Appendix 1

RUGGEDISED Task 4.2: Increase the Energy Efficiency at the District Level

Duke St Car Park Battery Analysis

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Overview

RUGGEDISED is a smart city project funded under the European Union's Horizon 2020 research and innovation programme. It brings together three lighthouse cities: Rotterdam, Glasgow and Umeå and three follower cities: Brno, Gdansk and Parma to test, implement and accelerate the smart city model across Europe.
Working in partnership with businesses and research centres, these six cities will demonstrate how to combine ICT, e-mobility and energy solutions to design smart, resilient cities for all. This means improving the quality of life of citizens, reducing the environmental impact of activities and creating a stimulating environment for sustainable economic development.
As part of the RUGGEDISED projects, the City of Glasgow and its RUGGEDISED project partners are installing a photovoltaic (PV) array and battery storage into a car park in Duke Street, Glasgow to provide a low carbon means to support the charging of electric vehicles (EV).
The Energy Systems Research Unit (ESRU) was tasked with undertaking a preliminary sizing exercise for the battery. This combined with predictions of energy supply and demand (including EV charging) for the car park along with electricity tariff information (provided by Glasgow City Council) was used to determine energy performance and costs associated with a range of battery sizes and operating scenarios.

Modelling

A single busbar electrical system model was established on the MATLAB modelling platform: this is shown in Figure 1. The model can estimate the energy performance of the car park electrical system over time. The boundary data used with the model is as follows:

- a static 30kW base load based on real measured car park load data (provided by Glasgow City Council);
- electric vehicle fleet charging profiles (derived from Scotland-wide EV charging data) for 10, 20 & 50 vehicles; and
- simulated power output from the 200kW PV array on the car park roof (Hand and Kelly 2017).

Each boundary data input to the model takes the form of a 1-year profile at 30-minute time resolution.

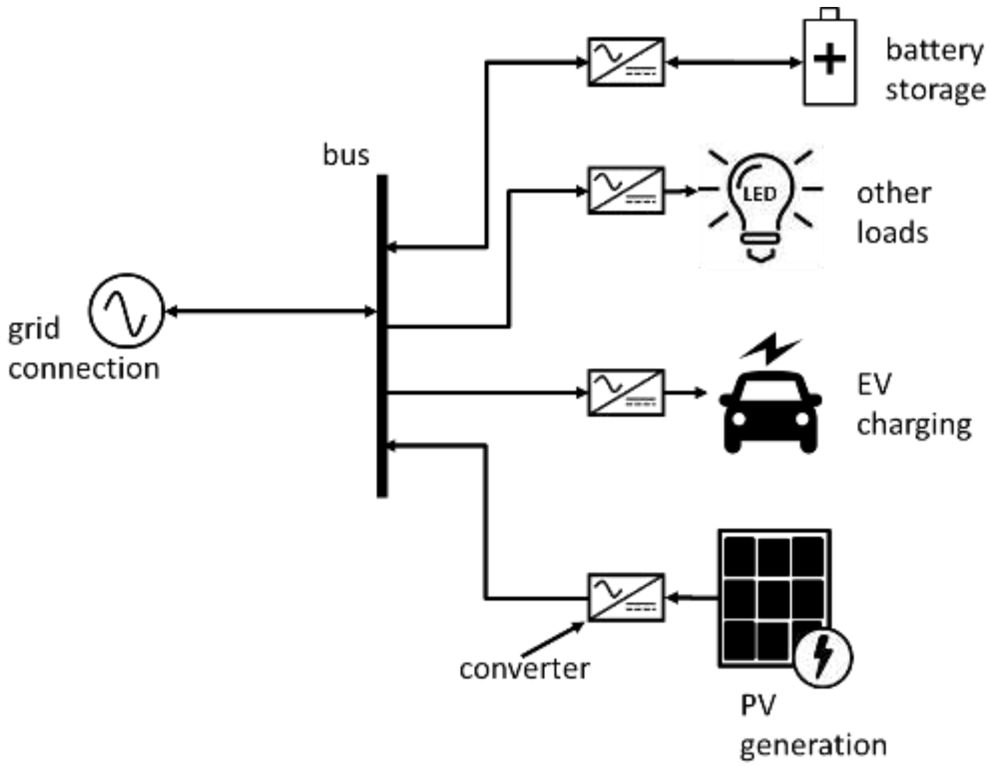


Figure 1: diagram of the modelled Duke St system.

