CONSORT

Bruny Island Battery Trial

Project Final Report

Participants' Solar and Battery System Financial Performance

Evan Franklin[1] (contact author), Archie Chapman[2]

[1]University of Tasmania and [2]The University of Sydney

Evan.Franklin@utas.edu.au

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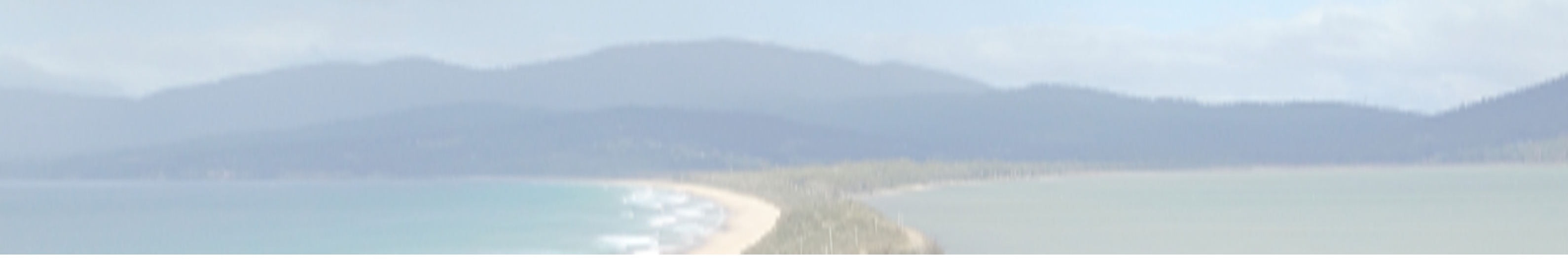
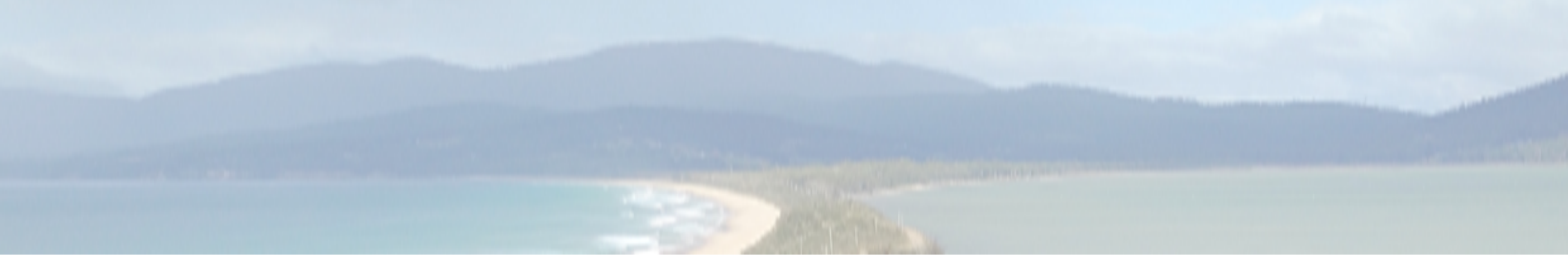
http://brunybatterytrial.org

CONSORT: "Consumer Energy Systems Providing Cost-Effective Grid Support" is a collaboration between The Australian National University, The University of Sydney, University of Tasmania, Reposit Power and TasNetworks. The Australian Government, through the Australian Renewable Energy Agency, is providing $2.9m towards the $8m trial under its Research and Development Program.





Executive Summary

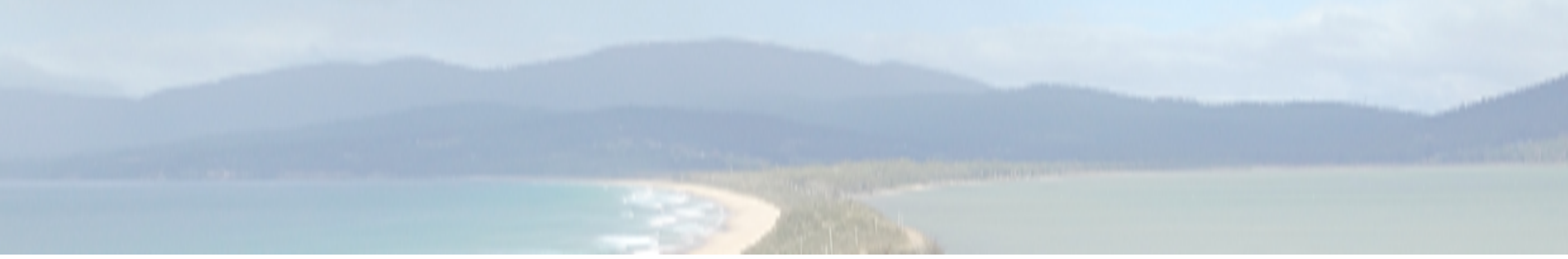
Householders generally chose to participate in the battery trial at least in part based on their judgement of the likely financial outcomes for them as energy consumers. The project team gave some initial, generic guidance to the participant group on what they might expect if they installed a solar and battery system. System vendors and installers generally then provided more detailed estimates of financial outcomes for individual participants, based on systems proposed for installation. However, an accurate assessment of the benefits of participants' solar and battery systems is only possible once detailed knowledge of energy use has been obtained. In this report we use data at sufficient level of detail, collected during the trial period itself, to analyse the financial performance of each participant's battery system. Furthermore, we break the financial outcome or benefit into each of its relevant constituent components: solar financial benefit, battery (simple) financial benefit, local energy optimisation financial benefit, and network support financial benefit.

While the analysis and conclusions contained in this report are specific to the project trial participants, they certainly have significance and wider meaning beyond the project context itself. The project participants in the Trial had diverse backgrounds, incomes and situations. While there were some gaps in age groups, the participant households did represent a range of [post-early adoption] residential energy consumer-types, particularly in terms of the quantity of and timing of energy consumption and make-up of households and dwelling type. Some findings of this analysis, therefore, may be considered to be broadly transferable to other Australian jurisdictions, notwithstanding the fact that both Time-Of-Use tariff settings and typical peak demand times do vary from region to region. The range of participant financial benefits seen in this project, and especially the relative value of the constituent components, can reasonably be expected to be broadly consistent with what might be observed for households in other jurisdictions, for similar sized solar and battery systems, household energy loads, and situations.

What this report covers?

This report provides analysis of individual participant data and key findings on each of the following:

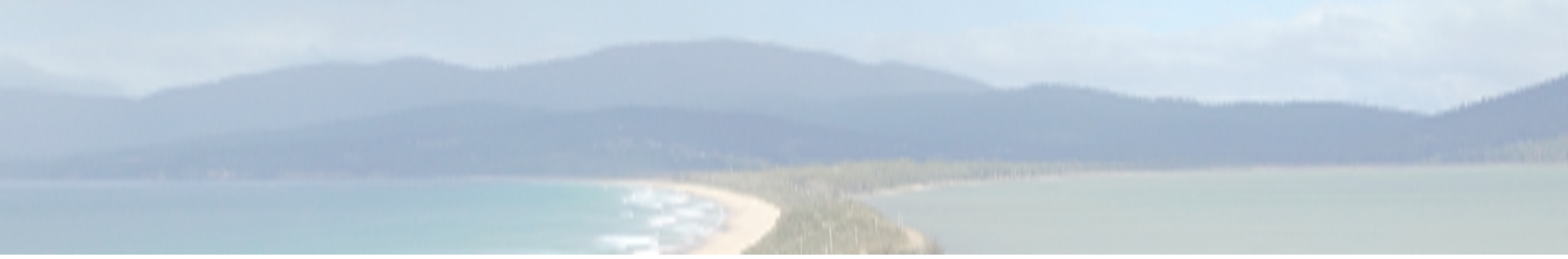
- Assessment of validity of data collected from household systems, and identification of data issues that could be resolved to enable extended analysis
- Assessment of financial performance (benefit) of each household's system on an annualised basis
- Decomposition, via accurate system energy balance modelling, of energy cost savings into PV, battery, Reposit algorithm and network support payments (including costs of participation)



- Assessment of relationship of customer financial benefit with tariff type and customer demand size.
- Assessment of benefit that would accrue under alternative conditions, primarily if customers switched tariffs or required particular levels of battery capacity reserved for back-up.

Summary of key findings

- 19 out of 34 systems had good quality data available for analysis; benefit analysis unable to be performed yet for remaining systems
- Average participant solar self-consumption: 41% without battery, increasing to 68% with battery
- Participant's batteries were utilised to shift daily an average of between 2.5 kWh and 6 kWh of load, with an average across all participants of 4 kWh.
- Total energy savings from all installed system sources ranged from $630 up to $1550 per year, with an average participant saving of $1100.
- Savings attributable to solar generation only: range $380 up to $1230, with $750 average
- Savings attributable to battery system (excluding Reposit optimisation and network support payments): range $60 up to $350, with $200 average
- Savings attributable to the TOU arbitrage component of Reposit's optimisation algorithm: for Flat-rate tariff customers ~ $0; for Time-Of-Use (TOU) customers: range ~$0 up to $140, with $70 average
- Savings (benefit) owing to NAC-driven Network Support Payments (16 separate peak demand events over 12 month period): $115 average across all participants. The cost of participation meanwhile, which is the lost benefit (or marginal cost) as a result of having a battery act to support network peaks rather than to meet household load, was no higher than $7 for any given participant, with an average of $1.40 across all participants for the 12 month period.
- Participants currently on flat-rate tariff would all be better off (in the order of at least $100 to $200 for most) by switching to TOU tariff, provided that their heating and hot water use is not particularly limited to weekday peaks only.
- All participants currently on TOU tariff would be worse off, by up to $500 per year, if they switched back to a flat-rate tariff.



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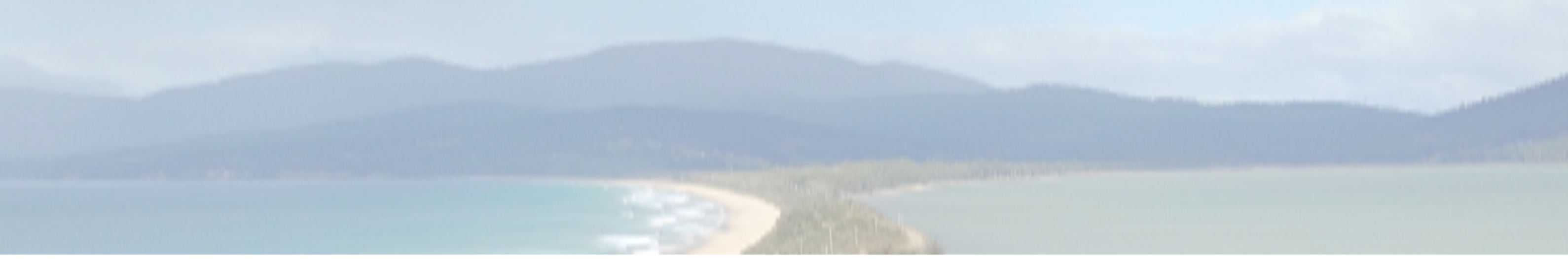


Approach and methodology

The analysis of this report uses time-series data, collected via Reposit, from each participant's system, along with summary installed system data from TasNetworks. We apply first a simple calculation of baseline costs to service total household load, assuming that all load would have been met by imported electricity in the absence of any installed PV / battery system, and then calculate energy costs based on actual observed PV, battery and meter average power data that result from the installed solar PV system and Reposit battery actions.

We subsequently calculate two counterfactual or reference energy costs: one for a scenario where the PV system had been installed without a battery, and one for a scenario where only a simple battery controller (based on maximising solar self-consumption) had been installed. This approach allows us to compare directly for each participant the value of the PV system only, the value of the battery (with simple logic) only, and the value of the advanced Reposit controller. In order to make such comparisons fair and accurate, it is necessary to model the battery and some of its key operating properties (efficiency, capacity, state-of-charge limits, inverter limits etc.) such that modelled behaviour reflects well observed behaviour for each system. We employ a data-driven approach, using measured data to infer key battery performance properties for each battery, which are then subsequently used by the battery model. The model itself is then validated against observed data for systems and time periods where tariff settings ensure that the Reposit algorithm should perform exactly a solar self-consumption function.

While this method ensures generally a fair comparison between measured and modelled systems, accounting for inaccuracies in measured data by applying the same driver of any inaccuracy in each case, some data which falls out of a reasonable range (efficiency > 100% for example) are discarded and analysis outcomes not reported here.

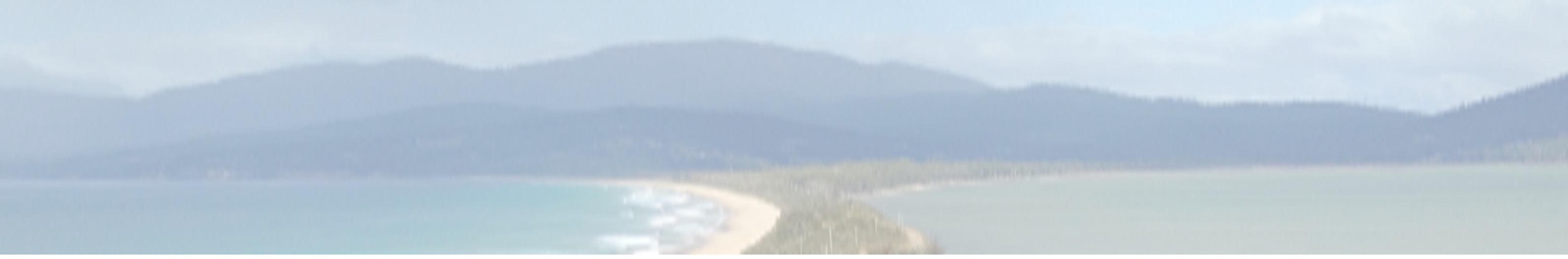
Data and data validity

Data used in this analysis comes from a variety of sources, described herein.

Metadata and time-series data used in analysis

The following metadata is used in the analysis:

- Installed PV and battery system details for participants, collated and supplied by TasNetworks on 24 January 2019. Primarily used in this analysis to determine 'reported' PV system size at each installation.
- Participant Aurora energy tariff list, provided by Reposit on 4 March 2019, and indicating dates upon which load transferred to TOU tariff, it at all, and/or back to flat rate tariff. This list does not include tariffs that customers were on prior to the trial and



does not indicate where customers may have other separate meters and metered loads (such as tariff 41 meters, or any second connection points).

- List of every“GridCredits” payment (either NAC-driven dispatch or Manual Fleet scheduled dispatch) made to and communicated to participants for the entire trial period,supplied by Reposit on 6 March 2019.

Time series data used in analysis is half-hourly interval data collected from each participant’s system, from 26 February 2018 to 25 February 2019. This period excludes the initial intensive manual Fleet scheduled dispatches in December 2017 and early Jan 2018, and NAC testing phase during Jan and Feb 2018. The period includes all of the NAC-driven battery dispatches of the trial and some manually scheduled dispatches at the end of September 2018 while the 11 kV network’s voltage regulator was out of service. Data points used are:

- average **meter power** (for preceding half hour period), measured by Reposit measurement hardware at revenue meter / grid connection point;
- average **generated solar PV power** (for half hour period), data transferred from third-party hybrid PV/battery inverter, and likely measured at DC side of inverter at PV array incoming MPPT connection point; and,
- average **battery power** delivered to battery (for half hour period), data transferred from third-party hybrid PV/battery inverter, and likely measured at DC side of inverter at battery pack / BMS incoming connection point.

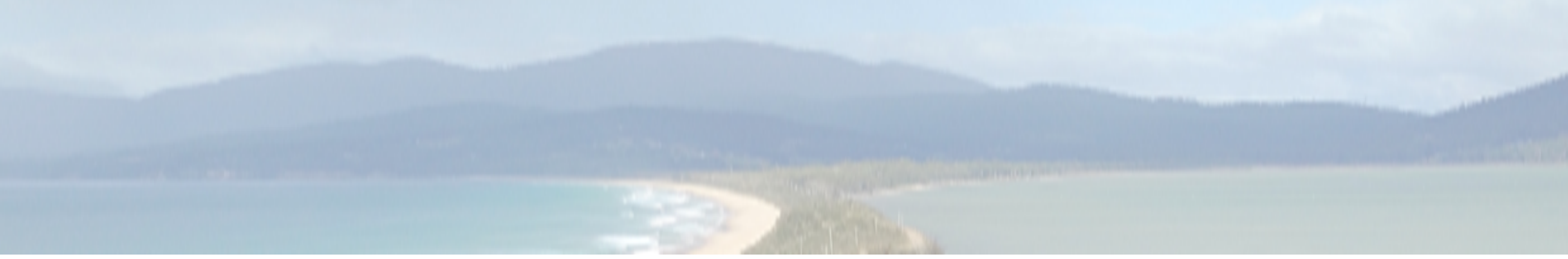
Note: Revenue meter data, collected for billing purposes by participants’ energy retailers,was not available when analysis was conducted. Inclusion of this data could be useful in future analyses, providing independent verification of detailed time-series data or potentially providing a means to better estimate financial performance in cases where significant chunks of time-series data are missing.

Data granularity and possible inaccuracies

The use of half-hourly data, rather than more granular data, can result in some inaccuracy with calculated revenue (or cost savings), owing to the averaging effect.

PV System benefit analysis:

The potential inaccuracy will be most prevalent when assessing the value of PV generation in servicing household load.This can be illustrated via a simple example: an average PV generation of 2 kW over a half hour time interval will apparently service completely (using half-hourly data only) a 2kW average load, and thus save the full cost of buying that 1 kWh of energy at the prevailing retail tariff. However, if the load was actually 1.5 kW for half the time interval and 2.5 kW for the remaining half, the PV system could only actually provide an



average power to the load of 1.75 kW, the remaining 0.25 kW (on average) is exported at the FiT rate. In $ terms the savings in servicing the load in this example, reduces from 26.4c (calculated on basis of half-hourly data) to 24.2c (actual) for flat-rate tariff customers. For TOU customers the difference would be about the same during peak tariff periods, but considerably lower during off-peak periods. Half-hourly data will usually result in a calculated cost saving or benefit for solar PV that is slightly higher than the actual saving.

