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Open Source Model for Operational and Commercial Assessment of Local Electricity Sharing Schemes in the Australian National Electricity Market

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Abstract

Local electricity sharing schemes have the potential to play an increased role in the Australian National Electricity Market as the penetration of distributed energy resources (DERs) continues to grow. These models allow participants to share energy between separately owned and operated DERs, however are largely untested. While embedded networks have generally been established for specific circumstances such as shopping centres and airports, there is growing interest in their wider application in providing a framework for local sharing of energy resources. However, the potential operational and commercial implications for key stakeholders (including consumers, network operators and retailers) are not well understood. An example of one such proposal is within the Byron Arts and Industrial Estate through which the community owned retailer, Enova, is seeking to offer a bespoke energy solution to its customers within the estate.

In this paper, a new open source software model for assessing technical and commercial outcomes of local electricity sharing is presented. The model is applied to the Byron Arts and Industrial Estate case study which demonstrates the relevance of modelling to support appropriate investment and operational decision-making.

1. Introduction

With significant reductions in photovoltaics (PV) and battery energy storage (BES) system costs over recent years, a range of new business and community models are emerging in electricity industries around the world, specifically designed to cater to a new class of consumer: participants that both generate and consume energy from distributed energy resources. These new approaches allow customers to buy and sell energy between each other (rather than from a centralised retailer or generator), and to aggregate their consumption to access a more beneficial interface with networks and electricity markets.

This includes a range of 'peer to peer' energy models, 'local energy trading' models, and new retail offerings in the Australian context (for example Powershop's "Your Neighbourhood Solar" scheme). While arrangements may vary significantly between specific scheme implementations, distributed technology types and jurisdictions, in this paper we focus on a subset of models that involve trading and aggregation between consumers in the same local network area (e.g. zone substation). We refer to these broadly as ‘local electricity sharing schemes’, defined below.

'Local electricity sharing scheme' is a broad term for any contractual structure under which locally[1] generated (or stored) electricity can be shared[2] between consumers within some subset of the grid.

Proponents of local electricity schemes point to a range of benefits. For instance, where they are community-owned, by enabling the sharing of PV electricity, they may act as a central focal point for communities wishing to attain some level of autonomy from electricity utilities. They may also provide increased reliability through islanding the local area during brownouts and blackouts. Furthermore, they may be able to provide network support and thereby be of value to DNSPs through the deferral of network augmentation or asset replacement.

Embedded networks are a subset of local electricity sharing schemes. The Australian Energy Market Commission (AEMC) which oversees rule making in the Australian National Electricity Market (NEM) describes an embedded network as follows:

“Embedded networks are private electricity networks which serve multiple customers and are connected to another distribution or transmission system in the national grid through a parent connection point. A party, other than the registered local network service provider (LNSP), owns and operates the private electricity network that customers connect to. The party is known as an embedded network service provider. Generally, the embedded network service provider also purchases electricity at the parent connection point and onsells it to customers within the embedded network.” (AEMC, 2017)

Examples include semi-autonomous community-owned ‘mini-grids’, which can enable the sharing of PV electricity within a community (Bowyer, et al., 2016), solar sharing within apartment blocks (Roberts, et al., 2016), greenfield urban developments, caravan parks, shopping centres and airports.

Embedded networks are commonly operated by an Embedded Network Operator (ENO) that is responsible for operating and maintaining the network infrastructure, and for buying electricity from an external retailer, which it then on-sells to households and businesses on the embedded network. Many embedded networks also have an Embedded Network Manager (ENM) that performs the market interface services for embedded network customers, which includes helping embedded network customers access an external electricity retailer if they wish to do so.

The expansion of interest in embedded networks has resulted in the AEMC initiating a review focussed on ensuring that embedded network customers have equivalent rights and access to competition as other ‘on-market’ customers. The most relevant outcomes of the Review’s draft findings for the work presented here are that (i) any party that sells electricity to a consumer in a new embedded network must hold a retailer authorisation from the AER (i.e. be a retailer) or be exempted under a narrow set of circumstances, and (ii) a retailer of an on-market embedded network customer can pay the ENO a network tariff that is equal to the standard published network tariff. These changes mean that for new embedded networks, ENOs are likely to hand

[1] 'locally' means within this subset of the grid, or behind a single point of connection

[2] 'shared' could include actually sharing (giving to local library for example), trading in a market place, netting off for a fixed tariff, or assigning under some bilateral agreements (selling to a specific friend down the road for example), or some other arrangement.

over the role of selling electricity to a conventional retailer (as the cost of obtaining a retail licence may be prohibitive), which must then pay the ENO's network component of the tariff applied to the parent connection point.

In cases where network services are to be provided, the role of the ENO may extend to operating and maintaining additional assets, such as PV systems (both rooftop and ground-mounted) and batteries, connected to the embedded network. This added functionality increases the financial complexity of operating an embedded network, making the ENO responsible for reconciling internal payments for local generation and subsequent use within the embedded network (for example, through 'peer-to-peer' trading).

While embedded networks are widely used in the current market, models that use the regulated utility network for local energy sharing, but are otherwise quite similar to an embedded network ('pseudo embedded networks'), are of particular interest. They allow the creation of what are essentially embedded networks on existing networks, which may increasingly occur given the emerging regulatory limitations on embedded networks.