The battery storage model accounts for SOC limits, battery self-discharge, charge and discharging losses and can support different battery operating strategies. The model can also limit the charging and discharging rates; however, in the current study this was not done.

For each case simulated, the model calculated the battery state of charge (SOC), battery charge and discharge, and rates of power exchange with the network. The Battery operating parameters were taken from a variety of sources, including the battery purchasing specifications produced by project partner Siemens and various battery studies. These are as shown in Table 1.

Table 1: Battery Parameters

Parameter	**Value or range**
Capacity	0 – 500 kWh
Minimum SOC	20%
Charge Efficiency	96%
Discharge Efficiency	97.2%
Self-discharge	0.3% of SOC/day
Converter efficiency	90%

Cost Calculations

The model of Figure 1 initially produced energy data, which was then converted to a notional battery running cost, using tariff data provided by Glasgow City Council.

The electricity tariff comprises: *consumption charges* per unit (kWh) of energy used, and *pass through charges* and each of these in turn has multiple cost components.

1.1.1 Consumption charges

1. *Energy use (E_x)*: the wholesale cost of energy used, which split into two periods, each with a different rate: Day (00:00/07:00), and Night (07:00/00:00). The cost is the same during weekdays and weekends.
2. *Infrastructure costs*: These relate to the cost of energy lost as it travels from the power station, through the transmission and distribution wires. The Distribution Use of System (DUoS) is charged at three different rates: Red, Amber, and Green. These bands change depending on time of day and day of the week and are summarised in Table 1. The Transmission Use of System (TUoS) is a fixed charge, given in Table 2.

3. *Service Charge (MF)*: These are the costs incurred to the electricity supplier. This is the management fee given in Table 2.
4. *Climate change levy (CCL)*: This is a tax on the energy used from the national grid to encourage businesses to reduce their energy consumption or switch to energy from renewable sources. It is paid at a fixed rate per kWh as given in Table 2.

Table 2: Time bands for DUoS charges

Time periods	Red Time Band	Amber Time Band	Green Time Band
Monday to Friday*	16:30/19:30	08:00/16:30 & 19:30/22:30	00:00/08:00 & 22:30/00:00
Saturday and Sunday		16:00/20:00	00:00/16:00 & 20:00/00:00

*(Including Bank Holidays)

1.1.2 Pass through charges

- *Standing charge (StC)*: Contributes to the installation and maintenance of the electricity distribution network. This is charged at a daily rate given in Table 3.
- *Agreed supply capacity* (ASc or *maximum import capacity*): This is a charge for the maximum amount of power that can come from the local distribution network at any given time. The site currently has an agreed capacity of 650 kVA and is charged at a monthly rate given in Table 3.
- *Reactive power charge (Rc)*: Reactive power is the difference between the electricity supplied and what is converted into useful energy. This is charged per kVARh and its rate is given in Table 3.
- *Combined half-hourly data charge (HHc)*: The costs associated with collecting and handling half-hourly metering. This is charged at a daily rate given in Table 3.
- *Settlement agency fees (SAF)*: Charge for the distribution companies, suppliers, and metering companies recovering costs from one another. This is charged at a daily rate given in Table 3.

Table 3: Summary of charges

Consumption-related charges:			
Charge	Unit price (£)	Unit of measure	Symbol
Unit charge (day)	0.07707	per kWh	U_D
Unit charge (night)	0.06613	per kWh	U_N
DUoS charge (green)	0.00093	per kWh	$DUoS_G$
DUoS charge (amber)	0.00935	per kWh	$DUOS_A$
DUoS charge (red)	0.11672	per kWh	$DUOS_R$
Climate change levy	0.00568	per kWh	*CCL*
Reactive power charge	0.00309	per kVArh	R_C
Fixed charges & pass through charges:			
TUoS charge	30.48098	per month[1]	*TUoS*
Management fee	6.92	per Each bill cycle	*MF*
Standing charge	0.26340	Daily	*StC*
Agreed capacity	0.723	per kVA/month	*ASC*
Combined HH data charges	0.70521	Daily	*HHc*
Settlement agency fees	0.02302	Daily	*SAF*

