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## **PV for Apartment Buildings: Which Side of the Meter?**

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### **Abstract**

Over 1.7 million Australian households have taken the opportunity to generate some of their own power and reduce both their electricity bills and carbon emissions by installing rooftop photovoltaic (PV) systems on their homes. However, regulatory, technical, financial and organisational challenges have largely prevented Australia's growing number of urban apartment dwellers from accessing these benefits.

Although a number of apartment buildings have installed PV systems to meet common property (CP) loads, over 60% of Australian apartments are in buildings of less than four storeys, where potential rooftop PV generation is likely to exceed CP demand. Shared PV systems in such buildings might be configured to supply local generation to apartments either 'behind the meter' (BTM) or via an embedded network (EN). There are, of course, different implications for these approaches in terms of the risks, costs and benefits for different stakeholders.

Aggregation of diverse apartment energy demands through an embedded network can flatten overall load profiles and increase PV self-consumption, as well as affording access to more beneficial retail arrangements. However, the complexities of the regulatory environment and costs of EN installation can create barriers to this approach. BTM solutions may allow residents to avoid engagement with the regulatory requirements placed on retailers and EN operators, but typically result in lower levels of self-consumption and higher household tariffs. This study seeks to compare the costs and benefits of these two possible arrangements.

There is a dearth of published interval load data for Australian apartment buildings. However, the Smart Grid Smart Cities (SGSC) dataset includes 30-minute annual load for 2080 apartments across New South Wales. Firstly, using this data, this study examines the effect of aggregating apartment loads on the variability of total load profiles and on PV self-consumption. Then, SGSC apartment load profiles are combined with CP load profiles collected for building energy audits at 10 sites in the Sydney metropolitan area to create multiple 'virtual apartment buildings' for each site. Rooftop solar generation is modelled for these buildings using historic weather data and visual assessment of rooftop potential, and energy flows are calculated throughout the buildings for both EN and BTM arrangements. Some initial financial settings are applied to assess the relative total benefits of each scenario.

## 1. Introduction

Australia leads the world in per-capita deployment of residential rooftop photovoltaics (PV) with 1.7 million solar households, averaging 23% penetration nationally (Vorrath, 2017), and exceeding 40% in some areas (Johnston and Egan, 2017). Although the generous feed-in tariffs that supported much of this deployment have now been discontinued in most jurisdictions, deployment rates remain steady, driven by declining PV prices and rapid increases in electricity costs. However, almost all of this PV is being deployed on stand-alone housing.

A number of stakeholders including, most recently, the independent review carried out by Australia's Chief Scientist into the Future Security of the Energy Market (Finkel et al., 2017) have highlighted the need to increase the opportunities available to residents of high-density housing to benefit from the ongoing transition of the energy market towards distributed generation and lower emissions. With 2.3 million Australians living in residential units or apartments<sup>1</sup> within multi-occupancy buildings, and such dwellings making up 28% of new residential building approvals in the first half of 2017 (ABS, 2017), a growing section of the population is excluded from participating in this transition. Nevertheless, despite a range of technical, organisational and regulatory challenges (Roberts et al.), apartment buildings also have a number of characteristics which could prove advantageous to photovoltaic (PV) deployment.

In an increasingly complex retail energy market, there may be distinct advantages to customers in co-ordinating their engagement with the market and their use of distributed energy resources, including renewable generation and battery storage. With feed-in tariffs (FiTs) in the range 5-16c/kWh, compared to average retail volumetric tariffs of 21-34c/kWh (AEMC, 2016), a lack of cost-reflectivity in network tariffs, a range of regulatory barriers to peer-to-peer energy trading, and declining costs of battery storage, there is growing customer interest in the financial benefits of maximising PV self-consumption (SC). For apartment residents, large roof areas can offer economies of scale in PV installation, while opportunities to aggregate diverse and physically proximate household loads may create flatter profiles and increase SC, as well as affording access to more favourable retail arrangements. A range of options are emerging to assist residents to utilize these opportunities, as explained below.

In this paper, we present some initial results from a model of on-site generation and energy distribution in apartment buildings under a number of different technical arrangements. The remainder of the paper is set out as follows: Section 2 gives a brief outline of the technical arrangements available for distributing on-site generation to apartments, while the method and data used for the study are described in Section 0 (see also Roberts et al., (forthcoming)). The impact of load aggregation on PV self-consumption is demonstrated in Section 4 and in Section 5 we present some initial quantitative analysis of the financial costs and benefits of PV for apartment buildings. In Section 6, we discuss some issues raised by the results and suggest areas for further study and, finally, we draw some tentative conclusions in Section 7.