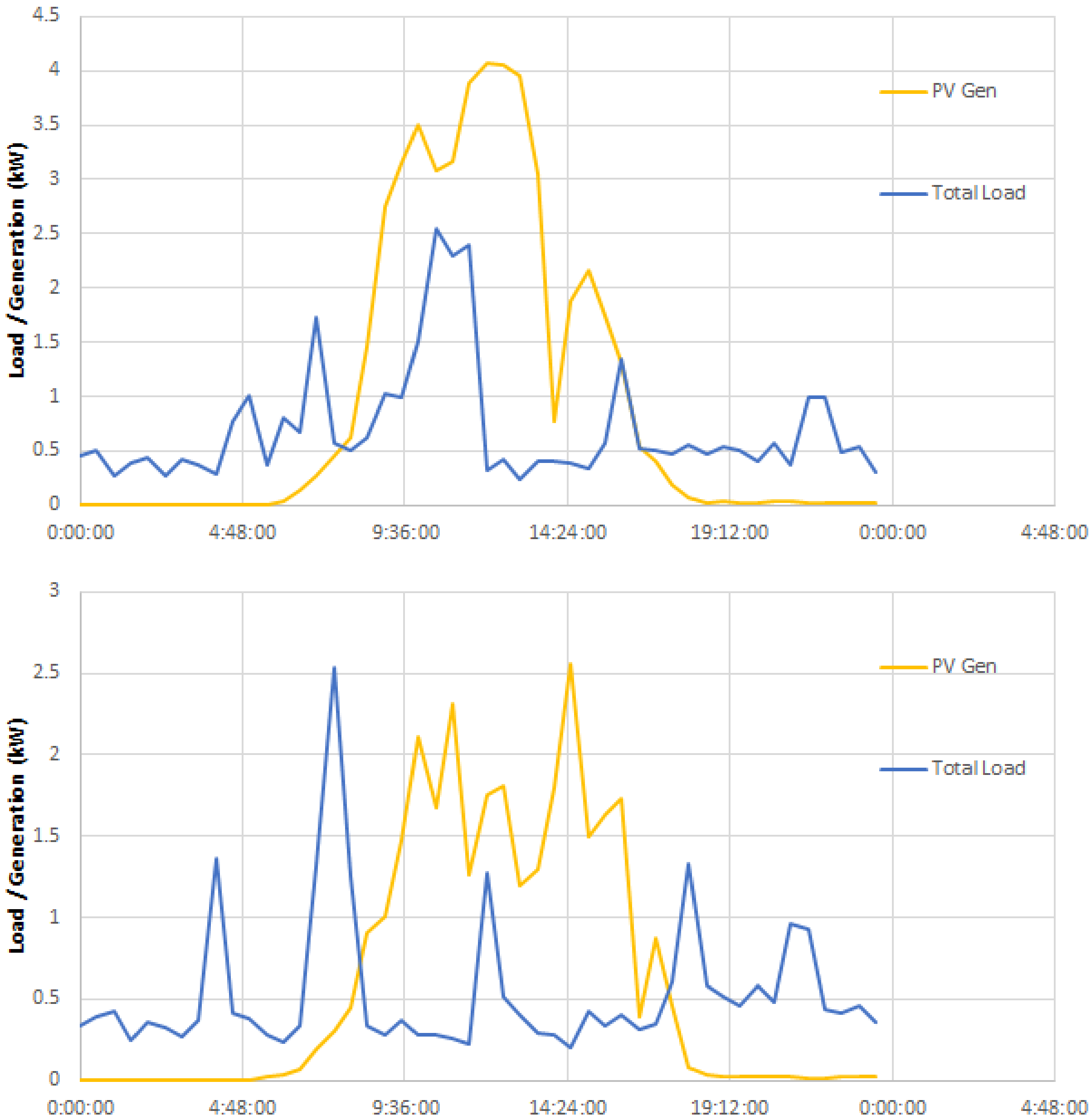
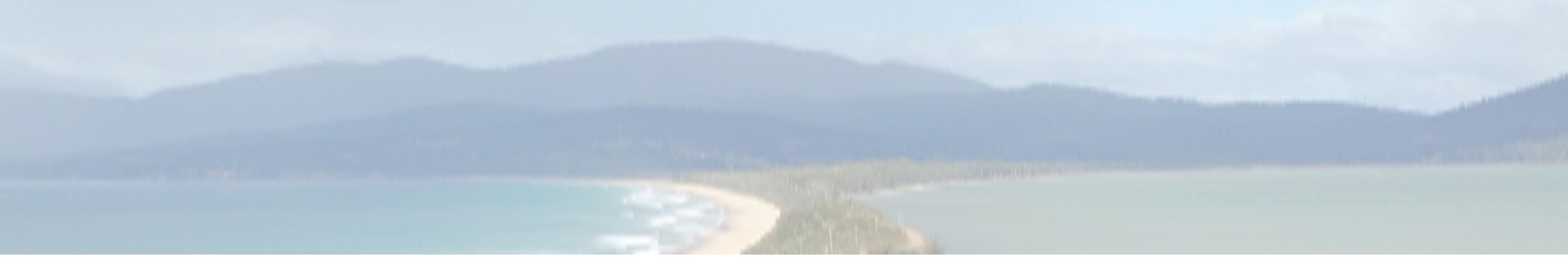


Figure 1. Examples of load and generation profiles using half-hourly data. Inaccuracies in analysis owing to lack of data granularity generally is only a potential issue at times when half-hourly average load and generation are very similar values, not often the case in practice.



It is impossible to determine definitively the impact of this on the analysis outcomes for the Bruny trial participants, unless assessing side by side each system using half-hourly and for example 5-minutely or 1-minutely data. This has not yet been conducted for this analysis, but could be done if deemed necessary. However, it is reasonable to have good confidence that the half-hourly data gives good enough accuracy for our purposes, based on inherent knowledge of household load and solar generation behaviour and inspection of profiles for customers on a variety of days. The issue with half-hourly average data is only a problem if the instantaneous value of PV generation varies between being greater than or less than load during a given interval. Load variation on short time scale is the most likely cause of this. But observations of data suggest that for the vast majority of days and participant systems generation is significantly higher than load other than usually for the two cross-over periods at the start and end of the solar generation period (examples shown in Figure 1).

We conclude that the inaccuracy introduced into calculations in this analysis of energy cost savings owing to PV generation alone, because of using half-hourly time interval data are likely no more than 5%. Given the uncertainty (at this stage) about customer tariff before the trial itself, along with the variation in both customer load and in solar generation from year to year, and thus in the direct comparison between not having a PV system and having a PV system, we think this is more than acceptable for this analysis.

Battery System benefit analysis:

The inaccuracy in calculation of the benefit of battery systems, because of the half-hour time interval data limitation, will certainly be smaller than is the case for calculation of the benefit of PV generation, and indeed is likely to be quite small. Battery operation itself is akin to that of mathematical ‘integration’, essentially the same as for half-hour average data. In other words, changes in load or generation on a short-time scale impact the total energy stored (or released by the battery in that time interval, and are thus accurately reflected by the average battery power flow (energy x time interval). Furthermore, there are likely to be very few instances only where battery power flow and net / revenue meter power flow both alternate direction within a single time interval, and thus where average values over the interval are insufficient to provide accurate calculations of value or benefit.

The main limit for half-hourly average analysis is that which might occur if/when the instantaneous load or generation (or, in fact, any difference between them) exceeded the power capacity of the inverter (5 kW for most customers) for a significant part of the time interval, while the average value is still below the capacity limit. We believe this will occur on a sufficiently small number of occasions so that the total effect on analysis outcomes is very small.

Moreover, we show later in this report that implementation of a simple self-consumption maximisation (SCM) model using half-hourly data yields results that are comparable with data measured on systems employing the Reposit algorithm, if customers are on flat-rate tariff. In this case, where customers being on a flat rate tariff, the Reposit system effectively operates in SCM mode and this provides a suitable validation reference..

Time-series data completeness, detection of invalid data

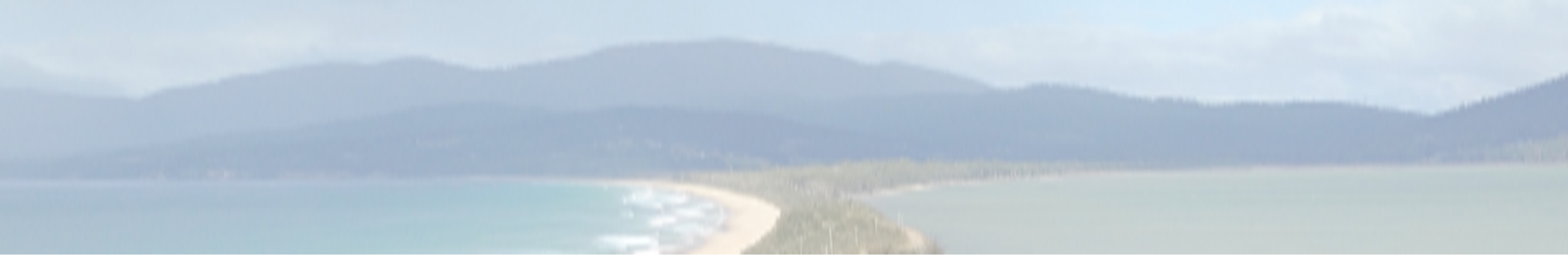
Data is analysed carefully to detect anomalies. This has generally been done by first inspecting data sets closely to see what type of anomalies might exist, then setting thresholds above or below which an anomaly is declared significant. Thresholds are chosen based on intuition and a basic evaluation of likely impact on final analysis. It is possible that not all anomalies are detected and it is arguable that the thresholds chosen are not correct.

Some systems have large sections of missing data: five systems have for example greater than 10% of the data missing. While we have reported on the % completeness of each data set (literally the % of empty data points over the year), we do not flag this as a warning. If the value is too much less than 100% it may trigger one of the other data warnings. All but two systems where detailed analysis results are reported on have > 99% data availability.

The main data warnings or errors used to screen data in this analysis are as follows:

PV output low: a calculation is made primarily for information only, based on reported generation (from time-series PV generation data) as a fraction of a reference system annual generation amount. This reference annual generation is based on an insolation of 1500 kWh / m^2, an annualised performance factor of 0.83, a customer-specific system size contained within the metadata and the data completeness fraction. In the event that measured PV generation in any timer interval exceeds the system size, the metadata system size value is over-written with the maximum observed average power output plus 5%. These values are consistent with a good quality solar installation on a north facing sloped roof in southern Tasmania. Any participant where the ratio of measured to reference generation is below 0.7 (a generous tolerance) is noted as such. These systems should be investigated further, and information on these systems has been passed on to and acknowledged by TasNetworks and Reposit.

Implied 2-monthly battery efficiency > 100%: over any appreciable period of time the energy coming out of a battery should be less than the energy going in. In other words there are losses and the round-trip efficiency is < 100%. Based on measured data, we refer to this as the implied efficiency. For Li-ion batteries this figure (excluding inverter losses) should be about 90%. For short periods of time energy out / energy in may exceed 100% (meaning that the SOC has increased) but not over a time scale of multiple days or weeks. We calculate a rolling 2-month average for each system and then flag any system which has an implied efficiency 100% or larger. Any such system clearly has data problems since this efficiency is an impossibility. It is not known whether the data problem is isolated to the time period where efficiency is > 100% or whether all data is invalid, but these systems are not included in analysis results. This situation is possibly owing to faulty data measurements, although we



note that it is the same measurement point (and likely same device) for both charge and discharge.

Negative total load occurrences: Total household load is calculated simply by adding PV generation power to meter point power and subtracting battery charge power (noting that battery charge power is a negative value during discharge). Total household load should always be greater than 0. Occasionally it could be expected that very low loads may appear as negative values, owing to compounding data measurement errors. However, a number of households the sum of all negative load values is significant. We flag any household where the total of all negative load values exceeds 100 kWh per year. Likely this occurs where one or more of the three measurement devices or data processing methods (including third-party inverter measurements and onboard data processing) is faulty or in error.

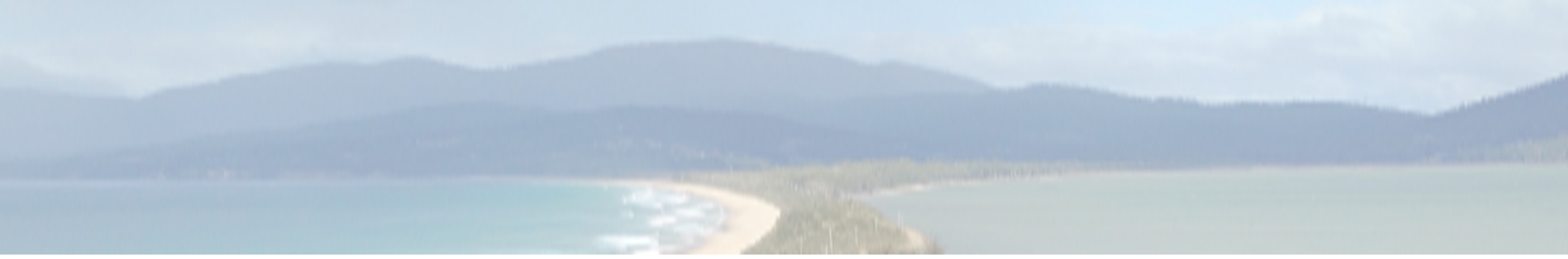
Implied battery efficiency < 70%: finally, we exclude from analysis any systems where the average battery efficiency over the entire period is less than 70%. Two cases where this is flagged, the implied battery efficiency is well under 50%. This situation is possibly owing to faulty data measurements or data handling, although we note that it is the same measurement point (and likely same device) for both charge and discharge, or could be because of very low battery cycling as a result of very low real or apparent / measured load.

Based on these defined criteria for data acceptability, data for 19 out of 34 participant systems was deemed to be complete (or sufficiently complete) and free of any significant data validity issues. The remaining 15 systems each had one or more data validity issue identified. The most common data validity issue observed (9 systems) was that of implied average battery efficiency being > 100% for an extended period. All analysis in this report, unless clearly specified otherwise, pertains to the 19 systems with data deemed free of validity issues.

Tariff types, tariff information and split tariffs / transitioning tariffs

Measured time-series net meter data is measured at one point only. It is assumed that this corresponds to the same tariff to which the battery and PV system is connected. If a participant has any other meter or meter point on the premises (whether in same location or even in the same meter and on T41, or in different physical location) then this is not included in any energy cost calculations. In other words, if a participant has a system connected to a T31 meter but also has a T41 meter (or two different registers in a single meter - if that has been allowed for new PV connections), then when we say the total energy costs are $1000 for a participant, that refers the cost of net consumption for load on the T31 meter only. This is certainly the case for a number of Bruny trial participants. All relative calculations (savings due to PV, battery etc.) are still valid, but special care needs to be used when comparing TOU and flat-rate customers and the impact of tariff switching.

It is assumed that all customers were on single rate tariffs until the solar / battery installation took place, and then chose to either stay on that tariff or change to the Time-Of-Use (TOU)



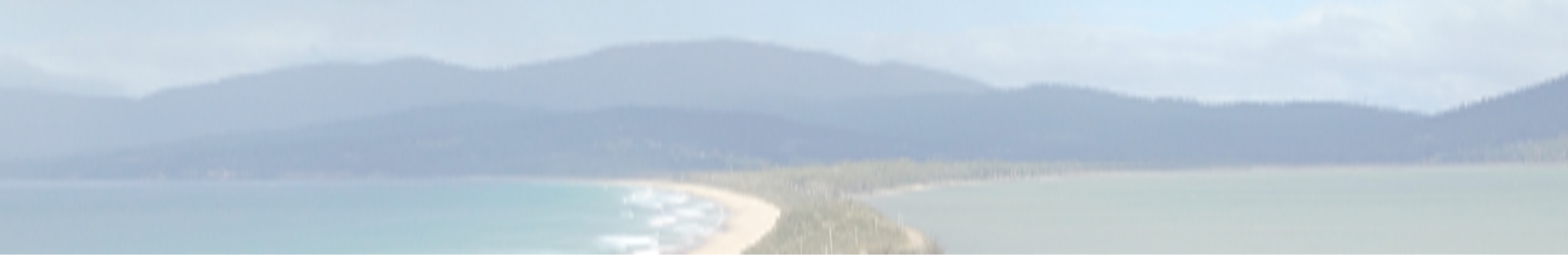
tariff. Some participants subsequently elected to change tariffs partway through the trial. Participant tariffs and tariff changeover dates (if applicable), as employed in the analysis of this report, are listed in the table below for all 34 participants. The householder's decision making process and drivers for that decision, when deciding whether or not to change from flat-rate to TOU is explored in further detail in the Final Social Science Report [1].

In the table, SR refers to flat or single rate (SR) tariff (Tariff 31), with energy cost of 26.431 c/kWh. TOU refers to Time-Of-Use with energy costs of 31.948 c/kWh between 07:00 AEST and 10:00 AEST and between 16:00 AEST and 21:00 AEST Monday to Friday inclusive and 14.876 c/kWh at all other times.

