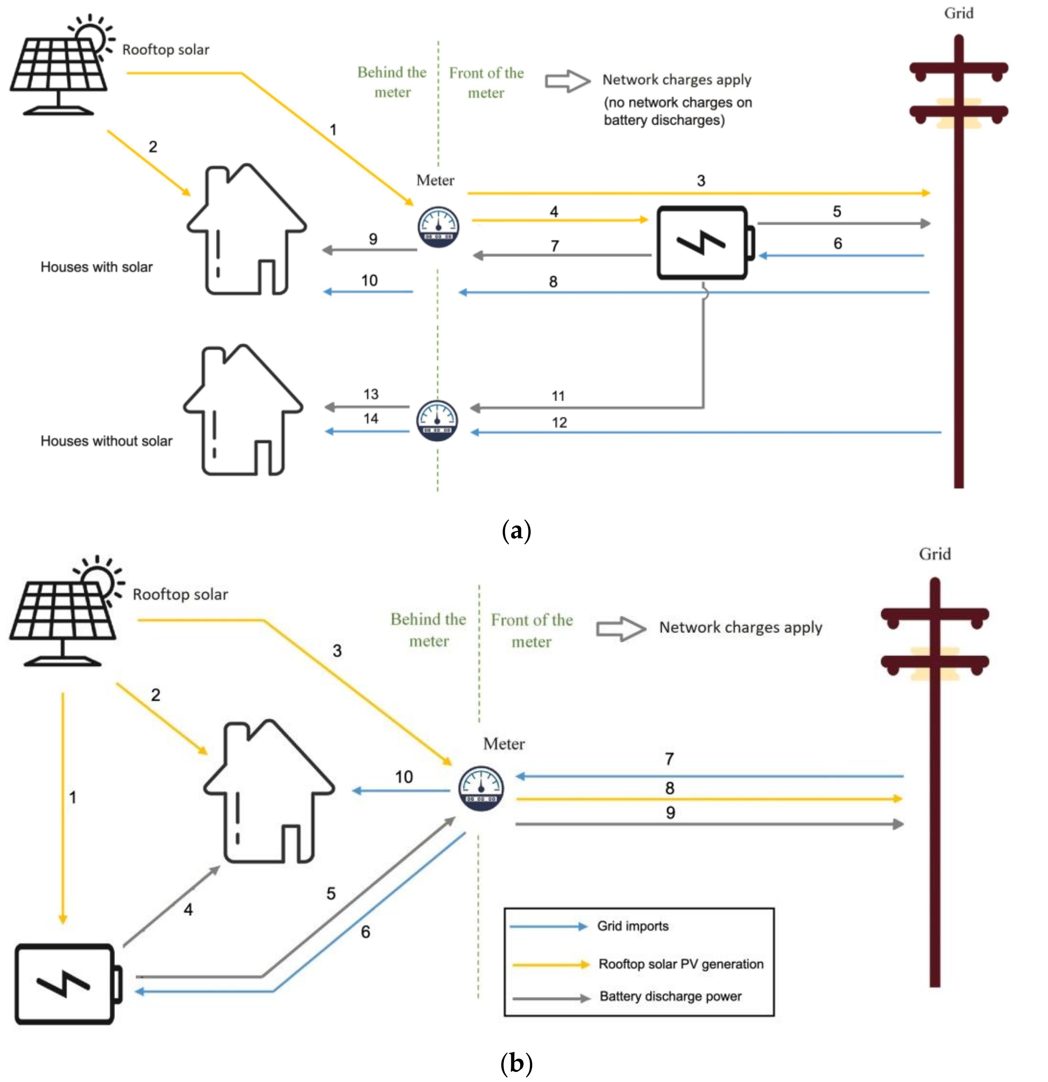


Figure 2. Comparison of the energy flows in (**a**) FTM and (**b**) BTM batteries (adapted from [76]).

While both battery types have the potential to leverage improved self-consumption, energy arbitrage, and participation in FCAS markets, they do so to varying extents and with distinct applications. BTM batteries primarily focus on consumption of energy generated from on-site renewables, reducing peak demand charges and providing backup power during outages. Conversely, FTM batteries are mainly designed to offer community- and grid-scale services, such as frequency regulation, peak shaving, and energy arbitrage, by charging during periods of low demand and discharging during periods of high demand.

In accordance with Figure 2, Table 3 provides a comparative summary of the potential sources of value for FTM and BTM batteries, along with their respective energy flow directions and relative importance. The table also illustrates the corresponding energy flows for each value category, using numerical values assigned to each flow in Figure 2.

Both FTM and BTM batteries offer value to their owners and the broader community through various means.

Table 3. Comparative summary of the value sources for FTM and BTM batteries.

Sources of Value	FTM Batteries		BTM Batteries	
	Energy Flow Direction(s)	Importance	Energy Flow Direction(s)	Importance
Increased self-consumption	$1 \rightarrow 4 \rightarrow 7 \rightarrow 9$ $1 \rightarrow 4 \rightarrow 11 \rightarrow 13$	Medium (at the neighbourhood level)	$1 \rightarrow 4$	High (at the customer level)
Arbitrage	$6 \rightarrow 5$ $6 \rightarrow 7 \rightarrow 9$ $6 \rightarrow 11 \rightarrow 13$ $1 \rightarrow 4 \rightarrow 5$	High	$7 \rightarrow 6 \rightarrow 5 \rightarrow 9$ $7 \rightarrow 6 \rightarrow 4$ $1 \rightarrow 5 \rightarrow 9$	Low
FCAS	5	High	$5 \rightarrow 9$	Low

2.4.1. Enhancing Self-Consumption

Both the FTM and BTM batteries offer the potential to increase the self-consumption of solar or other variable renewable energy types generated by end-consumers, although their applications differ. This involves storing surplus electricity generated on-site during periods of low demand (e.g., in the middle of the day) and utilising it during high-demand periods (e.g., evenings when solar production declines and household demand rises). By storing surplus solar energy during the day and using it during peak evening hours, households can reduce reliance on grid electricity and achieve cost savings on their energy bills.

Increased self-consumption serves as a potential value source for FTM batteries. In this analysis, the value of increased self-consumption for FTM batteries is defined as the difference between the feed-in tariff (FIT) rate paid by the retailer for exported solar energy and the wholesale electricity price at the time of export, minus the battery throughput charge. This difference reflects the avoided cost of purchasing wholesale electricity for the retailer and generally amounts to a relatively smaller value compared to the savings from increased self-consumption for BTM batteries.

Similarly, for BTM batteries, increased self-consumption of solar energy is an important source of value to households, enabling them to utilise more of their on-site solar generation, reduce dependence on grid power, reduce their carbon emissions, and achieve cost savings on energy bills. The value of increased self-consumption for BTM batteries is defined as the difference between the FIT paid for exporting excess solar energy to the grid and the per-kWh charge for grid electricity that is inclusive of all charges. This difference represents the avoided cost of purchasing grid electricity and can vary considerably based on location and tariff structure.

2.4.2. Utility Grid Arbitrage

In the context of battery storage, arbitrage involves buying electricity from the grid during low-price periods (e.g., off-peak hours), storing it, and selling it back to the grid during high-price periods (e.g., peak hours) to exploit price differentials. Additionally, arbitrage may encompass storing local excess generation when prices are low and exporting it back to the grid during more lucrative hours. Alternatively, it can involve purchasing low-priced electricity from the grid, storing it, and discharging it to meet local demand when prices are higher and local generation is insufficient.

