Multi-objective Battery Energy Storage Control Modelling for Residences Within Utilities

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Abstract

In this study, a residential battery system was modelled in MATLAB. The size and characteristics of the battery were held constant and the control algorithm altered for a range of objectives. The objective functions were designed to benefit residential homeowners, via energy arbitrage (EA Control), and/or the utility system, by peak sharing demand (PS Control). The models were tested using ten, one-year duration, measured 5-minute time-step residential load profiles and the measured local electrical utility load profile for the same year.

'EA Control' was designed purely for the benefit of the homeowners. A 'stacked' control (EA+PS Control) was designed to provide benefits to both homeowners and the utility. Finally, a rule-based real-time control (RT Control) strategy was designed to further optimize benefit sharing between the homeowners and the utility without relying on explicit load forecasting.

EA control raised the utility's bulk system demand charge by $4,365 while only saving the homeowners $5,408. EA+PS saved the utility $2,910 and the homeowners $4,459 for an overall savings of $7,369 per year. RT control reduced the utility peak load by the maximum possible 50 kW (aggregate system discharge power 50 kW) achieving utility savings of $7,275; combined with the homeowner savings of $5,077 the total annual savings becomes $12,352 for the system as a whole.

EA, EA+PS and RT control resulted in 277, 250 and 265 complete-discharge-equivalent cycles for the battery over the year, respectively.

The results of this analysis better the understanding of energy storage system control for multiple stakeholder operation.

Introduction

Pairing distributed generators such as wind turbines and solar panels with battery energy storage systems empowers municipalities to increase their energy security, reduce emissions and reduce electricity bills (Wu, et al 2019). High capital costs of these energy storage systems are a major obstacle to widespread deployment. Control strategies which provide multiple revenue streams by serving multiple energy storage applications simultaneously have the potential to reduce this barrier (Parra and Patel, 2019). Most of the research on this topic focuses on combining applications serving one stakeholder, such as load shifting and PV curtailment avoidance for a residential system. This paper explores applications which serve multiple stakeholders, specifically homeowners and an electrical utility.

In 2019 the Canadian Federal Government launched the Power Forward Project through Natural Resource Canada, with the aim of encouraging innovative technologies to develop, maintain and maximize Canada's power grids and systems (Challenge: Impact Canada, nd). The AlbaNova Project, a subsidiary of Power Forward Project, selected 10 residences in the town Berwick, Nova Scotia (population 2449 (Statistics Canada, 2017)) in which to install StorTera battery energy storage systems with the aim of proving their innovative control technologies and business model (PFC Finalist, n.d.). The ten systems are rated as 5 kW discharge, 3 kW charge, and 18 kWh usable discharge energy capacity. The 10 residences range widely in size, energy consumption, and type of heating system, each of which affect their electricity load profile (Pearre and Swan, 2019).

In the AlbaNova Project, both battery energy storage and solar PV are being added to the residences, and so they will enter Berwick's Domestic time of day (TOD) tariff and use net-metering. TOD has a monthly service fee and varying rate for electricity consumption depending on if it is used during low, medium, or high rate periods. These residences can reduce electricity costs via energy arbitrage (EA) by charging their battery during low pricing periods and discharging during high pricing periods.

As a member of the AlbaNova Project consortium, the Berwick Utility has a degree of control over residential battery systems operation. Viewed in aggregate and in the context of net metering which decouples battery operation from household load profiles, the 10 residential systems constitute a 180 kWh, 50 kW distributed, grid-tied energy storage system. While the residential batteries are cumulatively a net load due to energy inefficiency, if they are discharged when the utility is at peak load, they can offset part of those utility peaks, saving on bulk electricity purchases. The net effect will be Utility peak shaving (PS),

which due to ratcheted demand saves the Berwick Utility $145.50 per kW on demand charge cost throughout the year.

Berwick Tariff Structure Analysis

The ten tested Berwick residences operate on the Domestic Service Time-Of-Day (TOD) tariff under the Net-metering program, which is shown in Table 1. This tariff and program form the fundamental regulatory structure within which the battery system control strategy must operate. The control strategy must determine when, at what rate, and for what duration to charge or discharge the ten batteries, or to place them in standby.