Tariff	Changeover Date
SR	
SR	
SR	
SR	
SR	
SR	
SR	
SR	
SR	
SR	
SR	
SR	
SR	
SR	
SR	
SR/TOU	TOU Start: 2017-06-15
SR/TOU	TOU Start: 2017-09-07
SR/TOU	TOU Start: 2017-09-18
SR/TOU	TOU Start: 2018-02-02
SR/TOU	TOU Start: 2018-03-08
SR/TOU	TOU Start: 2018-09-14
SR/TOU	TOU Start: 2018-10-18
TOU	
TOU	
TOU	
TOU	
TOU	
TOU	
TOU	
TOU	
TOU	
TOU	
TOU	
TOU	
TOU/SR	SR Start: 2018-02-21

Network support events

All networks support events with non-zero NAC price are included in the analysis. Support payments made to customers and the approximate cost of the battery participating (forgone normal revenue from battery operation) considered. The following events are included:



- 16 NAC peak event days (Easter, ANZAC Day, June long w/e, July school holidays, January artificial peaks)
- ~ 6 manual fleet dispatch days (September/October)

Derived and assumed modelling inputs: a data-driven approach

The approach of this analysis is to calculate accurately the incurred total energy costs for each participant under the ‘actual’ observed scenario (with solar and Reposit-optimised battery installed), and then to calculate the financial benefit provided by the solar and battery compared to a baseline or reference case where no solar or battery had been installed. This benefit is further decomposed into component benefits, by calculating what the response would have been (what the net load at the revenue meter at each time interval) under a range of scenarios.

To ensure fairness in comparing scenarios for each participant’s system, and to account for difference between systems and deviations from their technical specifications, the key system characteristics are determined for each system from the observed data alone. The obvious alternative, to apply, for example, a fixed battery efficiency (i.e. as stated in vendor documentation), battery storage capacity and inverter capacity for each system, has been shown through our analysis to yield significant errors, rendering comparison virtually useless.

Battery efficiency & self-discharge

The key principle here is that the modelled battery should, over the course of the analysis period have the same total energy efficiency as the observed battery does from the available battery data. Thus, an implied battery efficiency is calculated for each battery system, based on the 12 month’s worth of time-series data used in this analysis (that is, 26 Februrary 2018 to 25 February 2019). Most batteries have observed implied efficiency of between 85% and 95%, with an average of 90%.

Self-discharge, a feature of Li-ion (and most batteries) even when idle, is not modelled separately. The approach of modelling self-discharge by first determining and including a constant self-discharge rate (eg 50 W) and recalculating the underlying efficiency was considered for this analysis. However, preliminary inspection of the data reveals a large variation in this rate (not appearing at all for some). Self-discharge is however incorporated in average efficiency values, and so is not unaccounted for. This is particularly valid since modelled and observed batteries have the same total cycling and energy throughput.

Battery energy capacity

The nameplate energy storage capacity and also the Battery Management System (BMS) state-of-charge (SOC) value are not used in the analysis for reasons similar those described above. The actual usable storage capacity, taking into account charge and discharge rates and implied efficiency is a much more accurate and fair value to use for comparison. The problem with such an approach (the problem with determining SOC generally) is determining for sure what a full cycle is.

For this analysis we create an implied SOC based on battery charge, discharge and efficiency and then observe the maximum change in SOC in a 24 hour period. Taking all of those daily variations we see a natural usable maximum emerge. To eliminate occasional extremes we use the 90th percentile value as the usable, efficiency-adjusted capacity in kWh. This is used in subsequent calculations.

Total household load calculation & inverter efficiency effects

Total household load is synthesised from the measured data. Measurement points for power flow is indicated in the schematic shown in Figure 2.

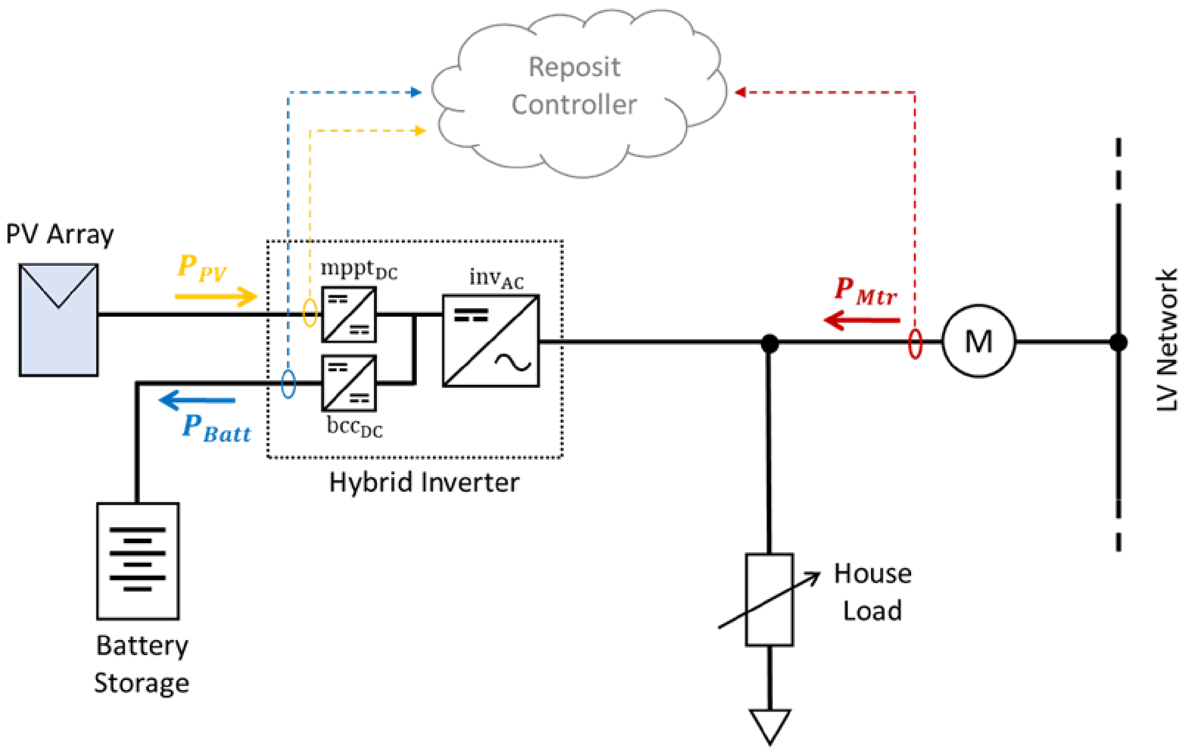
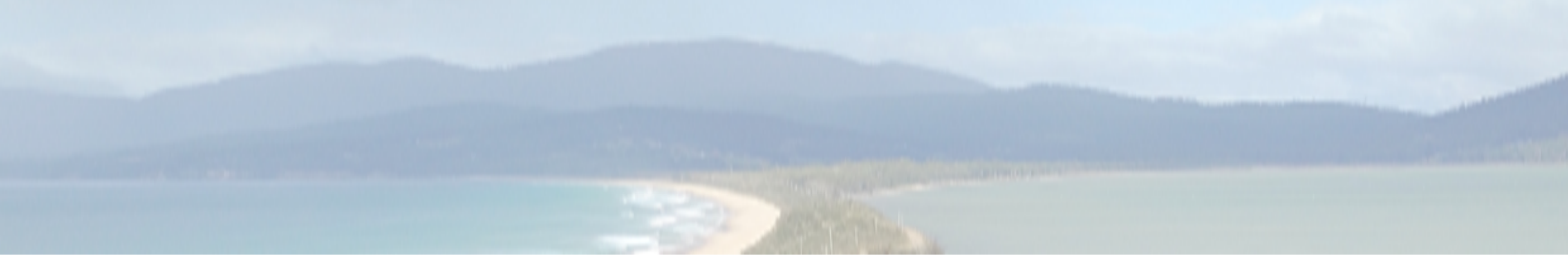


Figure 2 General schematic for hybrid PV / battery system configurations used in trial, showing measurement points for PV generation and battery power flow (within hybrid inverter) and main meter, with key power conversion blocks also shown. Household load is derived / calculated on the basis of these measured data points, with accurate calculations requiring inverter conversion efficiencies to be accounted for..

Total load is calculated for each time interval, using a simple summing of measured power flows, taking into account direction associated with each measurement. For accurate calculations, inverter DC-AC converter efficiency and PV and battery DC-DC converter efficiencies are required to be considered. Governing equations are shown below, with each



equation being applied according to the relative power flow at PV and battery respectively (note: in these equations the abbreviation 'bms' is used, but this should read 'bcc' for Battery Charge Controller).

For analysis in this report, efficiencies of DC-DC and DC-AC converters are set to 100%. This is done to remain consistent with the approach currently taken by Reposit, where an assumption that inverter efficiency is 100% is made, thus ensuring a like-for-like comparison between modelled and apparent observed outcomes. A more accurate approach would be to set these values to realistic fixed values, or to set them to be functions of power throughput as might be described in datasheets, literature or from more detailed models.

$$P_{Load} = P_{Mtr} + \eta_{inv_{AC}} \left(\eta_{mppt_{DC}} . P_{PV} - \eta_{bms_{DC}} . P_{Batt}\right) \quad \forall \quad P_{Batt} < 0$$

$$P_{Load} = P_{Mtr} + \eta_{inv_{AC}} \left(\eta_{mppt_{DC}} . P_{PV} - {}^{P_{Batt}}/_{\eta_{bms_{DC}}}\right) \quad \forall \quad P_{Batt} > 0 \quad and \quad \eta_{mppt_{DC}} . P_{PV} > {}^{P_{Batt}}/_{\eta_{bms_{DC}}}$$

$$P_{Load} = P_{Mtr} + {}^{\left(\eta_{mppt_{DC}} . P_{PV} - {}^{P_{Batt}}/_{\eta_{bms_{DC}}}\right)}/_{\eta_{inv_{AC}}} \quad \forall \quad P_{Batt} > 0 \quad and \quad \eta_{mppt_{DC}} . P_{PV} < {}^{P_{Batt}}/_{\eta_{bms_{DC}}}$$

Total household load for participants in this trial (from those systems that have no validity issues associated with collected data) ranges from a minimum of 6.4 kWh average daily consumption up to a maximum of 40 kWh average daily consumption, with an mean value of 18.7 kWh. For sake of reference, AER data (https://www.energymadeeasy.gov.au/) suggests that the average 1-person and 4-person household in postcode 7150 (Bruny Island) uses 16.7 kWh per day and 24.4 kWh per day respectively.

Impacts of power electronics efficiency

As indicated previously, results presented in this report were produced under the assumption of no power electronics losses in the inverter, to be consistent with the Reposit battery controller approach. However, PV and battery measurements for hybrid inverters are made at the DC side of the inverter (most likely on the external DC connection side of the converter) while load and revenue metering is on the AC side, as shown in Figure 2. Accurate determination of these power electronics efficiencies, themselves being functions of converter power transfer, would enable the most accurate calculation. This was outside of the scope of this analysis, and so consequent impacts were not included in detailed results. We do, however, briefly examine the type of and scale of errors that may be introduced as a result of ignoring these power conversion losses.

The main consequences of incorrectly assuming 100% inverter efficiency is twofold:

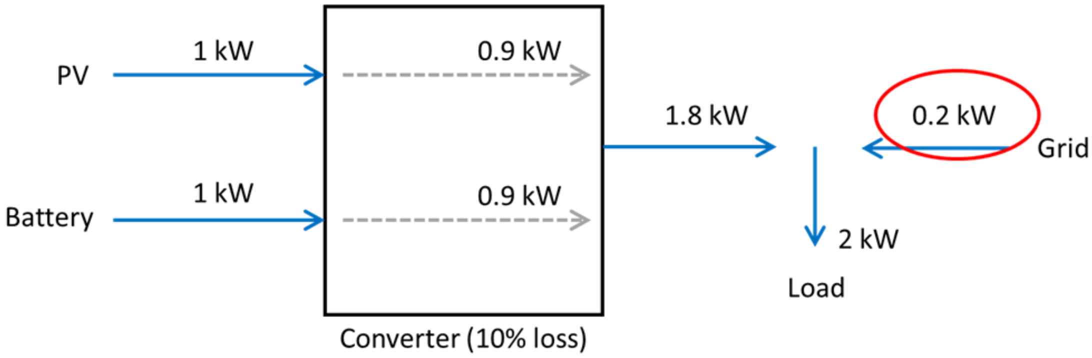
1. Calculated implied loads are inaccurate (less PV or battery discharge power is actually seen at the load point than has been assumed) and thus calculations of benefit are inaccurate (generally overstated) and use of historical load for forecasting will be slightly inaccurate.
2. Battery scheduling decisions will be slightly sub-optimal, since for instance scheduled / requested battery discharge rate should be larger (or schedule battery charge rate smaller) than what has been calculated from raw data alone.

Losses depend upon whether the battery is charging from PV generation or grid, and impact of losses on actual total load depend upon whether battery is charging or discharging.

To assess the impact of conversion losses on the calculation of a solar / battery system's financial performance, we model system performance and benefits using with a DC-DC converter for PV and battery of 98% each, and DC-AC or AC-DC converter efficiency of 96%, which are reasonable values (perhaps at the lower end) for typical converter hardware designed for this purpose at a normal operating point. In modelling battery operations, both calculated load values and subsequent battery charge/discharge instructions are adjusted to account for these efficiencies. We find that, using these converter efficiencies and adjusting load calculations and battery actions accordingly that the estimated daily load is reduced by about 1.1 kWh, the average calculated annualised benefit due to solar PV generation reduces by $65 (more solar generation is lost in conversion and thus unable to serve as much load), while the benefit owing to batteries reduces by $25 (again, more energy lost in conversion and therefore not stored and/or not able to service load). On average there is no change to the additional benefit provided by the Reposit algorithm, with minor increases or decreases observed for various participants.

The sub-optimal battery scheduling impact is perhaps not as immediately obvious, but can be very easily illustrated via a simple example (Figure 3). We can see, for this illustrative scenario with 90% full inverter efficiency, that the goal of minimising grid imports can only be achieved if losses are accounted for in the scheduling of battery discharge.

*<u>Illustrative example – converter losses **not accounted for** in battery scheduling</u>*



*<u>Illustrative example – converter losses **accounted for** in battery scheduling</u>*

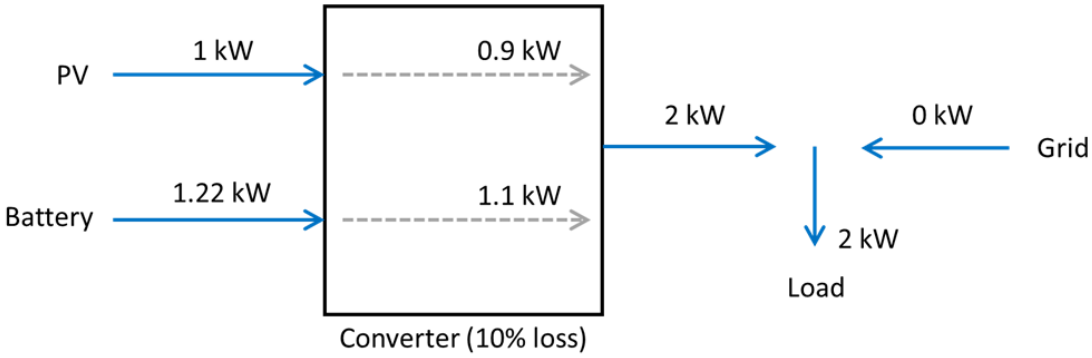
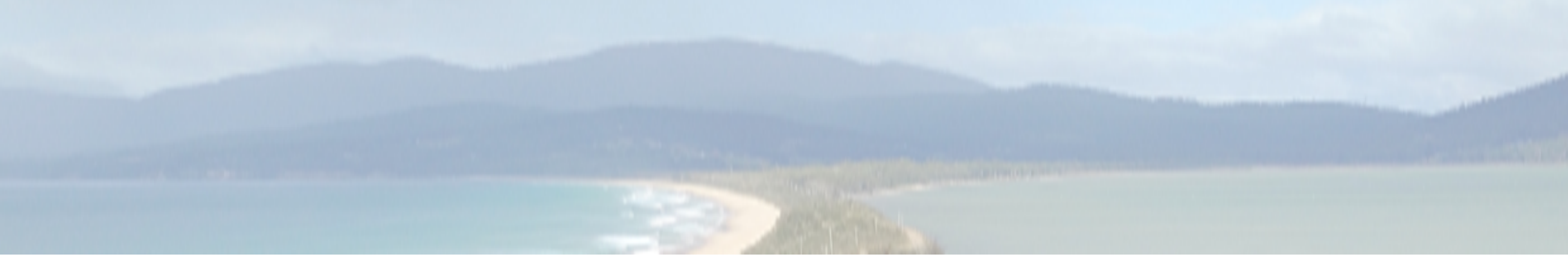


Figure 3. Illustration showing the importance of accounting for converter losses in solar and battery inverters. Incorrectly accounting for losses results both in an incorrect battery charge/discharge request of inverter.

We do not in this report included modelled system outcomes under the scenario where losses are accounted for in load calculation but where battery charge/discharge instructions are not altered to account for these losses. This is the scenario under which actual battery optimisation is currently operating on installed systems (battery scheduling decisions are made based on load calculations that are not adjusted for losses), and will most likely lead to lower battery benefit than could be achieved if losses had been accounted for correctly. It is anticipated that the difference would likely be small, perhaps in the order of $20 over a one year period, but no such analysis has been done to determine this. Nonetheless, it would be easy and sensible for any future battery control implementations (either simple SCM, or forecast & optimisation) to ensure that converter losses are accounted for appropriately.



Inverter power capacity

We use the absolute maximum discharge rate or charge rate that was observed for each battery. These values are consistent, for each system, with the nameplate ratings for the inverter used, as provided in the metadata files.

Battery / Inverter quantisation level

We assume that the inverter battery charge or discharge power is quantised, as reported, rather than a continuous function. We use a quantisation level of 0.05 kW for all inverters modelled, so as to more accurately / fairly represent the response of a real battery inverter.

Baseline / reference cost of serving household energy demand

For each household, a baseline or reference energy cost is first calculated. This is done simply by determining the applicable energy import tariff for each household at each point in time (some households transitions to / from flat-rate to TOU during the period inspected) and for each time interval determining the cost of supplying the total load. The sum of all time interval costs then represents the cost of energy for servicing that same load if the battery and PV system had not been operating (or had not been present at all) for the same period of time.