It is important to note that whether the benefits of local electricity sharing schemes can be realised is likely to be highly dependent upon the local conditions as well as the specific business models to be applied, and therefore the merits of local electricity sharing projects will need to be assessed on a case-by-case basis. This paper therefore presents a preliminary exploration of commercial and technical impacts on participants and operators in a local electricity sharing scheme. The case study examined is located in the Arts and Industrial Estate (A&IE) in Byron Bay, New South Wales, incorporating distributed photovoltaics (PV) as well as battery energy systems (BES). It is a 'pseudo-embedded network', where the DNSP Essential Energy intends to retain ownership of the internal network. While the proposed scheme does not meet the AEMC's standard definition of an embedded network, it involves similar commercial design decisions relating to the ownership of various assets, the tariffs applied, metering and billing approach, and technical design decisions relating to the selection, sizing and operation of distributed energy assets such as PV and batteries[3].

This paper is structured as follows; Section 2 provides background on embedded networks and local electricity sharing schemes, Section 3 presents the open source model, Section 4 provides preliminary results from the Byron A&IE case study and Section 5 sets out some discussion and conclusions.

2. Method

A case study in the Byron Bay Arts and Industrial Estate (Byron A&IE) was used as a preliminary exploration of some of the operational and commercial implications of local energy sharing models. A Python model for calculating energy and financial flows was created and applied to the case study. The tool is open source and was designed to be extensible, so that it can in future be extended to model other local electricity sharing schemes, including embedded networks. A brief background on the case study is provided in section 2.1, the model is described in section 2.2, and the inputs and PV/battery size scenarios used to apply the model to the case study are described in section 2.3.

[3] Noting also that many design decisions are interrelated, for instance a battery's charge/discharge strategy will be directly impacted by which party owns the battery asset.

2.1. Case Study Background

In March 2015, Byron Shire announced its intention to become Australia's first zero emissions community by 2025. Enova Community Energy commenced operations in mid 2016, with the express aim to be community-owned and to promote the uptake of renewable energy. Enova Community Energy is now planning a pilot local electricity sharing scheme in the Byron Arts and Industrial Estate, within Essential Energy's existing distribution network. Although not an embedded network in the regulatory sense (due to ongoing Essential Energy ownership and operation of grid assets) this project has many characteristics similar to that of an embedded network, including the presence of a gate meter at the interface with the local network to the wider grid.

The pseudo embedded network will include a large battery owned by Essential Energy so it can be partially included in their Regulated Asset Base and used for network support, but partially leased to the retailer Enova, potentially for use as a physical hedge against high spot prices. The battery will be located at the point of connection to the wider network, with the expectation that the subset of the network behind the parent meter may be operated in isolation from the main grid if needed. It will also include a number of large roof-mounted behind-the-meter PV arrays. A total of 69kW PV (with an inverter capacity of 54kW) is already connected, and the intention is to install sufficient additional PV to be able to meet the embedded network load in most circumstances. The battery capacity will ideally be sufficient to ride through the types of blackouts most likely to be experienced.

The case study presented here provides some preliminary analysis of the network load and financial impacts of the proposed scheme. It is intended that the results and the model may be used by parties like Enova and Essential Energy to support business decisions such as the structure of the internal tariffs and the required PV and battery capacities.

2.2. Model

A summary of inputs accepted, outputs generated, and the underlying logic to generate the outputs ('the model') is provided in Figure 1. The model logic consists of two packages of calculations. The first handles only electricity flows, calculating the volumes of kWh bought or sold by each participant in the scheme in each time period, and the state of charge of any batteries. The second package focuses on financial flows; it calculates the resultant costs and revenues for each participant, based on the preceding electricity flow calculations.[4]

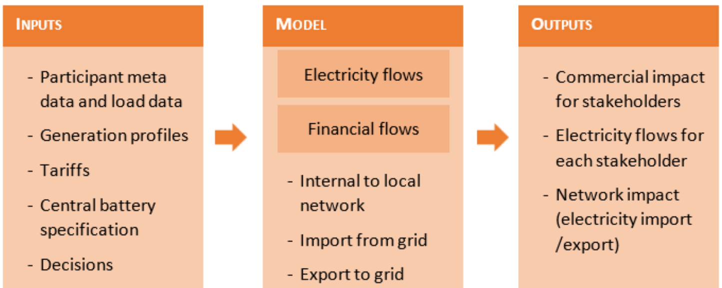

Figure 1 High level overview of the model components

[4] The code for the model can be found here https://github.com/luke-marshall/embedded-network-model

2.2.1. Electricity flows

In line with the AEMC's definition of an embedded network, the model allows for multiple participants that can import and export electricity to and from a central network, as well as electricity flows between participants on what is termed the 'local network.' The model allows for both 'participant' and 'centralised' DERs such as batteries and solar PV as shown in Figure 2.