Table 1: Domestic TOD Tariff Map

Tier	Low	Medium	High
Price ($/kWh)	$0.08	$0.13	$0.26

	TOD Tariff			
	Dec-Feb		Mar-Nov	
Hour	Workdays	Non-workdays	Workdays	Non-workdays
22 – 7	9 h period	24 h period	9 h period	24 h period
7 - 13	6 h period		15 h period	
13 - 16	3 h period			
16 - 22	6 h period			

The rate map in Table 1 map reveals the number of EA cycling opportunities a day. In the months of Mar-Nov one cycle opportunity is present each workday. On workdays during Dec-Feb the battery can be charged during the mid-day medium pricing period. The 18 kWh residential battery systems can fully discharge in the first high pricing period (5 kW discharge), partially charge during the medium period (3 kW charge) and then discharge fully again in the second high period resulting in ~1.45 cycle equivalents per winter workday. No cycling opportunity exists on non-workdays (weekends and holidays).

Contrasting Residential and Utility Load Profiles

Data Sources

Dataloggers are currently collecting timestep power data from the ten Berwick residential sites and will continue until over a year of data is collected. Since data has yet to be collected for a full year, proxy data from representative houses was utilized for modelling and analysis. Metadata for the Berwick homes such as heating system type (oil, elective resistance, electric heat pump, wood stove) and annual energy consumption (kWh) was used to select the proxy load profiles. Eight of ten load profiles were selected from a set of 50 recent measured residential load profiles provided by Efficiency Nova Scotia (ENS). Unfortunately, the ENS data set focused on electrically heated homes, resulting in a lack of non-electrically heated home load profiles. The two remaining load profiles for the non-electrically heated homes were selected from an older data set provided by Nova Scotia Power (NSP).

The Berwick Utility intertie demand history was provided for the years 2017 and 2018. Each of the proxy residential load profiles from the ENS data set (8 of 10) were recorded from July 2017 to July 2018. Measured Berwick Utility intertie demand from this date range was used to contrast the Utility and residential demand profiles. The remaining two load profiles (from NSP) were recorded in 2014 and are out of time sync.

Utility Load Profile

Berwick's electricity distribution system is a winter peaking system. The Berwick Utility purchases electricity principally through Nova Scotia Power, which charges based on electricity consumption ($/kWh) and a ratcheted annual peak demand charge (kVA) defined as the higher of the highest 15-minute average load for each month, or the highest 15-minute average load during the period of Dec 1 through Mar 1.

Berwick is billed for the higher value of the maximum demand of the current month, or the maximum demand experienced during the Dec-Feb period which occurred in the previous eleven months. Peaks during outage restoration periods are excluded.

Each kVA avoided from Berwick's yearly peak saves the utility $12.125 on demand charges per month. Assuming the Utilities peak occurs between Dec-Feb, $145.50 per kVA reduction would be saved per year.

Figure 1 shows the average and maximum demand values for the Berwick Utility through July 2017 and July 2018.

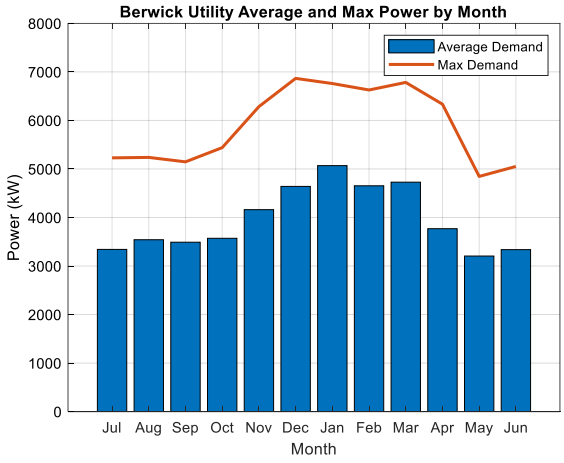

Figure 1: Berwick Utility average and max loads by month

Daily profiles for the months Dec-Mar were constructed using the average (blue line) and max (red lines) powers that occurred for every time of day and are plotted in Figure 2. Figure 2 reveals that the average load profile in Dec-Jan (top plots) is double peaked with a small afternoon valley. The months Feb-Mar (bottom plots) have very specific times of peak at 9:00 – 10:00 for both average and worst days, whereas Dec-Jan has longer duration peaks on the worst days. The actual peak in these months could occur at any

time of the morning. The longer duration peaks in Dec-Jan are of concern for peak shaving as they will be more difficult to peak shave than the Feb-Mar peaks.

