Operating a community-scale battery: electricity tariffs to maximise customer and network benefits

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Executive Summary

Community-scale energy storage systems (100kW-1MW) may offer benefits over residential and grid-scale energy storage systems. Depending on the operation of the storage, benefits include reduced energy costs, improved solar power self-consumption, reduced import and export peak load, and increased network hosting capacity for non-dispatchable energy generation such as rooftop solar power generation. Community interest in shared storage may in part reflect a broader enthusiasm from customers for a sharing economy.

In Australia, there is widespread interest in community-scale storage with several trial projects underway [17], [13]. However, there are many open questions regarding how best to operate a shared storage asset. Here we have investigated the operation of a community-scale energy storage system with residential solar power generation under both business-as-usual energy tariffs as well as our proposed local energy tariffs, and evaluated the outcome in terms of the customer and network benefits listed above. We focused on scenarios where a community-scale battery is installed in a neighbourhood in close proximity to customers. Our results show that:

- Different electricity tariffs impact the operation of the community-scale storage, and thereby impact the potential benefits for customers, battery operators and networks.
- Reducing tariffs for the local exchange of energy to and from the storage can improve the local consumption of solar energy, thereby reducing import and export peak loads.
- community-scale storage increases *hosting capacity* compared to residential storage (of equivalent total capacity) i.e. customers will be able to install more and larger solar photovoltaic (PV) systems.

Contents

Glossary

BAU business-as-usual. 4, 21

BESSs Battery Energy Storage Systems. 6

BTM behind-the-meter. 6

IFOTM in-front-of-the-meter. 6

LEM local energy model. 2, 10

NEM National Electricity Market. 10

P2P peer-to-peer. 10

PV photovoltaic. 1

TOU time-of-use. 12

VPP virtual power plant. 6

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1 Introduction

Energy storage is an important component of the global transition to renewable energy. The benefits of energy storage increase as the quantity of non-dispatchable distributed energy generation (e.g. rooftop solar systems) increases, as has occurred in Australia [2]. Indeed, Australia is a world leader in the installation of new residential battery storage [12]. However, community-scale storage (100kW-1MW) may offer benefits over residential battery systems. For customers, potential benefits include reduced energy costs and improved solar self-consumption. For networks, potential benefits include reduced import and export peak loads and increased network hosting capacity for distributed non-dispatchable energy generation, e.g., rooftop solar power generation. For this reason there is growing interest in this scale of energy storage from both networks and community groups alike.

For community groups, the interest in shared storage may be linked to a broader enthusiasm for a sharing economy, also seen in car-sharing, Airbnb and peer-to-peer energy trading. Depending on the operation of the storage, there may be an opportunity to improve energy equity with shared storage, by providing an opportunity for a broader range of customers to access renewable energy e.g. those renting or without the capital to invest in residential solar and battery storage.

In Australia, there is widespread interest in community-scale storage with several trial projects underway [17], [13]. However, there are many open questions regarding how to operate a grid-connected shared storage asset in such a way to create value for all stakeholders of the electricity system: customers, network service providers, and storage operators.

1.1 Operation of community-scale battery energy storage system (BESS)

In the distribution network, battery energy storage systems (BESSs) may be installed either directly to the distribution network (referred to as *in-front-of-the-meter*, IFOTM) or behind a customer's metering point (*behind-the-meter*, BTM). To date, BESSs have tended to be installed BTM where they can be charged by solar power produced BTM without owners being charged any network fees. BTM BESSs may also provide services to network service providers and/or system operators if their owners enter into contracts with these parties, such as by participating in a Virtual Power Plant (VPP). However, there is a growing interest in IFOTM community-scale battery storage that has larger energy storage capacities than typical BTM BESSs and can serve multiple customers, as well as networks and systems operators.

In general, a community-scale BESS can be operated to:

1. perform energy arbitrage with the grid by charging the storage from grid energy at low prices and selling energy to the grid when electricity prices are high
2. provide frequency control ancillary services (FCAS) services for revenue, and
3. utilise locally generated non-dispatchable energy generation to supply electricity demand of customers by charging the storage from non-dispatchable energy generation, e.g., rooftop solar, and discharging the storage to supply customer demand

Note that current network tariffs disincentivise option three, charging/discharging from locally generated solar energy and selling energy to customers locally. This is because, when the battery is operated in front-of-the-meter, network tariffs are charged on both energy transport into and out of battery[1]. This creates a financial disincentive to charge and discharge locally, and will result in the battery favoring arbitrage or FCAS mode, if the objective is to maximize battery revenue.

1.2 Local energy tariffs to incentivise local charging and local consumption of energy

The goal of this report is to investigate the reduction of local energy tariffs to incentivise charging from locally generated solar energy and selling energy to customers locally. We are motivated to do so because:

- Social research carried out in our group suggests that energy consumers want to generate and consume energy locally and are interested in shared 'community' energy assets [1].
- Local energy generation/consumption can bring large network benefits in terms of reductions in peak import and export loads. Peak export loads are increasingly becoming an issue for networks as PV penetration increases.

[1] Note that network charge only applies for energy imports such that the battery pays for the transport of energy for charging and the end user pays for the transport of discharged energy from the battery

In this report, therefore, we investigated the operation of a community energy storage under both business-as-usual energy tariffs as well as our proposed local electricity tariffs, and evaluated the outcome in terms of the customer and network benefits listed above. We focus on scenarios where a community-scale BESS - with power capacity in the range of 100 kW to 1 MW and physical size in the range of a distribution network kiosk to a shipping container - is installed in a neighbourhood in close proximity to customers. Customer benefits investigated were energy costs and local consumption of solar PV energy. Network benefits were net energy and peak power between the local network and remote network, as well as income for the network. For all scenarios we gave the optimiser perfect foresight of generation and demand. Future work will integrate energy forecasts for more accurate estimates of BESS performance.

2 Literature Review

In recent years, the concept of sharing and allocating the storage capacities of grid-connected energy storage systems to provisioning network services and economic benefits to customers, for instance, demand response, has gained attention in both industry and research communities. The related studies can be divided into two categories. The first category explores the use of behind-the-meter energy storage systems as shared energy storage assets. For instance, sharing the capacities of consumer-owned BTM energy storage systems for demand response has been investigated in [16]. In their work, the optimal shares of energy storage capacities for the network operators and customers are determined by studying a joint ownership method between network operators and customers. Similar to [16], joint-ownership of consumer-owned energy storage systems, e.g. between shared facility controllers in an apartment building and customers, has been explored in [15].

The second category deals with the application of grid-connected community energy storage systems in network operations. A range of pilot projects have been initiated worldwide exploring the capability of community battery systems to provide electricity network services with distributed renewable power generation. For example, in a project trial in Western Australia, a community-scale storage system (420 kWh, 105 kW) has been connected to the grid so that local PV customers can economically benefit by storing PV energy in the storage at peak generation times and drawing energy from the storage at peak demand times [17]. A similar project has been carried out at Alkimos beach in Western Australia with a large-scale battery system (1.1 MWh) [13]. In South Florida, US, community-scale batteries have been placed and operated to supply energy to residential communities during small service interruptions and improve service reliability [10]. Additionally, a community battery storage system (2.1 MWh/500 kW) has been operated within a housing development at Trent Basin, UK to enable demand response with local PV energy [7].

In addition to industry efforts, there has been extensive research to study the potential of community-scale energy storage systems in power system operation. For instance, the operation of community energy storage systems with residential solar PV power generation for electricity demand-side management of residential communities has been investigated in [4–6]. The optimum size of community battery systems to perform both PV energy time shift and demand load shifting has been explored in [9]. The value of energy arbitrage in terms of reducing energy costs, CO2 emission reductions, and peak shaving using community energy storage systems has been studied in [14].