In terms of FTM batteries compared with BTM batteries, arbitrage capability depends on factors such as market accessibility and the size and capacity of the battery system. BTM batteries may face more significant limitations in engaging in arbitrage compared to FTM batteries due to smaller system sizes, requiring aggregators to achieve a sufficient scale for market participation.

2.4.3. Frequency Control Ancillary Services

FCASs comprise fast-acting services that are essential for regulating power system frequency within narrow limits to ensure grid stability. These services rapidly respond to sudden changes in supply or demand, maintaining grid stability and avoiding disruptions or blackouts. Batteries are assumed to participate in contingency FCAS markets by maintaining their state of charge (SoC) and receiving payments for standby readiness.

FTM and BTM batteries can both contribute FCASs to the grid. While FCAS opportunities are potentially more lucrative for FTM batteries due to their larger size, BTM batteries can still offer certain FCAS services and contribute to grid stability. Similarly, akin to arbitrage, the potential for FCAS provision in BTM batteries may be notably constrained compared to FTM batteries due to their smaller size, necessitating aggregators to achieve sufficient scale for participation.

Overall, both FTM and BTM batteries offer various value streams to stakeholders, including the broader community. Through the adoption of these batteries, households can increase their self-consumption of solar energy, reduce electricity costs, and aid in maintaining grid stability.

2.4.4. Participant-Level Value Flow Configurations

Participant-level value flow configurations are depicted in this section, showcasing the specific setups used in each of the two models.

In Figure 3, the FTM battery model exhibits interactions among customers, the retailer, the network business, and the wider community, while Figure 4 provides a summary of the interactions involving participants for the BTM batteries on the residential feeder model.

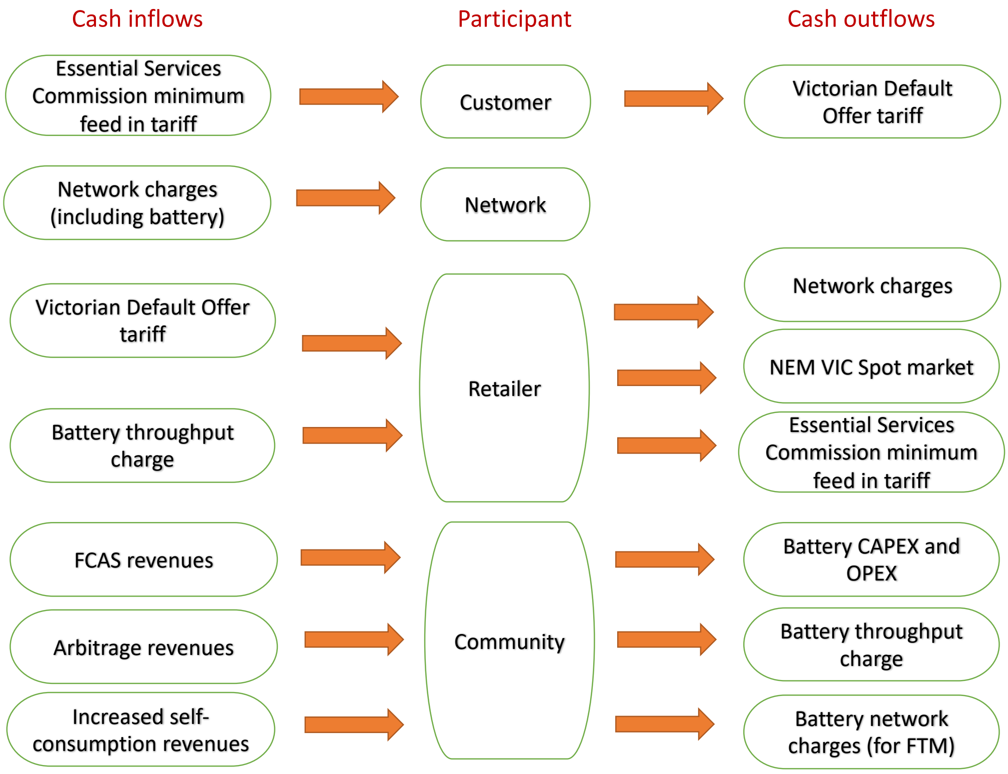


Figure 3. Participant-level value flow configurations in the FTM battery model.

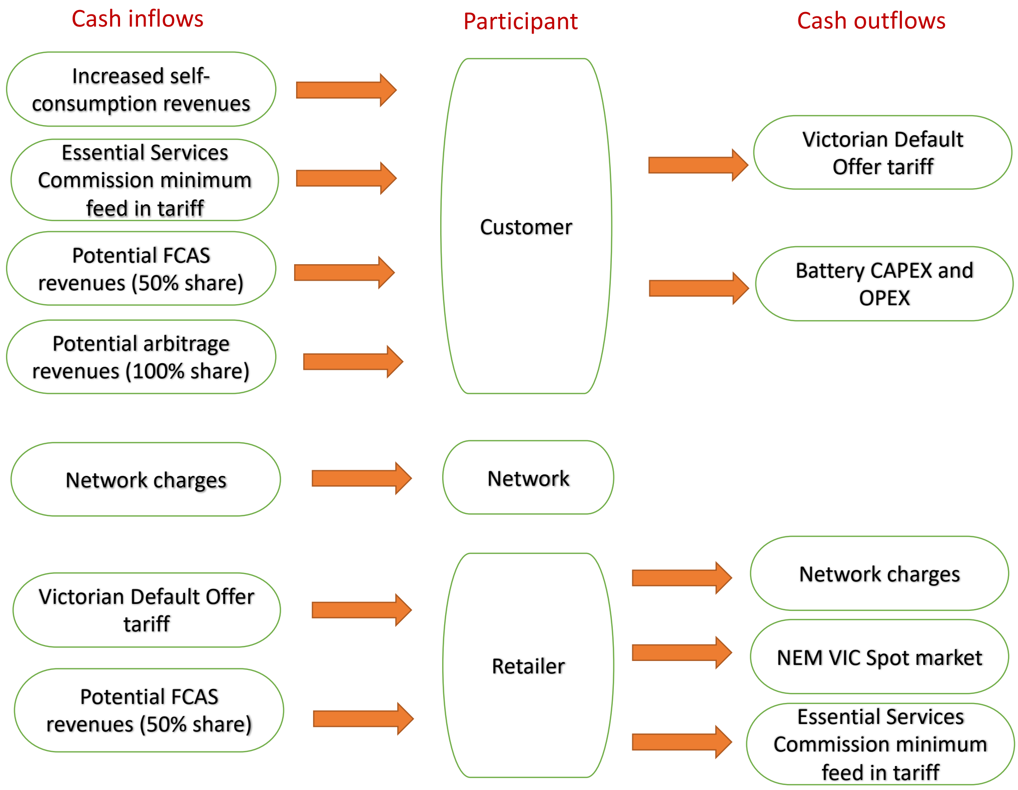


Figure 4. Participant-level value flow configurations in the BTM battery model.

3. Results and Discussion

This section presents and discusses the economic viability assessments conducted for the FTM and BTM battery scenarios before providing a direct comparison between the two scenarios.

3.1. FTM Battery

As mentioned earlier, this scenario focuses on analysing the economic feasibility of deploying an FTM battery on a residential feeder while considering how trial network tariffs support the project's financial viability.