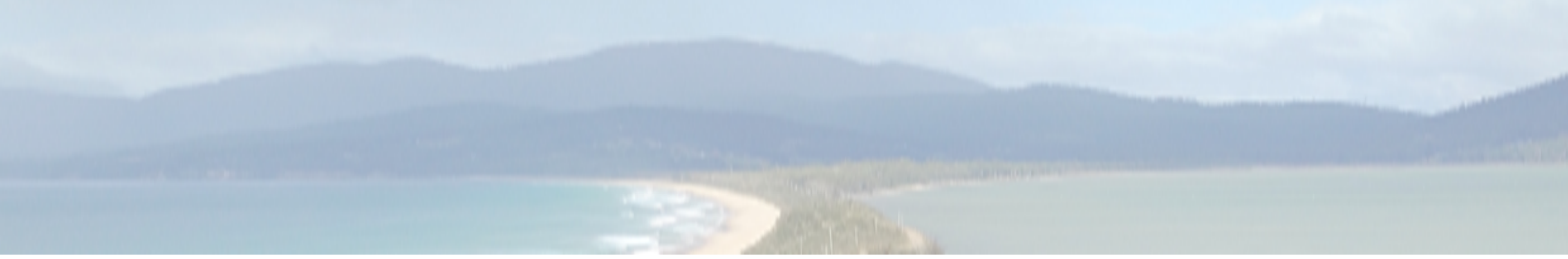
Note: although this provides a good indication of it, this doesn't necessarily represent the energy costs of that household in a year immediately prior to the system being installed, for three reasons:

- total load varies from year to year, and a household may have used more or less energy in preceding years
- a household may have changed tariffs between previous years and the current period after the PV/battery system was installed
- a household may have changed their energy behaviour (when energy was used for example) as a result of having had the PV/battery system installed.

Total baseline or reference cost of serving energy for participants ranged between $443 and $3,431, with an average of $1,511.

Observed cost of serving household energy demand (with solar & battery)

For each household, an observed cost of energy is calculated, based on metered power exchange for each interval. This measurements is based on the Reposit meter, which should be close to the consumer's revenue meter that is used for actual billing. This calculation simply takes the household's prevailing import tariff for each time interval and an export tariff of 8.541 c/kWh and used the average power flow into or out of the premises for that interval. A note is



made earlier on the potential inaccuracy that use of half-hour power flow average might introduce, noting again here this error can be significant but that it is anticipated to be nonetheless small compared to the impact of year to year variation in both household solar generation and load.

Battery SCM model description and comparison to observed data

The simple Self-Consumption Maximisation battery control model is entirely reactive, requires no knowledge of or forecasting of household load and solar generation. In a practical SCM control scheme (such as implemented by various battery system vendors), battery action (charge / discharge rate) is determined from instantaneous PV generation power and load power. For our SCM implementation, charge rate is based on half-hour average values (a note is made above regarding any potential inaccuracy that this might introduce), according to the following:

The lossy inverter modelling rules can written as,

> *If PV Gen (less DC and AC conversion losses) > Load:*
>
> > *Battery Charge Rate (plus DC conversion losses) = Min{excess PV power (less DC conversion losses), Batt / DC converter power capacity, (SOC_max - SOC)/time-interval};*
> >
> > *Exported Power = PV Gen (less DC conversion losses) - Battery Charge Rate (plus DC conversion losses) - AC conversion losses - Load*
>
> *If PV Gen (less DC and AC conversion losses) <= Load:*
>
> > *Battery Discharge Rate (plus DC conversion losses) = Min{(Load - PV Gen (less DC & AC conversion losses) plus AC conversion losses), Batt / DC converter power capacity, (SOC-SOC_min)/time-interval};*
> >
> > *Imported Power = Load - ((PV + Battery Discharge Rate)(less DC and AC conversion losses)).*

An example of observed battery action for a single 24 hour period for a participant on a flat tariff and with a relatively high generation and low load is shown in Figure 4. This figure shows data observed from an installed system (brown) with the modelled battery response using SCM algorithm shown alongside (green). There is no difference between the observed and modelled systems, in terms of both total energy flows and total costs. This holds true for any system where the participant is on a flat tariff. This shows that the battery / inverter model (with SCM) faithfully reproduces the actual observed response for a Reposit controlled system on a flat tariff, validating the modelling approach use in this analysis. Without a TOU tariff in place the Reposit algorithm can never do any better than a simple SCM algorithm (excluding any other functionalities that the Reposit algorithm may bring, such as network support payments for example).

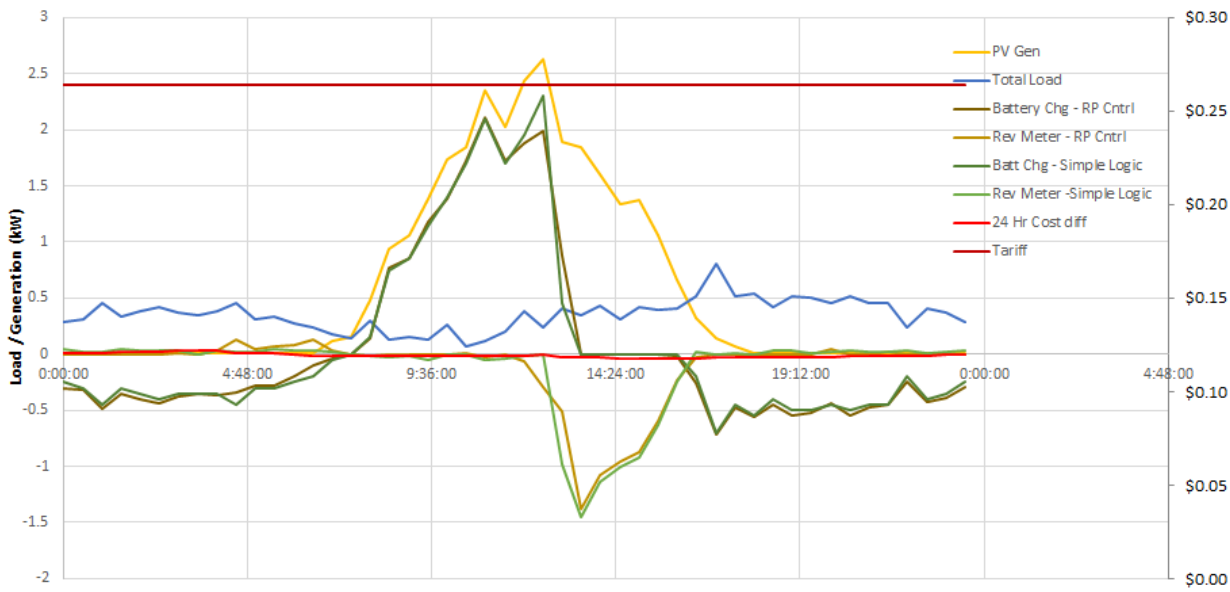


Figure 4. Example of generation (yellow), total household load (blue), battery charge rate (dark brown - observed with Reposit controller; dark green - modelled using simple SCM logic) and net / revenue meter power (light brown - observed with Reposit controller; light green - modelled using simple SCM logic), for a household with a flat-rate tariff. Values are average power flow for half hour intervals.

Cost of NAC participation

Cost of NAC participation is judged for each peak event by observing the actual cost saving achieved by the reposit algorithm on that day and comparing with what the SCM equivalent response would have been *without* any NAC response included. It is not possible to compare actual response with what a Reposit control scheme would have provided, at least not with the data available.

An example of actual (dark brown - battery, light brown - net load) and SCM counter-factual (dark green - battery, light green - net load) for a day with a NAC event is shown in Figure 5. The shaded areas represent the approximate costs incurred by this customer, from battery action that would otherwise not have occurred and which are sub-optimal from a cost perspective: charging the battery from grid at full tariff rates in advance of an anticipated peak, and then discharging the battery at larger than the prevailing local load and hence at cost of importing energy later. The cost can therefore be worked out for each day where a network peak event occurs, either a manually scheduled fleet command or a NAC-driven action. In this instance for example it cost the consumer an additional $0.50 in energy costs. In return, customers are rewarded for their support of the network, in this trial with a much larger payment than their cost of participation.

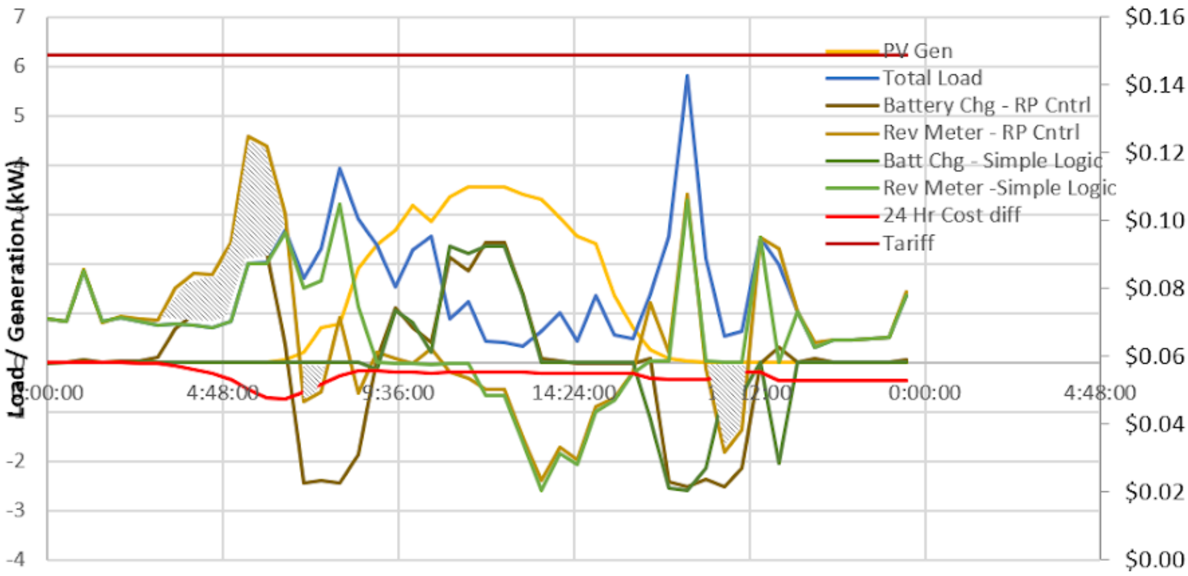


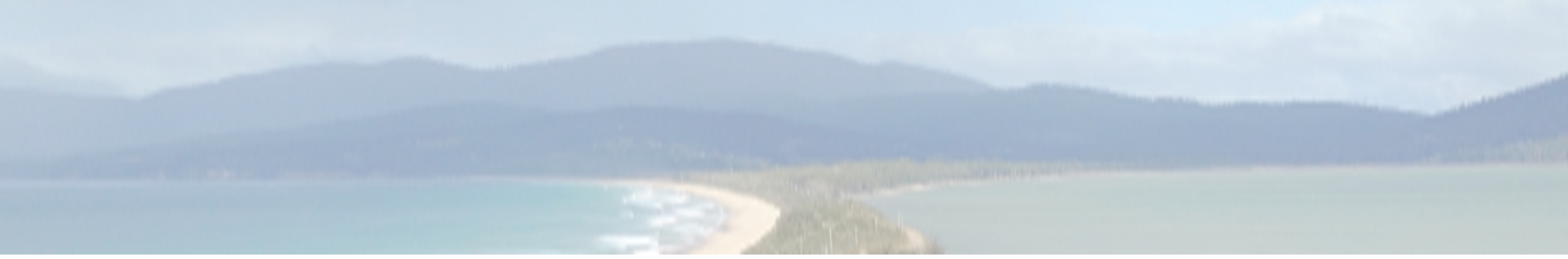
Figure 5. Example of generation (yellow), total household load (blue), battery charge rate (dark brown - observed with Reposit controller; dark green - modelled using simple SCM logic) and net / revenue meter power (light brown - observed with Reposit controller; light green - modelled using simple SCM logic), for a household with a flat-rate tariff on a day with NAC-driven network peak events. Values are average power flow for half hour intervals. Shaded areas represent energy that is stored in or released from the battery in order to meet network peaks, and represents a departure from and a cost compared to SCM battery control.

Calculated system performance metrics & energy costs

System performance metrics

Table of each main calculated parameter:

- PV system performance ratio:
- Average daily load:
- Average daily solar generation
- Solar self-consumption, PV only:
- Solar self-consumption, PV + Simple SCM battery:
- Solar self-consumption, PV + Reposit control (including NAC-driven responses to network peak events):



Financial benefit and key value metrics

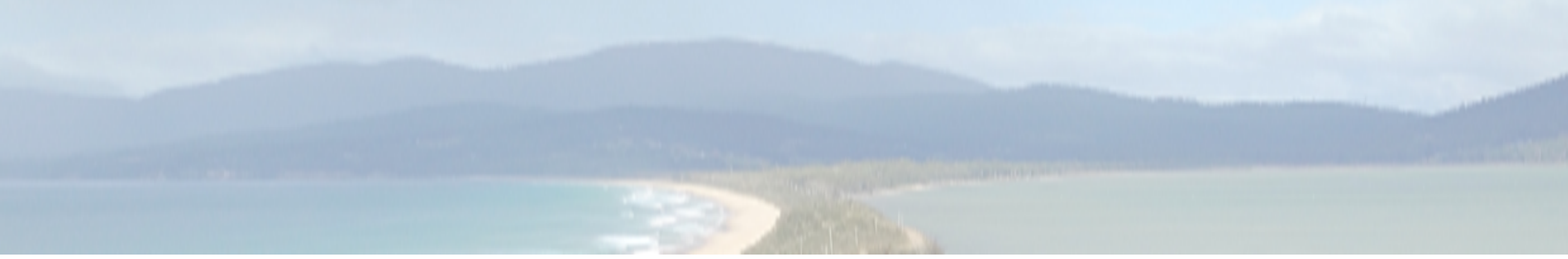
List of major outputs calculated for each system with valid data, and details if needed:

Energy Costs:

- Total cost of serving energy demand, with no PV and/or battery
- Total cost of serving energy demand, with PV system but no battery
- Total cost of serving energy demand, with PV system and simple SCM battery
- Total cost of serving energy demand, with PV system, battery and Reposit algorithm
- Total cost of serving energy demand, with PV system, simple SCM battery & alternative energy tariff (eg TOU for Flat-rate customers, OR Flat-rate for TOU customers)

System component benefits:

- Financial value of PV system on its own
- Additional financial value of battery with simple SCM logic
- Additional financial value of Reposit optimisation algorithm (NAC participation costs excluded)
- Value of NAC-based network support payments (includes reduction for cost of NAC participation)
- Value of manually scheduled Fleet dispatch support payments (“Grid Credits”) (includes reduction for cost of Fleet dispatch participation)
- Financial benefit of switching tariffs



Analysis Results

The following results are based on data analysed for all households where data is deemed valid.

Snapshots of typical battery actions: example household data.

We start by presenting examples of household load data (solar generation, household load, battery charge / discharge, and net revenue metered energy) for one house on three different days, chosen to illustrate different battery actions:

- battery responding to conditions resulting largely in self-consumption operation (SCM)
- battery responding to conditions resulting in predictive tariff optimisation (Reposit algorithm functionality)
- battery responding to a NAC driven network peak event (NAC response)

Figure 6 shows data for a weekday in the middle of January. The retail import tariff is overlaid on the plot, indicating periods where TOU peak and off-peak prices apply. Here we see relatively high solar generation and low load. Solar generation is more or less sufficient to meet morning household peak demand and so no imports during peak period is required. During the day the batter charges up from excess solar until full, after which excess solar is exported to the grid. The household's evening peak period power is supplied either from solar or from the battery, and overnight load is also largely supplied by the battery. There is essentially no benefit in the Reposit algorithm over a simple SCM algorithm days such as this.

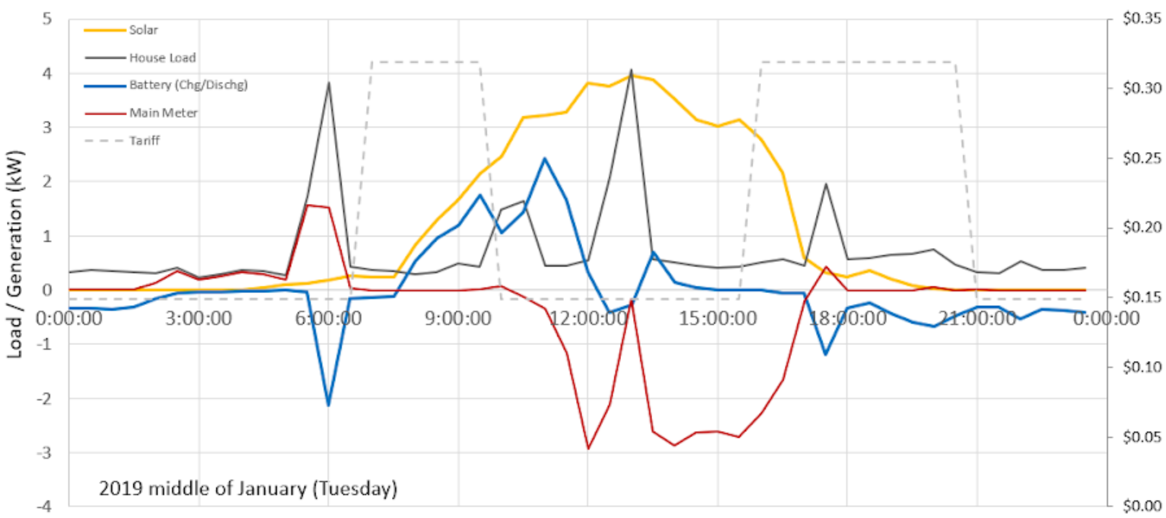


Figure 6. Example of observed generation (yellow), total household load (grey), battery charge rate (blue) and net / revenue meter power (red), for a household with a TOU tariff (tariff period shown via dashed grey line) on a day with conditions that lead to battery actions largely typical of SCM control.

