Aggregated impact of coordinated commercial-scale BESS and financial outcome

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Over the last decade, there has been a surge in the number of behind-the-meter battery energy storage systems (BESS) installed in distribution networks across the globe (Nosratabadi et al., 2017, Allan et al., 2015, da Silva et al., 2019). With this rapidly growing distributed BESS market comes an array of opportunities and challenges for both the customers and the network operators. For example, while BESS provide bill savings to customers, they also reduce the revenue for network operators (Laws et al., 2017, Young et al., 2019). However, BESS can also be coordinated to provde grid services that potentially defer the need for expenditures in network assets, which may then generate financial returns to both customers and the network operator (Burger and Luke, 2017, Pimm et al., 2018). One example of grid services is to coordinate the BESS response during times of peak demand on the electricity network to defer network augmentation and upgrades. This study models an approach that optimises this response in such a way that it maximises the financial outcomes for both the customers and the network operator. The results present an evaluation of the aggregated technical and financial impacts of coordinating BESS to reduce peak demand on the network under optimised situations.

This study uses 30-minute interval load data from 4 commercial buildings all connected to the City Central zone subtation operated by Ausgrid, for the period May 2017 to April 2018. These buildings are all high-rise office buildings with an energy rating of 5 stars or above on the National Australian Built Environment Rating System (NABERS) (GPT, 2019). The buildings operate under a combination tariff that consists of time-of-use (TOU) volume charges, a demand charge that is based on the maximum demand in a 30-minute interval between 2pm and 8pm on weekdays for each month, and some auxiliary charges based on the total amount of electricity consumed. This study developed a model for a BESS designed to minimise the first-year-cost-of-electricity (FYCOE) of each building and a photovoltaic (PV) system that was sized to fit the available roof area. The aim was to assess their impact on the energy use of the buildings and at the zone substation. The model was run for several scenarios of BESS unit pricing and the amount of compensation that the customer receives for each kW of network peak demand that was reduced by the BESS.

The FYCOE consists of the sum of the TOU, auxiliary and demand charges after the PV and BESS plus a single-year worth of the BESS capital cost amortised over its estimated lifetime of 10 years. Previous studies of BESS optimisation have used similar approaches to tie in the cost of the BESS with the electricity costs of the customer (Mariaud et al., 2017, Acha et al., 2018, Stadler et al., 2013). A portion of the network deferment value associated with the reduction in the zone substation peak demand was then added to the FYCOE to represent the incentive provided by the network operator to encourage customers to purchase larger BESS that may have a greater impact on network peak demand. This portion of the network deferment value passed through to the customer is then referred to as the pass-through value (PTV). The full network deferment value associated with peak demand reduction for the City Central zone substation was found to be \$500/kVA (Commonwealth Scientific and Industrial Research Organisation & Clean Energy Council, 2019). The FYCOE minus the PTV therefore makes up the financial outcome of the customer in adopting the PV and BESS and it is the BESS objective to minimise FYCOE while maximising the PTV, equation 1 shows how this is implemented.

$$
\begin{aligned}
CoE\ (\boldsymbol{D}, \boldsymbol{C_{BESS}}) \\
= \sum_{b=1}^{4} \Big(\sum_{t=0}^{T} (\boldsymbol{D_{g,t.b}} \times P_{TOU} + \boldsymbol{D_{g,t,b}} \times P_{AUX}) + \sum_{m=1}^{12} \boldsymbol{D_{max,m,b}} \times P_d \times Days_m \\
+ \boldsymbol{C_{BESS,b}} \times P_{BESS} \times ((r \times (1+r)^n)/((1+r)^n - 1)) - (D_{zs,max} - \boldsymbol{D_{zs,max,BESS}}) \times PTV
\end{aligned}
\qquad (1)
$$

where $D_{g,t,b}$ is the demand imported from the grid after PV and BESS in kWh during t for building number b, $D_{max,m,b}$ is the maximum demand imported from the grid after PV and BESS during the demand charge time window for month m in kW for building number b, $C_{BESS,b}$ is the energy capacity of the BESS for building number b, $D_{zs,max}$ is the original highest demand on the zone substation in kW, $D_{zs,max,BESS}$ is the highest demand on the zone substation after demand reductions from the BESS in kW, *PTV* is the pass-through value of the peak demand deferment value, which is \$500/kVA/year for this particular zone substation. Thus, if the network operator wishes to pass-through 10%, the customer receives \$50/kVA and the network operator retains \$450/kVA. This is then the objective function for a linear programming program that was used to optimise the BESS size and dispatch, the program is written with the python package PULP (Stuart et al., 2011). The model was run for a set of BESS prices from \$500/kWh to \$700/kWh in steps of \$50/kWh and a set of PTV from \$50/kVA to \$450/kVA in steps of \$50/kVA, unity power factor was assumed in the model.