The study assumes that customers are under TOU pricing, and the business case for the battery storage system is evaluated based on its revenue generation through improved self-consumption, grid arbitrage, and participation in FCAS markets.

Stakeholders involved include the network business, the retailer, residential customers (with and without solar), and the community as the owner of the shared neighbourhood battery asset.

The study explores five cases, including no battery, a battery operating under standard network tariffs, and three different trial tariffs offered by electricity network providers in other parts of Australia. As mentioned earlier, there is no trial tariff yet provided by the electricity network provider for the town of Heyfield (the subject of the study).

3.1.1. Key Inputs and Assumptions

Table 4 provides an overview of the main assumptions used in the study, covering tariffs, battery asset and enablement technology costs, and general modelling assumptions. Note that, throughout this paper, costs are always cited in AUD (average exchange rate in 2022: 1 AUD = 0.6948 USD [77]), and figures depict local Australian time for the relevant month.

Table 4. Summary of key assumptions for the FTM battery on the residential feeder model.

Parameter	Value(s) Used in Modelling	Remark	Ref.
Residential electricity tariff	Peak: 0.4081 AUD/kWh Off-peak: 0.1965 AUD/kWh Service charge: AUD 1.2994/day	Local state rates (Victorian Default Offer Rates) for the relevant electricity network provider (AusNet Services) area.	[78]
Network tariff (non-battery energy flow)	3 p.m.–9 p.m. weekdays: 0.2291 AUD/kWh All other times: 0.0477 AUD/kWh Service charge: AUD 125.07/year	Enables stakeholder outcomes' calculation for the network business and retailer.	[72]
Standard network tariff (battery charging energy flows)	9 a.m.–9 p.m. weekdays: 0.1932 AUD/kWh All other times: 0.0471 AUD/kWh Service charge: AUD 125.07/year	Based on the small business time-of-use tariff (NAST12) in the local electricity network provider area.	[72]
Feed in tariff *	AUD 0.05/kWh	The minimum feed-in tariff set by the State Government's economic regulator (the Essential Services Commission).	[79]
Battery type	Lithium ion	Currently the most available and cost-effective option.	[80]
Battery capacity	Power: 100 kW Energy: 200 kWh	Discharge duration = 2 h.	[81]
Expected lifetime (excluding battery cells)	10 years	Includes non-battery cell components, like a power conversion system, cables, cooling systems, and other equipment.	[81]
Battery capital cost (initial)	AUD 305,680	Excludes battery cell replacement; detailed components and underlying assumptions were considered.	[81]
Capital cost of replacing battery cells	AUD 88,768	The discounted cost of replacement at the end of year 5, based on CSIRO's GenCost report.	[81]
Battery O&M cost	AUD 16/kWh/year	Covers labour, materials, and equipment required to operate the system.	[82]
Battery round-trip efficiency	90%	Represents the ratio of energy output to input during a full charge–discharge cycle.	[81]
Depth of discharge (DoD)	95%	Refers to the percentage of a battery's capacity that has been discharged relative to its maximum capacity.	
Battery throughput cost	1 c/kWh	Assumes the retailer applies a surcharge of 1 c/kWh on battery throughput.	
FCAS market exposure	100%	The battery can offer all available electricity capacity for providing FCAS services in the market.	
Time period of original data	One year from July 2021 to June 2022 with hourly resolution	National Metering Identifier (NMI) data obtained from the local electricity network provider.	
Project lifetime/ planning horizon	10 years	January 2024 to December 2033.	
Discount rate	4%	The recommended discount rate for Australian Government infrastructure projects.	[83]

* Note that the current premium FIT of AUD 0.60/kWh expires in 2023 or 2024 depending on the start date, and, therefore, it is not considered in this study [84].

Furthermore, the load profiles and costs are assumed to remain constant throughout the project's lifetime, and the modelling does not account for load flexibility or energy efficiency potential. Though some assumptions are simplified for practical reasons, the modelling details are considered sufficient for meaningful insights into the initial community battery economic feasibility assessment process.

The methodology employed aligns with Section 2. Notably, in the FTM battery case, battery-related network charges apply only to charging the battery. Specifically, the retailer pays for the energy transport to charge the battery, while customers pay the retail tariff for any imports under the net metering (the method employed to calculate solar power consumption at a customer's premises, wherein only surplus or unused solar electricity is exported to the grid) mechanism, which includes standard network tariffs. Customers with solar power generation can receive FIT for excess energy exported to the grid, including the excess power used for battery charging.

The retailer's net profit or loss is determined by the algebraic sum (algebraic sum, also referred to as the net sum, is the total amount obtained by adding positive and negative numbers, considering their respective signs (positive or negative) of retail charges (positive, as income), network charges (negative, as expenses), and wholesale charges (negative) in the baseline case without a battery, plus the associated battery throughput charges in scenarios with a battery. Relevant battery throughput charges (positive) are added to the baseline revenue or profit of the retailer in the absence of a battery.

The community's net profit or loss is calculated by summing the algebraic values of retail charges (positive), network charges (negative), wholesale charges (negative), FCAS revenues (positive), battery's capital, cell replacement, and annual operation and maintenance (O&M) costs (positive), minus the retailer's profit or loss calculated above.

3.1.2. Economic Results by Stakeholder

Figure 5 illustrates the stakeholder analysis for the FTM battery without any grants. The base case without a battery yields a total net profit or loss of AUD 0, confirming that the community does not generate additional income or losses in the absence of a battery.

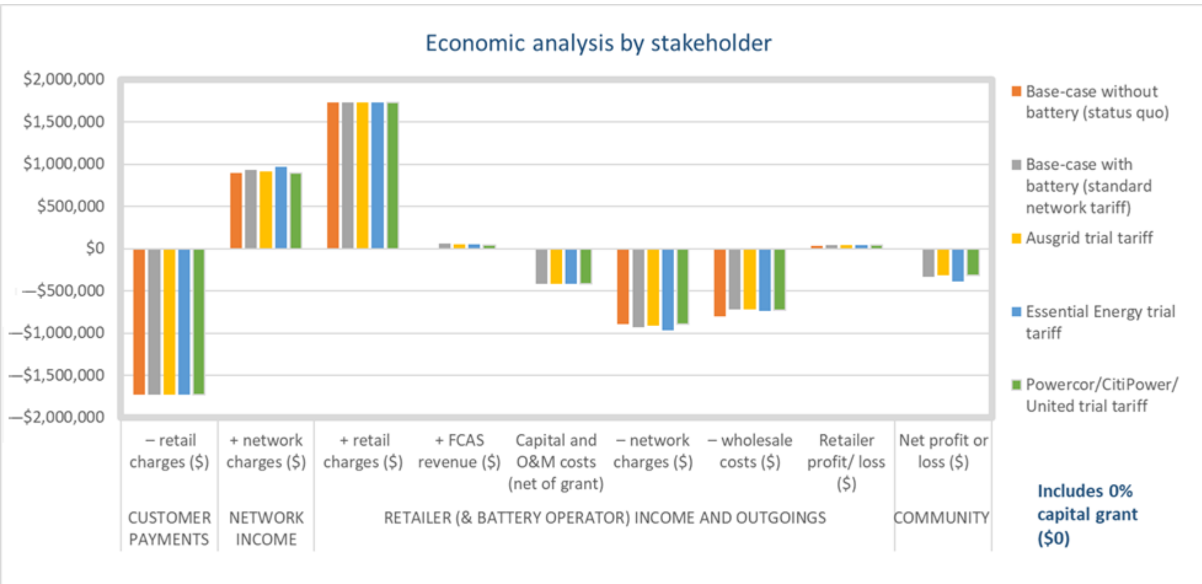


Figure 5. Economic analysis results by stakeholder for the 100 kW 2-h FTM battery without any capital grant.