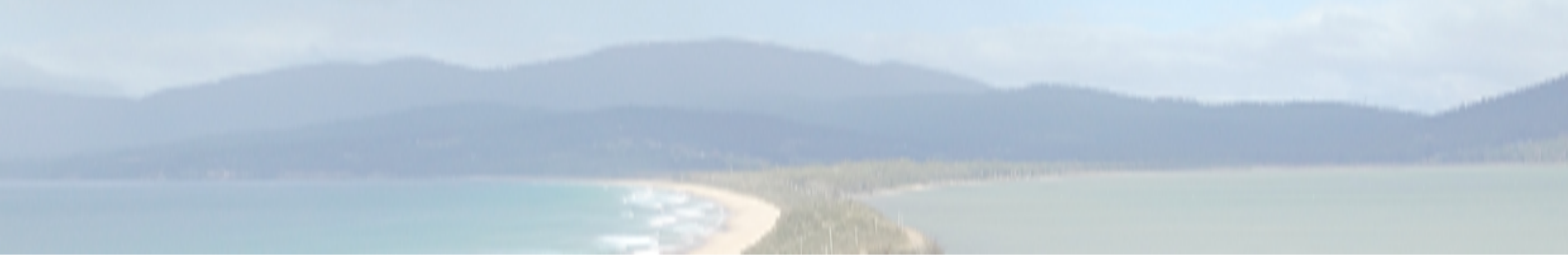


Figure 7 shows observed data for a weekday in the middle of June. In this case we see relatively low solar generation and considerable load in the morning and evening, largely coinciding with peak tariff periods. This scenario is a very good example of when predictive optimisation algorithms such as that employed by the Reposit controller offer the largest advantage. In the morning, the battery is charged during the period prior to the peak tariff period, even though during this period there is already significant load. This is done in anticipation of needing to meet considerable load during the peak tariff period. This is indeed the case, with the battery discharging to meet the peak tariff load until it runs out of stored energy. This represents a financial benefit for the customer in this instance because energy is bought at the cheaper rate to avoid purchasing it later at the higher rate. We note that if the predicted load during the morning peak tariff period did not eventuate, this would have ended up as a cost to the customer. Excess solar generation charges the battery during the day and is then used to at least partially meet the evening peak. For this example, there are no time intervals where power is exported to the grid (ie. battery discharge is only ever enough to supply local household load) and there are no periods during which energy was purchased from the grid for storage and not subsequently used. There is a clear benefit of the Reposit algorithm in this case, over simple SCM logic control.

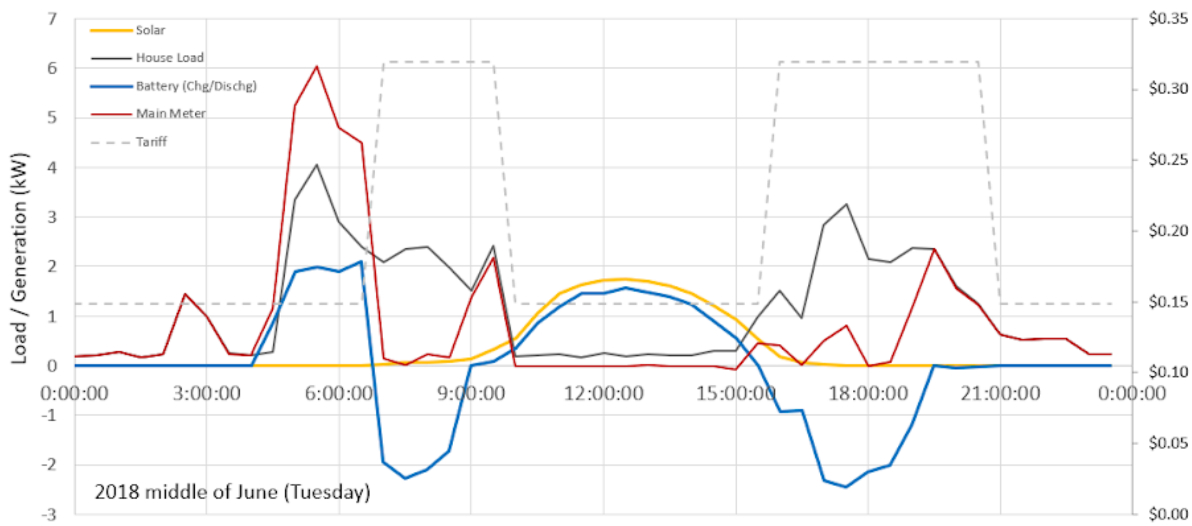


Figure 7. Example of observed generation (yellow), total household load (grey), battery charge rate (blue) and net / revenue meter power (red), for a household with a TOU tariff (tariff period shown via dashed grey line) on a day with conditions that lead to predictive tariff optimisation battery actions (realising the functionality of the Reposit algorithm).

Figure 8 shows observed data for a weekday at the end of the June long weekend. In this case we again see relatively low solar generation and significant load in the morning and evening, mostly coinciding with peak tariff periods. But here we can see the impact of NAC predicting a network peak demand event and setting NAC prices accordingly, in order to elicit the desired response from the battery. We can see here that in the morning, in advance of the network peak and prior to the start of the peak tariff period, the battery is charged up. When the network peak event occurs the battery is discharging (very likely at the maximum allowable discharge rate for this system's inverter) to meet the network peak. The power delivered by the battery during this network peak event is far in excess of household load at this time, resulting in export of energy at the low FiT rate and thus indicating that this action must have been driven by network peak pricing determined via NAC. While it is possible that the battery is prepared for and then discharges for an evening network peak on this same day, it cannot be determined from this data along in this instance. Far more likely that the battery is discharging to meet local peak demand only. This is an example where a predictive optimisation algorithm at the battery level coupled with Network-Aware-Coordination for network constraint management leads to battery actions that would simply not be possible with any other combination of battery control software and aggregator battery coordination available today.

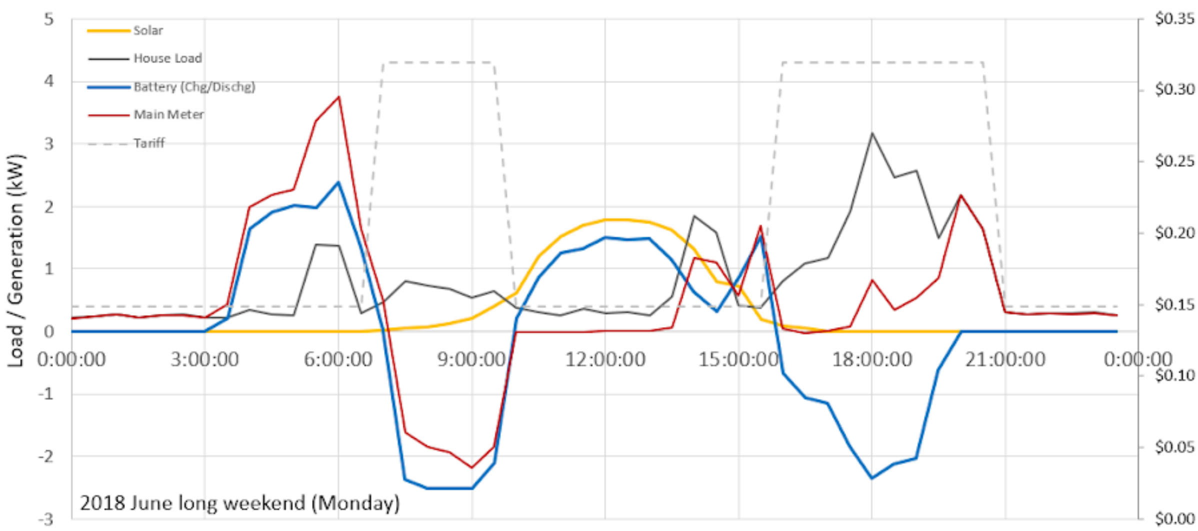
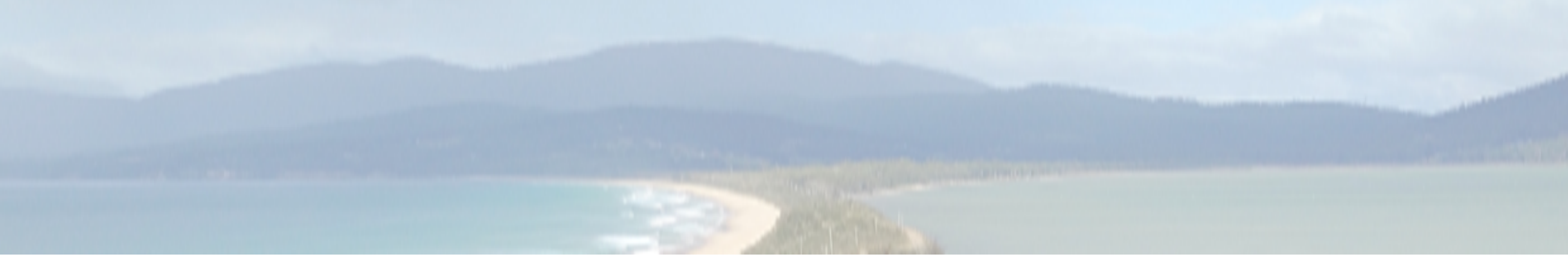


Figure 8. Example of observed generation (yellow), total household load (grey), battery charge rate (blue) and net / revenue meter power (red), for a household with a TOU tariff (tariff period shown via dashed grey line) on a day where there is a network peak event and where battery action is thus driven by marginal prices set by the Network-Aware-Coordination software.



Solar PV Self-Consumption Ratio (SCR) and Battery Performance

One common figure of merit for either a PV system or a PV/battery system is self-consumption ratio (SCR). SCR is the fraction of total solar generation which is consumed on the premises and therefore not exported.

Although it is highly related to financial outcomes - a higher value of SCR generally will produce a better financial yield in a typical tariff regime where exports are priced far lower than imports (which is certainly the case on Bruny Island) - it is also often associated with level of autonomy or self-sufficiency. It may thus be viewed as a good indicator of likely system owner satisfaction when it comes to both system sizing and performance: a high SCR value indicates that energy demand is well matched to energy generation.

A battery system generally increases SCR by shifting load to meet generation (or shifting ‘generation’ to meet load, depending upon which way you prefer to look at it). Therefore the before and after SCR is a useful measure of how well a battery system is matched to load and performing.

Figure 9 shows the SCR for all systems with PV only, PV + simple SCM battery, and PV + Reposit battery. We see firstly a clear trend of increasing self-consumption with load, since increased load generally means increased load during times when there is solar generation.

The difference between SCR for PV only and SCR for PV + battery + Reposit, meanwhile, reflects the utilisation of the battery. Battery utilisation is even better reflected by Figure 10, which shows the amount of load that is shifted by the battery each day, on average, in order to align with solar generation. Here we see, despite a relatively uniform gain of close to 30% in SCR across all the households, a significant variation in battery utilisation. Effective, usable battery storage capacity for most systems is in the order of 6 - 7 kWh (based on inspection of data as described in data analysis methodology), but some batteries are clearly being used more effectively than others. Battery utilisation is limited by both solar generation (a day with low generation sees little excess that can be stored and used later) and load (days with low demand see excess solar generation not being able to be fully used), and will vary seasonally for some householders. Given the variation in solar generation, owing to seasons and weather, and demand, owing to household consumptions patterns, it is perhaps reasonable to consider an average battery utilisation of 4 kWh per day or greater to be generally quite good. Systems with battery utilisation below this might be, on the other hand, considered to be somewhat ill-sized for either the size of generation or load for these households.

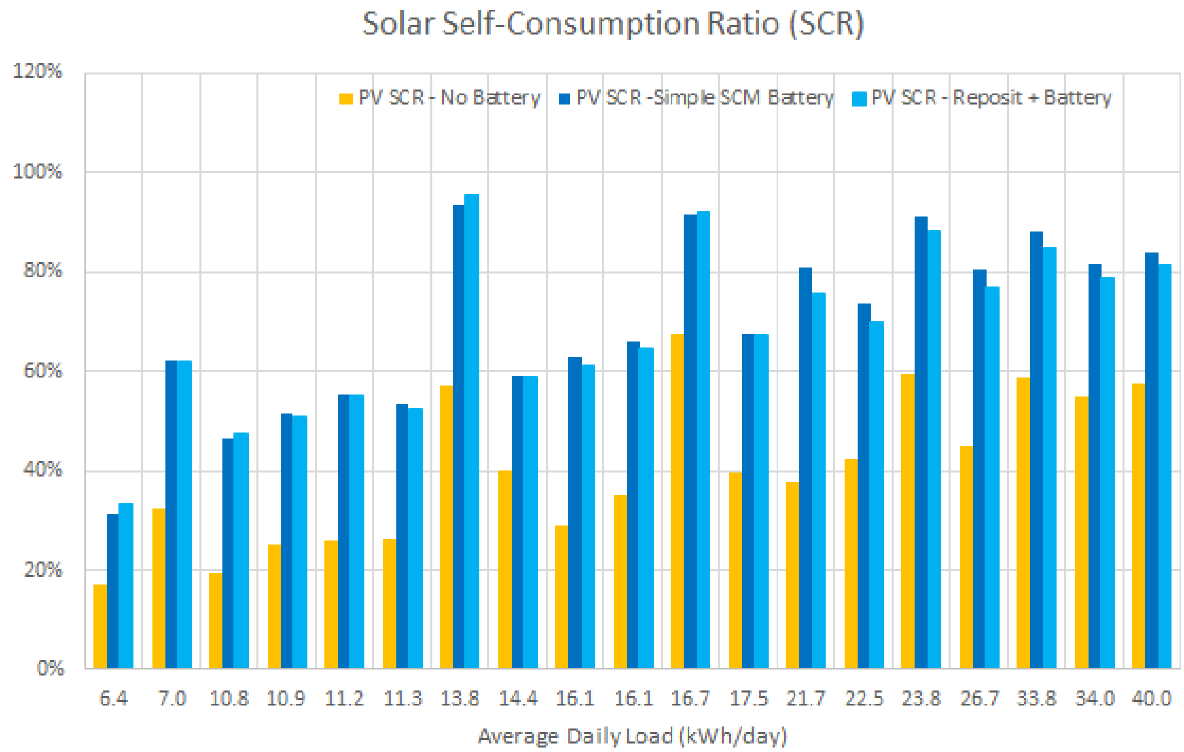
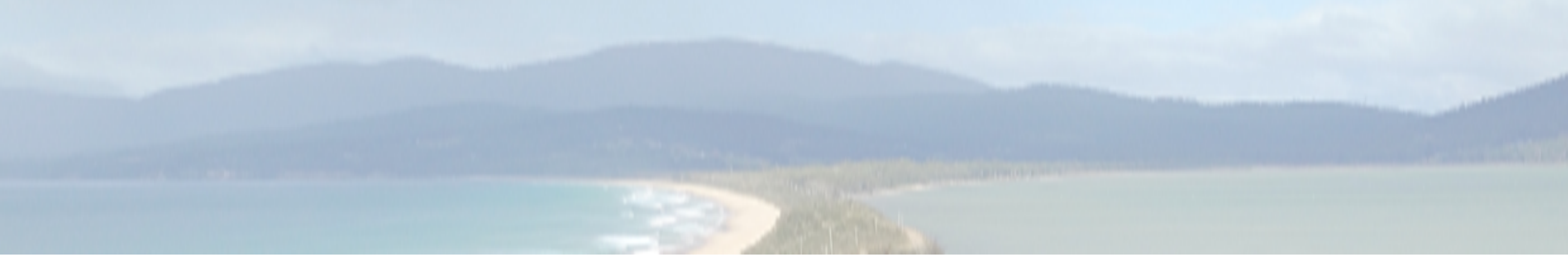


Figure 9. Solar self-consumption ratio (% of generated solar that is consumed by the household) for each analysed participant, under the scenarios of solar PV only being installed (yellow - modelled from observed data), solar PV and battery with simple SCM control (dark blue - modelled from observed data) and solar PV and battery with Reposit controller (light blue - observed data). Data analysed is for 12 months from 26 Feb 2018 to 25 Feb 2019, and is sorted by average daily household load (which excludes T41 heating and hot water energy).