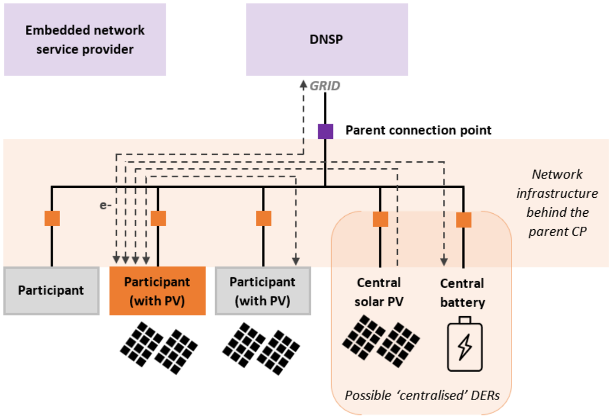

Figure 2 Energy flows for single participant

The local network may also include other loads or DERs that are not participants in the local electricity sharing scheme. The model takes interval load data and either net or gross metered PV generation data as input. Seven categories of electricity flow are recorded, these are shown for a single participant (orange) in Figure 2:

1. Electricity consumed from the grid
2. Electricity exported to the grid from the participant's PV
3. Electricity consumed from the central battery
4. Electricity exported to the central battery from the participant's solar PV
5. Electricity consumed from another participant's PV export on the local network
6. Electricity exported from one participant's solar PV to another participant
7. Electricity consumed from the central solar PV on the local network

An overview of the electricity flow calculations is provided in Appendix A.

Battery Discharge

In a local electricity sharing scheme, the discharge strategy for a central battery is likely to depend on which stakeholder owns and operates the battery, as well as any commercial agreements that may be in place. For this study, the battery is modelled to charge from locally generated solar electricity that would otherwise be exported via the parent meter and discharge when there is any load on the local network.

PV generation preferences

In the model, PV generation by a participant is 'used' where possible as follows, in order of preference:

1. Self consume
2. Sell to 'local load' (other participant within the local network)
3. Sell to central battery
4. Export to grid

The order of preference above does not change actual electricity flows and is primarily an accounting concept, however it determines the volume of energy sourced from local generation (etc.) that is recorded and therefore is relevant in the electricity flow calculations.

Local Electricity Allocation Algorithms

Any proposed local electricity sharing scheme must apply a rule to allocate locally generated energy to each participant and determine the subsequent amount of 'local' tariff revenues and charges that should be allocated to each generator and consumer. In the course of designing the local electricity sharing model for this study, a range of potential allocation rules were examined.

The simplest two rules were fractional allocation (local electricity is allocated in proportion to share of total consumption) and quota allocation (each participant currently consuming electricity is allocated an equal 'quota' of local electricity to consume). Under the quota allocation rule, if a participant uses less energy than their quota allows in a given time period, the remaining energy is added back to the pool of energy and re-allocated to other participants. For this case study, the quota rule was used to allocate local PV generation and battery export to participants, and to allocate local load to the available PV generation.

2.2.2. Financial flows

Financial outcomes are calculated for each participant (for each of the seven types of electricity flows listed above), the party managing the network, and the party managing the retail function of participant interface. Retail and network tariffs for each participant are applied to grid electricity. Separate tariffs are applied to 'locally traded electricity' (e.g. solar electricity generated by one participant and consumed by another participant behind the parent connection point). For the case study, network charges (NUOS) apply to each individual participant's load profile, as indicated in Figure 3.

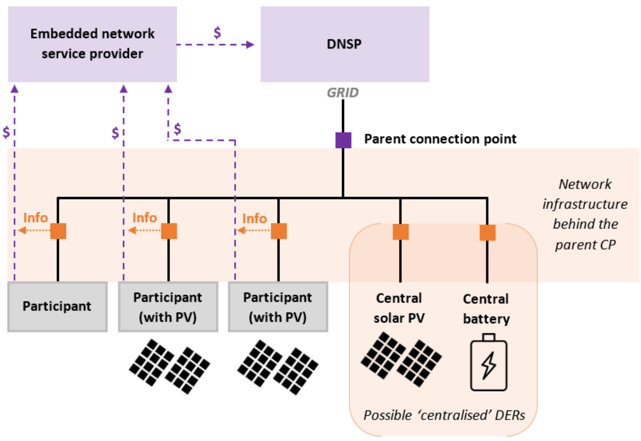

Figure 3 Case study embedded network NUOS payments

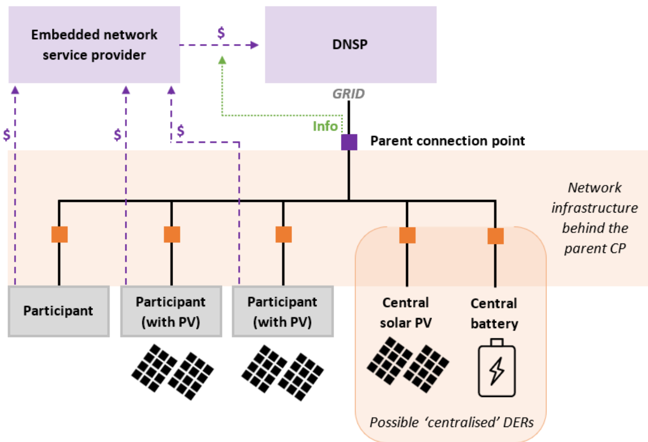

Figure 4 Typical embedded network NUOS payments

This is the main point of difference in the financial flows that apply for this case study and a typical embedded network arrangement, where the embedded network service provider pays NUOS based on load at the parent connection point meter, then passes through costs to individual participants indirectly via tariffs. Figure 4 provides a simplified view of this NUOS application, where the consumption information at the parent connection point informs the NUOS payment for electricity imported from the grid. The detailed data inputs, tariffs and scenarios for the case study are now described.

2.3. Modelling of the Case Study

Half hourly load data from eleven existing sites within the Byron A&IE local network for March and April 2017 were input to the model. PV is installed on four of the sites, with capacity shown in Table 1. Half hourly PV data was not available and so publicly available rooftop PV datasets from neighbouring systems (obtained from pvoutput.org) were normalised and then scaled to the known nameplate capacities of each system.