Our comparison between the base case and the battery with trial network tariffs reveals that deploying a battery under the standard network tariff results in a net loss of AUD 33,300 per year. Under the one alternative electricity network provider's trial tariff (Ausgrid), the net loss is reduced to AUD 31,400 per year; under another alternative electricity network provider's trial tariff (Essential Energy), the net loss increases to AUD

38,800 per year; and under another's trial tariff (Powercor/CitiPower/United), the loss is minimised to AUD 31,300 per year, representing the lowest overall loss (by AUD 100).

Without grants, a considerable reduction in the capital costs, or a considerable increase in the trial tariffs, there is a major lack in the financial viability of deploying an FTM battery in this context. Moreover, the battery operation surcharge constitutes a notable cost component, ranging from 2.66% to 3.31% of the net loss, depending on the associated network tariff.

The modelling indicates that the battery is economically unfeasible without a grant, with the break-even point estimated at a grant between 75% and 95% (or 75–80% excluding the Essential Energy trial tariff), an equivalent reduction in the cost of FTM batteries, or a combination thereof.

Figure 6 displays the stakeholder analysis for the FTM battery with a 95% grant of capital costs (approximately AUD 400,000). In this scenario, the estimated community income ranges from AUD 1200 to AUD 8700 per year. The project shows a positive net profit for all scenarios, with the net profit varying from AUD 1200 per year (Essential Energy trial tariff) to AUD 8700 per year (Powercor/CitiPower/United trial tariff). The standard network tariff yields a net profit of AUD 6600 per year.

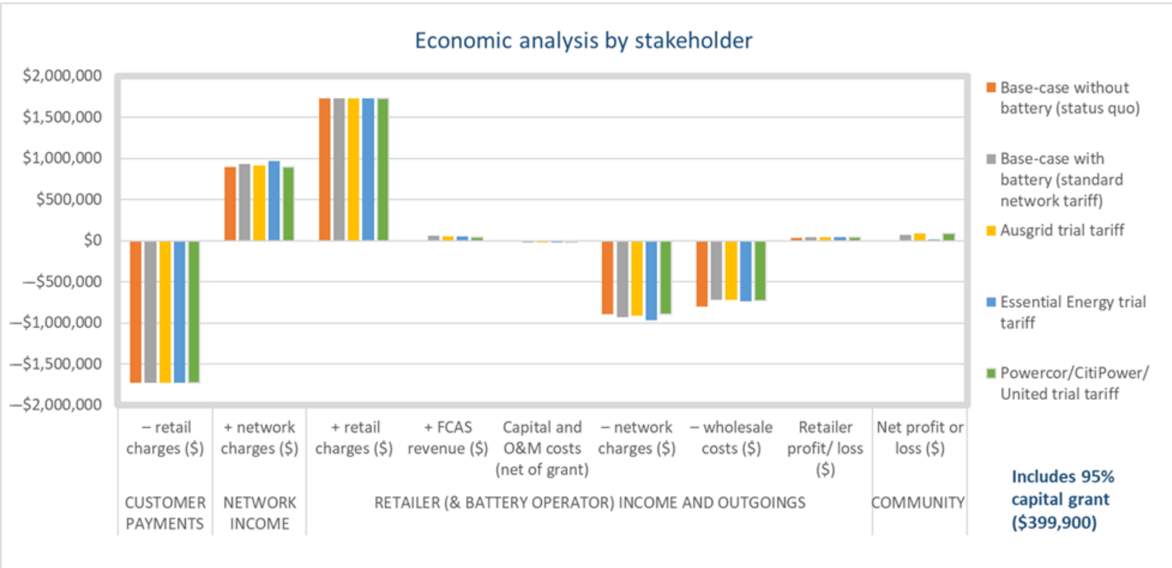


Figure 6. Economic analysis results by stakeholder for the 100 kW 2-h FTM battery with 95% capital grant. Note the legend for the corresponding network tariff for each colour.

The battery operation surcharge accounts for 12% to 85% of the net profit, underscoring the importance of battery operation arrangements on overall profitability.

Overall, the results indicate that the financial feasibility of deploying an FTM battery on a residential feeder at today's prices relies heavily on associated trial network tariffs and the availability of grants. This underscores the critical role that grants and tailored network tariffs can play in making neighbourhood batteries financially viable until the capital costs can be reduced.

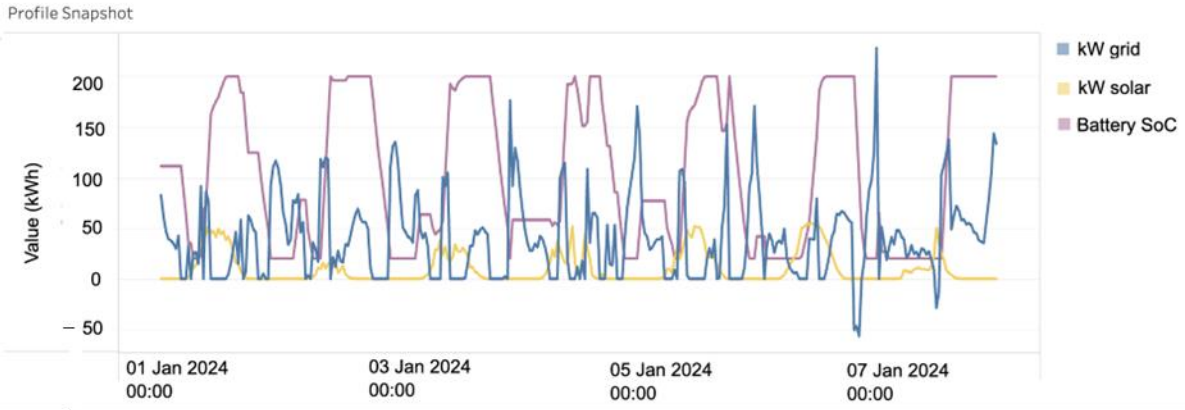
3.1.3. Load Shape Analysis: System Dynamics

To realise the identified value streams, robust forecasting systems are crucial. The employed software assumes "perfect foresight" on time-series data, meaning that it anticipates future loads, generation, and prices to maximise battery value. Practical situations require accurate forecasting and effective management to realise the value streams demonstrated in the analysis.

