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Sharing Benefits in Community Embedded Networks with Renewable Energy

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1. Abstract

The shift to low-emissions energy production has gained significant traction in Australia and around the world. Community Renewable Energy (CORE) projects are on the rise, reflecting the desire of communities to take control of their own energy goals, and embedded networks (ENs) are emerging as part of the CORE movement.

An EN is operated by an EN operator (ENO), who can purchase electricity at the parent point and on-sell it to customers within the EN. This provides the opportunity for innovative internal electricity tariff structures to be designed that can help meet community goals such as increased local renewable energy and improved equity impacts.

This study aims to understand the implications of Community EN arrangements and tariff design for the financial, environmental and social outcomes of those connected to the EN. An energy sharing EN model is used to simulate financial outcomes for participants and the ENO in a Community EN of 60 households as a function of:

- EN PV penetration, and
- internal retail tariff structure

It was found that with the appropriate internal settings all solar and non-solar customers could save an average of approximately $200 at all levels of PV penetration. However, arrangements with PV penetrations above approximately 50% were not viable as the ENO lost profitability since EN loads could be fully met by internal solar generation.

These results indicate that there may be some conflicts between Community EN financial, renewable and equity goals. While achieving all goals simultaneously can be difficult, it is apparent that the 'Community EN with energy sharing' model is a credible option in the CORE space to help meet community goals, and careful internal design can help ensure that the desired goals are prioritised. In addition, both non-solar and solar customers are able to benefit through a scheme such as that explored here, addressing a key inequity in the energy industry.

2. Introduction

"Community Renewable Energy is an approach to renewable energy development that involves the community in initiating, developing, operating, owning and/or benefiting from the project" (Community Power Agency, 2015). CORE initiatives are acknowledged as important contributors in the transition to a low-emissions energy market (Bauwens, 2016). They draw on the power of communities coming together to make a change, and by their very nature should serve the public interest as community participation is essential for successful deployment.

"*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*" (AEMC, 2015). Figure 1 provides a visualisation of an EN arrangement.

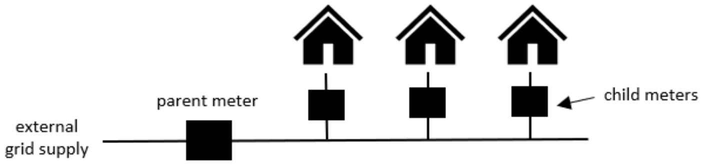

Figure 1. EN visualisation

They are generally operated by ENOs, which can purchase electricity and network services from the grid at the parent connection point and then sell this on to customers within the EN. Due to the aggregation of loads behind the parent meter, the load at the parent meter is likely to be large enough to be on a commercial tariff, which would have a lower usage charge than standard residential retail tariffs, and therefore costs passed onto customers within the EN can be lower than for a standard retail market customer (Bowyer, 2015).

"Community ENs" can be defined broadly as ENs that are owned by and/or provide benefits to the community of households connected to them. If there are renewables behind the parent meter, which is a common motivation for a community energy project, particularly with falling costs of distributed PV, they can therefore be classed as a subset of CORE and be used to facilitate CORE initiatives. Given that the ENO can set the tariff rate they pass on, there is an opportunity for innovative tariff structures to be designed to meet the goals of the community (Bowyer, 2015).

2.1. Motivations behind the CORE movement

There are many reasons for communities or parties within a community to engage in CORE projects. Firstly, the current pace of sustainable energy policy developments in Australia is generally perceived to be lagging behind technological advances, driving communities to take their own actions to meet local sustainability goals (Bowyer, 2015). Similarly, community-owned electricity sharing schemes (which are classified as CORE initiatives) are seen as a way to move away from traditional electricity grid arrangements and attain local energy autonomy (Stringer *et al.*, 2017). CORE initiatives may also provide a valuable and sustainable income stream to the community (Adams and Bell, 2015), since internal tariffs in Community ENs can generate monetary savings for participants compared to them remaining with market-offers. Further, the sale of energy produced by the community may generate income which can be used for additional community projects (Wen *et al.*, 2013).