Table 1 Key participant inputs

Participant	Enova Retail tariff*	Essential Energy Network tariff	Solar capacity (kW DC)	Gross demand over the period (kWh)
1	Business TOU	LV TOU <100MWh	0	5,984
2	Business TOU	LV TOU <100MWh	0	217
3	Business TOU	LV TOU <100MWh	0	35,476
4	Business TOU	LV TOU <100MWh	26	961
5	Business TOU	LV TOU <100MWh	0	3,470
6	Business TOU	LV TOU <100MWh	14.8	2,047
7	Business TOU	LV TOU <100MWh	0	744
8	Business TOU	LV TOU <100MWh	27.5	1,174
9	Business Anytime	LV Small Business Anytime	3	687
10	Business Anytime	LV Small Business Anytime	0	515
11	Business Anytime	LV Small Business Anytime	0	538

The relevant Enova retail, and Essential Energy network tariffs applied are listed in 1. Specific details of these and the local electricity tariffs used are plotted in Figure 4 and detailed in Appendix B.

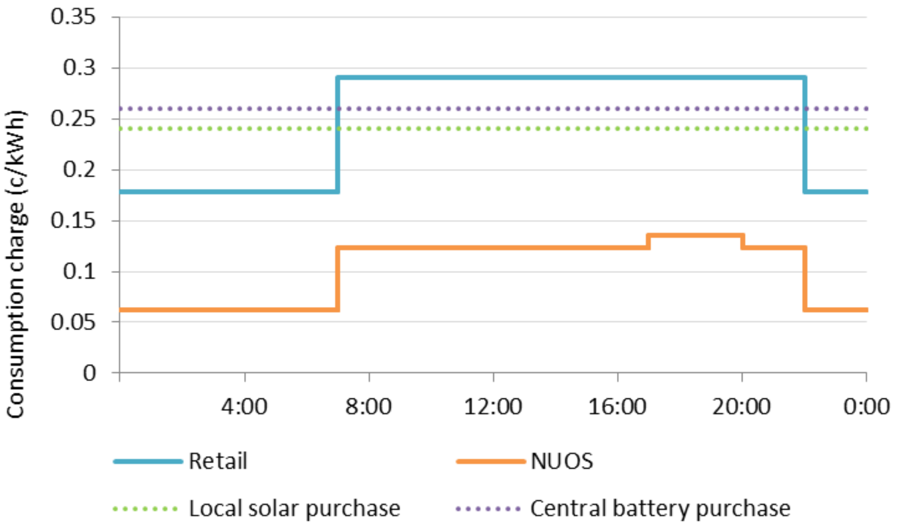

Figure 5 TOU tariff structures: retail and NUOS charges compared with local trading tariffs

A local solar tariff of 12c/kWh is paid for solar consumed locally by other participants or the central battery, in line with available on-market solar feed-in tariffs. A 6c/kW retail margin and a 6c/kWh local network charge are applied to these transactions, resulting in 24c/kWh paid for consumed solar. This falls between the energy component of the standard retail tariff and the solar feed-in-tariff on the wider network, except during off-peak times when the cost of importing electricity is only 17.8c/kWh. An approach similar to this would likely be used in a simple 'local energy trading' scheme, in order to encourage participation in the scheme. A 2c/kWh margin is added to the 24c/kWh local tariff for energy consumed by participants from the central battery. DNSP ownership, and addition of the battery to the DNSP's Regulated Asset Base is assumed, allowing the battery to be operated at very low cost to the participants. In practice, the tariffs chosen (including payment for the battery) will be the outcome of negotiation between Enova and Essential Energy. There is, of course, significant room for innovation in local electricity sharing tariffs, including the possibility of more complex price signals or market structures to incentivise certain behaviours.

The scenarios shown in Table 2 were used to explore the impact of varying the centralised battery size from 5kWh/5kW to 30kWh/30kW. The battery featured a simple dispatch strategy, charging when excess solar energy was available and dispatching as soon as electricity would otherwise be drawn from the grid. Local electricity sharing occurred in all non 'business as usual' (BAU) scenarios.

Table 2 Scenarios modelled

Scenario	Central battery capacity (kWh/kW)	Description
BAU* no PV	0	Assume all participants have no PV installed, no central battery and no central solar. Normal retail tariffs applied.
BAU	0	Participants have PV as above, no local electricity sharing arrangements in place and no local electricity trading occurs, normal retail tariffs applied.
1	0	Local electricity sharing arrangements in place so local electricity trading occurs, however no central battery present.
2	5 / 5	Local electricity sharing arrangements in place so local electricity trading occurs. Central battery charging occurs when there is excess solar generation (which is not being consumed by a Participant). Central battery discharge occurs when the following conditions are met: - It is not charging and - There is energy in the battery and - There is load on the local network which would otherwise be supplied by grid import
3	10 / 10	
4	15 / 15	
5	20 / 20	
6	25 / 25	
7	30 / 30	

3. Results

3.1. Network Impacts

The most likely implications of local electricity sharing at the Byron A&IE in terms of network operational and investment costs, changes to import and export volumes at the parent connection point, and impact on peak demand days are investigated in this section.

The average daily load profile at the parent connection point is shown in Figure 6 for the BAU scenarios (with and without PV) and for the largest battery scenario. The change to average load due to the local energy sharing scheme with battery is small in comparison to the change due to the installed PV. This is largely because of the excellent match between the PV and the load, and high local consumption of PV energy, reducing the utility of the battery.