In the majority of techno-economic assessments of community energy storage systems in literature, the use of electricity pricing signals has been realised as an effective way of enabling energy interactions between customer-owned distributed energy generation and community energy storage systems. Both PV energy time-shifting and demand load shifting using community energy storages have been explored by considering an energy import/export tariff structure [9]. The energy arbitrage model in [14] utilises a feed-in-tariff to value PV energy stored into the storage and a time-of-use pricing signal has been used to charge the customers for their external grid electricity consumption. In contrast to the literature, in this report, we present generalised frameworks to include tariffs that can characterise the costs associated with energy generation and network transport when operating community energy storage systems with consumer-owned solar power generation. In doing so, we analyse how different tariffs impact on the operation of community energy storage systems and evaluate potential benefits for customers, storage operators as well as for network operators.

3 Methodology

3.1 Community-scale BESS optimisation algorithm

The charging/discharging pattern of the community-scale BESS was dictated by an optimisation algorithm, written in-house and designed to calculate the optimal operation of the BESS to minimise some objective function. Here, the objective function was the minimisation of overall cost. Figure 1 shows the energy energy flows considered for the community-scale BESS optimisation algorithms, which were used to calculate the energy costs. These include energy flowing from the grid into the battery (E_{gb}), from the grid to meet the load (E_{gl}), from the battery into the grid (E_{bg}), from the battery to meet the load (E_{bl}), from solar generation into the battery (E_{sb}),from solar generation to the grid (E_{sg}) and from solar generation to the load (E_{sl}). E_{sl} is surplus generation from customers with solar that is used by other customers i.e. peer-to-peer

(P2P) energy trading. Further investigation of P2P trading through E_{sl} is an important area of future work for this project.

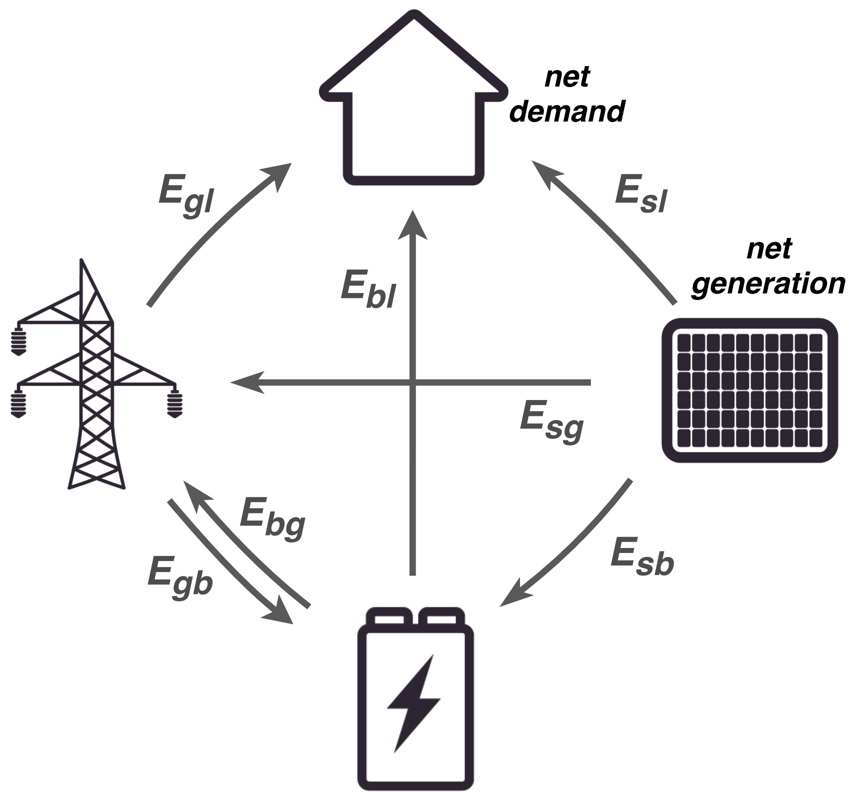


Figure 1: Energy flows considered for the community-scale BESS optimisation algorithm included energy flow from grid to battery (E_{gb}), from grid to load (E_{gl}), from battery to grid (E_{bg}), from battery to load (E_{bl}), from solar to load (E_{sl}), from solar to battery (E_{sb}), and from solar to grid (E_{sg})

3.2 Local Energy Models (LEMs)

As outlined in section 1, the goal of this work is to investigate whether the introduction of 'local' electricity tariffs can incentivise charging from locally generated PV and selling energy to customers locally. The local tariffs apply within a distinct sub-region of the electricity system, both in regards to the electrical network and the electricity market, that for simplicity has a single point of common coupling (PCC) between customers on the low voltage network, e.g. downstream from a feeder, to the wider national electricity market (NEM). We use the terms remote grid, and remote market to refer to the region outside of where this 'Local Energy Model' (LEM) applies,

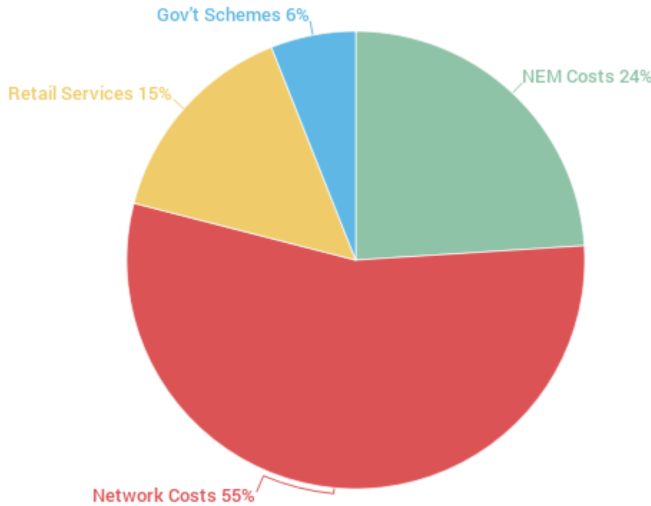


Figure 2: Proportions of energy cost in a typical Australian customer electricity bill [8].

and local grid and local market for the region within the LEM. For our calculations, 'remote' tariffs were applied to energy flows between the grid and battery (E_{gb}, E_{bg}), and energy flows from the grid to meet the local load (E_{gl}). 'Local' tariffs were applied to energy flows from the battery to meet the load (E_{bl}) and from excess solar generation to meet the load (E_{sl}).

3.3 Tariffs considered: BAU vs LEMs

Throughout the analysis we consider simulated 'wholesale market prices', by which we mean the customers and the storage operator receive the same price when buying (importing) and selling (exporting) energy from/to the remote grid.

In electricity markets, tariffs are charged to customers to cover various energy cost components incurred by electricity distribution companies. For instance, in Australian electricity markets, these cost components include, electricity wholesale market (NEM) costs or electricity generation costs, network transport and operating costs, retail service costs, and environmental policy costs mandated by governments [3]. For example, the proportions of electricity cost incurred by a typical customer through their electricity bill in NSW, Australia can be illustrated as shown in Fig.2. In particular, wholesale electricity costs or electricity generation costs (NEM costs) include electricity purchasing costs from the NEM, financial hedging contracts, ancillary services to maintaining power system reliability and security, e.g., frequency regulation, and the costs incurred by the retailers due to energy losses from transmission and distribution networks [3]. Network costs reflect the costs for transporting electricity to customer sites and for operating and building transmission and distribution networks. Retail service costs include the costs associated with billing and marketing as well as profit margins for electricity retailers. Environmental policy costs include Renewable Energy Target (RET) and other state and territory feed-in tariffs and energy efficiency services [3].

As depicted in Fig. 2, the energy cost incurred by an electricity customer is mainly driven by the costs associated with the electricity generation and network transport costs. Hence, in this report, we are interested in capturing energy generation and network transport costs when operating community-scale energy storage systems with consumer-owned solar power generation.