The total annual running cost is therefore:

$$C = U_D E_D + U_N E_N + DUoS_G E_G + DUoS_A E_A + DUoS_R E_R + R_C E_{VA} + CCL\ E_T + (StC + DAT + SAF + HHc)d + (ASC + TUoS)m + MF \tag{1}$$

[1] The billing for this quantity is ambiguous regarding the units or calculation method.

Where $E_{D,N,G,A,R}$ are the number of real power units (kWh) used in the day, night, green amber and red time periods over the year, respectively. E_{VA} is the total number of reactive power units used over the year and E_T is the total number of units used over the year. Finally d is the number of days (365) and m is the number of months (12).

Cases Modelled

A range of different cases were modelled and analysed. These were as follows:

1. different battery capacities (no-battery [base case] up to 780kWh);
2. different numbers of electric vehicles (10,20 and 50); and
3. two different battery operating strategies:
    a. the battery was supplied from the PV, with the grid used only to maintain the battery at the minimum state of charge (SOC);
    b. the battery was charged from the PV but is also topped up to 100% SOC overnight at low tariff periods (assumed to be 00:00-06:00).

In cases a & b above, the battery preferentially supports EV charging rather than exporting to the network. Power is only exported to the network from the PV array if the battery SOC is at a maximum.

In the second strategy, the overnight charge was spread out over the full off-peak period (00:00-06:00) to minimise the peak load on the network.

In *all* of the cases modelled, power was imported from the network, irrespective of the tariff period, if the battery SOC was forecast to drop below the minimum SOC – in this case 20%.

Figure 2 illustrates the basic time series outputs from the model, showing the PV generation and EV charging load, the battery SOC, exported and imported power, respectively. All of the results that follow were derived this base data emerging from each simulation.