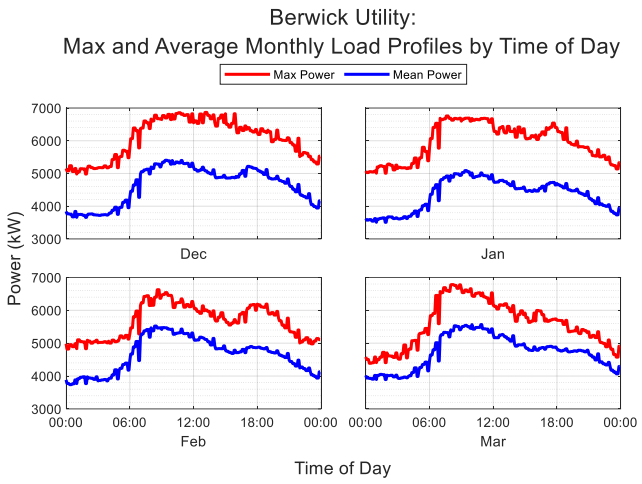

Figure 2: Berwick max and average load per time of day Feb-Mar

Figure 3 shows the daily Utility load profiles of December and January's six peak days. Two of six December day peaks show long duration (8+ hours). The remainder of days show a double peak and midday valley, similar to the average monthly profiles shown in January's peak days show more consistently long peak duration. This suggests that the residential battery systems must be available for discharge for 9 hours (07:00-16:00) on Berwick's peak day in order to successfully lower the Utilities ratcheted demand cost.

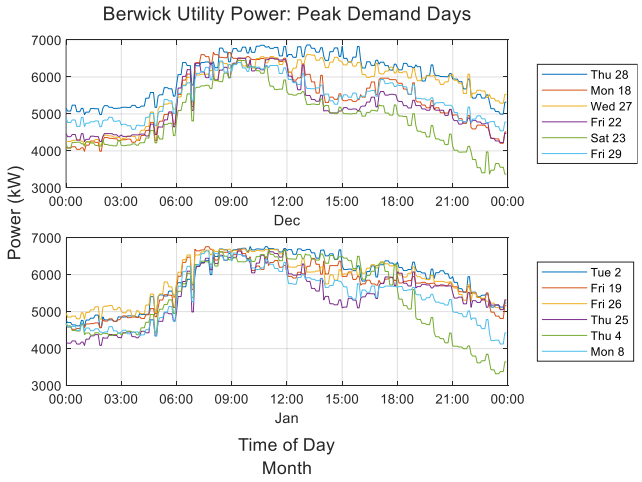

Figure 3: Berwick Utility peak days for Dec and Jan

Comparison of Berwick Utility and Residential Loads

It is critically important to understand potential dynamics between the residential sites and the utility peak demand. This analysis forms the basis of the battery energy storage system control strategies discussed in later sections. Figure 4 shows Berwick's peak of the year plotted with the average load profile of the residential sites for the same day. All profiles were normalized by their maximum value for the year.

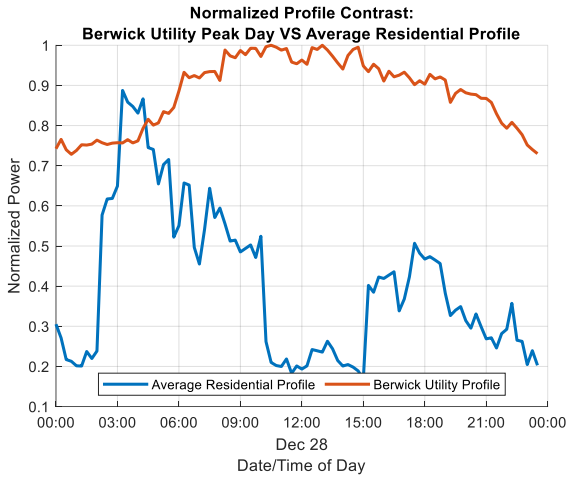

Figure 4: Berwick Utility peak day vs average residential profile

The homes examined experience their peaks in the morning and the evening, with a notable valley midday. This is in stark contrast to the sustained midday peak of Berwick Utility on Dec 28 (Figure 3). This finding suggests that net metering is critical to optimize utility benefit. Without net metering house load could be mitigated or eliminated during Utility peaks but could not provide further benefit by exporting to the grid mid-day.

Control Strategy Development

By contrasting the dynamics between the residential and utility load profiles and the structure of the Domestic TOD residential tariff, three control strategies were of interest: Energy Arbitrage Control (EA control), Energy arbitrage + Peak shaving control (EA+PS control) and Real-Time Control (RT control).

Energy arbitrage control

EA control was designed purely for the benefit of the ten Berwick residential sites. In this control strategy, the battery system conducts energy arbitrage by charging and discharging as fast as possible and at the first available opportunity while in the appropriate tariff price block. Charging and discharging occurs as fast as possible to reduce the likely hood that the cycle cannot be completed due to external events such as a grid outage. Dynamics between the residential loads and the utility load were ignored in this strategy.

There are two typical concerns in conducting a cycle (Pearre and Swan, 2015):

- What is the cost of the energy inefficiency of the system? A certain minimum price delta exists between the high and low pricing periods to make EA profitable. To obtain the second cycle, a sufficient pricing delta must exist between the high and medium pricing periods. In

the case of the Berwick Domestic Service TOD tariff the price delta is sufficient in both cases.