This report focused on four different tariff structures;

1. Tariffs that do not differentiate between energy cost and network transport cost in the local vs remote grid (Business-As-Usual (BAU) tariffs).
2. Local Energy Model where the network transport tariffs are reduced in the local grid (LEM1).
3. Local Energy Model where both the network transport tariffs *and* the energy tariffs are both lower in the local grid and the remote grid (LEM2).
4. Local Energy Model where both the cost of energy and the network transport costs are determined optimally based on game theory (LEM3)

The time-of-use (TOU) time-periods for the tariffs were off-peak (10pm-6am), peak (6-8am, 4-8pm) and shoulder (8-4pm). For BAU, the peak/shoulder/off-peak energy prices were 25/10/5c respectively. The transport prices were flat-rate set at 15c/kWh and only charged for energy imports. For LEM1, the transport prices was reduced to 3c/kWh. For LEM2, the transport prices was also reduced to 3c/kWh and the peak/shoulder/off-peak energy prices were reduced to 20/5/5c per kWh. LEM3 energy prices were also TOU but dynamically varying over the day based on game theory and as shown in Fig. 3.

3.4 Electricity cost calculations for BAU and LEM1/LEM2 models

As outlined in section 3.2, we have introduced 'local' electricity tariffs to incentivise charging from locally generated PV and selling energy to customers locally. To differentiate these prices, we have used the terms local and remote grid. We define λ_r^e, λ_r^t as the energy and transport tariffs that apply to energy imported/exported from the remote grid, respectively. The tariffs that apply for energy generated and transported within the local area are λ_l^e, λ_l^t. We further denote with a $+/-$ whether the energy is imported/exported. For example, λ_{r+}^e, and λ_{r-}^e, applies to the energy imported and exported from/to the remote grid, respectively. All tariffs are assumed to be positive values.

The costs were calculated for each of the following tariffs:

1. Business-As-Usual (BAU) tariffs, where the prices are not differentiated between the local and the remote grid: $\lambda^e_{r+} = \lambda^e_{r-} = \lambda^e_{l+} = \lambda^e_{l-} = \lambda^e$ (> 0) and $\lambda^t_{r+} = \lambda^t_{l+} = \lambda^t_+$ (> 0) and $\lambda^t_{r-} = \lambda^t_{l-} = 0$.
2. LEM1, where the transport prices are differentiated between the local and remote grid: $\lambda^e_{r+} = \lambda^e_{r-} = \lambda^e_{l+} = \lambda^e_{l-} = \lambda^e$ (> 0), $\lambda^t_{r+} \neq \lambda^t_{l+}$ where $\lambda^t_{r+},\ \lambda^t_{l+} > 0$, and $\lambda^t_{r-} = \lambda^t_{l-} = 0$. We consider transport tariffs for import energy to be lower in the local grid compared to those of the remote grid, i.e., $\lambda^t_{l+} < \lambda^t_{r+}$.
3. LEM2, where both the energy and transport prices are differentiated between the local and remote grid: $\lambda^e_{r+} = \lambda^e_{r-} = \lambda^e_r$ (> 0), $\lambda^e_{l+} = \lambda^e_{l-} = \lambda^e_l$ (> 0), $\lambda^t_{r+} \neq \lambda^t_{l+}$ where $\lambda^t_{r+},\ \lambda^t_{l+} > 0$, and $\lambda^t_{r-} = \lambda^t_{l-} = 0$. We consider both energy and transport tariffs to be reduced in the local grid compared to those of the remote grid, i.e., $\lambda^e_l < \lambda^e_r$ and $\lambda^t_{l+} < \lambda^t_{r+}$.
4. For LEM3, local energy and transport tariffs are determined optimally with game theory (see section 3.5)

For the following cost calculations, recall that the energy flows are denoted as: E_{gb} = from grid to battery, E_{gl} = from grid to load, E_{bg} = from battery to grid, E_{bl} = from battery to load, E_{sl} = from solar generation to load, E_{sb} = from solar generation to battery, and E_{sg} = from solar generation to battery. Note that, in the BAU-based LEM, LEM1, and LEM2, in addition to the existence of customers with solar, we allow having customers without solar who may discharge the community storage to supply their demand in addition to drawing energy from the remote grid. Therefore, for simplicity of cost calculations, we take $E_{gl,ws},\ E_{gl,wos}$, where $(E_{gl} = E_{gl,ws} + E_{gl,wos})$, as the energy flow from remote grid to customers with and without solar, respectively. Similarly, we take $E_{bl,ws},\ E_{bl,wos}$, where $(E_{bl} = E_{bl,ws} + E_{bl,wos})$ as the energy flow from the storage to the customers with and without solar, respectively.

Then, for the BAU-based LEM, LEM1, and LEM2, the total energy costs for the customers and the revenue for the network operator can be calculated by using the following equations.

The total energy cost for the customers without solar;

$$C_{wos} = \sum_{24hr} \Big((\lambda^e_{r+} + \lambda^t_{r+}) E_{gl,wos} + (\lambda^e_{l+} + \lambda^t_{l+}) E_{bl,wos} \Big) \tag{1}$$

The total energy cost for the customers with solar;

$$C_{ws} = \sum_{24hr} \Big((\lambda^e_{r+} + \lambda^t_{r+}) E_{gl,ws} + (\lambda^e_{l+} + \lambda^t_{l+}) E_{bl,ws} - (\lambda^e_{r-} - \lambda^t_{r-}) E_{sg} - (\lambda^e_{l-} - \lambda^t_{l-}) E_{sb} \Big) \quad (2)$$

The total energy cost for the storage operator;

$$C_{storage} = \sum_{24hr} \Big((\lambda^e_{l+} + \lambda^t_{l+}) E_{sb} - (\lambda^e_{l-} - \lambda^t_{l-}) E_{bl,ws} + (\lambda^e_{r+} + \lambda^t_{r+}) E_{gb} - (\lambda^e_{r-} - \lambda^t_{r-}) E_{bg} - (\lambda^e_{l-} - \lambda^t_{l-}) E_{bl,wos} \Big) \quad (3)$$

The total energy revenue for the network operator;

$$R_{network} = \sum_{24hr} \Big(\lambda^t_{r+} (E_{gl} + E_{gb}) + \lambda^t_{l+} (E_{bl} + E_{sb} + E_{sl}) + \lambda^t_{r-} (E_{sg} + E_{bg}) + \lambda^t_{l-} (E_{bl} + E_{sb} + E_{sl}) \Big) \quad (4)$$

3.5 Electricity cost calculations for LEM3 (game theory) model

For the third LEM, we used the game-theoretic approach proposed in [6] to calculate optimal local and remote grid electricity tariffs. For this work, electricity tariff of the remote grid , λ_r is calculated according to a dynamic pricing signal proposed in [6] which has a constant component δ_t and a variable component that depends on the total electricity load on the remote grid at each time instant, $\phi_t E_r(t)$, where $E_r(t)$ is the total electricity load on the remote grid at time instant t. According to different energy flows to/from the remote grid as shown in Fig. 1, $E_r(t) = E_{gl}(t) - E_{sg}(t) + E_{gb}(t) - E_{bg}(t)$ where $E_{gl}(t),\ E_{sg}(t),\ E_{gb}(t)$, and $E_{bg}(t)$ denote the total energy flow from the grid to the load, total energy flow from solar generation to the grid, total energy flow from the grid into the storage, and the total energy flow from the storage to the grid at time instant t, respectively. Then the remote grid electricity price at time instant t is given by $\lambda_r(t) = \phi_t E_r(t) + \delta_t$.