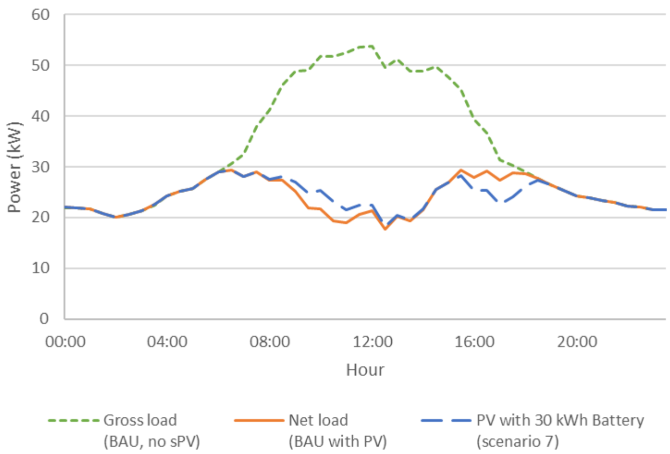

Figure 6 Average day, 30kWh/30kW battery

On the peak electricity export day (for the case where no battery was present), Figure 7 shows that adding a battery reduces network export during morning hours and subsequently reducing import from 3:30pm to 6:30pm. The peak electricity import day (Figure 8) occurred during an extreme weather event that resulted in widespread flooding in the region, while the peak load was more than three times the average peak load. On this day, PV had minimal impact and adding a battery had no impact on network usage, as the battery was unable to charge due to all PV electricity being consumed by participants at the time of generation. It should be noted that the battery algorithm allowed charging only from excess locally generated PV, limiting the ability of the battery to reduce peak demand in this case.

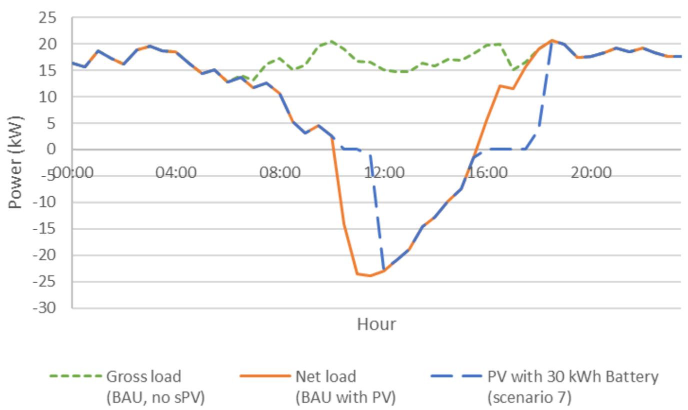

Figure 7 Peak solar export day (9th April 2017), 30kWh/30kW battery

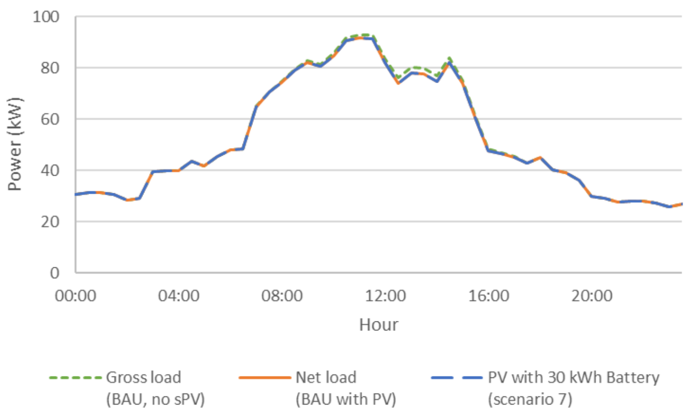

Figure 8 Peak network import day (30th March 2017), 30kWh/30kW battery

Figure 9 shows that increasing battery size resulted in a minimal reduction in grid imports, primarily due to good match between PV and load resulting in (immediate) consumption of local PV behind the parent meter, and also use of PV electricity by other loads within the pseudo embedded network. Similarly, as the battery size was increased, there was minimal reduction in electricity exported to the grid. Figure 10 however indicates a substantial reduction in the proportion of the time in which export of PV to the wider grid occurs.

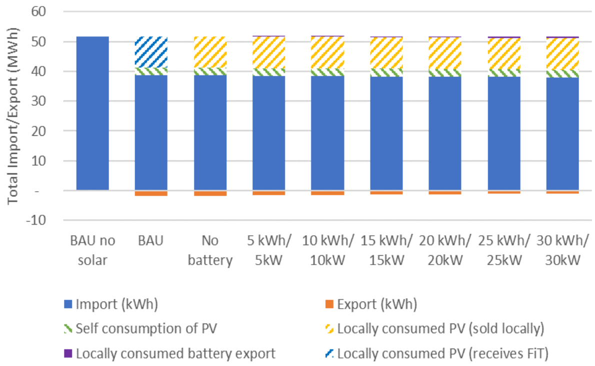

Figure 9 Grid impacts: change in electricity imports and exports with change in battery capacity

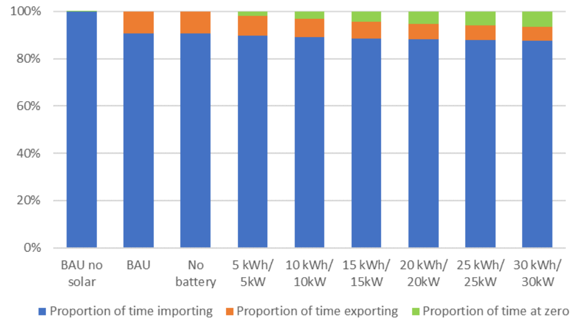

Figure 10 Grid impacts: proportion of time importing and exporting with change in battery capacity

Figure 11 shows more clearly the decrease in PV exported to the grid and increase in battery electricity consumption as the battery size is increased. While the changes observed are small with respect to overall electricity consumption, this is largely due to lack of opportunity to charge given good match between PV and load and relatively low PV capacity. If more PV were to be installed then battery utilisation would likely increase.