2.2. Assessing equity in CORE projects

Adams and Bell (2015) explore the equity issues associated with local energy projects. They refer to how the costs and benefits, risks and impacts of such projects may be unevenly distributed. Their findings also highlight the risks associated with the high upfront costs for such projects which contribute to being inaccessible to certain members of the community. Where the impacts, costs and benefits aren't clearly explained, even those who can afford the upfront cost, may not realise that the investment would be beneficial for them.

Incentives such as solar FiTs (Adams and Bell, 2015), and policy schemes (Rogers *et al.*, 2008), are recommended to help ensure individual participation in CORE projects, but many of these studies do not address the potential inequities that might arise due to the exclusion of participants who may not be able to afford the infrastructure costs but may still wish to participate. Chan et al. (2017) explored the use of community shared solar as a method to allow more inclusion in community projects. Although they discussed a variety of models in which communal solar arrays may be owned and consumers can purchase a certain portion of generated electricity, they focussed on offsite solar projects. While ENs are quite widespread in Australian shopping centres, airports and sometimes apartment buildings, community owned or run ENs focussed on supporting sustainable energy outcomes are a relatively new phenomenon, and there is scant analysis or published best practices assessing the impact of different arrangements on the outcomes for the participants or the community. Thus, given the potential of CORE EN projects to address inequities in the energy system and support RE deployment, this paper examines the impact of different PV penetration levels and different tariff arrangements on the financial outcomes for participants, the incentives for PV uptake and the equity implications. .

2.3. Existing Australian Community EN case studies

2.3.1. Byron Arts and Industrial Estate

The Byron Bay Shire in Australia is in the process of implementing a 100% Renewables initiative (ITP Renewables, 2017). Stringer et al. (2017) reported on a case study of a local energy sharing scheme for a pseudo-EN (essentially a peer to peer trading arrangement) in the Byron Arts and Industrial Estate. It modelled 11 commercial customers with and without solar, and quantified the financial outcomes for the participants, the DNSP and the retailer. Only simple flat and TOU tariff designs were tested. While there was limited quantitative comparison between outcomes for the customers in the EN, it was noted that the benefits of the local electricity sharing scheme were unevenly shared, providing a key opportunity for further research.

2.3.2. PV for Apartment Buildings

Roberts, et al. (2017) explored the potential for PV in apartment complexes to offset apartment loads. They included details on three designs for such a scheme – individual solar behind the meter (BTM), shared solar BTM, and an EN – and discussed the financial benefits for the complex as a whole. The results indicated financial savings for the complex when implementing an EN arrangement with and without solar, but only presented financial outcomes for the building as a whole. As such, Roberts identifies a “clear need for more detailed analysis of the distribution of costs and benefits between all stakeholders under a wide range of financial settings” (p.11).

2.3.3. Nerara Ecovillage

Nerara Ecovillage is currently under construction in the NSW Central Coast Region and includes a Community EN. It is an example of a ‘greenfield’ EN as the internal infrastructure will be purpose-built for this project. Bowyer (2015) conducted an in-depth analysis into potential arrangements for Nerara Ecovillage EN, exploring residential and commercial electrical load and water supply options, including a preliminary exploration of the implications of different internal tariff designs. However, the paper did not propose assessment criteria for appropriate tariff design and therefore did not specifically assess the tested tariff designs.

Existing Australian studies of CORE EN projects have explored community embedded networks in greenfield scenarios, apartments and commercial settings, but not for existing communities of stand-alone residences. These studies have not attempted to quantify distributional impacts across different types of participants in CORE ENs, and have provided only a preliminary exploration of the impact of PV penetration levels.