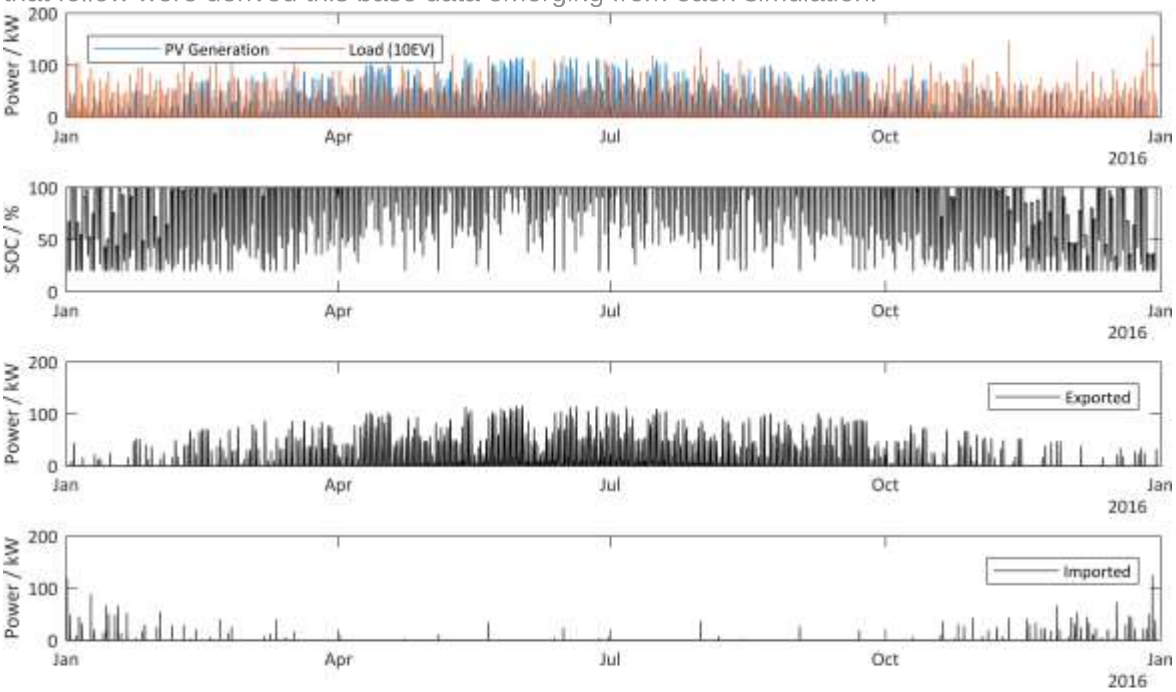


Figure 2: illustration of basic time series outputs from the model.

Results and Discussion

The performance of the system of Figure 1 was simulated for a 1-year time period. Figure 2 shows the type of data of data generated from the model; this was then converted to an annual running cost using Equation 1. Also shown is the calculated renewable utilisation fraction (F) from each simulation. This is calculated as follows:

$$F = 100 \times \left[1 - \frac{Annual\ Imported\ Energy\ (kWh)}{Annual\ Energy\ Demand\ (kWh)}\right] \qquad (2)$$

In the results that follow, the annual running cost and renewable utilisation fraction for the system of Figure 1 is shown for increasing battery capacity. The two different battery operating strategies are differentiated by colour. Each graph figure represents the results for the system servicing a fleet of 10, 20 or 50 EVs. A battery size of zero indicates the results of the base case, which has no battery and where power is extracted from or exported directly to the network as required.

Analysis Considering Only EV Charging

The initial figures consider *only* the energy associated with EV charging, i.e. the battery services the EV load only. Later figures show the costs associated with servicing the EV load and the car park base load.

1.1.3 Case: Servicing EV Load Only – 10 Vehicles

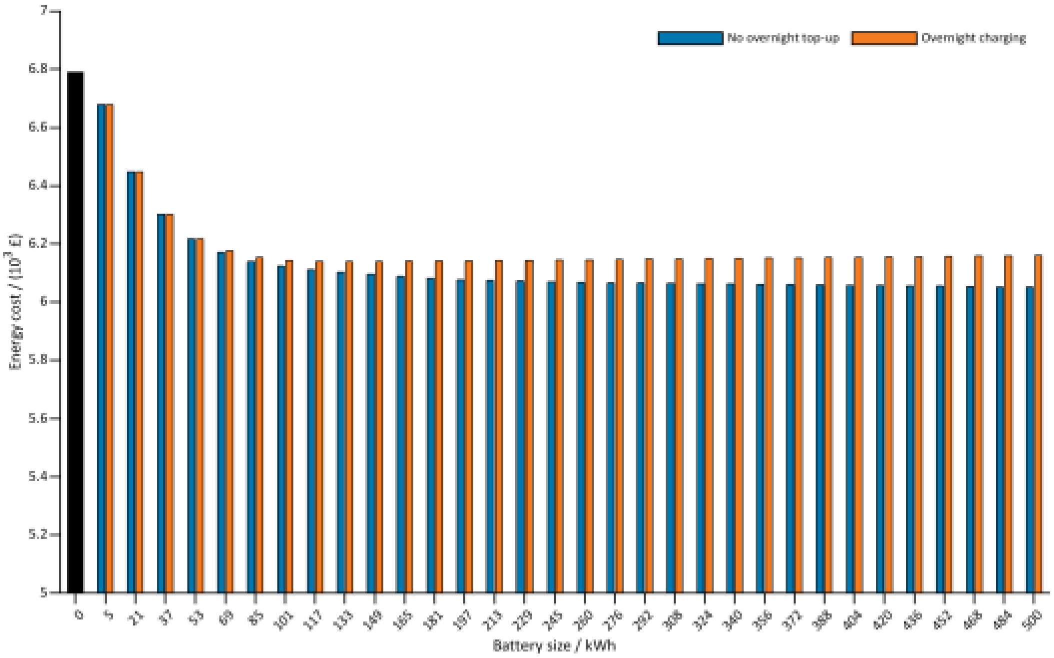


Figure 3: Annual energy cost for 10 EV vs battery size

Figure 3 shows that running costs drop steeply from the no-battery case up to a battery size of approx. 80 kWh and then level off. Overnight top-up charging results in slightly higher costs as battery size increases.