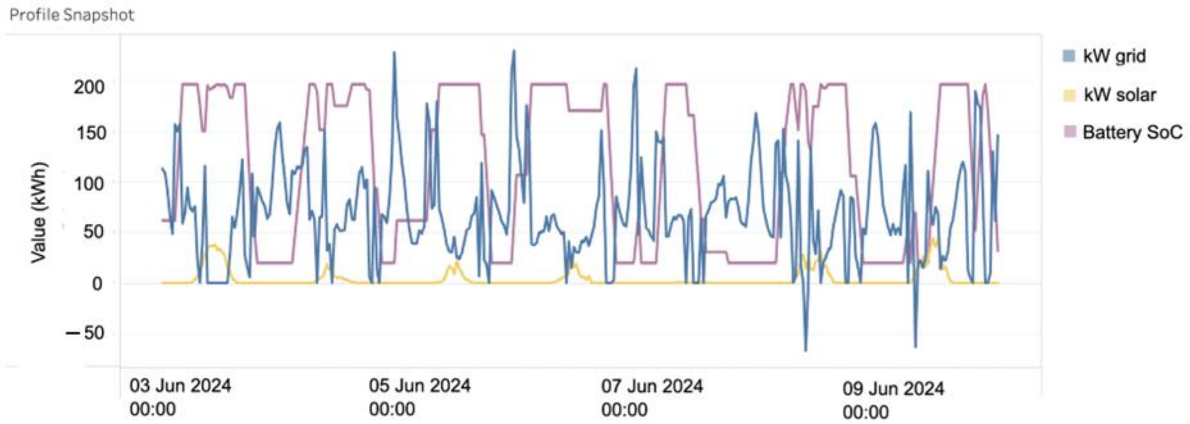
Within this context, this section presents the system dynamics observed in the case of the 100 kW/200 kWh FTM battery on the residential feeder. The developed model has the ability to make decisions regarding the utilisation of excess PV generation, including selling it to neighbours for improved self-consumption, selling it back to the grid, storing it in the battery for later onsite use, storing it for more remunerative exports, or any combination of these operational schedules at each time-step of the system operation. The model also considers the physical constraints of charging and discharging the battery and optimises the system to maximise revenue by analysing all possible combinations of operational modes and revenue streams.

It is essential to note that the optimal results vary depending on the network tariff to which the battery is connected. Therefore, the model makes different decisions based on the overall cost and availability of energy from the grid.

Figure 7 illustrates the system dynamics for a summer and a winter week for the FTM battery case attached to the standard network tariff (NAST12). The graph displays the SoC profile as a purple line, representing the battery's charge level over time. The slope of the SoC profile indicates the rate at which the battery is charging or discharging. A positive slope indicates charging, while a negative slope denotes discharging. The moments when the slope changes from positive to negative or vice versa signify the start of the charging or discharging process.



(**a**)



(**b**)

Figure 7. Illustration of the dynamics taking place within the system for a week in (**a**) summer and (**b**) winter.

The graph demonstrates the battery's charge and discharge cycles throughout the week, synchronised with the current and upcoming net load. Each cycle initiates with the battery charging in the morning, utilising surplus solar energy when the load is light. Subsequently, the battery discharges in the afternoon and evening, when the load is high, making it profitable to sell energy back to the grid or use the stored energy onsite.

Note that the term "net load" in this study refers to the actual electricity demand from the power grid after subtracting the amount of electricity generated by on-site sources, such as rooftop solar panels. It should be distinguished that the net load mentioned here pertains to the electricity demand before considering the battery's impact. This is different from the net load shown in the figure, which represents the net load of the battery-integrated system. The net load before the battery serves as the starting point for evaluating the potential benefits of introducing a battery system, while the net load of the battery-integrated system demonstrates how the battery's operation impacts the overall energy balance, including grid interactions and revenue generation opportunities.

The analysis emphasises the significance of optimising the battery's charge and discharge cycles to maximise revenue while considering available solar energy, grid demand, and network tariffs. Achieving such optimisation necessitates a thorough understanding of upcoming load demands, electricity prices, and onsite generation availability.

It should also be mentioned that the perfect foresight assumed in the model may not always be feasible in real-life situations. Various factors can influence the behaviour of the energy system, making accurate forecasting software essential to achieve a similar level of cost-effectiveness as estimated by the model. Thus, while the developed model can make optimal decisions based on perfect foresight, practical applications may require adapting to real-world uncertainties.

It is essential to note that the selected weeks are not exhaustive representations of the entire year's solar irradiation variability but were deliberately chosen based on their typicality and relevance to system operation during specific seasons. As highlighted in the paper, these weeks serve as illustrative examples rather than comprehensive snapshots of the entire annual solar irradiation spectrum.

The additional modelling results have provided insights into the system dynamics of the FTM battery on the residential feeder. The model has demonstrated the ability to optimise charging and discharging cycles, considering various operational modes and revenue streams, based on perfect foresight assumptions. However, it is essential to acknowledge the potential challenges to achieving perfect foresight in real-life scenarios, which may require accurate forecasting software to adapt to uncertainties.

3.2. BTM Batteries

This case study investigates the installation of BTM batteries at individual households on the residential feeder. Our analysis aims to assess the economic viability of deploying a fleet of BTM batteries by considering various solar PV-equipped customer categories with different hot water (standard resistive and heat pump) and space heating systems—with/without heating, ventilation, and air conditioning (HVAC).

The objective is to comprehensively understand the economic implications of deploying a fleet of BTM batteries, while adequately reflecting the overall load shape of the community. This allows for a detailed evaluation of the potential value streams and benefits that BTM batteries can offer different stakeholders, including the network business, retailer, and solar customers on the LV feeder. Notably, customers without solar PV systems were excluded, as batteries without solar would not have a positive economic impact.

The primary focus is on evaluating the impact of a fleet of single-sized BTM batteries on electricity bill reduction and self-consumption improvement for individual customers. Additionally, we assess the potential for participation in the FCAS market and grid arbitrage. The assumption of individual customer battery ownership underpins our analysis, focusing on the potential value streams and benefits provided by BTM batteries to these customers.

The study also concentrates on customers on the TOU tariff, as they are most likely to benefit from BTM batteries due to potential variability in their energy usage throughout the day. TOU tariffs incentivise customers to shift energy consumption to off-peak periods with lower electricity prices, and battery storage facilitates this by storing excess energy for use during evening peak periods.

We examined eight solar-equipped customer types based on hot water and HVAC configurations: (i) element hot water/HVAC, (ii) element hot water/no HVAC, (iii) heat pump (HP) hot water/HVAC, (iv) HP hot water/no HVAC, (v) controlled element hot water/HVAC, (vi) controlled element hot water/no HVAC, (vii) controlled HP hot water/HVAC, and (viii) controlled HP hot water/no HVAC. These customer categories were identified through energy audits and a data analysis, using energy monitoring devices [85] deployed within homes and businesses in the town.

3.2.1. Key Inputs and Assumptions

Table 5 provides a summary of the key assumptions used in this study for tariffs, battery costs, associated technologies, and general modelling assumptions. The modelling maintains steady load profiles and costs over the project's lifetime, with no consideration of load flexibility or energy efficiency.

A 3 kW, 3.3 kWh residential battery energy storage system was selected, as it aligned with typical residential solar PV systems in the area, while also offering a balance between cost and performance (offering longer duty cycles to enable higher revenues for a faster payback). The battery's basic operating regime was to store excess solar energy generated during the day for later use during periods of insufficient solar power production.

Table 5. Summary of key assumptions for the BTM residential batteries.