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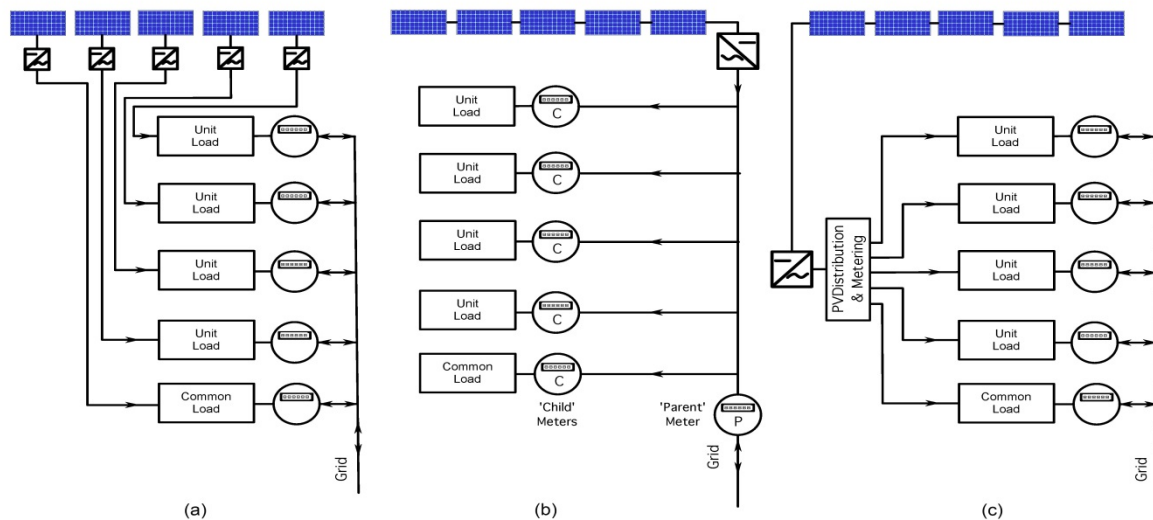
<sup>1</sup> The terms 'unit' and 'apartment' are used interchangeably in this paper.

## 2. Technical Arrangements

The simplest arrangement for deploying PV on apartment buildings is to install a shared system to supply common property (CP) energy loads behind the meter, and for many sites this is sufficient to fully utilise the available roof area without exporting PV electricity. However, with 60% of Australian apartments in buildings of 3 storeys or less (ABS, 2016), the potential PV generation may often exceed CP demand (Roberts et al., 2016) and there are opportunities to use PV to help offset apartment loads as well as CP. Three possible arrangements to facilitate this are shown in Figure 1 and described below.

Installation of independent PV systems behind the meter to meet individual apartment loads (Figure 1(a)) is relatively straightforward for greenfield sites, and the availability of micro-inverter systems also makes it an increasingly attractive option for brownfield sites. While this arrangement avoids the additional infrastructure requirements and regulatory complexity of an embedded network, it risks lower levels of self-consumption and consequently less financial benefit for apartment owners and residents.

Installation of a shared PV system has the advantage that, under Strata Title (the governance arrangement for most Australian apartment buildings (Sherry, 2008, Randolph and Easthope, 2007)), the roof is a shared resource managed by the Owners' Corporation (OC) or Body Corporate. Distribution of the PV generation throughout the building can be organised via an embedded network (EN) (Figure 1(b)) whereby the Owners Corporation or other body sells electricity to residents through a 'child' meter for each apartment. As well as selling electricity generated on-site, the OC may also leverage the aggregated demand across the building to access advantageous market arrangements (in the form of commercial tariffs) for the purchase of imported electricity which can be on-sold to residents.



**Figure 1: (a) Individual BTM, (b) Embedded network (EN), (c) Shared BTM**

Alternative arrangements for utilising a shared PV system behind the meter (BTM) may help avoid the potentially high capital costs and increasingly difficult regulatory environment (AEMC, 2017) faced by embedded networks. In this scenario (Figure 1(c)), a (usually low-cost) secondary metering arrangement is used to distribute the on-site generation whilst residents continue to purchase their off-site generation directly from an energy retailer.

### 3. Method

#### 3.1. Load data

This study uses 30-minute interval load data for 2000 New South Wales apartments, collected for the AusGrid Smart Grid Smart City (SGSC) trial, details of which are described in the various SGSC reports (AusGrid et al., 2014, Ausgrid, 2014c, Ausgrid, 2014a, Ausgrid, 2014b). Apartments with more than 10% of missing load data for the calendar year 2013 were excluded from the dataset, and missing data in the remainder were filled with data from the timestamp in the period with the most similar load data across the dataset, following a method adapted from (Berry et al., 2015).