The objective of this paper is:

> *To understand the implications of PV deployment and internal EN tariffs on financial, environmental and social outcomes for participants in Community ENs and use this to evaluate the place of Community ENs in the CORE space.*

3. Methodology

To fulfil the objective of this study, we propose criteria for assessing the appropriateness of EN arrangements, use a model developed in Python to simulate a Community EN with energy sharing, and under different arrangements, calculate outcomes for the for the ENO, compare financial and equity outcomes between participants with and without solar and A/C, and assess the incentives for PV deployment. An existing Python model developed for use in the study by Stringer et al. (2017) and adapted for this purpose.

The model can track electricity and financial flows for participants and the ENO, with an inbuilt energy sharing regime that allocates excess locally generated solar amongst participants before exporting via the parent-point of connection to the main grid. The critical model inputs required were half-hourly load profiles for each participant, half-hourly solar generation profiles for each participant, and solar and tariff pricing and timing for the required tariff types[1].

The Community EN modelled is a 'brownfield' design, rather than a 'greenfield' design such as that in Bowyer et al., (2015). A 'brownfield' design is one based predominantly on existing infrastructure in comparison to 'greenfield' which uses purpose-built infrastructure. Brownfield Community ENs, such as existing communities of houses, e.g. community housing precincts, don't require significant new infrastructure beyond the necessary metering.

3.1. Data grouping

Participant load data was sourced from the Ausgrid Smart Grid Smart City (SGSC) dataset, and solar data was sourced from the Ausgrid 300 Solar Homes study, both for the year July 2012-June 2013. The demographic data available in the SGSC set allowed customers to be grouped by house type.

A Community EN with 60 participants (households) was chosen to represent a 'brownfield' community in which this type of EN might be applied. The key assumptions used for selecting participants for the EN included: no gas, so that the load profiles could be assumed to include all electric appliance use, no pool pumps, to ensure the controlled load (CL) data was all water heating, and no solar water heating, to simplify interpretation of the data. Participants both with and without air-conditioners (A/C) were included in the Community EN.

The characteristics of the Community EN used in this study are as in Table 1:

Table 1. Characteristics of Community EN in this study

Number of households (participants)	60
Number of non A/C participants	15 (25%)
Number of A/C participants	45 (75%)[a]

[1] More comprehensive details of model logic may be found in the paper. The original model script may be found here: https://github.com/luke-marshall/embedded-network-model

The altered model scripts used in this study may be found here: https://github.com/emily-banks/embedded-network-model/tree/emilyfinal and https://github.com/emily-banks/embedded-network-model/tree/fast

Annual load (inc CL)	449 MWh

[a] This figure was determined by consulting census data from the ABS (2014)

Participant annual consumption (including CL) ranged from approximately 3000 to 12000 kWh for non A/C customers and 2000 to 17000 kWh for A/C customers, with A/C customers having higher daytime usage than non A/C.

3.2. Case modelling

The PV penetration cases used for testing are presented in Table 2:

Table 2. Overview of test cases

Case name	Case
Base	No EN, no participants with solar
No solar	Within EN, no participants with solar
25% solar	Within EN, 25% of participants have solar (assigned randomly)
50% solar	Within EN, 50% of participants have solar (assigned randomly)
75% solar	Within EN, 75% of participants have solar (assigned randomly)
100% solar	Within EN, all participants have solar

For the modelling of all scenarios with solar (25-100%), controlled load (CL) data for all participants (solar and non-solar) was shifted to be between 11am and 3pm to minimise exports at the parent point (since no FiT is received here), and solar data was scaled to have each system between 4 and 5 kW to reflect current system size trends. Several iterations of randomly assigning solar data to households were conducted to achieve a spread of results.

3.2.1. Setting the internal tariff rate

The base case was tested with each participant not within an EN, on a flat tariff with the price set at 15% below both fixed and volumetric charges provided by EnergyAustralia (2018), since customers on a market offer tariff are likely to pay around 15% less than on a standing offer (AEMC, 2017; Roberts, et al., 2017). Each tariffs scenario within the EN had an additional discount of 12% applied to the volumetric charges only based on achieving a balance between customer savings and ENO profit (fixed charges remained constant to reflect the costs of supplying electricity).