- What is the added wear that occurs on the battery? This essentially attributes a portion of battery system capital cost to each of the cycles that can occur in its life. In the case of the AlbaNova project, the battery system price is subsidized for homeowners and so this concern is alleviated.

A consequence of this control strategy is midday charging during winter workdays between 13:00-16:00. As indicated in Figure 3, charging during this period during the months of Dec-Jan may increase the Berwick Utility peak, negatively effecting the Utility demand charge.

EA + utility peak shaving control

A 'stacked' control strategy was created which aimed to provide the residential stakeholders with as much EA savings as practical while alleviating the negative impacts on the utility peak of the previous strategy and providing PS benefits to the Utility. During the mid-pricing period (13:00-16:00) of winter months, not only was charging prohibited but mandatory continuous discharge was enforced to aid in utility PS. This strategy was termed EA+PS Control.

EA+PS control disregards the mid-pricing period of the winter, acting as if there is one high-pricing period spanning 15 hours (07:00-22:00) as in the summer months. However, the winter month discharge power is limited to 2 kW making discharge last 9 hours (18 kWh usable energy/2 kW). This time frame was chosen, as discussed in the Utility Load Profile section, so the residential storage systems are discharging for the full time of the worst utility load peak (07:00-16:00). Charging is delayed until 00:00 to coincide with the Berwick Utility lowest load period. The battery can fully charge within six hours (by 06:00) and be ready for the start of on peak pricing (07:00).

The EA+PS control strategy shares benefits between homeowners operating within the *Domestic TOD* tariff and *Net metering* program and the utility subject to electrical demand charges.

During Mar-Nov all benefits go to the homeowner. During Dec-Feb, peak shaving benefit is provided to the Berwick Utility, and the cycling value to the homeowner is reduced from 1.45 cycles to 1 cycle per day. Note that the 0.45 cycles lost in this control strategy constituted the minority of the cycling value to the homeowner, not only because it is an incomplete cycle but because the pricing delta is lower than the initial cycle (high-medium price delta instead of high-low price delta).

Real Time Control

EA + PS control shares the benefits of the residential battery systems between the Utility and the homeowners. The strategy is limited however by its lack of flexibility. Berwick Utility experiences annual peak demand only one day a year and only one day that come within 50 kW of that peak. Ideally, the battery systems would operate in EA control every day except those peak days when it would operate purely as a Utility peak shaving system. The RT control strategy was designed to make real time decisions on how to operate to further optimize benefit sharing. The RT control strategy is rule-based but could be improved using a machine learning algorithm.

As discussed in the Berwick Tariff Structure Analysis section, Berwick's domestic Time-of-Use (TOU) high pricing period begins at 7:00, while daily peak loads do not typically occur until 9:00 - 10:00. This gives RT control a window of time in the mornings to collect and analyse load data and decide whether to operate in EA control or pure utility peak shaving control for the upcoming day. Figure 5 shows Berwick Utilities average load profile by time of day using data from 2017 and 2018, a red line depicts the start of the high pricing period. Utility Load tends to rise sharply between the hours of 6:00 and 7:00. By 7:00 the load has risen ~80% of the way from the its night-time valley to its daily peak. This suggests that the maximum load in the morning (before 7:00) could be used to predict the daily peak load.

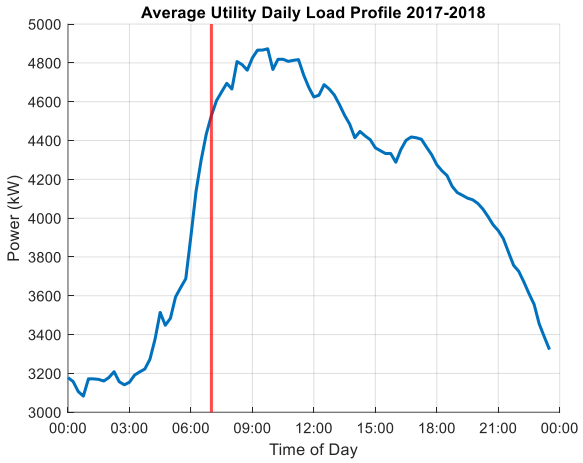

Figure 5: Average Utility Load profile by time of day

Figure 6 shows how strongly correlated the Utilities daily peak is with the maximum demand detected between 6:00 and 7:00. RT control uses this correlation to estimate the daily peak load before the beginning of the high pricing period. If the estimated peak is above a threshold, PS mode is activated for the upcoming day.