#### 3.2. Load Variability Metrics

The diurnal and annual variability of load profiles is important in calculating network capacity requirements, assessing suitability for PV and sizing storage. We have used three metrics to explore the effect of aggregation on the variability of apartment loads.

A general measure of the variability is given by the *coefficient of variation (CV)* calculated as the ratio of the standard deviation of the daily load to its mean value, as shown in Equation(1) where  $E_{d,j}$  is the  $j$ th 30-minute energy reading on day  $d$ .

$$\overline{CV} = \frac{1}{365} \sum_{d=1}^{365} \frac{\sqrt{\left(\sum_{j=1}^{48} (E_{d,j} - \bar{E}_d)^2 / 48\right)}}{\frac{1}{48} \sum_{j=1}^{48} E_{d,j}} \quad \text{Equation(1)}$$

The *load factor (LF)*, equal to the mean energy divided by the peak energy, and calculated on a daily or annual basis (Equation(2), Equation(3)), is commonly used in sizing battery storage capacity.

$$\overline{LF}_{daily} = \frac{1}{365} \sum_{d=1}^{365} \frac{\sum_{j=1}^{48} E_{d,j}}{48 \times \max_{1 \leq j \leq 48} \{E_{d,j}\}} \quad \text{Equation(2)}$$

$$LF_{annual} = \frac{\sum_{d=1}^{365} \sum_{j=1}^{48} E_{d,j}}{17520 \times \max\{E_{d,j}, 1 \leq d \leq 365, 1 \leq j \leq 48\}} \quad \text{Equation(3)}$$

#### 3.3. Aggregation and Self Consumption

In order to gain an understanding of the impact of aggregation of apartment loads on variability and PV self-consumption (SC), load profiles were selected at random from the filtered SGSC dataset and combined in groups of between 5 and 200 apartments for analysis. For each aggregation, the coefficient of variation and the daily and annual load factor were calculated to assess the effect of aggregation on load variability.

The NREL's System Advisor Model (SAM) (NREL, 2010, Balir et al., 2013) PV Watts module was used to simulate hourly PV production for a North-facing array in Sydney, optimally tilted (to match the latitude) using Bureau of Meteorology satellite-derived irradiance data and automatic weather station temperature and wind speed data for 2013. The output was scaled to model the generation from PV systems between 500W and 600kW and

combined with the aggregated load profiles. For each load profile and PV system, the percentage of PV generation self-consumed over the 12-month period (SC) was calculated.

### 3.4. *Virtual Buildings*

In order to assess financial outcomes from installing PV on apartment buildings under different implementation arrangements, ‘virtual building’ load profiles were created, using interval CP data for actual apartment buildings at ten sites across Sydney (collected for building energy audits (Roberts et al., 2016)) and SGSC apartment load data. For each site, 50 virtual apartment buildings were created, each one comprising the actual CP profile for the site combined with a randomly selected sample of SGSC apartment load profiles, one for each apartment in the building. As the CP data was for a range of periods not coincident with the apartment data, only buildings with no evident temperature-dependent common load (such as HVAC or swimming pools) were selected.

For each site where the CP load data was available, a visual analysis of the roof area was carried out using multi-viewpoint aerial imagery (Nearmap Ltd., 2015) to assess roof orientation and inclination, and to identify obstructions and sources of shading. In line with previous studies (Copper et al., 2016), roof areas shaded between 10am and 2pm on the winter solstice were excluded from useable roof area, along with access routes. A PV array was designed for each roof based on the maximum usable area with panels arranged flush to the roof, and the output of this system was modelled in SAM using 2013 weather data as described in Section 3.3.

### 3.5. *Financial Modelling for Virtual Buildings*

Using Python, a model was constructed to calculate energy and cash flows for the building occupants throughout each virtual building under each of the EN and BTM system configurations shown in Table 1. The modelling was used to assess overall outcomes for the building, so distribution of financial benefits between apartments and the owner’s corporation was not considered. The technical and financial parameters used for the model are set out below.