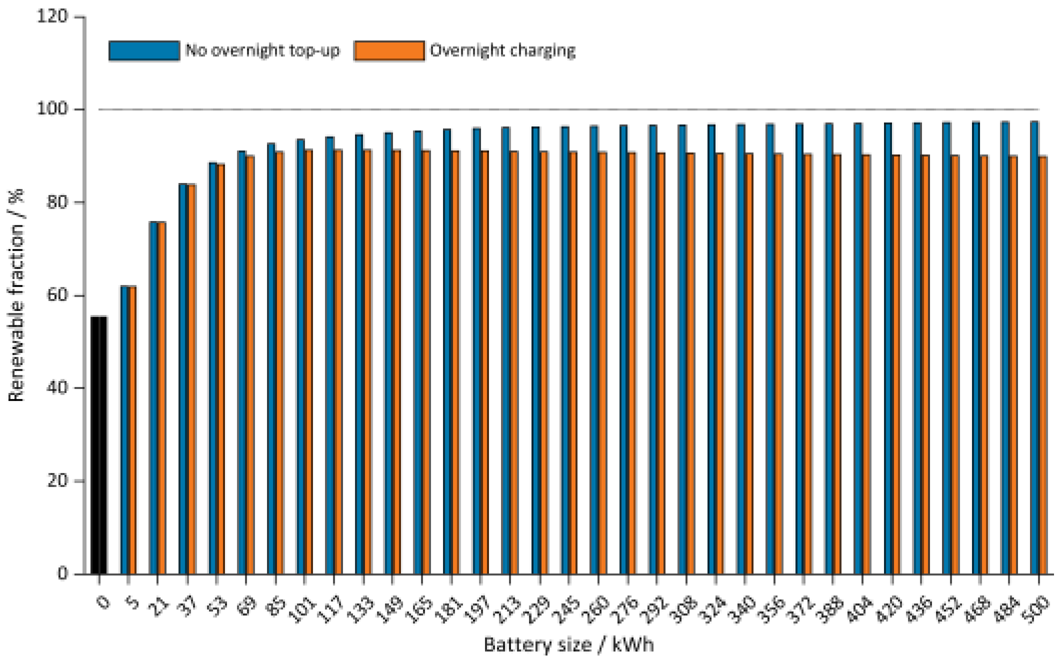


Figure 4: Renewable utilisation fraction for 10EV vs battery size.

The renewable utilisation fraction (*F*) shows the opposite trend, rising with battery size, but again levelling off around 80-100 kWh. Without top-up, utilisation of close to 100% is possible. With an overnight top up, peak renewable utilisation fractions are approximately 90%. Note that without a battery, renewable utilisation fraction is approx. 58%.