Parameter	Value(s) Used in Modelling	Remark	Ref.
Residential electricity tariff (including battery)	Peak: 0.4081 AUD/kWh Off-peak: 0.1965 AUD/kWh Controlled: 0.1962 AUD/kWh Service charge: AUD 1.2994/day	Local state rates (Victorian Default Offer Rates) for the relevant electricity network provider (AusNet Services) area.	[78]
Network tariff (including battery)	3 p.m.–9 p.m. weekdays: 0.2291 AUD/kWh All other times: 0.0477 AUD/kWh Service charge: AUD125.07/year	Enables calculation of stakeholder outcomes to include network business and retailer.	[72]
Feed in tariff *	0.05 AUD/kWh	The minimum feed-in tariff set by the State Government's economic regulator (the Essential Services Commission).	[79]
Battery type	Lithium ion	Selected for availability and cost-effectiveness.	[80]
Battery capacity	Power: 3 kW Energy: 3.3 kWh (2.9 kWh usable)	Discharge duration = 1 h.	[86]
Expected lifetime	10 years	Proven safety and 10 years warranty.	[86]
Battery capital cost	AUD 1500/kWh	Includes an additional inverter for managing the battery bank in a DC-coupled configuration.	[87]
Capital cost of replacing battery cells	N/A	The battery's throughput over 10 years does not necessitate replacement costs.	[86]
Battery O&M cost	N/A	No O&M costs are considered for household-level BTM batteries.	
Battery round-trip efficiency	90%	The ratio of energy output to energy input during a full charge–discharge cycle.	[86]
Depth of discharge (DoD)	95%	Refers to the percentage of a battery's capacity that has been discharged relative to its maximum capacity.	
FCAS market exposure	100%	The battery can offer all available electricity capacity for FCAS services in the market, not just energy sales.	

Table 5. *Cont.*

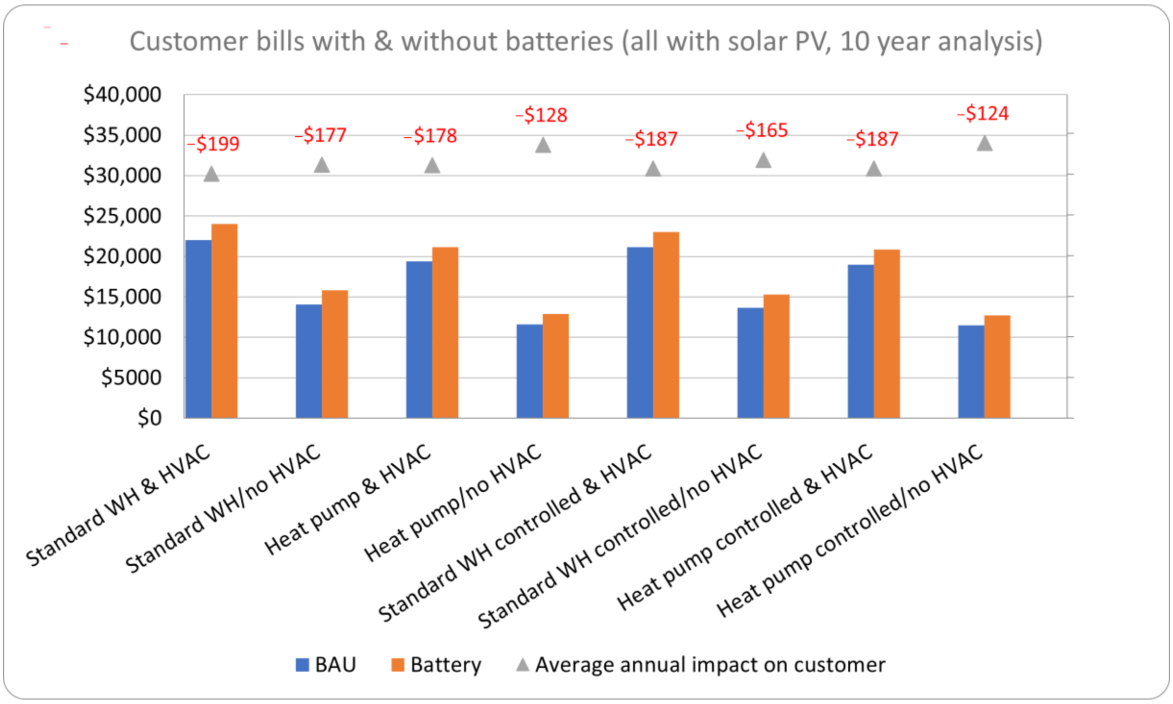
Parameter	Value(s) Used in Modelling	Remark	Ref.
FCAS revenue allocation	Customer's share of FCAS revenues = 50% Retailer's share of FCAS revenues = 50%	The total FCAS revenues are equally shared between the retailer and customers. The retailer acts as an aggregator and facilitates access to the FCAS market, retaining 50% of the revenues and passing the rest to end-consumers.	
Time period of the original data used	One year from July 2021 to June 2022 with hourly resolution	Typical load and solar PV generation profiles derived from energy usage patterns of local households.	[71]
Project lifetime/ planning horizon	10 years	January 2024 to December 2033.	
Discount rate	4%	The recommended discount rate for Australian Government infrastructure projects.	[83]

* Note that the current premium FIT of AUD 0.60/kWh expires in 2023 or 2024, depending on the start date, and, therefore, it is not considered in this study [84].

The chosen battery size is regarded as a practical and cost-effective solution, maximising solar energy utilisation and reducing grid dependence for homeowners. Though assumptions are simplified for practicality, the level of detail in the analysis was considered adequate in the initial BTM battery economic feasibility assessment process.

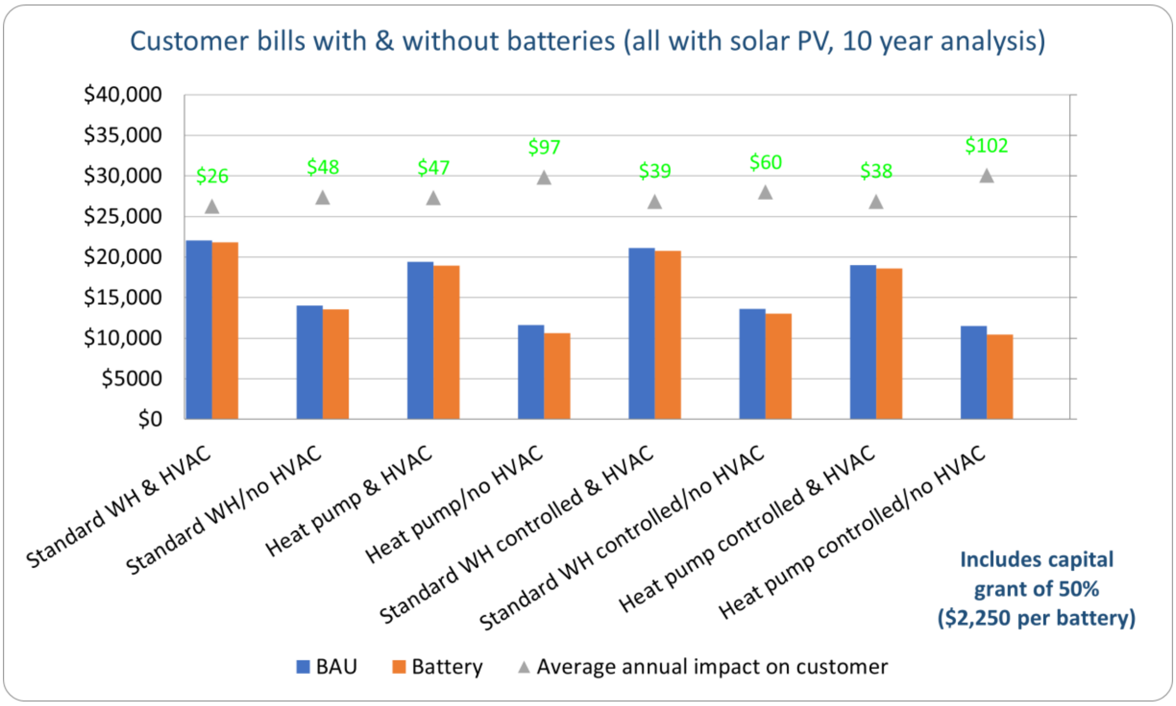
3.2.2. Economic Results for Households

Figure 8 depicts the impact of BTM batteries on customer bills for various customer categories with and without batteries, both with and without a 50% grant. Without a grant, the batteries are not economically viable, and they reach the break-even point at a 50% grant (AUD 2250 per household).