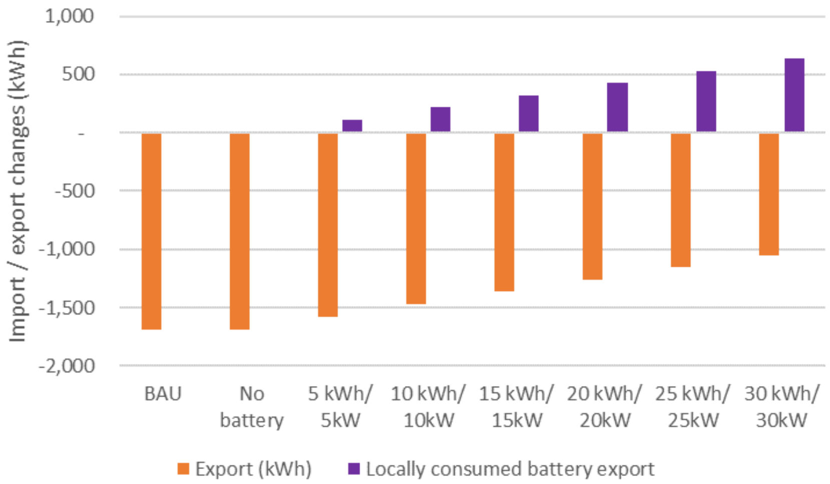

Figure 11 Grid impacts: PV exports and locally consumed battery electricity

3.2. Financial outcomes

It is important to recognise that the financial outcomes presented here are entirely dependent on the choice of tariff design, which has not been investigated in this case study (which instead focused on the impact of varying battery size) and therefore only high level financial results are presented.

Considerable bill reductions for participants were observed under the local electricity sharing scheme compared to business as usual (with PV) as shown in Table 3. A 10% aggregate bill saving was achieved in the 30kWh/30kW battery local electricity sharing case (scenario 7) compared with the BAU case (with PV). These savings were not however distributed equally across all participants, with a minimum saving of 1% and a maximum saving of 163% (i.e. some cases resulted in a net payment rather than net bill). Those with high levels of PV export benefitted more than those with low export or without rooftop PV, due to the more profitable local solar tariffs. It is worth noting that participant 3 enjoyed the greatest absolute saving (in dollar terms), despite not having PV, because participant 3 had the largest BAU electricity bill, and benefited most from the purchase of locally generated PV electricity. Furthermore, it is important to note that all savings observed by Participants are at the expense of the DNSP and, to a far lesser extent, the retailer. This is explored in greater detail below.

Table 3 Participant financial outcomes

Participant	PV capacity (kW DC)	Total bill over the period			Difference***	Percentage difference***
		BAU no PV	BAU	Local Electricity Sharing Scheme**		
1	0	$2,122	$2,122	$2,041	-$80	-4%
2	0	$475	$475	$469	-$6	-1%
3	0	$9,458	$9,458	$8,893	-$564	-6%
4*	26	$685	$185	-$117	-$303	-163%
5	0	$1,357	$1,357	$1,279	-$77	-6%
6*	14.8	$965	$499	$375	-$124	-25%
7	0	$614	$614	$603	-$12	-2%
8*	27.5	$712	$308	-$63	-$371	-120%
9*	3	$319	$193	$164	-$29	-15%
10	0	$266	$266	$235	-$31	-12%
11	0	$273	$273	$242	-$31	-11%

* This participant has solar installed (refer to Figure 1)
** Only results for scenario 7 are shown here, where battery capacity is 30kWh/30kW
*** BAU bill compared with local electricity sharing scheme bill.

All participants experienced some savings on their overall bills as central battery capacity was increased, but for non-PV participants this was negligible (< 1%). This is the expected result; the benefits of battery export are shared among all participants, while battery import payments only accrue to those with surplus rooftop PV. Subsequent simulations with a more equal share of rooftop PV among all participants demonstrated that the savings as a result of a central battery are more equally distributed.

Figure 12 shows the aggregate financial impact on each of the stakeholder groups (participants, DNSP, central battery, retailer). The increased capacity of a central battery appeared to have a negligible impact on the aggregate energy spend of the participants, especially compared to the large initial saving that participants gained by entering into the local solar sharing arrangement, or indeed installing PV. This is probably because PV exports and battery use are relatively minor. The tariff settings applied in this case study result in benefits for retailers compared with the BAU (with PV) scenario since they are no longer paying a tariff for exported PV and instead are earning revenue on locally traded PV. In contrast, the DNSP is significantly worse off, whilst the central battery earns minimal revenue (a maximum of $99 over the two month study period when a 30kWh battery is installed). As discussed above, these outcomes are a function of system sizing and operation and tariff design, which has not been optimised for this case study.