**Table 1: PV system configurations for virtual buildings**

Abbreviation	PV System Configuration	Allocation of PV Generation	
		To CP	To Apartments
BAU	Business as Usual (no PV)	N/A	
BTM-I	Individual PV behind the meter (units only)	None	Equal share of roof capacity
BTM-ICP	Individual PV behind the meter (units + CP)	Proportional to the ratio of CP load to building load <sup>2</sup>	Equal share of remaining capacity
BTM-S	Shared PV behind the meter	Proportional to instantaneous load	
EN	Embedded network without PV	N/A	
EN-PV	Embedded network with PV	Proportional to instantaneous load <sup>3</sup>	

<sup>2</sup> The ‘PV ratio’ as defined in Section 5.1

<sup>3</sup> For EN-PV, there is no distinction between energy generated from PV or imported from the grid in assessing outcomes for the building.



### 3.5.1. *PV Allocation*

In all cases, total PV capacity was sized as per Section 3.4, with PV generation allocated to apartment and common property loads as shown in Table 1. For the EN-PV arrangement, the PV was treated as a single system connected between the parent and child meters, with the PV energy netted off the aggregate load. For the BTM-S model, the PV energy was distributed between all apartment and CP loads in proportion to instantaneous demand (behind the retailer meters). For the BTM-ICP scenario, the CP PV system was allocated a percentage of the total PV capacity equal to the percentage contribution of the annual CP load to the annual building load, with equal-sized systems allocated to all the apartments utilizing the remaining capacity available on the roof. For the BTM-I scenario, all apartments were allocated systems with equal shares of the total PV capacity.

### 3.5.2. *Capital and Operating Costs*

Average installed costs for commercial PV installations in NSW for September 2017 were used to calculate the capital costs for the PV systems. These ranged from \$1.22<sup>4</sup> for 10kW peak capacity to \$1.08 for 100kW, after federal government subsidies and sales tax (Solar Choice, 2017).

Capital costs for retrofitting embedded networks are highly site-dependent. As a minimum, installation of a parent or gateway meter at a cost of around \$2000 (Roberts, 2017) is necessary, and replacement of child meters (approximately \$400 each) is likely to be required because of regulatory and ownership issues, even where technically suitable smart meters have already been installed and paid for by the customer. Additional costs for upgrading outdated wiring, switchboards or meter rooms, may also be applicable, depending on the age of the building and the standards of the local distribution network service provider. For this study, a total cost of \$20,000 plus \$400 per unit has been allowed for the installation. All capital costs have been amortized over a 12-year period at a nominal annual interest rate of 6% to calculate monthly repayments.

Embedded network operating costs include components for meter-reading, billing, marketing, customer-assistance, maintenance of the embedded network and an element to cover the risk of bad customer debts. With the exception of maintenance of the EN, these cost elements are common to a retailer in the energy market, for whom these costs have been estimated by the Australian Competition and Consumer Commission to be \$230 (15% of the total bill) for an average NSW residential customer (ACCC, 2017). As actual EN operating costs are obscured by commercial confidentiality, a value of \$250 has been chosen to align with these estimated retailer costs. The operation and maintenance costs of the PV system have been assumed to be zero over the 12 years of the capital repayments, although there is a possibility of course of an inverter replacement over that period.

Installation of a PV system configured to share generation behind the meter (as in Figure 1(c)) will also require capital expenditure for distribution and metering infrastructure and may also incur operating costs for meter reading, billing, and related services. Although these costs are likely to be substantially less than those associated with embedded network arrangements, business models supporting this arrangement are very new to the Australian market so a

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<sup>4</sup> All monetary amounts are given in AU\$ and include goods and services tax (GST) of 10%

detailed analysis has not been possible for this study. The relative financial benefits of BTM configurations have therefore been considered separately from EN configurations (in Section 5.3).

### 3.5.3. *Tariffs*

For Business-as-Usual (BAU) and BTM scenarios, all customers were assumed to be paying a market tariff equivalent to the 2017 standing offer Time of Use (TOU) tariff from the “Retailer of Last Resort” in the relevant network area for the case study (Energy Australia, 2017), with a 15% discount applied to fixed and volumetric components<sup>5</sup>. This corresponds to the total saving made by a representative NSW customer in 2016 (AEMC, 2016). These tariffs represent bundled network tariffs and energy costs, along with various additional costs including environmental levies and retailer costs and margins. A feed-in-tariff (FiT) of 12.5c (as included in the standing offer TOU tariff) was applied to PV exports in all the BTM scenarios.