Figure 1 shows the distribution of optimised BESS sizes under the different BESS prices and PTVs modelled in this study. Overall, BESS sizes decreased with higher BESS prices and increased with higher PTVs. However, the BESS sizes plateaued at PTV = \$400/kVA and BESS price = \$700/kWh because the BESS sizes reached a capacity that would completely mitigate the demand of the 4 buildings during the time of the zone substation demand peak.

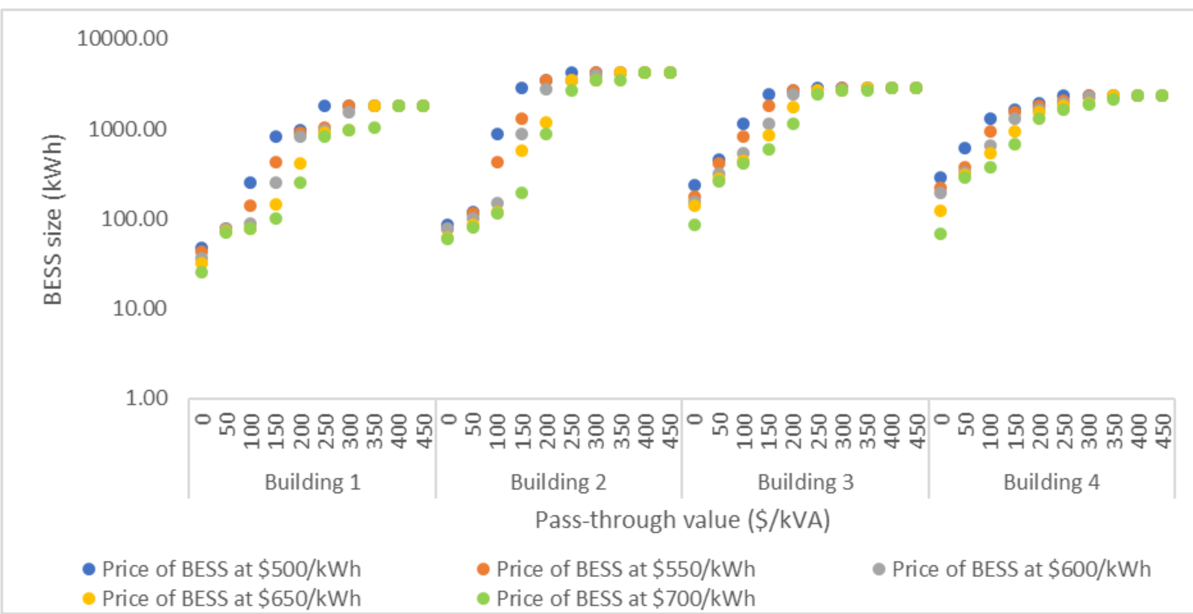

Figure 1 BESS sized for each building under different BESS price and PTV scenarios

Figure 2 shows the distribution of the financial outcomes for customers after they adopt the PV and BESS sized under different scenarios of PTV and BESS price. Overall, the financial outcome of the customer improves with lower BESS prices and higher PTVs, with the majority of the benefits of the BESS coming from reductions in the demand charges. However, the customers do end up with a positive financial outcome even when there is no PTV, hence the benefits of the PV and BESS on the customers' bill alone made it a worthwhile investment. The PTV signficantly improves the financial outcome of the customers and even at relatively low levels becomes more important than the tariff charge reductions caused by the BESS.