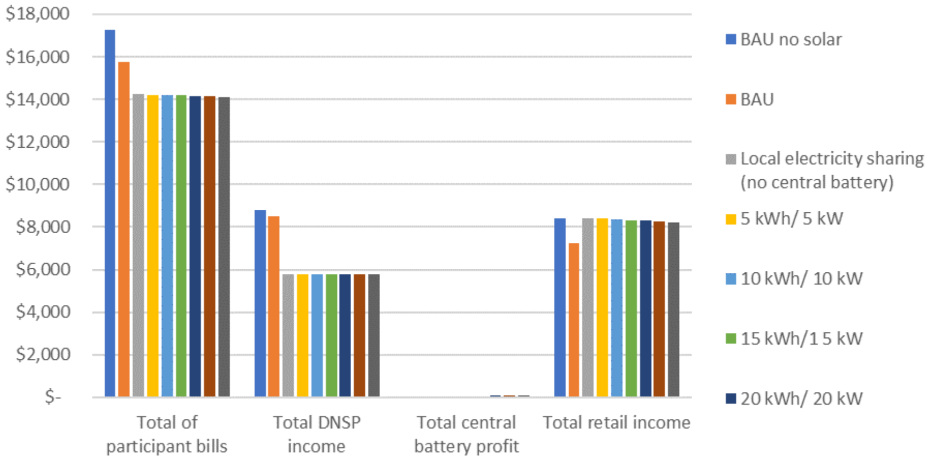

Figure 12 Financial outcomes for stakeholder groups (with varying battery capacity)

4. Discussion and Conclusions

The Byron A&IE case study demonstrates that the benefits of a local electricity sharing scheme for participants can be unevenly distributed. While financial outcomes of different tariff designs were not explicitly tested in this study, under the simple tariff arrangements modelled, PV-equipped participants were seen to benefit disproportionately from both local solar sales and the presence of a central battery system, highlighting the need for consideration of the desired social, community and fairness outcomes when designing local electricity sharing schemes. The results also indicate that tariff design has significant implications for total DNSP and retailer revenue, and should ideally reflect their costs and benefits. While Essential Energy would bear the greatest revenue reduction, it does not appear to receive significant network benefits in the form of reduced peak or network import/exports.

The installation of a 30kWh/30kW battery reduced total electricity import from the grid by only 1.6%, and reduced the total proportion of time which grid imports were required by 2.9%, with approximately zero import reduction on the peak day of the simulation period. Overall, there were minimal opportunities to use the battery given good PV-load match and low local PV exports. This highlights the importance of PV-battery sizing and the battery dispatch algorithm if the intention is to use the battery to provide network support services, which would be required if the Australian Energy Regulator is to allow the battery to be included in Essential Energy's RAB as proposed. Testing higher PV penetrations and using more sophisticated algorithms that target network benefits could enable the business case for a central battery to be tested.

If adopted widely, local electricity sharing schemes featuring significant generation and battery storage capacities may also have technical implications for network operators and the Australian Energy Market Operator as demand and generation profiles change across regions. Such schemes may present a useful tool for technical, economic and social integration of DERs, which involve a number of key stakeholders, namely individual consumers, communities, DNSPs and retailers. However, a number of regulatory challenges remain as local electricity sharing schemes evolve, in particular ensuring adequate customer protections and retail competition. Given these challenges, further work to understand the implications of such schemes is required, and robust, verifiable and open source modelling of different local electricity sharing scheme arrangements is likely to play an important role.

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Appendix A: Model Electricity Flow Calculation Overview