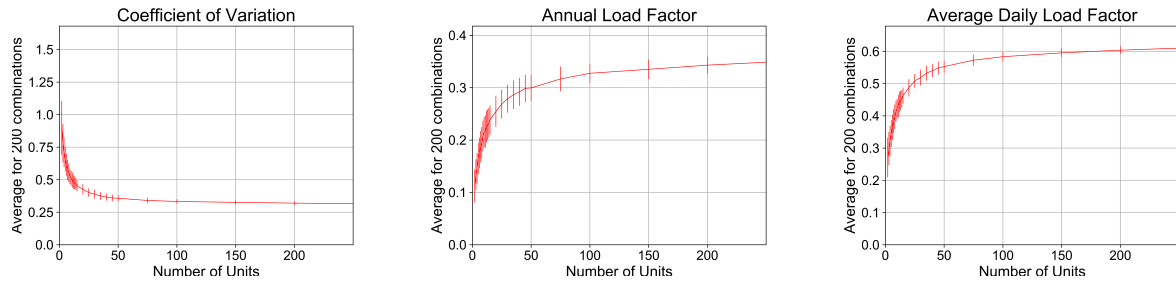
For the EN scenarios, the tariff paid at the parent meter would be a commercial tariff, comprising a regulated network component and a market retail energy component that will typically be lower than for single apartment tariffs. The network tariffs are determined by the size of the annual load and, assuming all the sites have a low voltage grid connection, in the relevant network area would be EA305 for loads between 160MWh and 750MWh and EA310 for loads above 750MWh (Ausgrid, 2017a). Both these commercial tariffs have a relatively high ratio of fixed and capacity to volumetric charges, with the daily capacity charge based on the customer’s peak load in the preceding 12-month period. The energy component is determined by negotiation with the retailer, but for the model has been assigned a value of 9.5c/kWh, 20% below the estimated 11.84c paid by a representative NSW retail customer (AEMC, 2016). Although avoided transmission use of service costs may be paid for embedded generation where network benefit is demonstrated (Ausgrid, 2017b), there is no automatic export payment available to commercial scale customers so sensitivity to a FiT at the parent meter was modelled.

## 4. Results - Aggregation and Self Consumption

Figure 2 shows the variability metrics for the aggregated apartment load profiles. For aggregations of 200 units, the annual load factor is increased from 27% for individual units to 61%, the average daily load factor from 11% to 35%, and the coefficient of variation drops to 32% from an average value of 90% for a single apartment. However, there is little further decrease in the coefficient of variation for aggregations above 50 apartments, and load factor increases very little above 200 apartments. This highlights that the benefits of load diversity are not just available to larger apartment buildings.

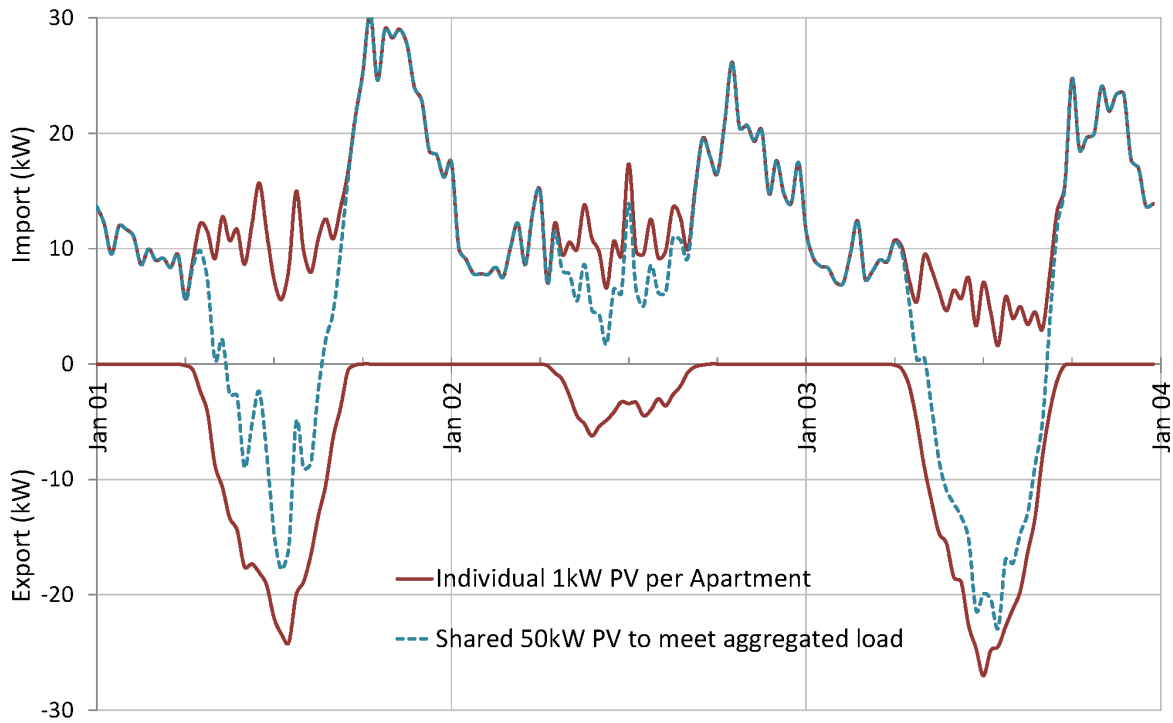
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<sup>5</sup> In 2016, the electricity price paid by a ‘representative customer’ on a ‘representative market offer’ in NSW was 15% less than one paying the standing offer tariff. (AEMC, 2016)