Four internal tariff cases were tested for each PV penetration case (excluding the base case). These were:

- Flat tariff with 12.5 c/kWh FiT and 12.5 c/kWh local solar charge[2]
- Flat tariff with 15 c/kWh FiT and 15 c/kWh local solar charge
- TOU with 12.5 c/kWh FiT and 12.5 c/kWh local solar charge
- Seasonal TOU with 12.5 c/kWh FiT and 12.5 c/kWh local solar charge

The appendix gives the rates and structures for each of these internal tariffs.

[2] The local solar charge is the rate for which excess locally generated solar is sold to neighbours

3.2.2. Setting the tariff rate at the parent-point

A commercial tariff is usually applicable at the parent-meter of an EN since the load is a similar scale to a large commercial customer. These rates are lower than residential rates, giving the ENO some flexibility in setting the internal tariff paid by participants. Commercial rates depend on the annual load of the customer, which in this case is the aggregate of the annual loads of the participants, equal to 449 MWh (Table 1).

The 2018/2019 Network Price List for the Ausgrid Zone (Ausgrid, 2018) was used to obtain Network Use of System (NUOS) component of the commercial tariff at the parent point assuming a Low Voltage connection. The EA305 tariff applies to a customer with this annual load range of 160-750MWh. The retail component of the commercial tariff, which is subject to a market offer, was set at an additional flat rate of 9.5 c/kWh based on the approach of Roberts et al. (2015) (Table 3). The combined tariff was applied to total energy imports to determine the ENO's costs at the parent connection point, assuming a billing period of July 1-June 30 for the capacity charge. Note that there is typically no FiT offered to commercial customers for solar export, so any excess generation exported to the grid provides no financial benefit.

Table 3. Commercial tariff applied at parent point

Tariff Code	**Tariff Name**	**Network Access Charge (cents/day)**	**Network Energy Charges**			**Network Capacity charge (cents/kVA)**	**Retail charge (cents/kWh)**
			Peak (2-8pm) (cents/kWh)	Shoulder (7am-2pm and 8pm-10pm) (cents/kWh)	Off-peak (cents/ kWh)		
EA305	LV 160-750 MWh (System)	2138.3581	5.8132	2.6617	1.2152	40.1023	9.5000

No additional charges were added to account for EN infrastructure costs as ENO's are prohibited from retrieving these costs via tariffs. In addition, these are highly case dependent and not always paid by the ENO (Roberts et al., 2018).

4. Results

4.1. ENO profit

To calculate the benefits to the ENO, the profit at the parent point was determined for each case by applying the commercial tariff rate to energy imports then subtracting this from the total bill paid by all participants to the ENO. For the EN to be viable, it needs to make profit. This may be fed back into the community in a variety of ways, for example, to community projects, for communal solar or storage, etc., and can also be used to recover capital costs. Figure 2 gives the annual profit made by the ENO for each PV penetration level, with each tariff structure.