In addition to $\lambda_r(t)$, there is a local grid tariff $\lambda_l(t)$ for the local energy transactions between the storage and the customers with solar power generation. Prices $\lambda_r(t)$ and $\lambda_l(t)$ are determined by using the game-theoretic algorithm proposed in [6]. Details of the algorithm can be found in [6]. Note that, in this LEM, all energy flows shown in Fig. 1 exist except for the energy flow between solar generation and the load, i.e. E_{sl}. Further, both network transport and energy generation costs of the local and remote grids are assumed to be bundled into the corresponding tariffs $\lambda_r(t)$ and $\lambda_l(t)$, and therefore, network transport and energy generation tariffs are not considered separately as for the BAU, LEM1 or LEM2 models in Section 3.4. Hence, in this model, we consider energy cost calculations only for the customers and the storage operator except for the network operator. For simplicity of notation, we remove t from the following equations.

Then, the total energy cost for the customers without solar is given by

$$C_{wos} = \sum_{24hr} \lambda_r E_{gl,wos} \tag{5}$$

The total energy cost for the customers with solar is given by

$$C_{ws} = \sum_{24hr} \Big(- \lambda_r E_{sg} - \lambda_l E_{sb} + \lambda_r E_{gl,ws} + \lambda_l E_{bl,ws} \Big) \tag{6}$$

Additionally, the total energy cost for the storage operator is given by

$$C_{batt} = \sum_{24hr} \Big(\lambda_r (E_{gb} - E_{bg}) + \lambda_l E_{sb} - \lambda_l E_{bl,ws} \Big) \tag{7}$$

3.6 Data: load, PV and battery storage parameters

For our calculations, we considered electricity demand and PV generation data of 55 real customers randomly chosen from the NextGen dataset [11]. We set 60% customers to have their actual values of solar PV generation. For the remaining 40% of customers, solar PV was set to zero. Total solar capacity for these 60% of customers was 184.96 kW. We selected two random days: January 10th and July 10th, 2018. We varied both residential BTM and community-scale BESS power/capacity storage parameters. We considered all customers to have the same retailer, and to have opted in to access the community-scale BESS asset.

Analysis of break down by customers with and without solar, and individual customers is future work. We do not consider BTM storage with LEM tariffs as this would introduce interactive co-optimisation of all the BTM assets for the available excess solar (at the LEM prices).

3.7 Evaluation metrics

As outlined in section 1, a community-scale BESS can have numerous potential benefits for both customers and networks, depending on how the asset is operated. Here we evaluated the potential benefits in terms of (i) impact on energy flows within and into/out of the network (ii) impact on peak power import/exports in and out of the network and the related measure of *hosting capacity* and (iii) impact on costs to customers, the battery operator and the network operator.

3.7.1 Impact on energy flows

We investigated the impact of community-scale BESS, under the different tariff models outlined above, on energy flows depicted in Fig. 1 i.e., from the grid into the battery (E_{gb}), from the grid to the load (E_{gl}), from the battery into the grid (E_{bg}), from the battery to the load (E_{bl}), from solar generation to load (E_{sl}), from solar generation into the battery (E_{sb}), and from solar generation directly into the grid (E_{sg}).

We also investigated the impact on net energy through the point of common coupling (PCC) between local network and remote network. We were particularly interested to investigate whether local electricity tariffs increase energy flows to and from the shared BESS i.e. E_{sb} and E_{bl}, and reduced the energy flows between the local and remote networks.

3.7.2 Does the community-scale BESS result in increased hosting capacity?

To create network capacity, networks build, configure and operate poles and wires and other network assets. This infrastructure creates safe, electrical pathways for the flow of electricity between connection points within the electricity system. The ultimate goal for the networks is to build sufficient network capacity. This ensures that generators and customers are able to utilise the network to access the energy they need throughout the day without breaching the operational thermal or voltage limits within the network. A network has sufficient capacity when the network does not breach the allowable network constraints anywhere within the network during its intended operation. In Australia, the network constraints due to voltage typically occur before thermal limits are approached.

In the context of local energy models, one of the key assessment criteria is therefore the extent to which they can reduce the deviation of the voltage profile from the nominal voltage (230V) and ensure that the limits of voltage (216V - 253V) are not breached. For the current report, we used peak power into/out of the network as a proxy measure of potential voltage breaches. We expected that the shared, larger BESS would result in increased *hosting capacity*, compared to residential BTM storage. That is, a greater amount of solar energy could be generated locally without exceeding network voltage/thermal limits. Specifically, we measured how peak import/export power increased as a function of increasing local solar generation, both the shared BESS as well as residential BTM storage.

3.7.3 Impact on customer costs and battery/network revenue

The shared BESS is expected to be cheaper, both for purchase/installation and because less energy will need to be purchased from the grid due to higher solar self-consumption. However, it will be important to ensure that the savings are equitably shared across customers, the battery operator and the local network operator. Here, these costs were calculated as shown in equations in Sections 3.4 and 3.5.

3.8 Results and Discussion

3.8.1 Impact on energy flows

As shown in Fig. 4, we found that, in the BAU scenario, the community-scale BESS does not charge from locally generated solar energy. Rather, the BESS arbitrages based on the remote energy prices. For the BAU tariffs in this report, this led to the BESS charging in morning off-peak and discharging across the peak tariff periods, as shown in Fig. 5. Further, there is no incentive for the BESS to discharge to meet the local load i.e. the battery discharged equally to the load and the grid (E_{bl} = E_{bg}). As a result, net energy imported, net energy exported, and peak power export, were all higher under the BAU scenario. Peak power imported was also higher under the BAU scenario compared to the LEM1/LEM2 scenarios, for all battery capacities except 100 kWh (see Fig. 7).

Under the LEM1 scenario – where the network transport costs are reduced in the local grid (but the cost of energy is the same) – the community-scale BESS was incentivised to charge from locally generated solar (see Fig. 4), leading to two full cycles of the battery in the day (see Fig. 9).

Under the LEM2 scenario – where both energy and transport costs are lower in the local grid), we observed the same power flows associated with the community-scale BESS as with LEM1 (see Fig. 4), but the BESS revenue was higher 9 for capacities greater than 200kWh. Network revenue and customer costs were similar. Net energy imported was reduced for both LEM1 and LEM2, particularly for larger batteries (>300kWh), although further reductions were minimal > 400kWh. Peak power imported and exported was reduced for LEM1 and LEM2 models. Reduction was greatest for a 400kWh battery.

Under the LEM3 scenario – when the energy capacity of the storage increases, the amount of energy exported to the remote grid from the storage, i.e., E_{bg}, increases, as shown in Fig. 4. Therefore, the net energy exported to the remote grid increases as illustrated in Fig. 7. Additionally, the net energy imported from the remote grid by the LEM decreases with increasing storage capacity (see Fig. 7) due to the increase of exported energy from the battery to the remote grid (E_{bg}) and the reduction of energy drawn by the battery from the remote grid (E_{gb}). Additionally, as depicted in Fig. 4, the amount of solar energy transferred to the battery is greater than the amount of solar energy transferred to the grid, $E_{sb} > E_{sg}$.

3.8.2 Impact on customer costs and battery/network revenue

The sum of the costs is less for the LEM1 model compared to BAU, because on the whole, the local network is importing more energy than it exports, and it now is paying only half the transport tariff on this net import. Network revenue (negative is revenue) is highest for LEM1 and LEM2 for batteries greater than 600kWh. Under the LEM2 scenario, the BESS revenue was higher 9 for capacities greater than 200kWh. Network revenue and customer costs were similar.

Under the LEM3 scenario – as discussed in Section 3.5, we used the game-theoretic algorithm proposed in [6] to find the remote grid price λ_r and the local grid price λ_l. In this algorithm, the revenue for the battery operator is maximised, and the energy costs for the customers are minimised. The local grid price λ_l is set through the battery operator's revenue maximisation problem. Fig. 3 shows the local grid price and the remote grid price variations throughout the day. It is evident from the graph that the local grid price derived from the algorithm closely follows the remote grid price. However, at midday, when solar energy is plentiful, local grid price is slightly lower than the remote grid price. Additionally, when there is little or zero solar energy generation, local grid price is slightly higher than the remote grid price. This is to optimise the battery operator's revenue. Even though the local grid price is slightly lower than the remote grid price at midday, users still prefer to sell more of their solar energy to the storage rather than to the grid (E_{sb} > E_{sg} in Fig. 4) as they can discharge the battery when solar power is insufficient. The game-theoretic algorithm achieves the dual objectives of maximising the battery operator's revenue and minimising the user cost by deriving these price signals.