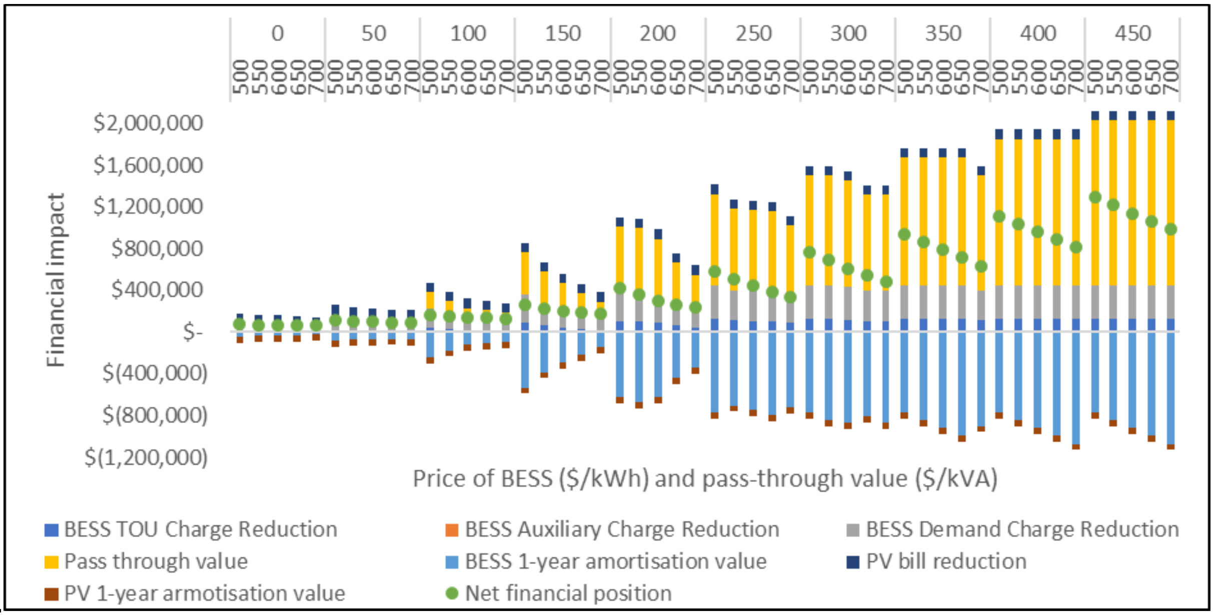

Figure 2. Sum of the financial impacts of the 4 BESS on the buildings, net financial position is the sum of the positive financial flows (charge reductions + pass through value) and the negeative financial flows (amortisation values of the PV and BESS)

Figure 3 shows the distribution of the financial outcomes for the network operator under different BESS prices and PTV. Overall, the financial outcome for the network operator firstly increased when PTV was between $50 to $200/kVA then decreased as PTV increased to over $250/kVA. This was because although higher PTVs resulted in customers adopting larger BESS to reduce the network peak demand, the amount of the value that the network operator retained for themselves decreased. In addition, the larger BESS also increased the bill reductions for the customer and thus also decreased the network operator's revenue. Considering the average across different BESS prices, the optimal PTV for the network operator was $200/kVA (or 40% of the deferment value).

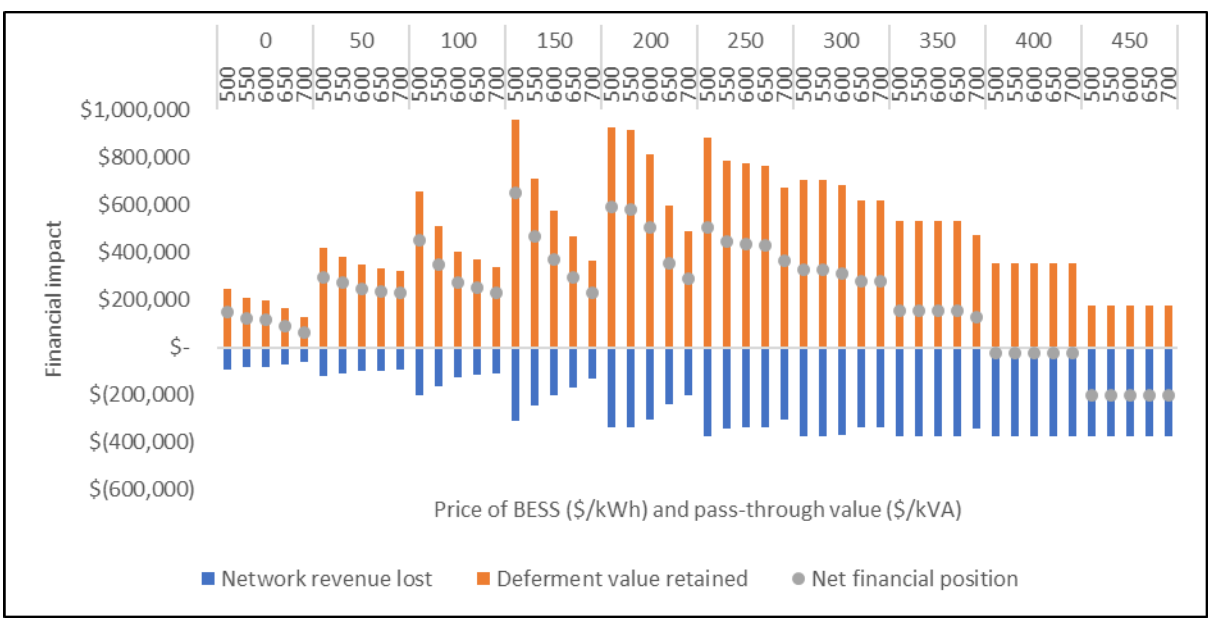

Figure 3. Sum of the financial impacts of the 4 BESS on the network, the network revenue lost is calculated from the difference of applying the network charges to the annual grid import before and after the PV and BESS reductions

In conclusion, although the circumstances would differ between different buildings and zone substations, it is clear that the level of the PTV affects both the optimal size of the battery and the financial outcomes for the customers and the network operator. Having a low PTV can result in a smaller battery size that reduces benefits for both parties – although even with no PTV both parties still benefit. Conversely, having a larger PTV improves outcomes for customers, but it can also result in the network operator losing money.

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