**Figure 2: Average variability metrics for aggregated apartment loads  
(error bars =  $\pm 1$  standard deviation)**

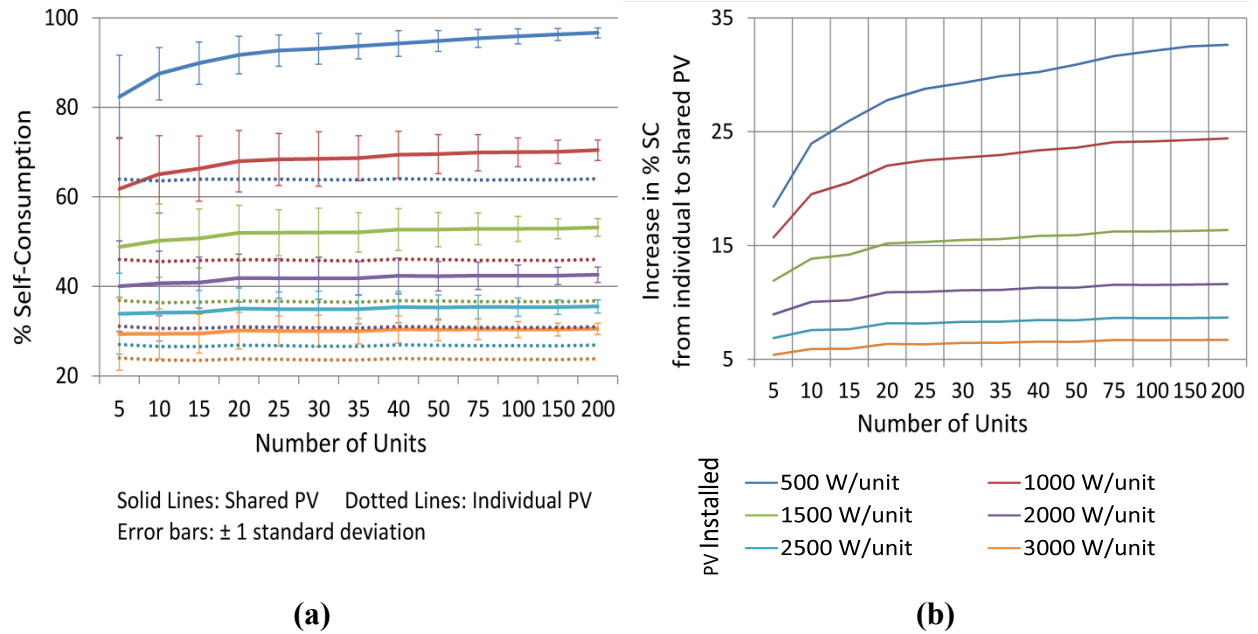
Figure 3 shows the effect of aggregation on PV self-consumption over three summer days for a group of 50 randomly-selected apartments. The solid lines show the total import and export if each apartment has an individual  $1\text{kW}_{\text{peak}}$  PV system, with PV generation exported (even on a cloudy day) while electricity is simultaneously imported to the building. The dotted line shows the effect of aggregating the loads and sharing a  $50\text{kW}_{\text{peak}}$  system: PV generation is used to meet internal building loads first, and consequently imports and export are reduced.



**Figure 3: Total import and export for 50 apartments with 50kW PV over three days**

Figure 4 (a) shows the % PV self-consumption (SC) of aggregations of unit loads for a range of PV system sizes. The solid lines show SC for EN and shared BTM arrangements, where the PV generation is netted off the aggregate load, and the dotted lines for individual behind the meter systems, where the PV generation is individually netted off apartment loads. Figure 4 (b) shows the increase in SC made possible by aggregation and the impact of varying the PV system size.