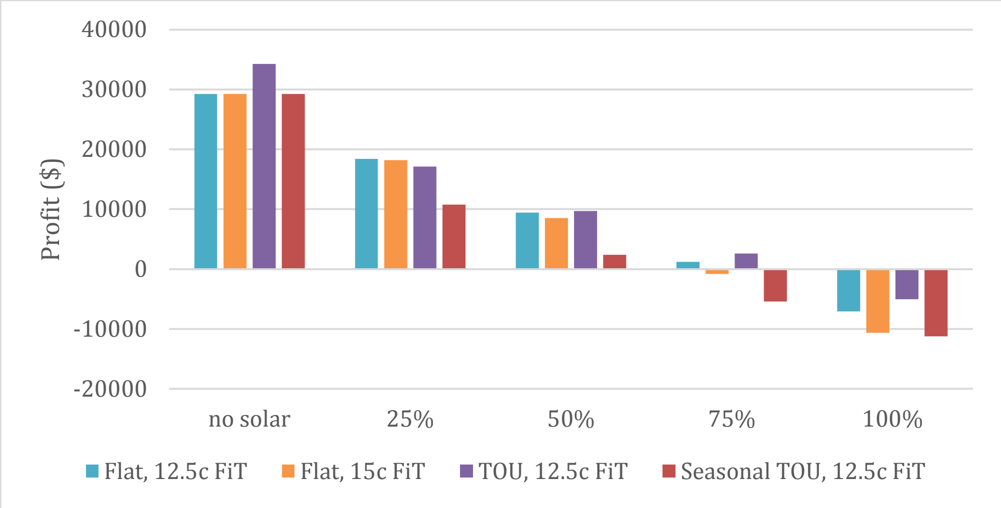

Figure 2. ENO annual profit variation with PV penetration and tariff structure

The ENO profit decreases as solar uptake increases because there is less demand for electricity from the main grid due to the increase in local solar sharing, which reduces the profit it makes from the difference in the retail and commercial tariffs. This is partly offset by the benefits it receives from the decrease in demand charges at the parent point due to greater solar generation.

Note that the decrease is not linear. Between the no solar and 25% cases, the ENO profit decreases by approximately $15,000 and between the 75% and 100% cases only by approximately $10,000. At the high solar percentages, the level of solar within the EN becomes ‘saturated’, and so instead of being sold to other customers in the EN, it is exported to the main grid. At these levels, there are three different impacts, which when combined, result in smaller incremental losses for the EN:

1. For each kWh of solar electricity generated, the losses incurred because of reduced sales of grid electricity are smaller (because they were often already buying internal solar),
2. For each kWh of solar electricity generated, the benefits from reduced demand charges are reduced (because the new demand charge peaks are outside the time of solar generation), and
3. The ENO does not receive any payment for electricity exported to the grid.

Importantly, at 75% and 100% solar uptake, the ENO is losing money, or is close to losing money, posing obvious issues for its viability. This means that this scheme cannot support higher PV penetrations at the modelled internal tariff rates. Correcting this would involve increasing the internal retail tariff offered to customers and/or decreasing the local solar payments, but this would mean that customers would not make as much (or any) savings from joining the EN.

ENOs earn the least profit under the Seasonal TOU scenario. This is most likely because the PV generation reduces sales during the Summer and Winter peak time from 2pm-8pm. Under the TOU, the peak time is 5pm-10pm year-round.

The increase in FiT to 15c/kWh understandably decreases the ENO profit as the solar percentage increases because a greater proportion of the solar generation is exported to the main grid, for which, as above, the ENO receives no payment.

Overall, losses (or gains) for the ENO due to changing the internal tariff range from $12,000 to $4,000 per year, so the internal tariff design is a significant design consideration for the viability of an EN. At high PV percentage this loss can be approximately 25% of profits, although the absolute amount is greater at lower PV penetrations.

4.2. Participant Impacts

To analyse outcomes for participants, the yearly bill for each participant was calculated and the spread of outcomes presented for solar and non-solar customers with and without A/C. To ensure that customers purchase electricity from the ENO, it is important that their bills are lower than in the base case (no EN). Figure 3 gives the total bill (averaged across all PV penetration cases) for each participant within the EN compared to what they would pay outside it (base case). Because of space constraints only the results for the flat tariff are shown.