Figure 7 shows the Utilities peak days for each of 2013 through 2018. This figure illustrates that Berwick's yearly peak load value is highly variable (ranging > 1000 kW). The variability of the peak value suggests that a universal threshold value would not be sufficient to determine when the 50 kW battery system (aggregate) should operate in PS mode, and that a predictive threshold must be set using the context of the current year.

Since the aggregate discharge power of the ten residential battery systems is 50 kW, RT control utilizes a moving threshold equal to the maximum load experienced thus far in the year minus 50 kW.

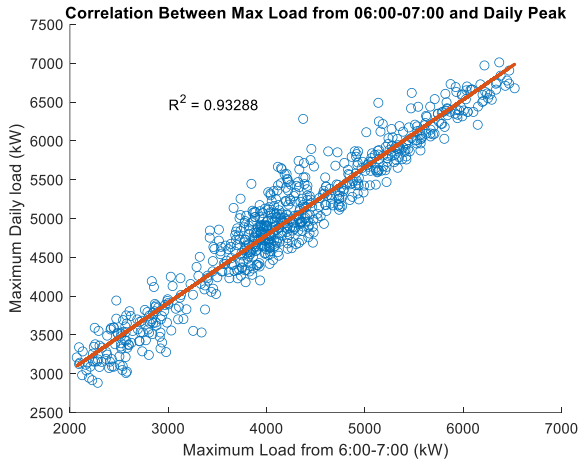

Figure 6: Correlation between Utility Peak Load and Max load from 6:00 to 7:00

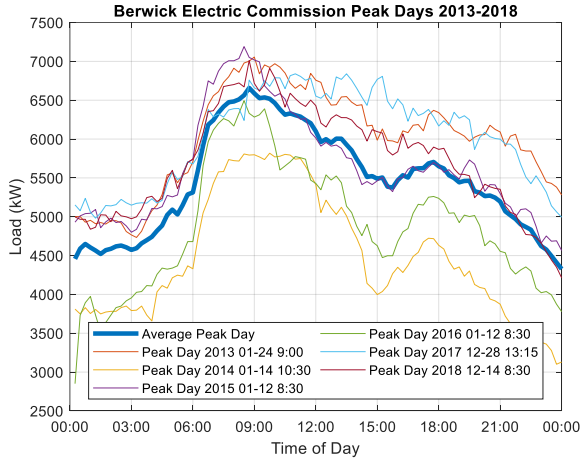

Figure 7: Berwick Utility peak day profiles 2013-2018

To provide the reader a visual representation of how RT control decides whether to operate its EA or PS algorithm, Figure 8 shows the moving threshold of RT control. The threshold is only relevant during winter pricing months thus is overridden to zero the remainder of months. At the start of December, the threshold value is set to 50 kW below the maximum load that has occurred the current year so far. This happened to occur on Nov 20th in this analysis. This value remained the threshold until Dec 18th when the Utility power peaked at greater than 50 kW above the threshold. The threshold was then set to 50 kW below the new Utility peak. The threshold was moved again of Dec 28th which was the Utilities peak day for the year. The threshold was only moved on two days throughout the entirety of the winter pricing months.

The net Utility load with both the moving threshold and load predictions is shown in Figure 9. There is precisely one prediction per day during the winter pricing months, made at the beginning of each day's high pricing period (7:00). If the prediction (green circle) is above the moving threshold (black line), the PS algorithm is selected for that day.