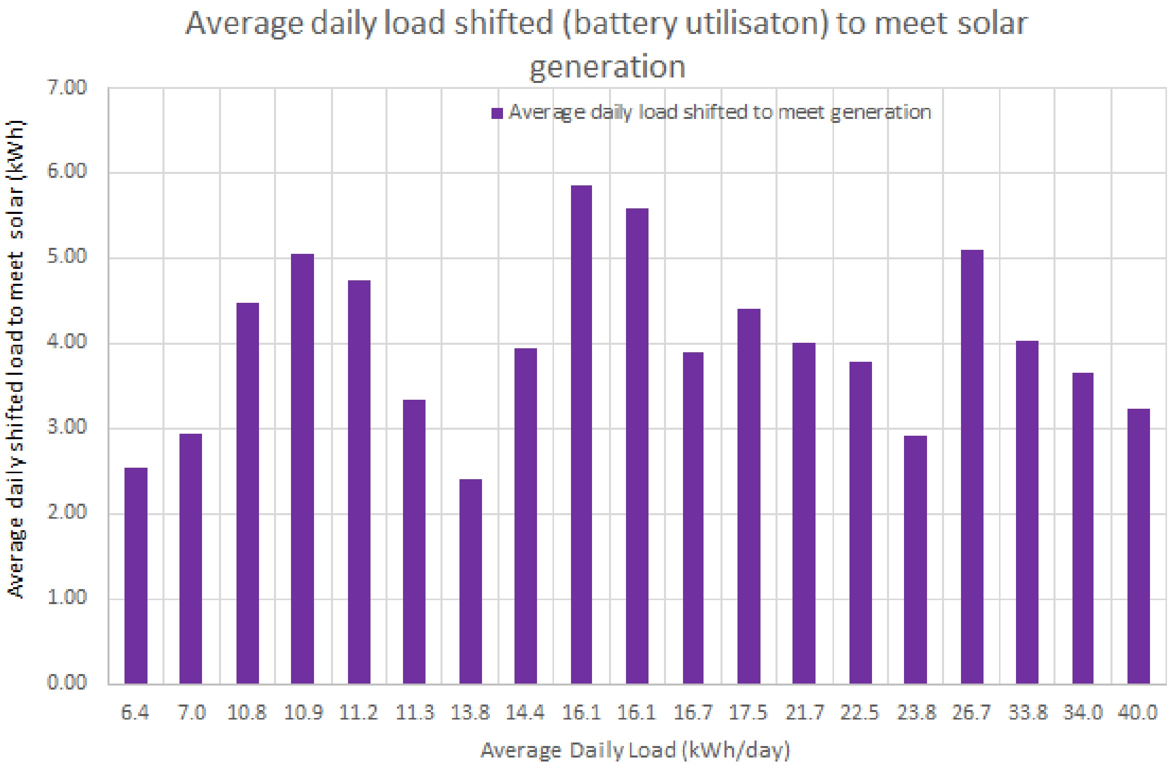


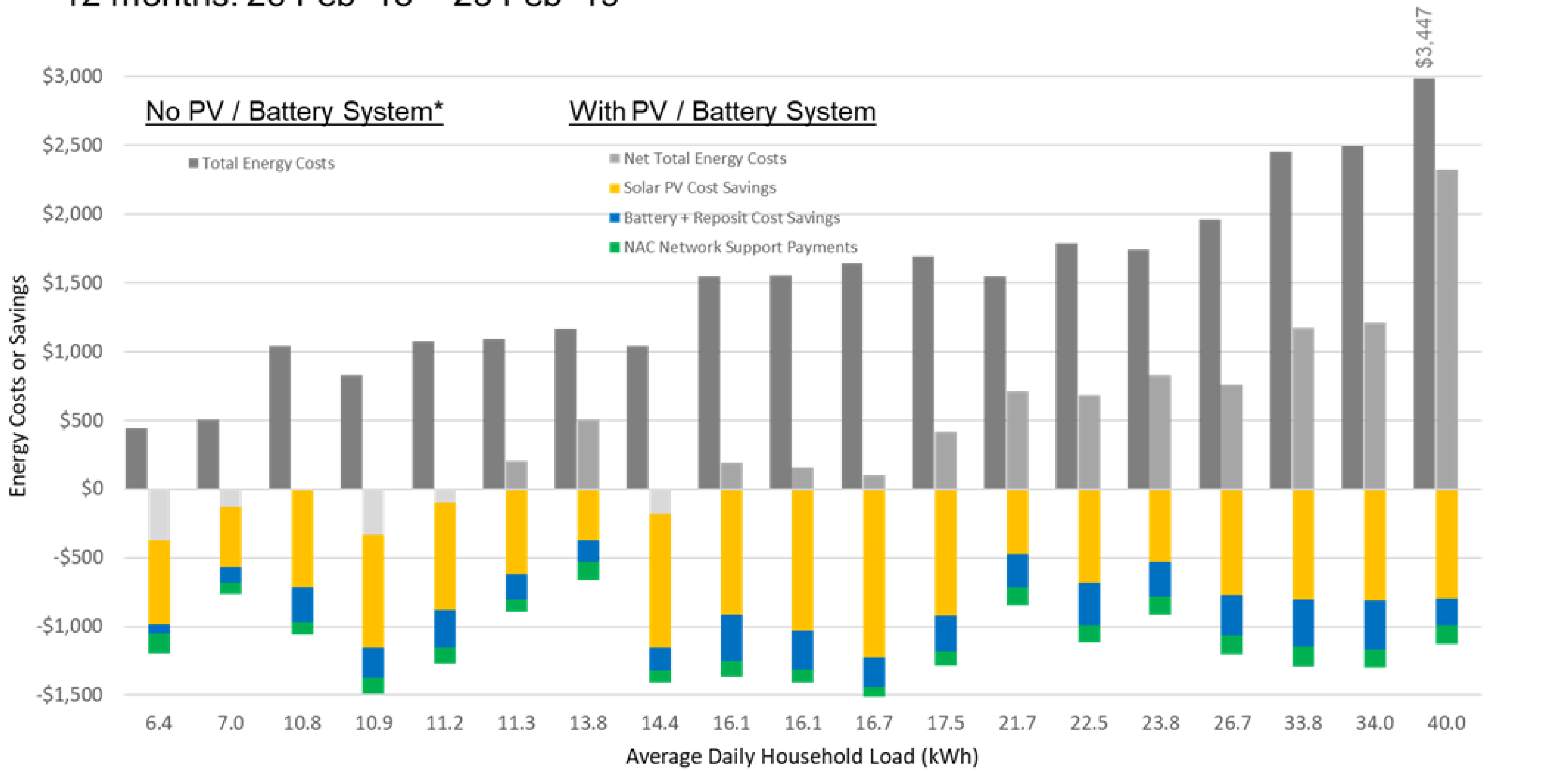
Figure 10. Average daily shifted energy demand (daily battery usage), in kWh, for each analysed participant. Data analysed is for 12 months from 26 Feb 2018 to 25 Feb 2019, and is sorted by average daily household load (which excludes T41 heating and hot water energy).

Financial benefit for all households, by system component

Figure 11 shows each household's (those with valid data) financial benefit of their installed system, ordered by average daily energy demand.

Figure 11 (overleaf). Total annual energy costs without PV/battery system installed (dark grey - modelled from observed data), and with system installed (light grey - observed data), and breakdown of energy cost savings by component - PV only (yellow - modelled from observed data), Battery plus reposit control (blue - modelled from observed data) and NAC-driven network support payments (green - observed). Data analysed is for 12 months from 26 Feb 2018 to 25 Feb 2019, and is sorted by average daily household load (which excludes T41 heating and hot water energy).

Annualised household energy costs per year (excl. fixed charges, excl. load on T41 if applicable), 12 months: 26 Feb '18 – 25 Feb '19



Referring to Figure 11, the dark grey columns represent the total energy costs that would have been incurred by the household if no PV/battery system had been installed (and if energy usage had remained unchanged), assuming the same tariff applied as that reported for each household. The lighter grey columns represents the final net cost of servicing energy demands for each household, with the PV/battery system installed; this column is above the $0 line (mid grey) if the PV/battery system has reduced costs but there is still a net energy cost to the household, or be below the $0 line (light grey) if the savings exceed the energy costs and the net energy cost is therefore negative. The difference between the dark grey and lighter grey columns is thus the savings, which are then shown as being attributable to PV generation alone (yellow), combined battery + Reposit algorithm (blue) and network support payments owing to use of batteries for peak demand reduction via NAC (green).

The total benefit (sum of yellow, blue and green) is also shown in separate plots in Figure 12.

We can see that the benefit is significant for all customers, with energy costs being reduced to close to or below $0 for most customers using less than about 16 kWh per day on average. The combined benefit itself is in the same order for most customers, with no major trends evident as a function of average daily load, although benefit is generally smaller for those households with low load (as expected, since benefit is only accrued if there is sufficient load to be met by solar and/or battery). A clearer (and also largely expected) relationship between benefit and average daily solar generation exists, with benefit naturally increasing with solar generation size up to a point, beyond which there is little additional benefit from increased solar generation (likely low day-time load and/or battery energy capacity limits further benefit from accruing).

Average annual benefit across all participants owing to system components were

Solar PV generation:	$752
Battery + Reposit:	$238
Total Solar + Battery:	**$990**
NAC Network Support:	$116

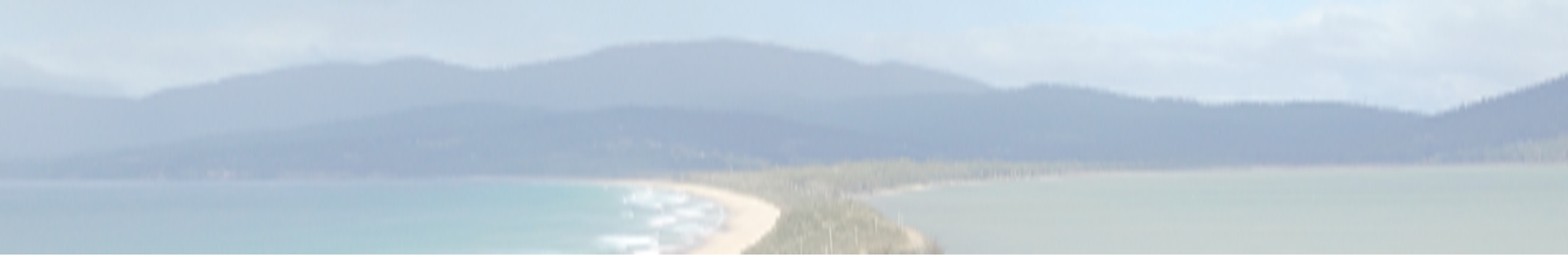
This is consistent generally with expectations of benefit for residential systems with typical solar, load and battery sizes. Indeed it is quite close to the modelled anticipated outcomes for ‘typical’ Bruny customers, prepared for the project in June 2016 for possible provision of information to would-be trial participants at the initial Bruny consumer forums (but, in the end, not provided).

Finally, in Figure 13 we show the total net energy costs for all customers, including those with data that has been flagged with warnings and excluded from other analysis. Columns in grey are for systems with valid data, and is a repeat of data presented in Figure 11, while the orange columns are the energy costs for other participants. This net cost of energy figures presented here are themselves accurate for all participants. However, it is not possible to accurately determine the x-axis value, that is the average daily household load. The same data validity issues also prevent us from determining the total energy cost for these participants and thus the savings attributable to PV and battery systems.

Our view is that it is likely that for many of these participants, the daily energy consumption figure used in Figure 13 will be reasonably close to their actual load, and moreover we expect that total actual energy savings for these participants will have been in the same range as for customers where data is deemed valid. Indeed, for most of these participants the solar generation recorded is more or less as expected and, since this has been shown to provide the most benefit regardless of battery action, this will also provide similar benefit as for other customers. Most of the additional effort or specialised data analysis for each of these participants may be able to resolve or overcome data issues for each participant and at least allow an attempt to clean data and thus estimate benefit to some level of accuracy. This has not been attempted.

Some important notes in relation to results with energy demand or energy cost calculations:

- the total energy costs and daily average energy demand is based on data collected only for the meter to which the PV/battery system is connected.
- Any customers with pre-existing Heating & Hot Water tariff 41 who elected to retain that meter and the accompanying flat rate tariff structures will still be metered and billed separately for that component of energy consumption, and this cost does not appear in this data. Approximately 9 participants in total (of 34) appear (from Aurora metering data) to still have T41 metering and energy usage, at an average energy cost of about $600 per year.
- Likewise, daily fixed charges are also not reflected in these plots, although they certainly appear on customer bills, totalling in the order of $400 per year for all residential customers.



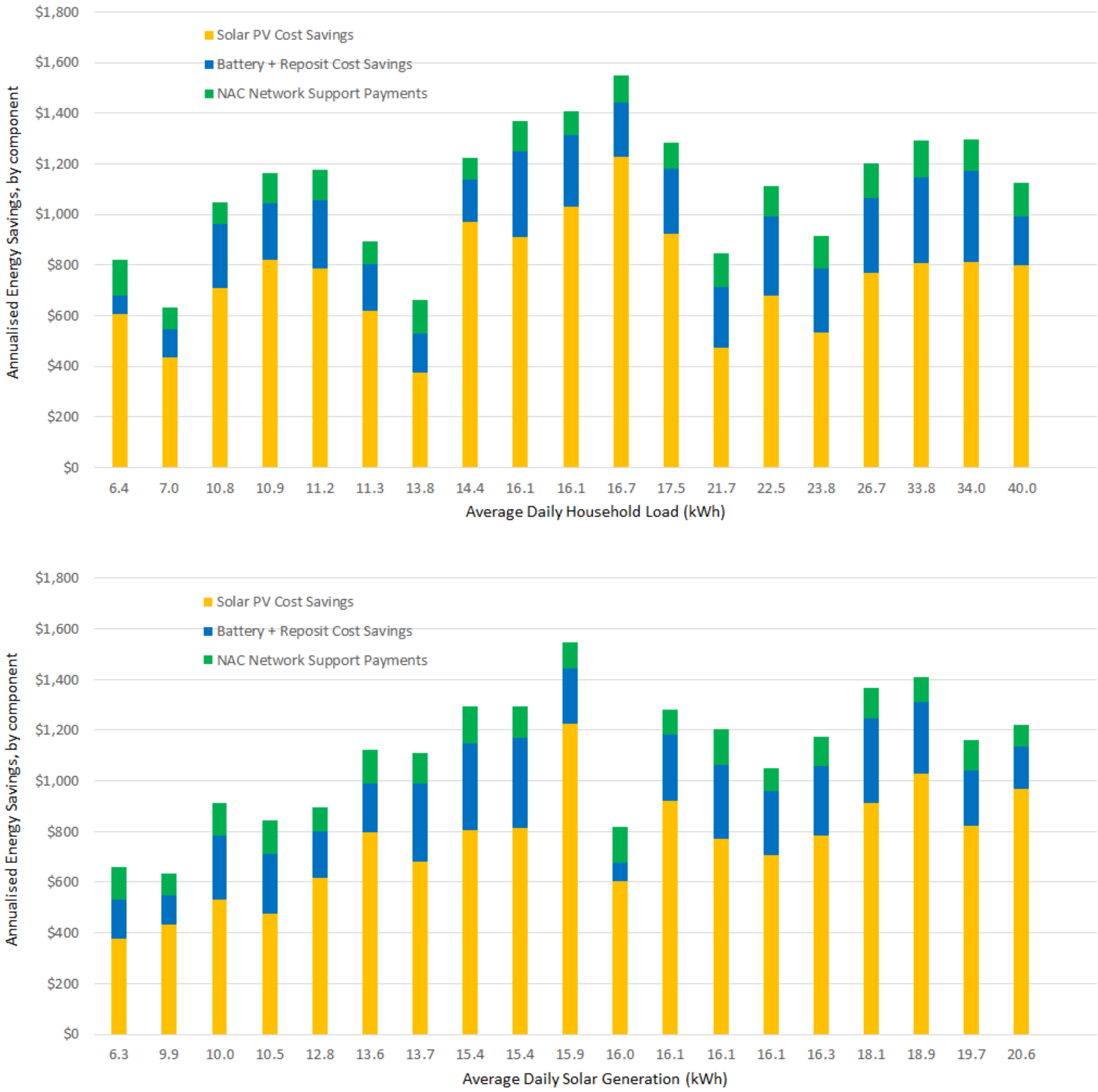
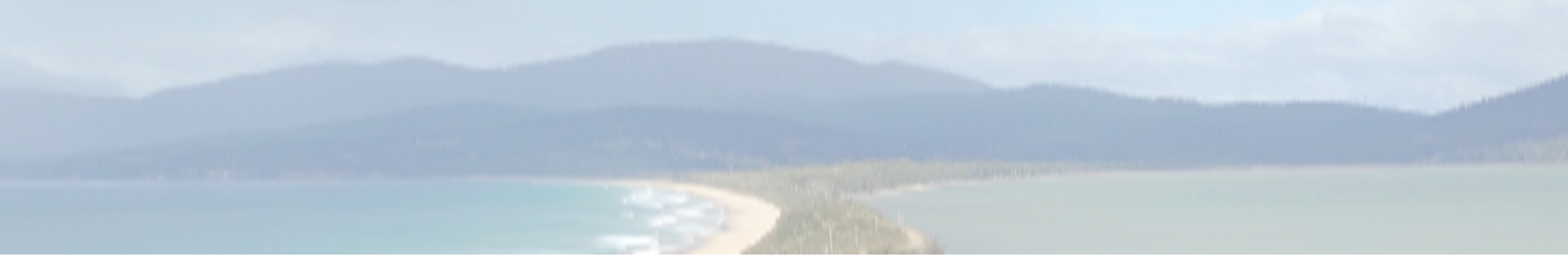


Figure 12. Total annual energy cost savings by component - PV only (yellow - modelled from observed data), Battery plus reposit control (blue - modelled from observed data) and NAC-driven network support payments (green - observed). Data analysed is for 12 months from 26 Feb 2018 to 25 Feb 2019, excludes T41 heating and hot water energy, and is sorted by average daily household load (top) and by average daily solar generation (bottom).