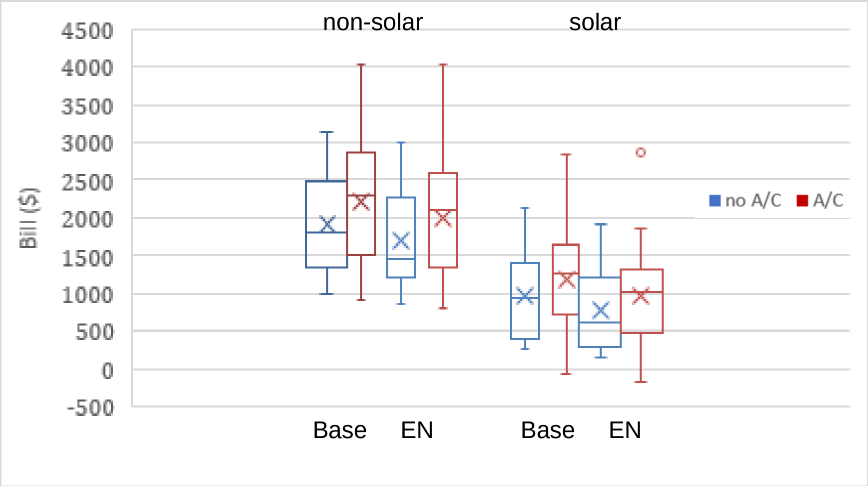

Figure 3. Annual bill for each customer averaged across all PV penetration cases

As is expected, each participant benefits from being in the EN compared with the base case on average across each of the PV percentage cases. This is due to a combination of the solar sharing scheme and the cheaper retail rate (12% discount on volumetric charges). Bills for A/C customers are greater than for non-A/C customers, given the greater annual load. The bill for solar participants is also significantly smaller, as expected.

The savings accessed by **non-solar** customers by joining the EN and participating in the buying component of the solar sharing scheme are given in Figure 4.

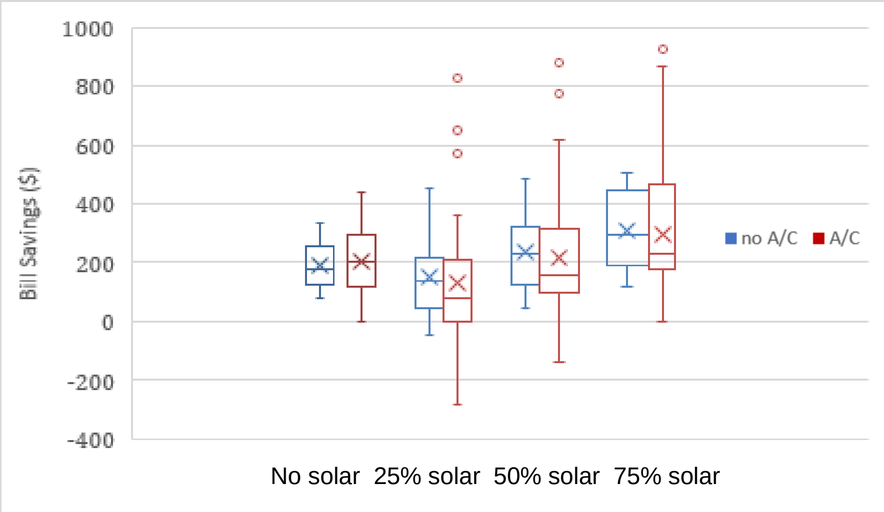

Figure 4. Savings on total bill compared with base case for non-solar customers on flat tariff

Non-solar customers can benefit most from participating in these schemes when there is a high percentage of solar and therefore greater potential for solar sharing. Simply being within the EN in the no solar case also produces savings given the discount on retail tariff rates. The decrease in savings for non-solar customers between the no solar and 25% solar cases has likely occurred due to the shifting of CL to daytime for all participants for all the solar cases. Gains from receiving shared solar at the FiT rate to meet regular load does not outweigh losses of paying for the CL at the retail rate (which is higher than the CL rates) for such a small pool of shared solar available. In this case, having these participants remain on the CL tariff for a low solar percentage case could avoid this problem.

The savings accessed by **solar** customers in participating in the EN and solar sharing scheme are given in Figure 5.