In LEM3, the revenue received by the customers with solar leads to a greater reduction of the aggregated cost for customers as shown in Fig. 9. Additionally, the battery operator's revenue increases with increasing storage capacity. However, since the battery operator pays a higher price for buying solar energy from the customers at midday, the operator receives less revenue in LEM3 compared to LEM1 and LEM2 (see Fig. 9). As mentioned in Section 3.5, since prices are not differentiated between network transport and energy generation costs in LEM3, the revenue for the network operator is not calculated and therefore, is not illustrated in Fig. 9.

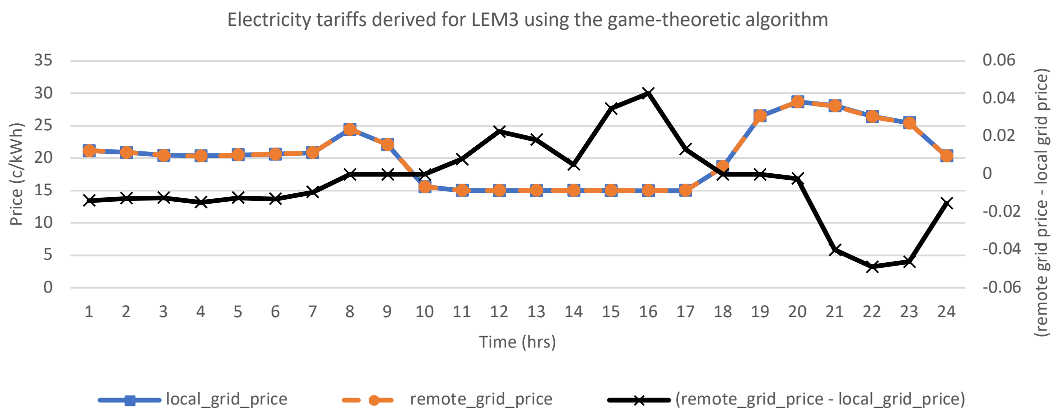


Figure 3: Local vs remote energy prices derived for LEM3 using the game-theoretic algorithm for January 10th, 2018. Note that the two prices are almost exactly the same.

Some further comments to inform future tariff design:

- If the battery is operated under a financial objective then arbitrage value is the key factor determining the BESS charging and discharging cycles, with the greatest arbitrage value being prioritised. This means that the BESS will prioritise buying and selling into the remote network if the arbitrage potential is greater there. The simplest way to mitigate this is to set a significant larger remote transport tariff, relative to the local transport tariff, as we do in LEM1.

- In all of our scenarios, including LEM2, we set import and export energy prices to be equal, ie. $\lambda_+^e = \lambda_-^e$. Were this not the case, the BESS could generate revenue by simply funneling power through the battery, charging and discharging in the same tariff period, which is a perverse outcome. Another consequence of this - in the absence of a strong pricing signal in transport tariffs - is that the BESS will not charge from local solar to later discharge to meet local demand, unless the local energy tariff has some temporal variability (e.g. a TOU tariff profile) with sufficient arbitrage value. Under the assumption that local energy tariffs should be lower than remote tariffs at all times, this requires the local energy tariff to have very cheap periods, in order to create the largest arbitrage value. Again the cost difference between local and remote transport tariffs aids in reducing the arbitrage value required of the energy tariff.

- We illustrate the influence of tariff design, and arbitrage value in particular, in Fig. 6 where in Fig. 6(a),(b) we removed the overnight off-peak rate, setting it equal to the daytime shoulder rate. Comparing this with Fig. 5(b) we see that the BESS is charging a lot less energy overnight because it no longer exports energy into the remote network in

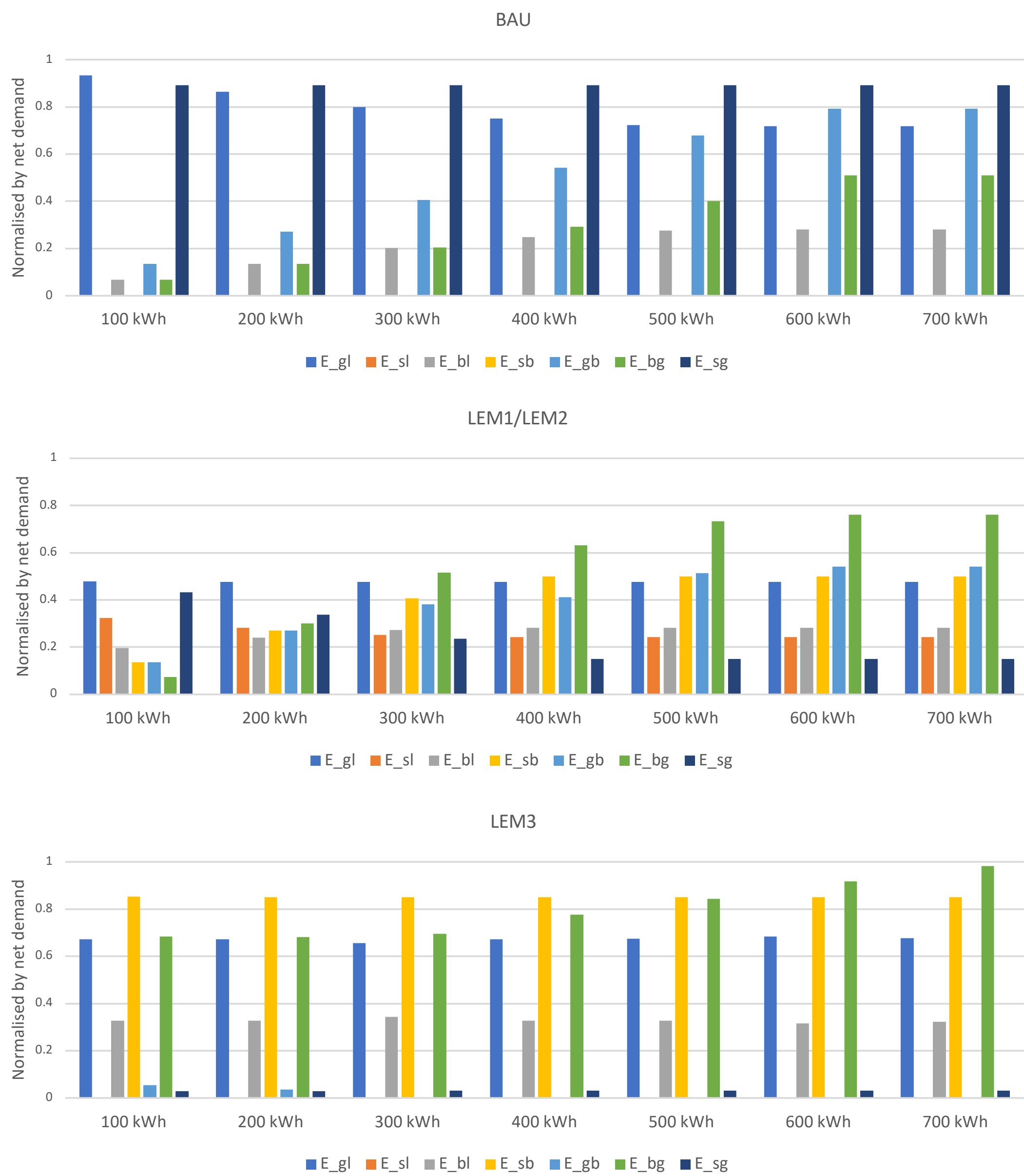
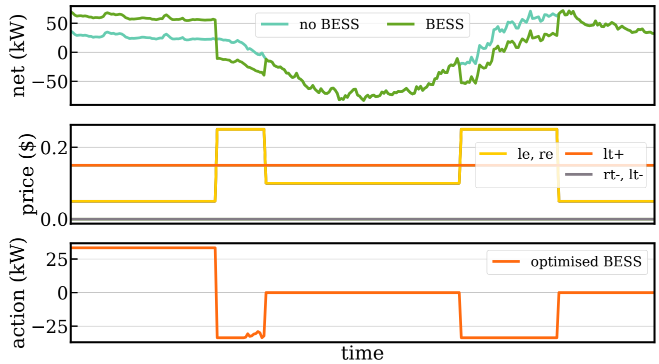
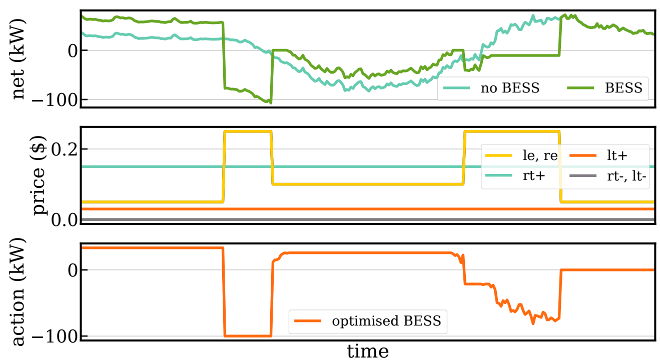