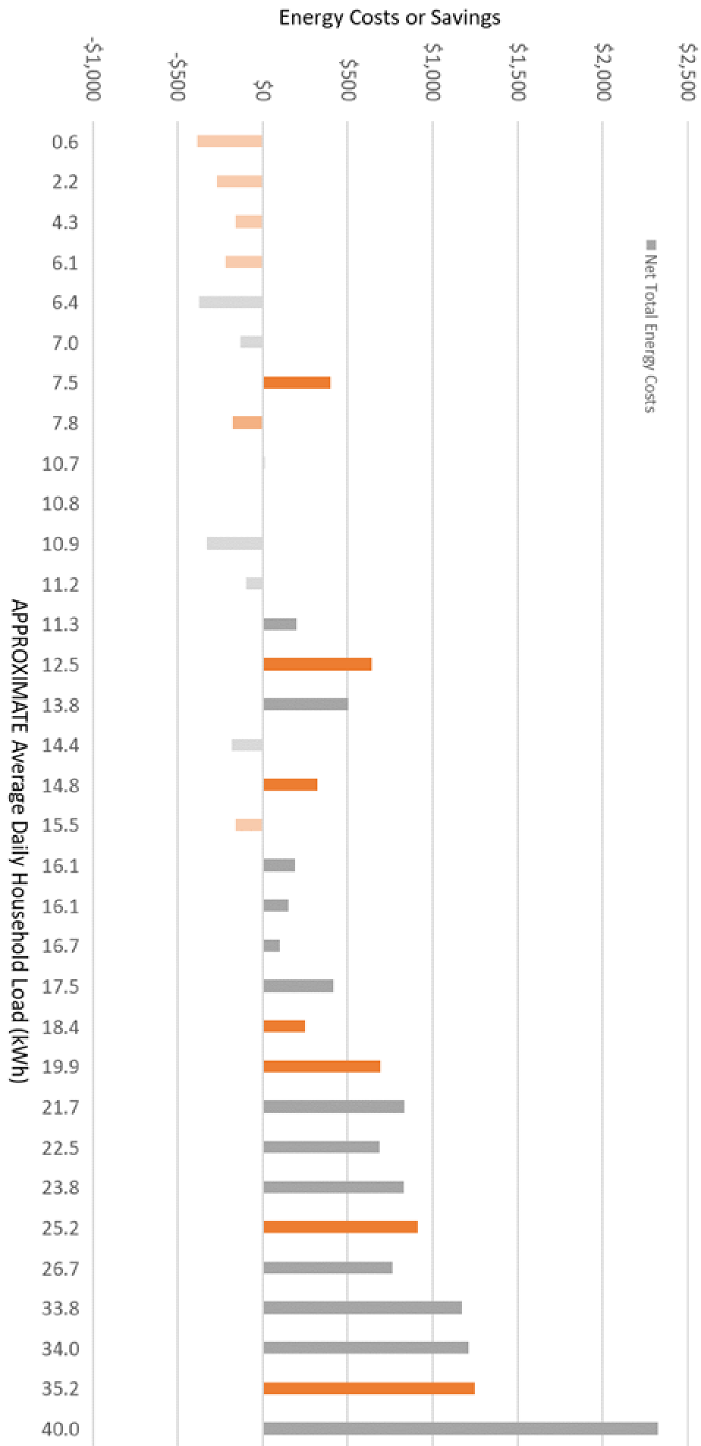
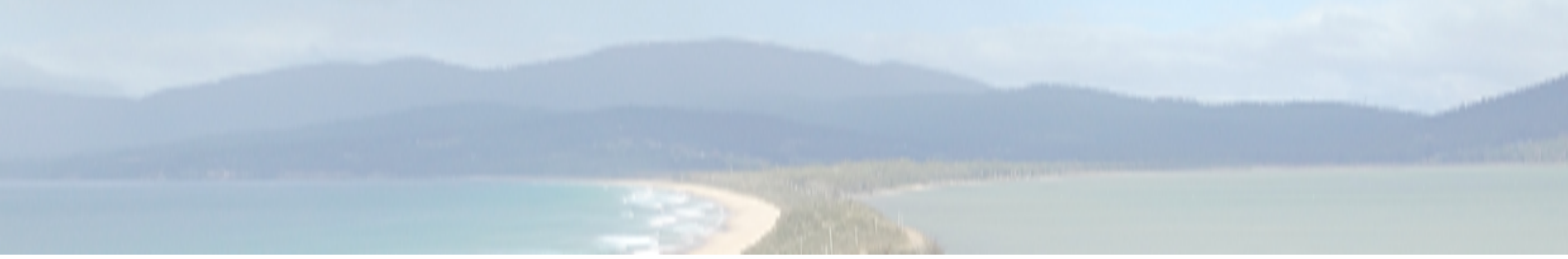


Figure 13. Total annual energy cost savings for all installed systems (grey - systems with validated data; orange - systems with unvalidated data). Data analysed is for 12 months from 26 Feb 2018 to 25 Feb 2019, and is sorted by average daily household load (which excludes T41 heating and hot water energy).



Battery benefit break-down (SCM control & Reposit algorithm)

Overall system benefits presented in the preceding section show the combined financial benefit of the battery and the Reposit algorithm. However, it is useful to examine how much of that benefit results from the battery itself and how much additional benefit is owing to the battery optimisation (the Reposit algorithm). The battery benefit alone is defined (detailed earlier in this document) as the benefit that the simplest battery control could provide, that is the benefits from simple self-consumption maximising logic. The reposit benefit is then defined as the difference between the actual benefit observed as a result of the battery with Reposit algorithm less the simple SCM battery benefit. All costs associated directly with preparing with peak events requiring network support (which appear to the consumer as an additional energy cost, albeit very small - discussed later in this report) are removed from these calculations, meaning that these benefits are effectively all evaluated for the scenario where no peak events had been explicitly called. We recognise that modelling of battery and inverter systems are always imperfect (this is described in some detail earlier in this document) but we estimate that the decomposition of battery benefit into the two components (simple SCM battery, Reposit algorithm) is accurate to within about +/- $10 per year. The results presented for customers on flat-rate tariff support the claim of this level of accuracy.

The breakdown of benefits are shown in Figure 14 for all systems where valid data existed. This plot shows that many customers are not benefiting at all from the Reposit algorithm. However, we know that many customers are on a flat-rate tariff, and it is quite obvious that Reposit’s optimisation cannot provide any additional benefit for those participants. We therefore show the data divided into two sections, for participants with each tariff type.

We observe that the battery benefit (without Reposit algorithm) is generally a little larger for flat-rate customers, but that the combined benefit is approximately the same in each case. It is not shown in graphs here, but the benefit owing to solar PV only also is higher for flat-rate customers than TOU customers. This indicates that load avoided by both solar generation and a simple SCM battery would have been met at a higher average import tariff rate for flat-rate compared to TOU, but that Reposit’s forecast and optimisation algorithm mitigates this difference. It might be easy to then conclude that a PV and battery system on its own (ie. no smart optimisation) has more value for flat-rate tariff customer and that they are therefore better off on flat-rate. We show later that the opposite is true for all of these customers.

Participants on TOU tariffs with low loads generally also see no benefit of the Reposit algorithm, with the benefit of the Reposit algorithm generally increasing with increasing average household load. This is a logical result to observe, since larger loads generally mean that there is a larger peak period load to offset via optimised battery storage.

On the face of it, many participants in this trial did not yield large benefits from the Reposit algorithm, although we note that some of these customers (low / irregular load patterns and/or remaining on flat-rate tariffs) are likely not ideal or target customers for this technology, but at the same time present excellent test cases for the Reposit algorithm which is at least in part based on patterning regular energy use. We also note that customers simply cannot access Network Support Payments without having such a battery optimisation algorithm in place.

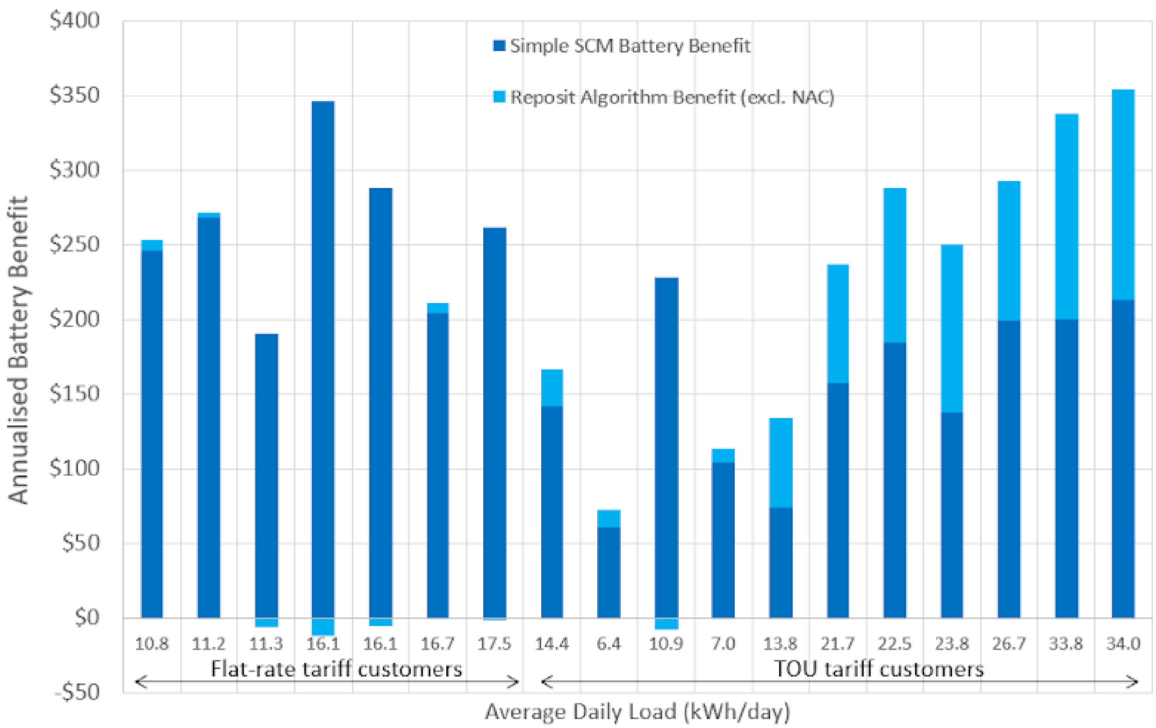


Figure 14. Total annual energy cost savings attributable to battery with simple SCM control only (dark blue) and additional benefit due to Reposit algorithm functionality (light blue) for all analysed systems. Data analysed is for 12 months from 26 Feb 2018 to 25 Feb 2019, and is grouped into Flat-rate and TOU tariff participants and then sorted by average household load. Although batteries appear here to return a better benefit for flat-rate customer than for TOU customers, it should be noted that total energy costs for flat-rate customers are higher than if they had been on TOU and thus potential for savings via PV and batteries is larger.

Flat-rate vs TOU participants

The decision on whether or not to switch from flat-rate to TOU tariff is a difficult one for any customer, especially in absence of reliable data with which to make that decision. This is elaborated on in the accompanying Social science final report [1]. The decision is made even more difficult in Tasmania for some customers because of the existence still of the Heating & Hot Water Tariff 41. Customers who choose to move on to the new TOU tariff are required to move all of their load to that tariff. If they have significant loads on Tariff 41 then it is highly likely that they will incur greater costs to meet that part of the load (unless there is accompanying behaviour change, which certainly cannot be assume to be possible for many households) on TOU tariff than on a flat-rate tariff. This change itself may be mitigated by battery action directly shifting heating and hot water load, may be offset simply by reduced costs of meeting other energy needs on TOU tariff, or may be offset by the benefits provided by a battery in shifting other loads to avoid peak periods.

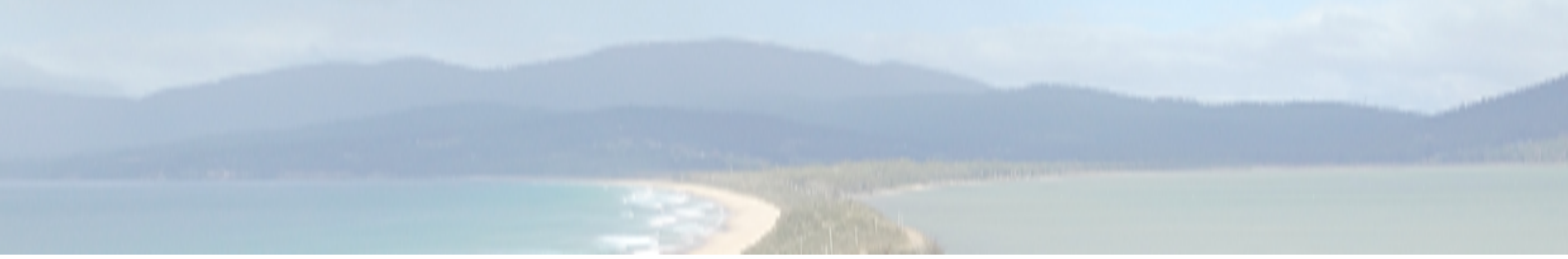
It is very difficult to evaluate, without detailed interval data on loads attached to Tariff 41 meters, what the best course of action for an individual customer is. This sort of data is not available in this project. We can however assess the impact of tariff change on all other loads, and on PV and battery system benefits. This, if combined with quarterly meter data from Tariff 41 meters, could provide at least some guidance on the likely benefit or cost of switching tariffs, although this level of individual guidance is out of the scope of the project.

Flat-rate and TOU participant ‘behaviour’

We start by looking briefly at what the energy consumption data says about participant energy usage behaviour. Customers who have switched to TOU tariffs are generally aware of the different times and charges at these times, and have the opportunity to alter their load patterns to reduce energy costs. Some participants have indicated, through interviews, that they have made some alterations to their energy use (refer to the Social science final report [1] for further discussion on this topic). Unfortunately, we don’t have before and after data for many participants and the seasonal variations makes it invalid to compare what before and after data we do have. However we can compare the behaviour of users on Flat-rate and TOU tariffs, to see whether there are any obvious differences between cohorts.

Figure 15 plots again Self-Consumption Ratio (SCR) for PV system only, showing those customers on each tariff type. There is of course a large range and this is a small sample space, so it is difficult to arrive at any strong conclusions. Self-consumption is higher for TOU customers, but this could equally be driven by other factors (load size for example) than any behaviour of using more load during periods of solar generation.

Figure 16 indicates peakiness of load for each customer, with peakiness index being a measure of average load during tariff peak periods (regardless of whether on the tariff or not) compared to average load across all periods. A peakiness value of 1 therefore simply means that energy consumption during those morning and evening peaks is the same as for any other time of the day or night. Most participants would have a peakiness index well above 1. We find that TOU customers in fact have peakier loads than flat-rate customers, which is the opposite of what might be expected. However, we must recall that TOU customers have their heating and hot water connected to their TOU meter and therefore this energy use is included in our peakiness calculation, while flat-rate participants only have general light and power included, with no access possible to Tariff 41 data at required granularity. Since heating and hot water load is peaky in nature, the peakiness index will certainly increase for those customers. Additionally, participants may have self-selected for TOU tariff or not, based upon



their own understanding of their daily energy use patterns. We conclude that this comparison presented is therefore of little value here.

In short, we cannot yet conclude anything about impact of customer behaviour on their energy usage patterns.

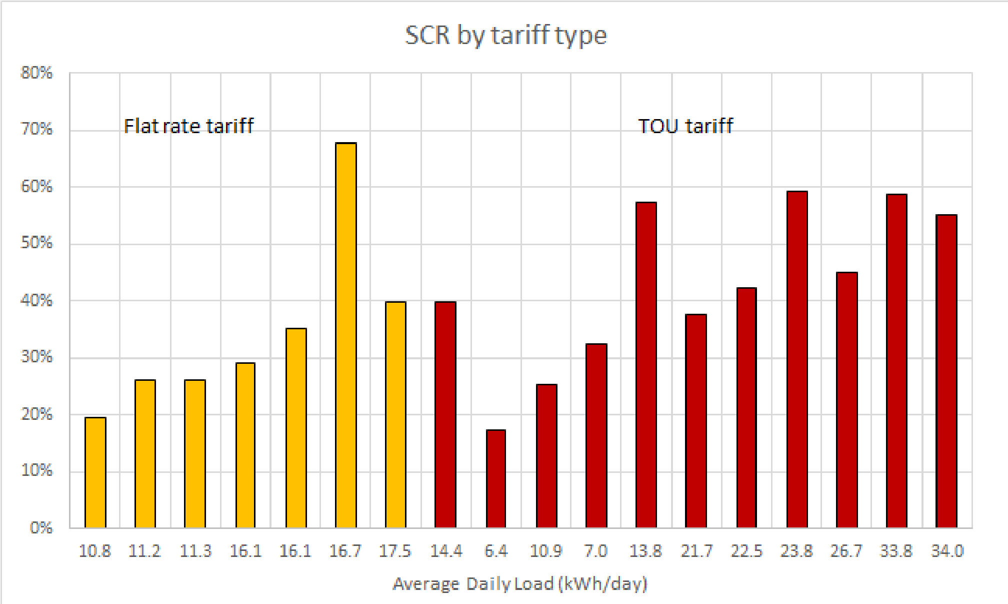


Figure 15. Solar Self-Consumption Ratio (SCR) due to PV only, for customers on flat-rate and TOU tariffs.

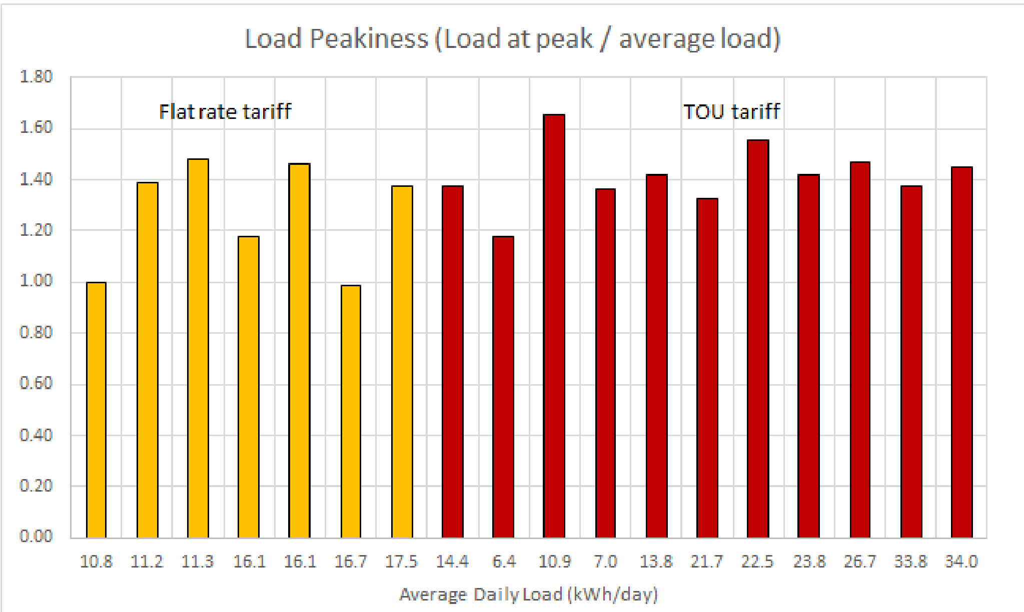
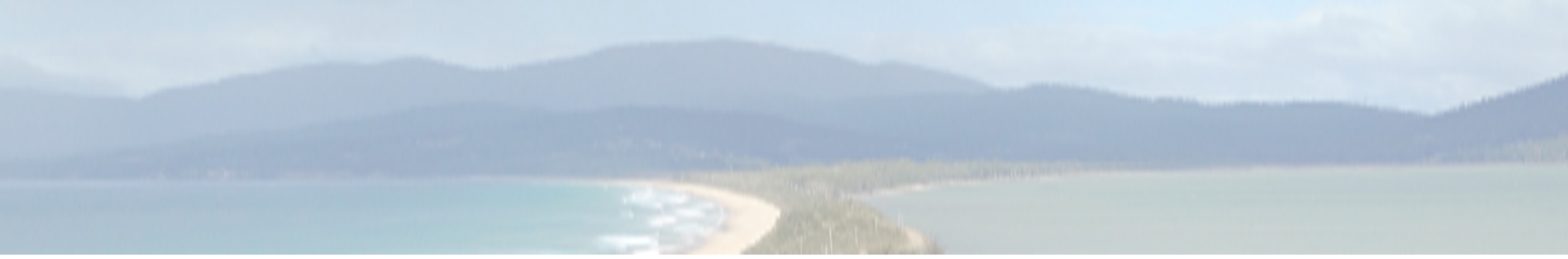


Figure 16. Load peakiness index (ratio of load at peak tariff periods to average load, for customers on flat-rate and TOU tariffs.