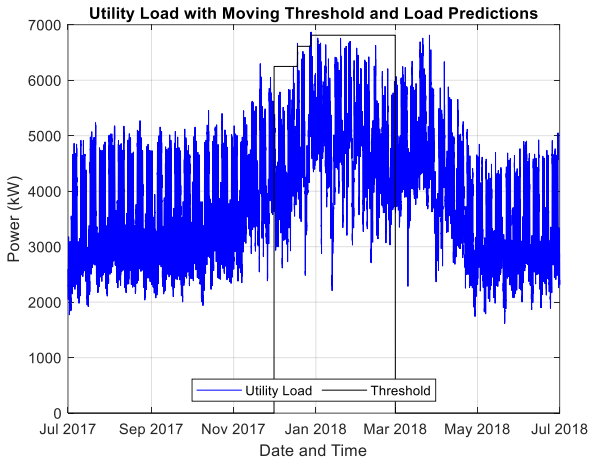

Figure 8: RT control moving threshold

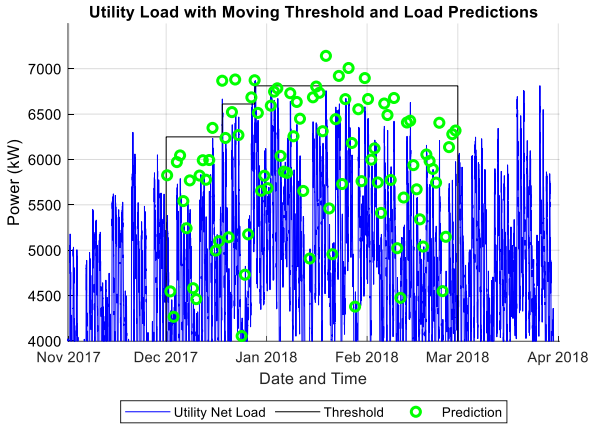

Figure 9: RT control, moving threshold and load predictions

Modelling

A battery system with 18 kWh useable energy and discharge and charge power limits of 5 kW and 3 kW respectively, was modelled in MATLAB, with a round trip efficiency of 86 %, representative of typical lithium ion battery systems. The model is a feedforward model where all values are initialized in timestep 1, with the battery fully charged but in standby mode. All three control strategies were executed, and relevant outputs were saved for analysis. The model calculated the homes' new load profiles accounting for the impact of the energy storage system. Additionally, the electricity cost of the homes under the TOD tariff were calculated for both the energy storage and no energy storage scenarios. The original house load profiles and the battery charge/discharge power arrays were also saved.

Results and Discussion

The results are presented initially in timestep form to enable the reader to see the power flow, net effects, and to validate that the model is executing as expected by implementing charge or discharge at the appropriate rates and times.

Following this, aggregate results are presented. including cost savings to residences and the Berwick Utility.

Timestep Results

Figure 10 and Figure 11 show the timestep results for EA control and EA+PS control respectively.

As expected, EA Control aggressively discharged and charged the batteries to provide the homeowners with the maximum achievable savings.

Figure 10 shows the battery completing 1.45 cycles equivalent this day. As expected, EA Control aggressively discharged and charged the batteries to provide the homeowners with the maximum achievable savings.

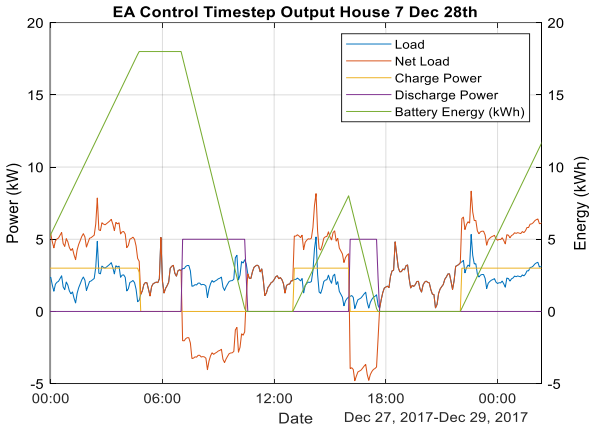

Figure 10: EA Control timestep results representative day

Figure 11 shows the EA + PS Control completing one cycle equivalent on the same day. Notable differences from the EA control of Figure 10 include: The battery does not become fully charged until 06:45. (principally because charge start is delayed until 00:00) and it conducts a long slow discharge throughout the day, including both the high and medium pricing periods, becoming fully discharged just prior to 16:00.

The EA+PS Control scheme provides less energy arbitrage benefit to the homeowners but is less battery intensive (less wear) and provides peak shaving benefit to the utility. The net load of the home is reduced by 2 kW from 07:00 to 16:00, providing both energy arbitrage benefits to the homeowner as well as peak shaving benefit to the utility. If over 2 kW was used, the battery would become fully discharged partway through the long Berwick Utility; once fully discharged, the residential load would again be fully applied to the Utility and likely no peak shaving cost savings would be realized.

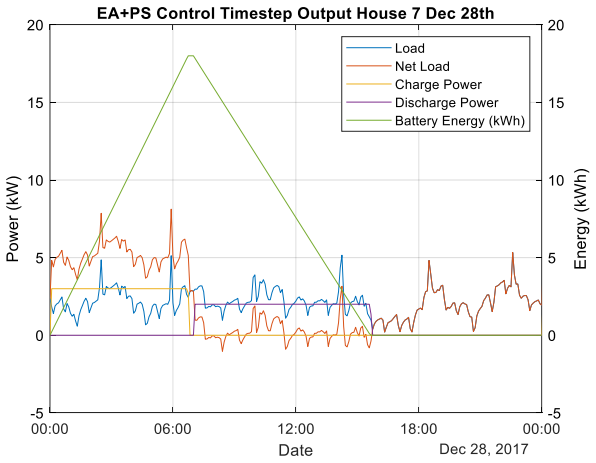

Figure 11: EA+PS Control timestep results two representative days

Figure 12 shows the timestep results of the RT control strategy on one home for two days. The left half of the figure shows the RT control utilizing its PS algorithm during the Utility peak day (Dec 28th); the right half of the figure shows the RT control utilizing the EA algorithm on the following day, which was a non-peak day. Note that the timestep results for the RT control strategy resemble that of the EA control for Utility non-peak days (right); during a Utility peak, the residential homes are disregarded and the timestep result may appear random unless examined in contrast with the Utility load (left).