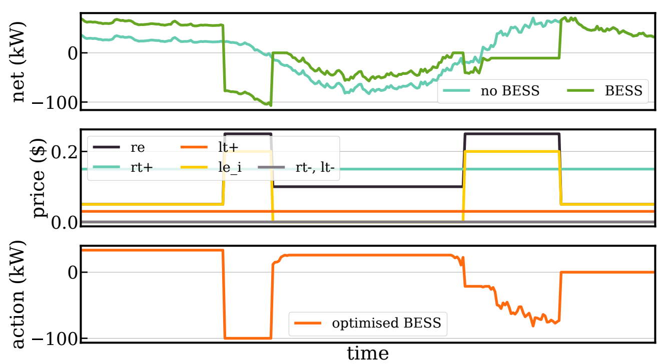
Figure 4: Energy flows for BAU, LEM1/LEM2 and LEM3 tariffs, as a function of BESS capacity (kWh). Energy flows (y-axis) were normalised by net demand. Note that the energy flows for LEM1 and LEM2 were the same. Energy flows were: E_{gl} = from grid to load, E_{sl} = from solar generation to load, E_{bl} = from battery to load, E_{sb} = from solar generation to battery, E_{gb} = from grid to battery, E_{bg} = from battery to grid, and E_{sg} = from solar generation to battery.



(a) BAU



(b) LEM1

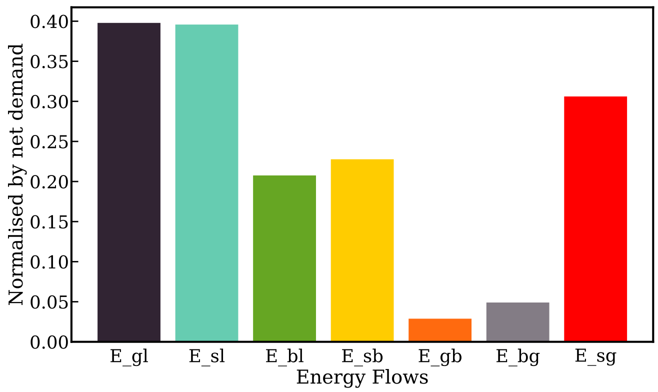


(c) LEM2

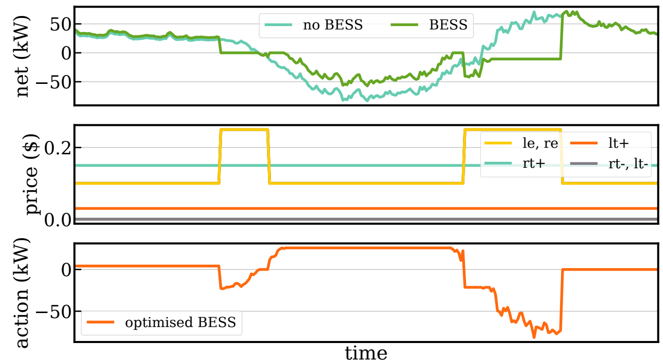
Figure 5: Aggregate load and battery operation profiles for (a) Business-As-Usual (BAU) tariffs (b) LEM1 (reduced local network transport costs and (c) LEM2 (reduced local energy and network transport costs). Prices labeled as remote energy tariff (re), remote transport tariff for import (rt+), remote transport tariff for export (rt-), local energy tariff (le), local transport tariff for import (lt+) and local transport tariff for export (lt-).

the morning peak but instead only discharges at this time to cover the local demand. In Fig. 6(c),(d) we achieve a similar outcome without changing the energy tariff, but instead doubling the price of remote transport. These demonstrate how relatively small price signals can drive great changes in the operation of the BESS, in one case causing a large reverse power flow out of the local network (Fig. 5(b) - large remote market arbitrage) of over 100kW, and in the other suppressing reverse power flows to close to zero (Fig. 6 - removed remote market arbitrage).

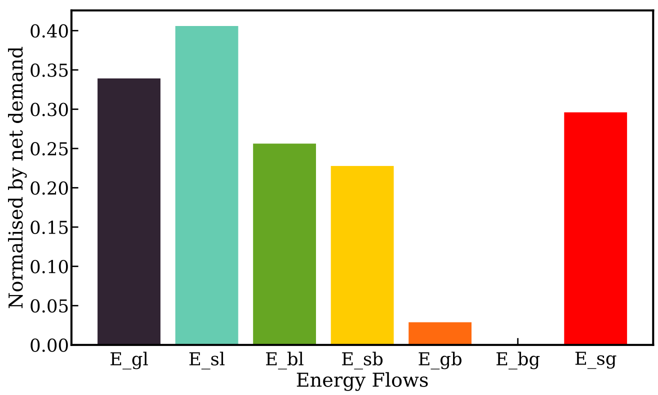
These insights form only the very beginnings of the work required to investigate and design appropriate and optimal Local Energy Model tariffs.



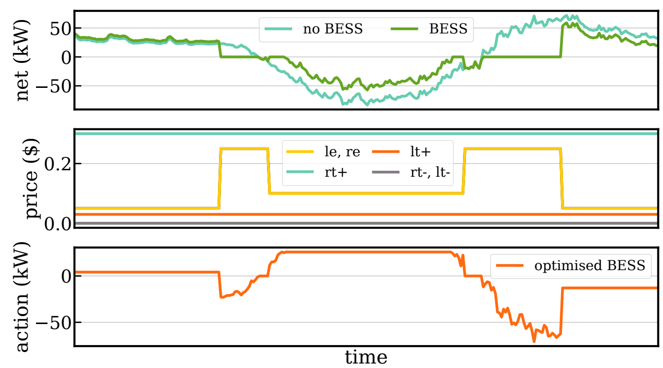
(a) Energy flow without off-peak period



(b) Aggregate load and battery operation profiles without off-peak period



(c) Energy flow with very expensive remote transport price



(d) Aggregate load and battery operation profiles with very expensive remote transport price

Figure 6: (a) Energy flows and (b) aggregate load and battery operation profiles for LEM1 when the overnight off-peak tariff is increased the arbitrage potential is insufficient (when considering transport costs) to justify buying off-peak from remote market and selling into the remote grid at the peak time. (c) Energy flows and (d) aggregate load and battery operation profiles for LEM1 when the remote transport tariff is increased to to 30c/kWh to dissuade the battery from arbitrating from overnight off-peak prices to the morning peak price.