Benefit of switching tariffs

We examine the benefits that a customer would see if they changed from flat-rate to TOU tariff, or the extra cost incurred if a TOU customer changed back to flat rate tariff. Looking at net benefit figures on their own can be misleading, and so first the general impact of such a change requires a brief explanation.

Changing load from flat-rate Tariff 31 to time of use (TOU) tariff has four main impacts, when it comes to energy use and costs:

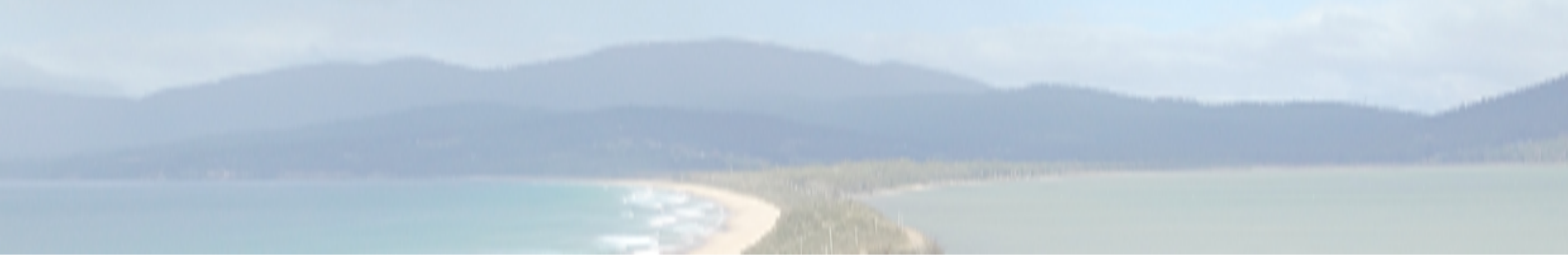
- the baseline cost of servicing the load (excluding Tariff 41 load) changes, generally decreasing for most customers in Tasmania and participants on Bruny
- the benefit for a simple battery SCM control changes, generally decreasing since using the battery to meet off-peak load has less value.
- the total load under battery control increases, thus the realisable quantity of energy that can be beneficially shifted increases (especially has impact if battery is otherwise under-utilised)
- the benefit of having a smart optimisation (eg Reposit algorithm) becomes significant (from being zero benefit for flat-rate customers)

The opposite impacts generally occur for customers who might switch back from TOU back to flat-rate tariff. In our trial, there is no impact on ability to, cost of, or value of participating in network support events.

The net result of these impacts for Bruny participants is a net benefit for those customers switching to TOU. Similarly, there would be a net loss for customers who switched back to flat-rate tariffs. This is summarised in Figure 17, which shows the net gain or loss from switching tariffs for each participant, plus also the two components of this gain / loss: total length of column represents reduced / increased baseline energy costs alone owing to tariff change, while coloured part represents the reduced / increased benefit owing to combined PV/battery system.

NOTE: the net gain for participants switching to TOU assumes a simple SCM battery only, and as such does not include the additional benefit accrued on TOU via the Reposit algorithm (which might be an additional $0 to $100 for these participants). Net loss for those switching from TOU to Flat already includes loss of Reposit optimisation value, and already includes heating and hot water load considerations.

NOTE: we again remark that any saving made by switching to TOU must be weighed up against any potential increased cost (or, additional benefit) that might arise for those customers who currently also have load on a tariff 41 meter. Each individual circumstance should be looked at on its own merit. As a general rule we note again that every customer with equal or greater demand intensity on weekends compared to weekdays will almost certainly be better off if they convert their T41 load to TOU. Our analysis later shows that almost all participants have almost equal or higher load on weekends and thus fall into this category.



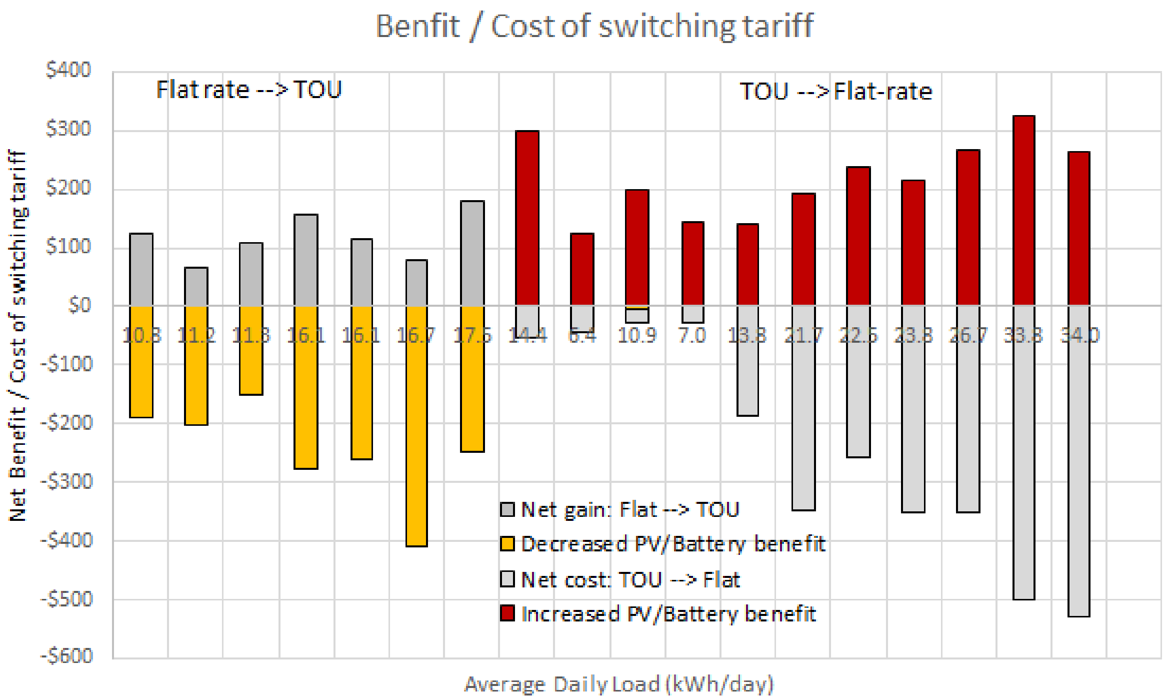


Figure 17. Net gain or loss in energy savings (grey column) if switching tariffs (from participant's current tariff), and corresponding decrease or increase in actual benefit due to PV/battery system. A change from TOU to flat rate, for example, generally sees a large increase in total cost of serving energy, which the increased PV/battery system value is not able to match, resulting in a net loss in energy savings. Note: data for participants currently on flat-rate tariff does not include the separately metered T41 Heating and Hot Water energy costs.

Network support payments and cost of participation

Having the Reposit optimisation allows for NAC-driven peak event support and hence networks support payments. No other battery control regime, as far as we are aware, would enable this at present. Manual fleet dispatch to meet expected peaks is also enabled via Reposit's functionality, although this is not unique to that control solution alone.

We calculate the cost, using the method described earlier, of participating in network support events, and then compare with the compensation, or network support payments, paid to each customer for supporting the network peak. Cost of participation is the cost incurred to meet energy for the day compared to the cost if a simple SCM battery actions were instead carried out. This may slightly overestimate costs for some TOU participants. Figure 18 shows the benefit and cost of NAC participation for the 12 month period, while Figure 19 shows the same data for any of the manually scheduled fleet events.

We can make some immediate key observations:

- The cost of participating in network support is very small compared to the payments made to customers. Total payments for NAC-driven network support (from 16 peak event days) was $115 on average across all participants, while the average cost to participate was only $1.40.
- The cost of participating varies significantly between participants, while the payments made does not vary by as much. This largely reflects the different load patterns of participants. In many cases there is no net cost of participation, or indeed a negative cost, which can occur if the charge and discharge actions of the battery to meet network peaks would have either happened anyway (but perhaps at different times during peak tariff periods) or resulted in a better servicing of local load than would have otherwise been the case based on load forecast and normal scheduling only. Some negative cost (compared to the simple SCM battery control alternative) could also be attributable to other artefacts: an incorrect forecast on the previous day resulting in a Reposit controlled battery fortuitously having excess stored energy on the day of the peak event (but unrelated to it being a network peak). It is not possible, without doing detailed day-by-day investigation to rule such effects out, and this second order effect is considered not worth pursuing within the scope of this analysis.
- The cost of participating in network support events is, in relative terms considerably lower than for manual fleet dispatch events. The average cost for fleet events was $3.10, with payments averaging $60. Since payments in both cases were based on a consistent rate per kWh battery discharge, this analysis suggests a 4-fold reduction in costs to procure network support using NAC compared to manual dispatch. This observation holds, regardless of the purpose or effectiveness of the manual dispatch events.

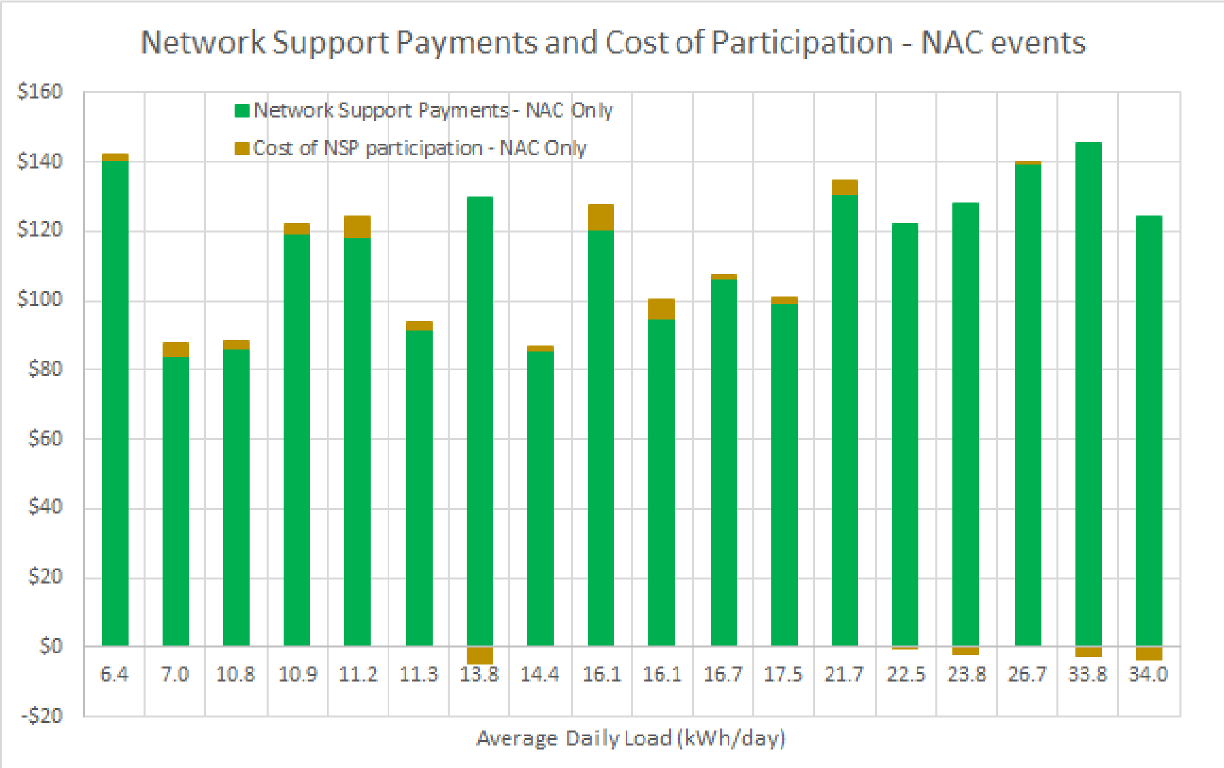


Figure 18. Payments received for NAC-driven network support (green) and cost of participating in those network peak events (brown), for period 26 Feb 2018 to 25 Feb 2019, sorted by average daily household load. Note: a cost of participation below $0 means that preparing for and then discharging to meet a network peak resulted in lower cost to serve energy than if the battery had simply acted to maximise self-consumption.

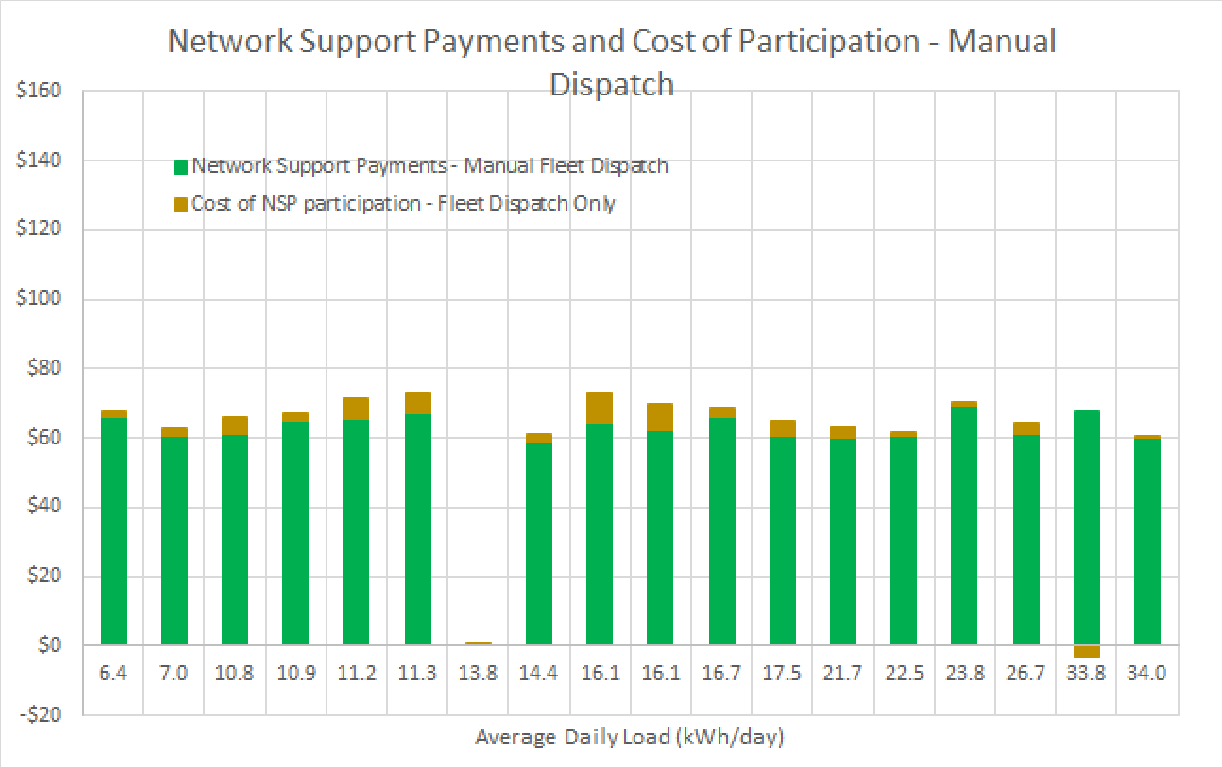
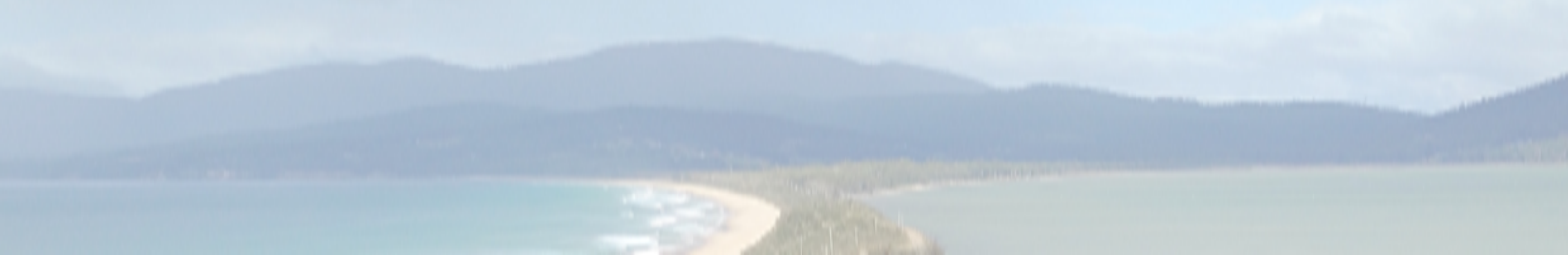


Figure 19. Payments received for manually scheduled network support (green) and cost of participating in those network peak events (brown), for period 26 Feb 2018 to 25 Feb 2019, sorted by average daily household load. Note: a cost of participation below $0 means that preparing for and then discharging to meet a network peak resulted in lower cost to serve energy than if the battery had simply acted to maximise self-consumption.



References

[1] Phillipa Watson, Heather Lovell, Hedda Ransan-Cooper, Veryan Hann, and Andrew Harwood. Social Science, Final Report, CONSORT Bruny Island Battery Trial Project. April 2019.