(a)

Figure 8. *Cont.*



(**b**)

Figure 8. Impact of BTM batteries (1-h energy storage) on electricity bills for various PV-equipped households: (**a**) without grant and (**b**) with 50% grant.

The battery proves slightly more cost-effective in cases without HVAC, owing to the increased surplus solar storage for later use. This finding holds for comparisons between cases with day-rate standard and HP hot water systems, with HP hot water cases associated with lower consumption during solar generation.

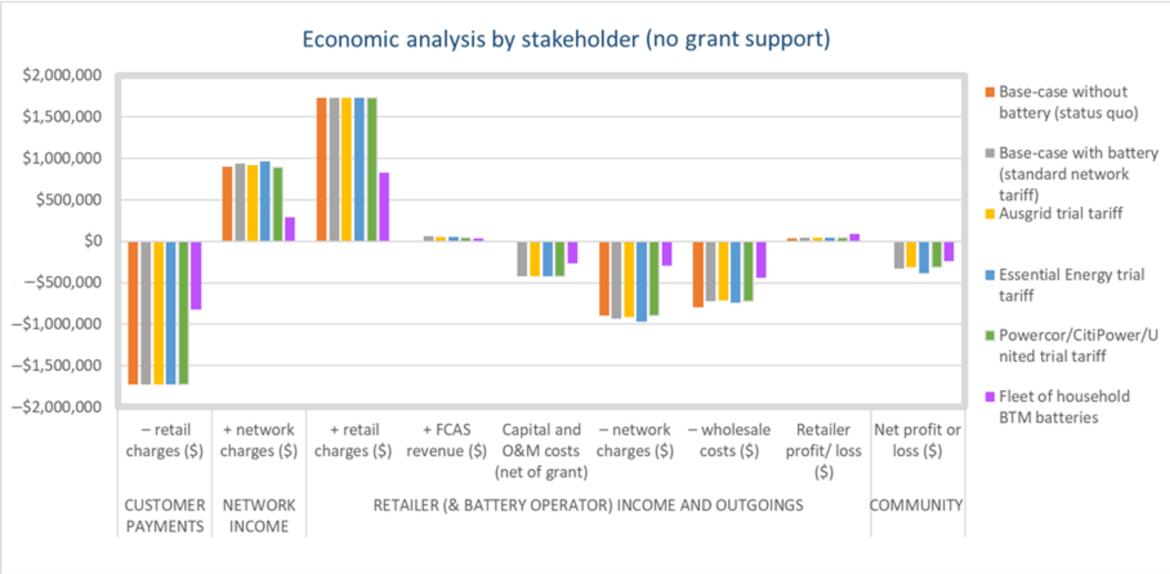
Moreover, connecting the hot water sub-load to the controlled load tariff reduces customer bills for all four relevant customer types compared to corresponding cases without the controlled load tariff applied to the hot water sub-load.

In this setting, the results indicate that solar PV-equipped households with TOU tariffs might not significantly benefit from BTM battery deployment without grant support. The battery's cost-effectiveness is enhanced in cases without HVAC, where surplus solar can be stored for later use. Connecting the hot water sub-load to the controlled load tariff leads to reduced customer bills for all customer types.

A 50% grant is crucial to bringing the battery close to cost neutrality. Alternatively, a more generous trial tariff or a decrease in battery costs could also help bridge the financial gap associated with the BTM battery installation. Overall, these findings offer valuable insights into the feasibility of deploying BTM batteries in residential households, providing potential benefits in self-consumption improvement and grid reliance reduction. The results of this household-level case study serve as a basis for a direct comparison of FTM battery scenarios with a fleet of BTM batteries of equal total energy capacity in the next section.

3.3. Comparison of the FTM and BTM Scenarios

Figure 9 illustrates a comparative analysis of the feasibility of deploying a fleet of BTM batteries in contrast to an FTM battery. The comparison assumes that both systems possess the same storage capacity of 200 kWh and share the same feeder. Specifically, the FTM battery scenario entails a 100 kW/2-h battery installed on a residential feeder, catering to 101 customers, 31 of whom have solar panels installed. Conversely, the BTM fleet of batteries assumes there to be 60 customers equipped with solar panels and 3.3 kWh batteries.



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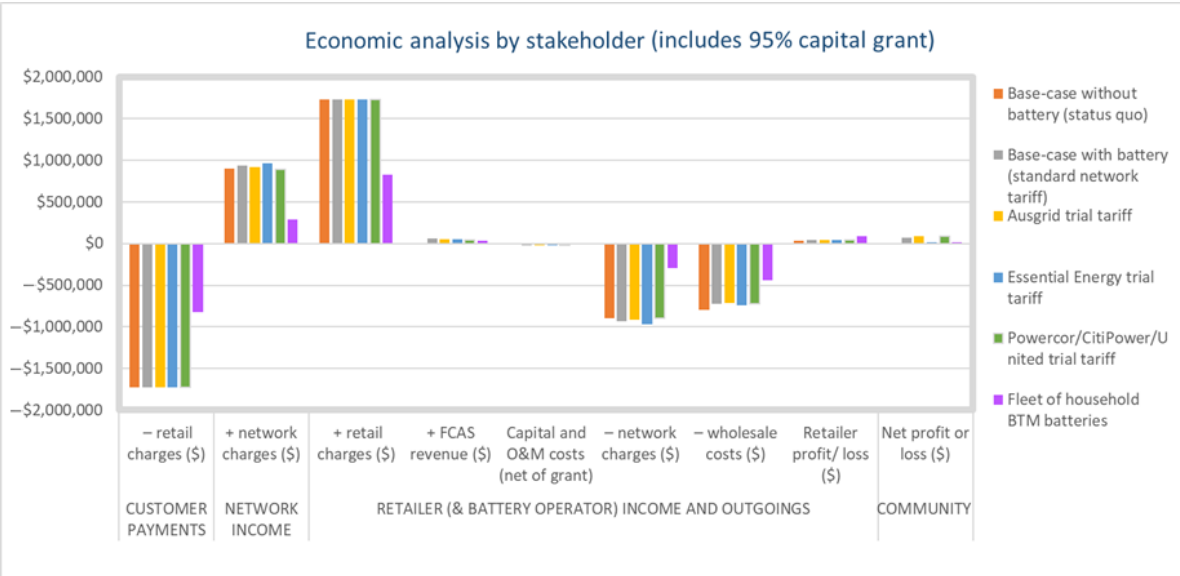

(**b**)

Figure 9. Comparative analysis of FTM battery and fleet of BTM batteries on the same residential feeder: (**a**) without grant support and (**b**) with 95% grant support.

Deploying the BTM fleet would necessitate a substantial increase in homes with solar panels, from the existing 30% to approximately 60%. Such an expansion would not be viable without battery storage, considering the feeder's hosting capacity limitations. It is important to emphasise that the costs considered in the comparison pertain solely to battery storage, excluding the expenses associated with increasing the number of solar installations.