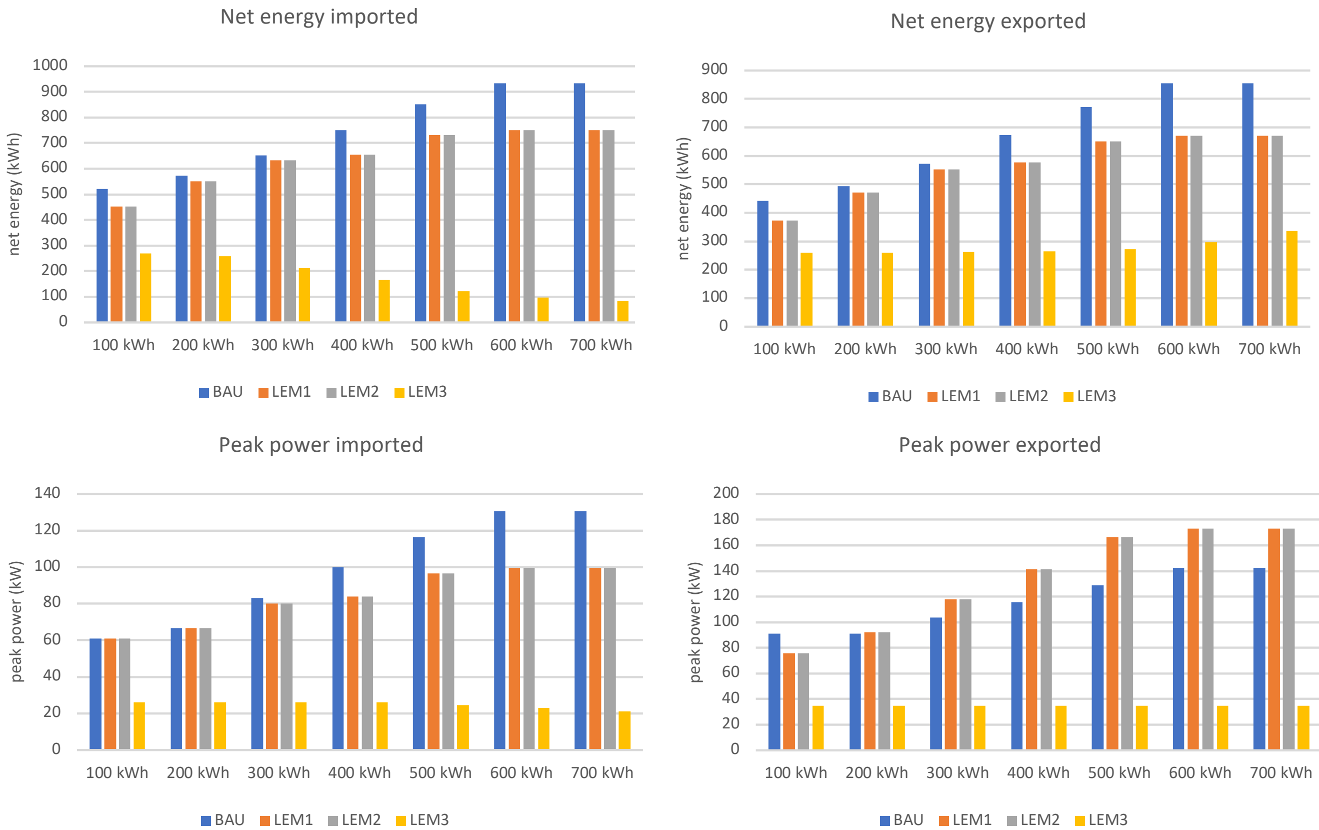


Figure 7: Net energy imported and exported (top) and peak power imported and exported (bottom), for each scenario.

3.8.3 Community-scale BESS increases local hosting capacity

We expected that the shared, larger BESS would result in increased *hosting capacity*, compared to residential BTM storage. That is, a greater amount of solar energy could be generated locally without exceeding network voltage/thermal limits. For the current report, we used peak power into/out of the network as a proxy measure of the impact of locally generated solar on the network. Specifically, we measured how peak import/export power increased as a function of increasing local solar generation, both the shared BESS as well as residential BTM storage. In order to focus on the effect on hosting capacity we operated both the shared BESS and BTM with a simple and pure objective of minimising the peak power flows, without any financial (tariff) considerations.

We compared the impact of a shared BESS and BTM batteries by calculating the peak power import and export into the local network under varying levels of installed solar capacity. The results, shown in Figure 8 confirm that, as expected, export peak power (negative power) increases as solar capacity increases, and that the greatest exports occur for the 'No battery' scenario. While BTM batteries decreased the export peak power by around 50kW, regardless

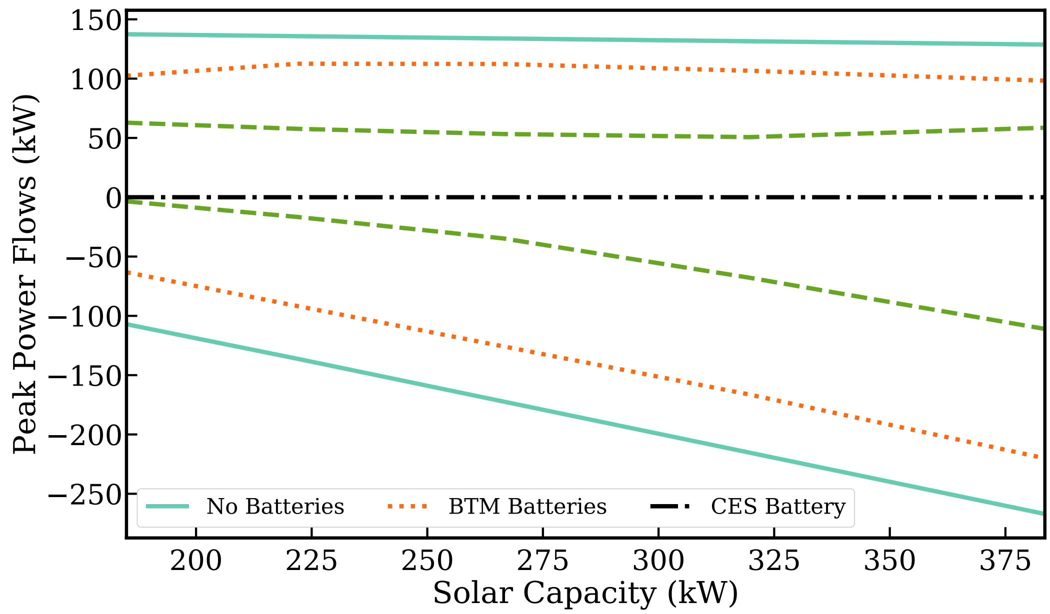


Figure 8: Export peak power (negative) increases as solar capacity increases, with the greatest increases for the 'No battery' scenario. BTM batteries decreased the export peak power by around 50kW, regardless of solar capacity. The community-scale BESS (CES) battery reduces peak export power to almost zero until solar capacity reaches around 275 kW, with a reduced increase in peak export power (compared to BTM batteries), for increased solar capacity thereafter. Note that the curves are not monotonic, which is a result of our objective minimising the magnitude of the difference between peak power import and export, which can be achieved with various emphasis on either import or export.

of installed solar capacity, the community-scale BESS battery resulted in minimal peak export power until solar capacity reached around 275 kW. From 275-375 kW installed solar capacity, peak export power increased with the community-scale BESS, but at a slower rate compared to BTM batteries.

These results consolidate the intuitive reasoning that the larger, shared BESS has an advantage over the BTM batteries in regards to managing peak events (such as solar exports) because it can dedicate the whole larger BESS capacity to the worst export peaks, unlike BTM batteries that are not aware of the export from other properties.