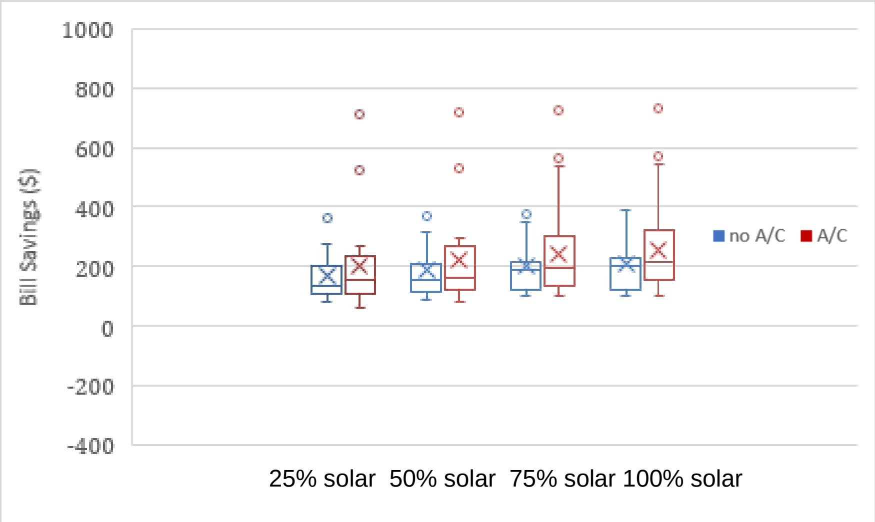

Figure 5. Savings on total bill compared with base case for solar customers on flat tariff

Solar customers save more in an EN when there is a higher solar percentage. But savings are quite consistent and only vary by approximately $50 per year.

Overall, solar and non-solar customers can access similar savings within the EN scenarios modelled. Although solar customers do benefit more, compared to the base case (conventional grid), an EN decreases the inequity between solar and non-solar customers in that the non-solar customers can purchase solar electricity at the FiT rate, rather than at the full retail tariff. While a higher FiT incentivises PV deployment, the 15c FiT skews savings further towards the solar customer. Here there is inequity between solar and non-solar customers, as savings to the former increase while savings to the latter decrease with the FiT change.

5. Discussion

5.1. Overall Financial Benefit

The results indicate that significant financial benefit can be achieved by both the ENO and participants in Community ENs through access to cheaper parent-point/child-point rates and solar sharing schemes.

The overall financial benefit to the ENO was greatest in the Solar TOU case because the peak rate was applied all year round. Income to the ENO would decrease on both TOU tariffs if customers shifted their load out of the peak period and into the solar time. Participants were also able to access savings to varying degrees simply by participating in the EN. These savings averaged approximately $200 for joining the EN to access the 12% discount on retail tariff charges and the solar sharing scheme, and an additional $900 if solar was installed.

It was found that customers with solar and A/C accessed the largest savings, given the existence of the solar FiT and the suitability of the load profile for accessing benefits of solar sharing. While non-solar customers were somewhat disadvantaged (with negative savings) in some cases due to the shifting of controlled load data into peak times, this could be remedied to ensure that participants would not exit the EN.

5.2. Encouraging PV Deployment

As was expected, the higher the FiT, the greater the benefits from installing PV, thereby encouraging PV deployment by the customer. The payback times for PV when in the EN were approximately 1 year less than outside the EN because of the higher FiT rates (although this effect would have been offset to some extent by the on-site use of solar avoiding a lower retail rate in the EN). Although not shown here, the 15 c/kWh FiT approximately doubled yearly participant savings compared to the 12.5 c/kWh FiT. As more customers installed solar, the per customer savings for doing so decreased, although by a small amount relative to the approximately $900 saved.

5.3. Equity Outcomes

Equity outcomes under community ENs were assessed based on differences in benefits between groups of participants and the payback time for installing PV. A key inequity in the energy industry is that between solar customers and those who may wish to install solar to access savings (or encourage RE production) but cannot afford it. The Community EN in this study addresses this inequity to some extent through the solar sharing scheme, because non-solar customers can access electricity at a lower rate than the daytime EN retail rate.

Another point apparent in the results from modelling that has not often been considered in the literature is the disparity between A/C and non-A/C customers which was likely due to the shape of their load profiles. While the difference is not of major financial significance, it is still an interesting finding. A/C customers pay more overall for their electricity for all cases explored, but the savings they were able to make on their bill in the solar sharing scheme were greater than for non-A/C customers in some cases. This is potentially problematic as it reduces the disincentive for high energy consumption. On the other hand, the proportions of bills saved are similar across A/C and non-A/C customers and this may be a more important driver of energy consumption decisions.