To facilitate the comparative analysis, we conducted an independent stakeholder analysis for the eight customer types, defined based on their hot water and space heating systems. Subsequently, we scaled up the BTM fleet by taking the average of the analysis results and multiplying it by the number of solar customers with batteries (n = 60), achieving a total battery capacity equivalent to the FTM battery (200 kWh).

The results demonstrate that BTM batteries necessitate lesser grant support, requiring approximately 50% to break even, in contrast to the 75–95% required for the FTM case. However, it should be noted that, in the BTM scenario, the grant would benefit private individuals, possibly lacking the same community-wide advantages as the FTM case. The decision to install either a fleet of BTM batteries or an FTM battery should consider multiple factors, encompassing costs, community benefits, and technical considerations.

4. Conclusions and Future Work

Neighbourhood batteries are increasingly being sought, as they are seen to represent a convergence of technical advancement, grid stability, placemaking, and energy resilience within a decarbonising energy landscape. A key advantage lies in aggregating energy resources for efficient consumption and surplus variable renewable energy utilisation, mitigating curtailment and enhancing local energy utilisation.

This study delved into the economic viability of deploying various battery storage systems in a rural town in Australia (Heyfield, Victoria). The focus was on an FTM battery on a residential feeder and a fleet of BTM batteries in residential households. Each case was analysed under different scenarios to comprehensively assess their economic feasibility and potential benefits for stakeholders.

The analysis of the FTM battery scenario over a 10-year period revealed that deploying the battery is not financially viable without grant support, as all investigated network tariffs resulted in significant losses. However, with a 95% grant of capital costs, the project showed positive net profits for all scenarios, ranging from AUD 1200 to AUD 8700 per year, depending on the associated network tariff. The break-even point was estimated to be between a 75% and 95% grant. The battery operation surcharge had a substantial impact on overall profitability, ranging from 12% to 85% of the net profit. Overall, the deployment of an FTM battery in this context is economically feasible only with a high level of grant support.

The examination of BTM batteries in residential households with solar PV systems over a 10-year period demonstrated that a 50% grant is necessary for such batteries to be economically viable, with a break-even point of approximately AUD 2250 per household. Without any grants, the batteries are not economically viable.

Based on the analyses and findings, none of the battery storage cases are economically compelling without subsidies. The most economic case was found to be the BTM fleet on the residential feeder, followed by the FTM neighbourhood battery on the residential feeder. Each case would likely require grants ranging from 50% upwards to be economically viable and provide a return to the community and/or customers.

As neighbourhood-scale batteries continue to be pursued, funded, and installed around Australia, the importance of an economic return without a substantial grant is clearly not a hinderance. However, a clear idea of the objectives of a community, which can then determine the optimal battery sizing and operating mode, is suggested before undertaking the business case assessment.

The implications of this study extend to a wide range of stakeholders. Policy makers can use the findings to design effective grants, policies, and programmes aimed at supporting community battery integration. Communities stand to gain valuable insights into the financial viability of community batteries compared to existing household installations in their neighbourhoods. Furthermore, retailers can leverage the study's insights to strategize their involvement in community battery projects and explore opportunities to maximise profits, while also benefiting local communities.

Network businesses also stand to gain valuable knowledge regarding the potential impact of community batteries on network stability, load management, and grid operations, which can inform their decisions in supporting and regulating these installations. Practitioners, consultants, and researchers will find this analysis valuable when conducting similar assessments for various battery configurations. Additionally, local government authorities can benefit from a better understanding of the advantages and disadvantages associated with requests for community battery installations within their jurisdictions. These implications underscore the practical relevance and broad applicability of the study's findings in informing decision-making processes for diverse stakeholders.

It is also crucial to acknowledge the inherent risks associated with the economic modelling used in this study. Some of the key risks and caveats include the availability of trial tariffs, potential stranded assets when replacing storage cells, variability of retailer's throughput charge, speculative costs of software and control technologies, and limitations of the modelling software and assumptions. Community awareness programmes and education initiatives should also be developed to promote the understanding and adoption of energy storage systems effectively.

Furthermore, this study has several limitations that should be acknowledged. Firstly, the economic modelling heavily relies on various assumptions and data, including load profiles, solar generation, and tariff structures. The real-world conditions may deviate from these assumptions, leading to variations between predicted outcomes and actual results. Secondly, the analysis assumes perfect foresight, which may not be practically achievable, potentially affecting the actual savings of the battery systems. Moreover, the study is based on a representative year with high wholesale prices due to gas prices, and market volatility could impact revenue streams in different years. Additionally, the availability of trial tariffs to support FTM batteries may vary, influencing the project's economics. Lastly, the study does not account for all possible factors that could affect battery system economics, necessitating cautious interpretation of the results.

Given the limitations identified in this study, there are several areas that warrant further investigation. Firstly, future research should focus on refining economic modelling by incorporating more realistic scenarios, considering uncertainties associated with wholesale market dynamics, and actual load and solar generation data. Improved modelling techniques that account for the imperfect foresight and dynamic control of battery charging/discharging could also be explored to provide more accurate projections.

Furthermore, conducting sensitivity analyses to assess the impact of changing parameter settings and market conditions can enhance the robustness of the findings. It is also crucial to monitor and evaluate the expiration of premium feed-in tariffs on solar customers and investigate the potential implications on usage patterns. Moreover, conducting detailed business cases for different battery deployment options, as well as evaluating wider project objectives, will enable better-informed decision making regarding the optimum battery size and operating mode.

In conclusion, this study assessed the economic viability of deploying FTM and BTM batteries on a residential feeder in Heyfield, Victoria. The analysis highlighted that both FTM and BTM batteries require grant support for economic feasibility. The most economic case was identified to be the BTM fleet, requiring grants of at least 50%. However, the ultimate choice between FTM and BTM batteries should be driven by community objectives, taking into account costs, community benefits, and technical and regulatory considerations. These findings extend beyond local dimensions, bearing relevance and importance for comparable communities worldwide, thereby amplifying the study's global implications.

Author Contributions: Conceptualisation, S.M., J.R., H.S. and S.D.; methodology, S.M., J.R. and H.S.; software, S.M.; formal analysis, S.M., J.R. and H.S.; investigation, S.M., J.R., H.S., S.D. and F.T.; resources, S.M., J.R., H.S. and S.D.; literature review, S.M. and F.T.; writing—original draft preparation, S.M. and J.R.; writing—review and editing, J.R., H.S. and S.D.; visualization, S.M.; supervision, J.R.; project administration, J.R.; funding acquisition, S.D. All authors have read and agreed to the published version of the manuscript.

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Data Availability Statement: The data presented in this study are available upon request from the corresponding author.

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Conflicts of Interest: The authors declare no conflict of interest.

Nomenclature

Acronym	
BTM battery	Behind-the-meter battery
DNSPs	Distribution network service providers
EV	Electric vehicle
FCAS	Frequency control ancillary services
FIT	Feed-in tariff
FTM battery	Front-of-the-meter battery
HP	Heat pump
HVAC	Heating, ventilating, and air conditioning
kW	Kilowatt
kWh	Kilowatt hour
LUOS	Local Use of Service
LV	Low voltage
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
NMI	National Metering Identifier
O&M	Operation and maintenance
ROI	Return on interest
SoC	State of charge
Solar-PV	Solar photovoltaic
TOU	Time of use

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