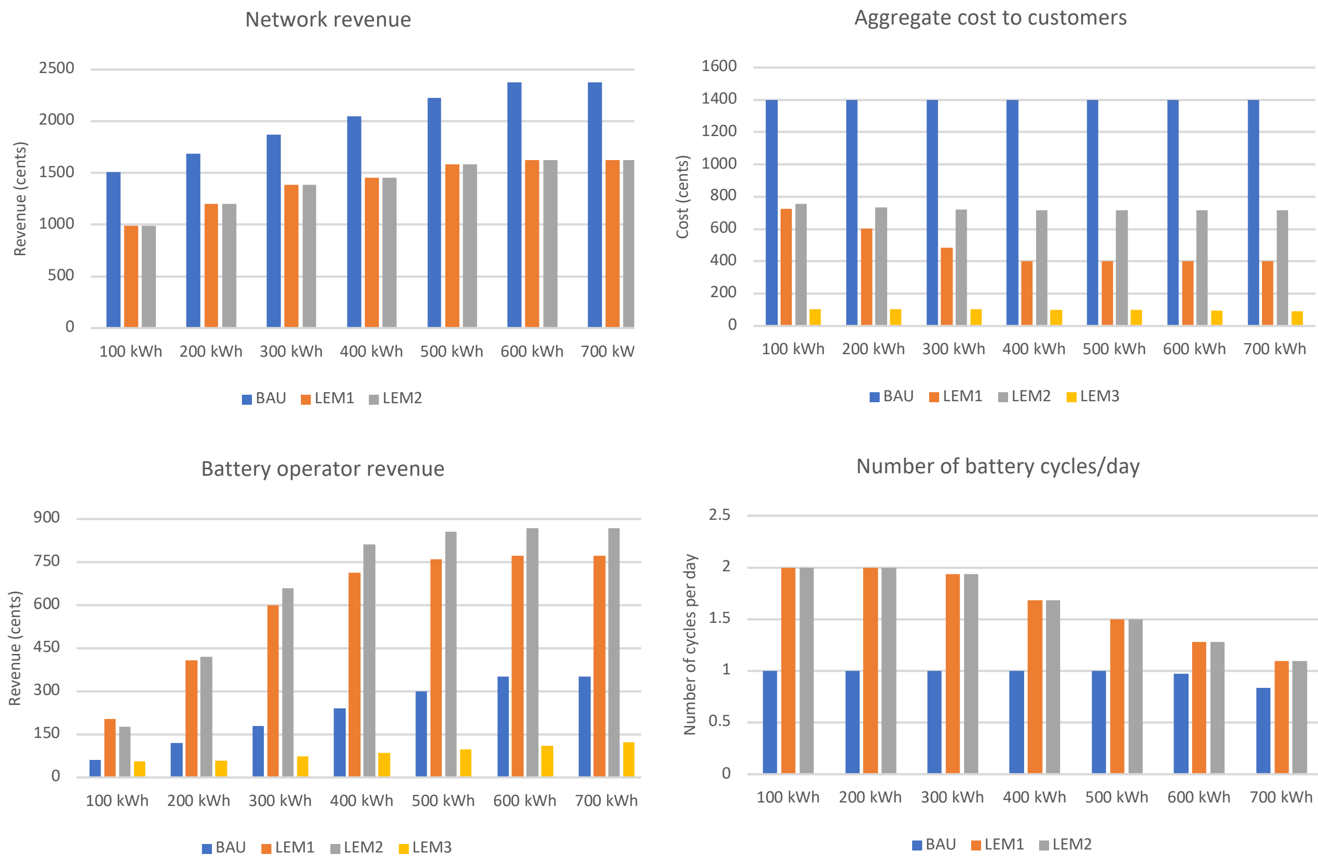


Figure 9: Network revenue and aggregate cost for customers (top), and battery revenue and number of battery cycles/day (bottom), for each scenario.

4 Conclusions and Next Steps

A community-scale BESS may offer benefits for both consumers and networks, but it remains unclear how best to operate a shared BESS such that the potential benefits can be allocated appropriately between stakeholders. Here we carry out an analysis of the impact of different tariff schemes on the operation of a community-scale BESS, investigating how each scenario impacts outcomes for customers and networks. We introduced reduced local energy and transport tariffs, with the goal of increasing the charging of the community-scale BESS from locally generated solar energy, and discharging to meet the local demand. For all scenarios we gave the optimiser perfect foresight. Future work will integrate energy forecasts for more accurate estimates of BESS performance.

We found that BAU tariffs provide limited scope for tuning the operation of the community-scale BESS, which greatly restricts the impacts that the BESS has on the servicing of local customer and network needs. Under financial operation the BESS will pursue the arbitrage value in the remote energy tariff with no regard for local network or customers conditions. Such operation may have positive impacts, such as lowering peak energy and power imports if the peak in customer's net energy demand (for grid power) coincides with peak tariff periods coincide. But it may also have negative impacts, such as creating new periods of large reverse power flows when local demand is low and the BESS discharges due to the remote market energy arbitrage potential - as shown in Fig. 5(a).

The introduction of differentiated local energy transport tariffs in LEM1 provided a well suited lever by which to bias the operation of the community-scale BESS towards charging and discharging based on the energy flows of the local network over the remote market. Since the energy tariffs and arbitrage value are equal in the local and remote markets the difference between local and remote transport tariffs has a very direct and tractable impact on the battery prioritising charging from local energy. The battery will however still discharge into the remote market (as under BAU conditions) because we continue to not charge generators transport tariffs for the energy they export. A future extension of our work will examine the impacts of altering this to charge for transport for both the import and export of energy, although we note that this would require a revision of NER clause 6.1.4 that explicitly prohibits the charging of DUOS for the export of energy.

LEM1 type models of distinguishing transport costs between local and remote areas are also appealing because they match the physical reality that the cost of energy transport increases as a function of the transport distance, while retaining the simplicity of a single market price for energy, whose tariffs can be shaped to reflect aggregate demand profiles that encourage desired customers and BESS behaviours such as diversifying aggregate loads or shifting loads to times of solar generation.

While LEM2 opens additional degrees of freedom through the setting of local energy tariffs, this was found to be of limited practical use. The reasons for this were that, on the principle of fairness and to avoid perverse incentives for continuous battery cycling, we considered local energy prices to be symmetric in import and export, and that we bounded local energy prices to be less than prices in the remote market. This latter constraint was also imposed to ensure that the LEM decreased customers costs. In future work we will explore the co-optimisation of local energy and transport tariffs, as it may be possible to reduce customers total costs with premium local energy tariffs complemented by very low local transport tariffs.

The tariffs produced by game theory optimisation potentially provide a valuable reference for tariff design in that they specify the optimum tariff that results in lowest energy costs for all users [6]. However, for the current study, the local and remote energy prices derived from game theory were almost identical.

We also investigated the performance of community-scale BESS on the local network's solar system hosting capacity. As expected, we found that a large, shared BESS was far better able to manage peak power flows into and out of the local network than residential BTM batteries of equal total storage capacity. The superior performance is due to the shared BESS directing all of its power capacity to the worst peaks in aggregate net load/solar, whereas the BTM BESS are unaware of the behaviour of other customers.

In summary, we show that community-scale battery systems may offer advantages over residential batteries, both for consumers as well as the electricity network. Further, we show that, if implemented with appropriate settings, the benefits can be allocated appropriately between customers and the grid.

Key insights:

- Business-as-usual (BAU) tariffs limit the operation of the community-scale BESS. In this study the BESS did not charge the battery from locally generated solar energy under the BAU tariff.
- Community-scale BESS can increase hosting capacity, allowing a greater percentage of local energy to be generated by solar PV.
- Local energy tariff models LEM1 and LEM2 improved the local consumption of solar energy. Associated network benefits included decreased energy and peak power imports and exports.

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