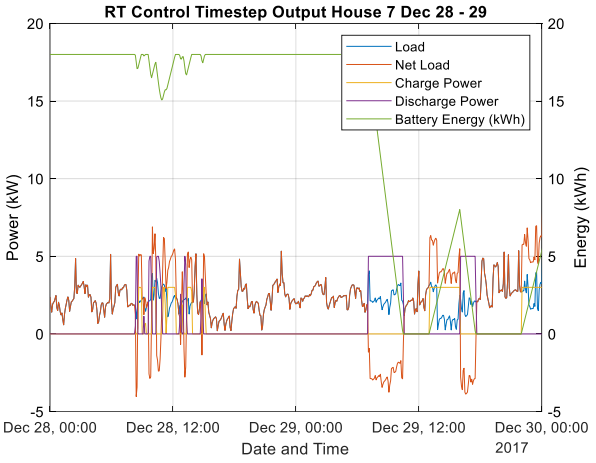

Figure 12: RT control timestep results two representative days

Aggregate Results to Homeowners

The saving presented in this section are relative to the annual electricity cost of the homes using the Domestic Service Rate (flat rate). Figure 13 shows the electricity bill of the homeowners under the flat rate, the TOU rate and under the three control strategies.

The cumulative homeowner savings of operating the battery systems on EA control total $5,408/year over standard Domestic rate, equal to an average $540 per house per year.

By switching to the EA+PS Control strategy, the arbitrage opportunities are reduced for the homeowner. Consequently, cumulative savings are $4,459, equal to an average $445 per house per year, a savings reduction of $95 (17%) per homeowner per year.

Switching to the RT Control strategy, homeowners regain a portion of the lost arbitrage opportunities. Cumulative savings are $5,077, equal to an average $507 per house per year. This shows that the RT control strategy comes at a savings reduction $33 (6%) per house per year compared to EA control and a saving increase of $62 compared to EA+PS control.

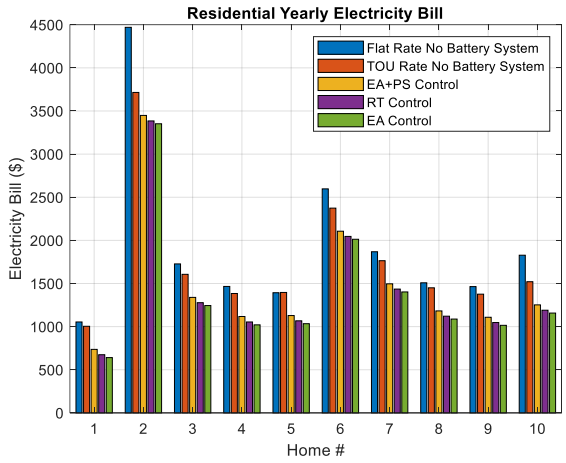

Figure 13: Residential Savings under by tariff and control strategy

Because all ten batteries are executing the same control strategies at the same time, they pass identical amounts of energy. The total quantity of discharge energy and the equivalent number of complete-discharge-equivalent cycles for each control strategy are shown in Table 2. Note that, unlike EA and EA+PS control, the equivalent number of cycles for RT control will vary yearly as the Utility load profile changes.

Table 2: Battery discharge cycles for each control strategy

	EA Control	EA+PS Control	RT Control
Discharge Energy (kWh)	4985	4493	4771
Complete-Discharge Equivalent Cycles	277	250	265

Aggregate Results to Utility

The impacts of the EA, EA+PS and RT control strategies on the utilities peak demand were analysed. Figure 14 shows the new Utility peaks resultant from the control strategies. Note that the y-axis begins on 6500 kW for better resolution.

In December, EA control raised Berwick's peak by 30 kW. At a cost of $12.125/kVA for 12 months this totals an increased annual cost of $4,365. Comparing this increase in cost with the homeowner savings of $5,408 it is evident that this is a poor control choice for the AlbaNova Project ($1,043 net savings).

In contrast, the EA+PS Control in Dec reduced the utility peak by 20 kW. The peak reduction achieved saves the utility $2,910. This is combined with the homeowner savings of $4,459 for an overall savings of $7,369 per year for the AlbaNova project.