6. Conclusions

The results of this modelling suggest that a Community EN with solar sharing can be a credible option for a community wishing to meet various goals through a CORE project. All that remains is the question of prioritising what is most important to the community.

It is evident that there are inherent conflicts between some aspects of CORE EN design. While ENO profits are highest at low levels of solar penetration, savings may be greatest to participants at higher levels. While a higher FiT encourages PV deployment, this is at the expense of non-solar customer savings and ENO profit.

There are, however, some aspects of a CORE EN that can address these tensions and help to meet community goals through careful design, which would not be available on-market. Where an ENO may lose profit under some arrangements, customer savings may be viewed as more important, or if potential customer savings are compromised by ENO profit, this can be fed back into the community through initiatives such as RE deployment or communal batteries.

Limitations of the research should be considered when interpreting results, including the limited scope of inputs explored, and the lack of consideration of impacts on the wider electricity market. Nevertheless, it is hoped that this study may simply encourage a broader discussion of social outcomes in relation to energy projects.

7. References

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8. Acknowledgements

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9. Appendix

Table 4. Flat tariff used for modelling with no EN

Flat Rate	Price (inc GST)
Consumption charge	27.4423 cents per kWh
Daily charge	78.6335 cents per day
Controlled Load 1	**Price (inc GST)**
Consumption charge	11.2761 cents per kWh
Daily charge	3.366 cents per day
Controlled Load 2	**Price (inc GST)**
Consumption charge	14.8291 cents per kWh
Daily charge	13.9315 cents per day

Table 5. Flat tariff used for modelling within EN

Flat Rate	Price (inc GST)
Consumption charge	24.1492 cents per kWh
Daily charge	78.6335 cents per day
Controlled Load 1	**Price (inc GST)**
Consumption charge	9.923 cents per kWh
Daily charge	3.366 cents per day
Controlled Load 2	**Price (inc GST)**
Consumption charge	13.0496 cents per kWh
Daily charge	13.9315 cents per day

Table 6. TOU tariff used for modelling within EN

TOU rate	Price (inc GST)
Peak (5pm-10pm) (weekday only)	44.3489 cents per kWh
Shoulder (7am-5pm)	23.203cents per kWh
Off-peak (10pm-7am)	14.1522 cents per kWh
Supply charge (all year)	**Price (inc GST)**
Daily	78.6335 cent per day
Controlled Load 1	**Price (inc GST)**
Consumption charge	9.923 cents per kWh

Controlled Load 2	Price (inc GST)
Consumption charge	13.0496cents per kWh

Table 7. Seasonal TOU tariff used for modelling within EN

Summer rates (1 Nov-31 Mar inclusive)	**Price (inc GST)**
Peak (2pm-8pm) (weekday only)	44.3489 cents per kWh
Shoulder (7am-2pm, 8pm-10pm)	23.203cents per kWh
Off-peak (10pm-7am)	14.1522 cents per kWh
Winter rates (1 Jun-31 Aug inclusive)	**Price (inc GST)**
Peak (5pm-9pm) (weekday only)	44.3489 cents per kWh
Shoulder (7am-2pm, 9pm-10pm)	23.203cents per kWh
Off-peak (10pm-7am)	14.1522 cents per kWh
Autumn/Spring rates (1 Apr-31 May and 1 Sep-31 Oct inclusive)	**Price (inc GST)**
Shoulder (7am-2pm, 9pm-10pm)	23.203cents per kWh
Off-peak (10pm-7am)	14.1522 cents per kWh
Supply charge (all year)	**Price (inc GST)**
Daily	78.6335 cent per day
Controlled Load 1	**Price (inc GST)**
Consumption charge	9.923 cents per kWh
Controlled Load 2	**Price (inc GST)**
Consumption charge	13.0496 cents per kWh