**Figure 4: Effect of aggregation showing (a) self-consumption for shared and individual PV systems and (b) increase in self-consumption through sharing**

## 5. Results -Virtual Buildings

### 5.1. Self-Consumption

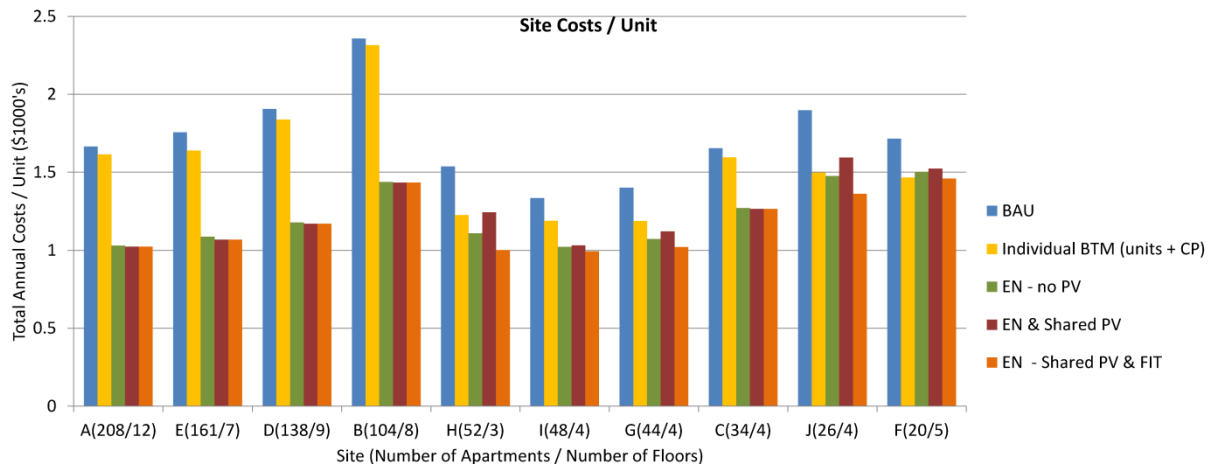
Table 2 shows the number of floors and apartments for each site and the total annual building load and rooftop PV capacity, along with the proportion of annual building load used on the common property (the “CP ratio”) and the ratio of the annual PV generation to total annual building load (the “PV ratio”) averaged across all virtual buildings for each site. Also shown is the average self-consumption of PV generation for both individual behind-the-meter PV systems feeding individual apartments and shared PV supplying aggregated load.

**Table 2: Site statistics and self-consumption averaged over 50 virtual buildings at each site**

Site	Floors	Apartments	Total Load (MWh/year)	PV Capacity (kW <sub>peak</sub> )	CP Ratio %	PV Ratio %	SC % (individual)	SC % (aggregated)
A	12	208	1100	47.25	35	5.9	95	100
B	8	104	840	18.75	58	3.1	99	100
C	4	34	180	9.5	34	7.4	93	100
D	9	138	860	42.25	45	6.6	95	100
E	7	161	900	90.25	38	13.4	86	100
F	5	20	110	31.5	37	41.5	61	77
G	4	44	180	76.75	17	54.7	45	64
H	3	52	250	141.5	26	78.1	37	47
I	4	48	190	52.5	9	36.5	53	78
J	4	26	160	78.5	43	67.5	45	54

## 5.2. Embedded Networks

Figure 5 shows the total annual costs (aggregate electricity bills seen by individual apartments, at the CP meter, and by an EN where applicable, plus capital repayments amortised over 12 years) averaged across all virtual buildings at each site under different technical scenarios and with the cost and tariff settings outlined in Section 3.5.



**Figure 5: Total annual costs for virtual buildings (including EN costs) ordered according to the total number of apartments**

The results indicate clear financial benefits associated with embedded networks, with or without PV, particularly for larger sites (and provided capital and operating costs do not exceed those outlined above). These benefits are derived from the reduced energy and network tariffs accessed by aggregating electricity loads at a single point of grid connection, and so are sensitive to the (non-regulated) energy component of the tariff.