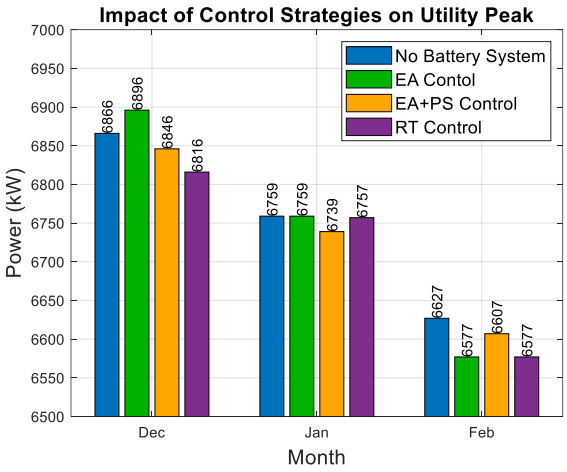

Figure 14: New Utility peaks under each control

RT control reduced the Dec peak by the maximum possible 50 kW achieving Utility savings of $7,275. Combined with the homeowner savings of $5,077 the total savings becomes $12,352 for the AlbaNova Project.

There were nine occurrences in which RT control predicted a peak day and operated in PS mode. This means that the battery systems provided EA savings to the residential homes 356 of 365 possible days and provided the Utility PS benefits on nine different days. RT control successfully detected the Utilities peak day as well as detecting eight 'false' peak days.

An unexpected result was observed in Figure 14 for the month of Feb as the EA Control resulted in a lower utility peak than the AE+UPS Control. This is supported by the peaking analysis presented in the Utility Load Profile section. Peak demand in February happened to occur at 08:45, during the 5 kW (50 kW aggregate) battery discharge of the EA Control strategy. The peak was maintained for a relatively short duration and the peak ended before the batteries were fully discharged. The AE+PS Control is designed for a longer duration peak and was discharging less aggressively during this time period, thus shaved the peak by a lesser amount. This indicates how RT control is superior to EA+PS control due to its ability to shave a peak by 50 kW instead of just 20 kW. It also demonstrates how sensitive the results can be to spurious events and unusual load profiles.

It can also be observed that RT control did not result in the biggest utility peak reductions in January and February. The

reason being that the moving threshold of RT control was set in December and the peaks of the following months did not necessitate shaving as they would not affect the Utility demand charge. In January, the load just barely crossed the threshold and RT control utilized PS mode to shave the peak by 2 kW; this was one of the eight 'false' peak days detected by RT control. In February the RT control never suspected a Utility peak and operated purely in EA mode which coincidentally shaved the peak by 50 kW as mentioned.

Conclusion

Three battery system control strategies were designed with the aim of sharing the benefit of ten battery systems between homeowners, by energy arbitrage, and a Utility company, by peak shaving.

The EA Control was designed purely by analysing Berwick's *Domestic Service TOD* tariff structure. Designing the EA + UPS Control required contrasting the residential load profiles with the Berwick Utility Load profile over the same time period. Measured Berwick Utility load data was analysed to identify average and peak demand values, determine the shape, duration, and frequency of peaks, and compare these peak periods to the dynamics of the residential electricity loads. While the largest single utility peaks were found to occur in the morning for all months, the months of Dec-Jan showed that these peaks could occur anywhere in the morning. The findings based on examination of timestep data suggested that residential battery systems must discharge throughout the continuous 9-hour peak demand period on the highest load day for Berwick Utility to have an impact on its ratcheted demand cost. The RT control strategy was designed with both a homeowner EA algorithm and a Utility PS algorithm. Historic data was used to form a correlation between morning load and daily peak load allowing the controller to predict whether the upcoming day is a peak or non-peak day and operate in PS or EA mode respectively.

The importance of net metering on these control strategies was highlighted.

A battery system with 18 kWh useable energy and discharge and charge power limits of 5 kW and 3 kW respectively, was modelled and used to execute the control strategies using ten residential load profiles and a utility load profile for the same year.

EA control raised Berwick's demand charge by $4,365 while saving the homeowners $5,408 resulting in net savings of only $1043. EA+PS saved the utility $2,910 and the homeowners $4,459 for an overall savings of $7,369 per year. RT control reduced the Utility peak by the maximum possible 50 kW achieving Utility savings of $7,275. Combined with the homeowner savings of $5,077 the total annual savings becomes $12,352 for the AlbaNova Project. The next steps of this project will use machine learning algorithms to better predict Berwick's peak days and ensure the residential stakeholders obtain maximum EA benefits while ensuring the Utility peak load is shaved by 50 kW.

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