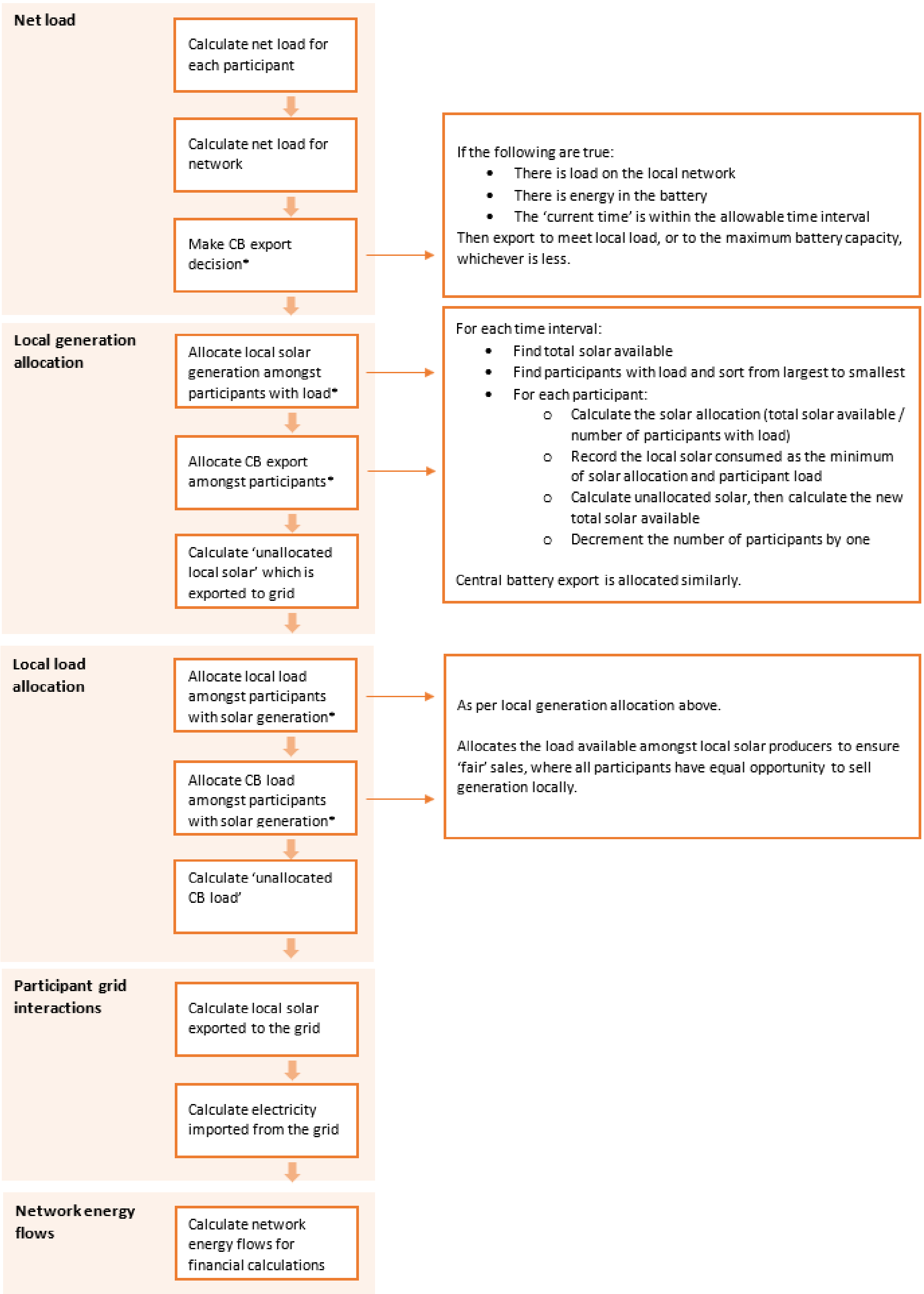

Figure 13 Model electricity flow calculations

Appendix B: Retail and network tariffs applied in the case study to electricity imported from the grid

Table 4 Enova retail tariffs applied in case study

Tariff component	Units	LV Small Business Anytime	LV TOU <100MWh
Connection charge	($/day)	$1.65	$6.55
Block 1 charge	(c/kWh)	0.3113	-
Block 2 charge	(c/kWh)	0.278	-
Block 1 volume	(kWh/day)	54.7945	-
Peak charge	(c/kWh)	-	0.29
Shoulder charge	(c/kWh)	-	0.29
Off-peak charge	(c/kWh)	-	0.178
Peak 1	(hr)	-	07:00 – 09:00
Peak 2	(hr)	-	17:00 – 20:00
Shoulder 1	(hr)	-	09:00 – 17:00
Shoulder 2	(hr)	-	20:00 – 22:00
Off-peak	(hr)	-	22:00 – 07:00
Solar feed in tariff 1	(c/kWh)	0.10	
Solar feed in tariff 2	(c/kWh)	0.06	
Solar feed in tariff cut-off	(kW_p)	10	

Table 5 Essential Energy NUOS tariffs applied in case study

Tariff component	Units	Business Anytime	Business TOU
Connection charge	($/day)	$0.7789	$6.1644
Flat charge	(c/kWh)	0.13851	-
Peak charge	(c/kWh)	-	0.135409
Shoulder charge	(c/kWh)	-	0.123165
Off-peak charge	(c/kWh)	-	0.061697
Peak 1	(hr)	-	17:00 – 20:00
Shoulder 1	(hr)	-	07:00 – 17:00
Shoulder 2	(hr)	-	20:00 – 22:00
Off-peak	(hr)	-	22:00 – 07:00

Table 6 Local Electricity Sharing Scheme Tariffs

Electricity source	Tariff component	Description	Case study values
Local solar	Energy	Energy component for locally generated solar. Paid to the participant who owns the solar generator.	12 c/kWh
	Retail	Retail component for locally generated solar. Paid to the retailer (or 'embedded / local network service provider') when local solar is consumed.	6 c/kWh
	NUOS	Network component for locally generated solar. Paid to the party owning and operating the local network when local solar is consumed.	6 c/kWh
	Total	*Total tariff paid by participants for consumed local solar.*	*24 c/kWh*
Central battery local solar import	Energy	Energy component for local solar used to charge the central battery. Paid to the participant which owns the solar generator.	12 c/kWh
	Retail	Retail component for local solar used to charge the central battery. Paid to the retailer (or 'embedded / local network service provider').	6 c/kWh
	NUOS	Network component for local solar used to charge the central battery. Paid to the party owning and operating the local network.	6 c/kWh
	Total	*Total charge paid by central battery operator for local solar imported to charge the battery.*	*24 c/kWh*
Central battery export	Energy	Energy component for central battery export consumed by participants locally. Paid to central battery operator.	12 c/kWh
	Retail	Retail component for central battery export. Paid to the retailer (or 'embedded / local network service provider').	6 c/kWh
	DUOS (TUOS?)	Network component for central battery export. Paid to the party owning and operating the local network.	6 c/kWh
	Profit	Profit earned by central battery. Paid by participants consuming battery export to central battery operator.	2 c/kWh
	Total	*Total charge paid by participants for central battery export.*	*26 c/kWh*