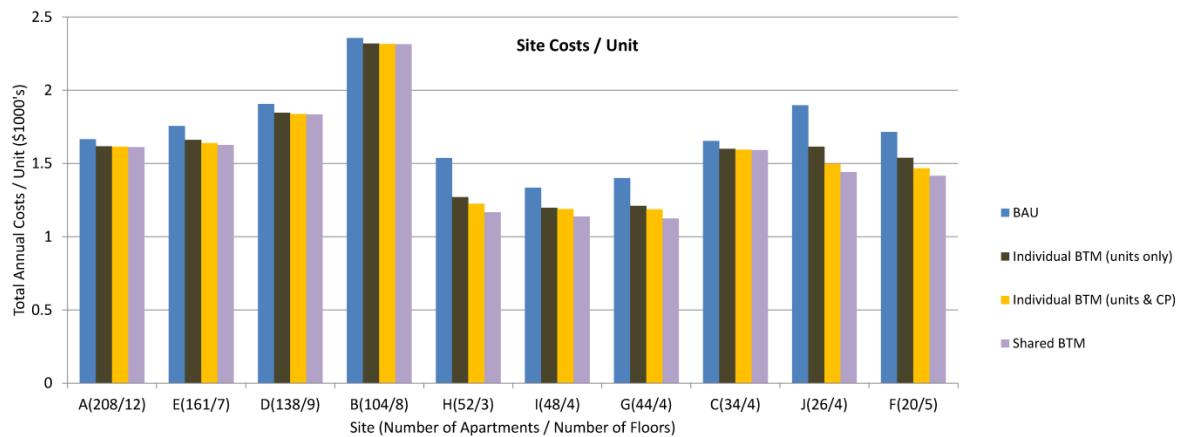
The deployment of individual behind-the-meter PV systems for all units and CP reduces the total annual costs for all of the sites, though these benefits are marginal for sites with a low PV ratio. The impact on total costs of adding PV to an embedded network is negligible for sites with a low PV ratio, while for smaller sites with a high PV ratio and lower self-consumption, there is increased benefit to adding PV where a suitable feed-in tariff is applied, but a reduced benefit where there is no payment for exported generation, if the capital cost of the PV must be repaid over 12 years.

Similarly, in the absence of a feed-in-tariff at the parent meter, installation of an embedded network to distribute of PV may increase costs compared to individual BTM systems, even though self-consumption is increased.

## 5.3. Behind the Meter

Figure 6 shows building energy costs and PV repayments averaged across all virtual buildings for the different BTM arrangements outlined in Section 3.5. For sites with a low PV ratio (and therefore high self-consumption), there is only a small overall benefit to adding PV BTM, and the difference between the 3 arrangements is negligible. For those with a higher PV ratio and lower self-consumption, the annual energy costs with a shared BTM PV system are up to 11% less than where individual PV systems are installed for units only and 4% less than the

individual system for units and CP. However, any additional capital and operational costs of the shared system have not been included in these calculations.



**Figure 6: Total annual costs for virtual buildings under BTM arrangements (ordered according to the total number of apartments)**

## 6. Discussion

The results presented here indicate that there are diversity and aggregation benefits to communal arrangements such as shared behind the meter PV for apartments and particularly to embedded networks, which enable access to more favourable retail arrangements. However, these results depend on a range of assumptions and should be seen as preliminary. Further research could usefully explore the sensitivity of the results to the negotiated retail / wholesale tariff at the parent meter, to the use of flat rate, demand-based and diverse TOU retailer and EN tariffs, and to a wider range of capital cost scenarios.

The results are likely to be particularly sensitive to the financial assumptions. Typical residential PV installations in NSW can expect payback within 5-7 year years (Martin, 2017) and there is evidence (Altmann, 2013, Roberts et al.) that perceived long payback periods for apartment owners (particularly compared to other sustainability retrofits) can act as a barrier to investment, so it is arguable that a shorter amortization period should be used. Conversely, the typical lifetime of a PV system (allowing for inverter replacement) is 20-25 years, so it may be appropriate to consider a longer period or to consider the increased benefits accruing once PV & EN infrastructure costs have been repaid.

The results presented only address *total* benefits across the building, and it is important to note that, depending on any internal tariff arrangements, these benefits will be shared unevenly between customers with different load characteristics, with some residents likely to be worse off under these scenarios, particularly if their individual self-consumption is low. There are also potential complexities in financial flows between unit occupants and owners, as represented by the Owners Corporation. It should also be noted that EN scenarios will result in reduced income for both market retailers and the local distributed network service provider, which may present a barrier to widespread implementation of this model. There is a clear need for more detailed analysis of the distribution of costs and benefits between all stakeholders under a wide range of financial settings, which can also explore how load aggregation and storage affects the value of embedded PV.

## 7. Conclusions

Shared PV systems, distributed via EN or BTM arrangements, can significantly reduce load variability and increase self-consumption of on-site generation in apartment buildings, but the economic benefits of these arrangements (relative to each other, to individual PV systems or to business as usual) are dependent on a range of site characteristics (including the PV ratio, determined by available unshaded roof space) and external tariff and financial factors. In a range of circumstances, PV can increase the economic viability of embedded networks or can provide resident benefits behind the meter, but these benefits may be returned over a long timeframe relative to typical preferred payback periods for apartment sustainability investments.

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