1.1.4 Case: Servicing EV Load Only – 20 Vehicles

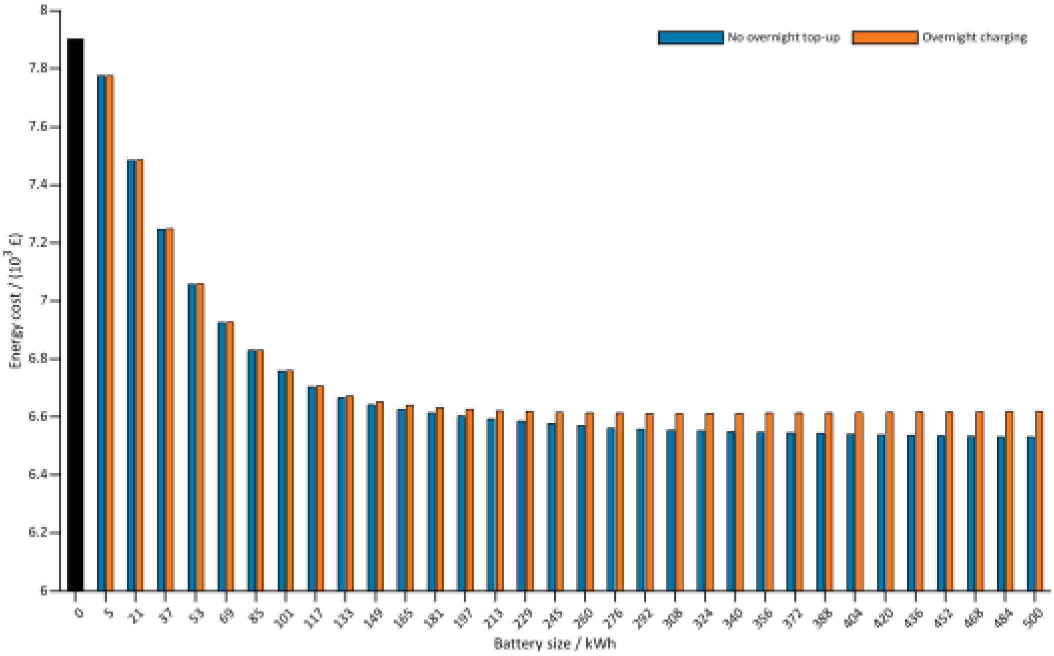


Figure 5: Annual energy cost for 20 EV vs battery size.

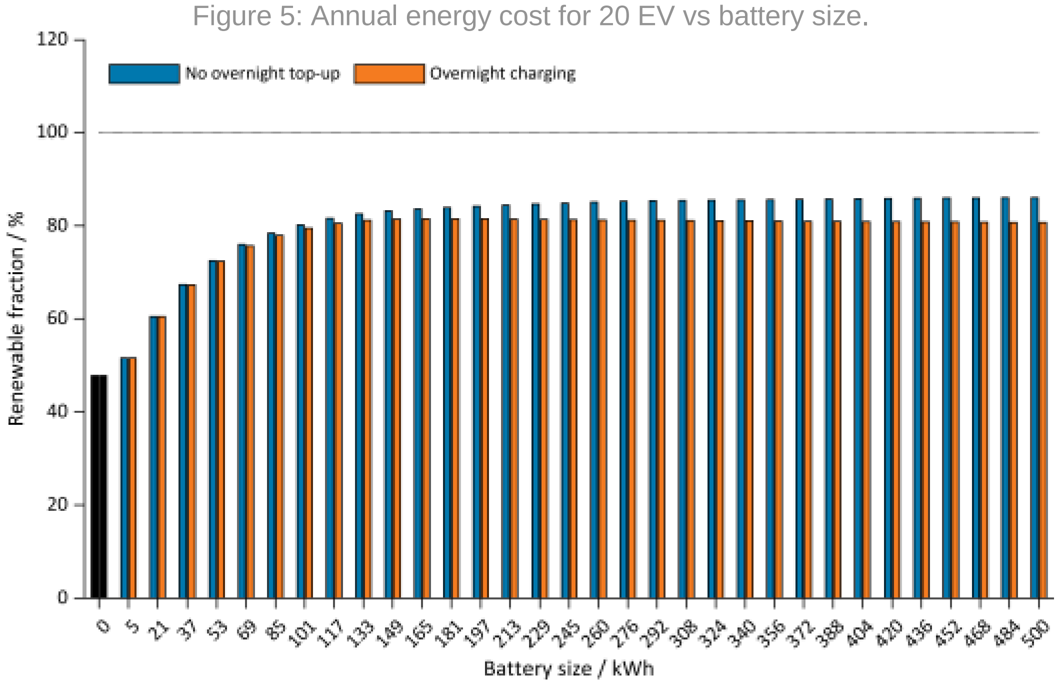


Figure 6: Renewable utilisation fraction for 20EV vs battery size.

Again, running costs drop steeply, but then level off at approx. 180 kWh. Overnight top up charging is marginally more expensive than using only energy from the PV array to support charging. *F* shows the opposite trend, but like running costs, improvements level off around a battery capacity of 180 kWh. Renewable utilisation fractions of over 80% are achievable without top up. With overnight top up of the battery, the renewable utilisation fraction is marginally less.

1.1.5 Case: Servicing EV Load Only – 50 Vehicles

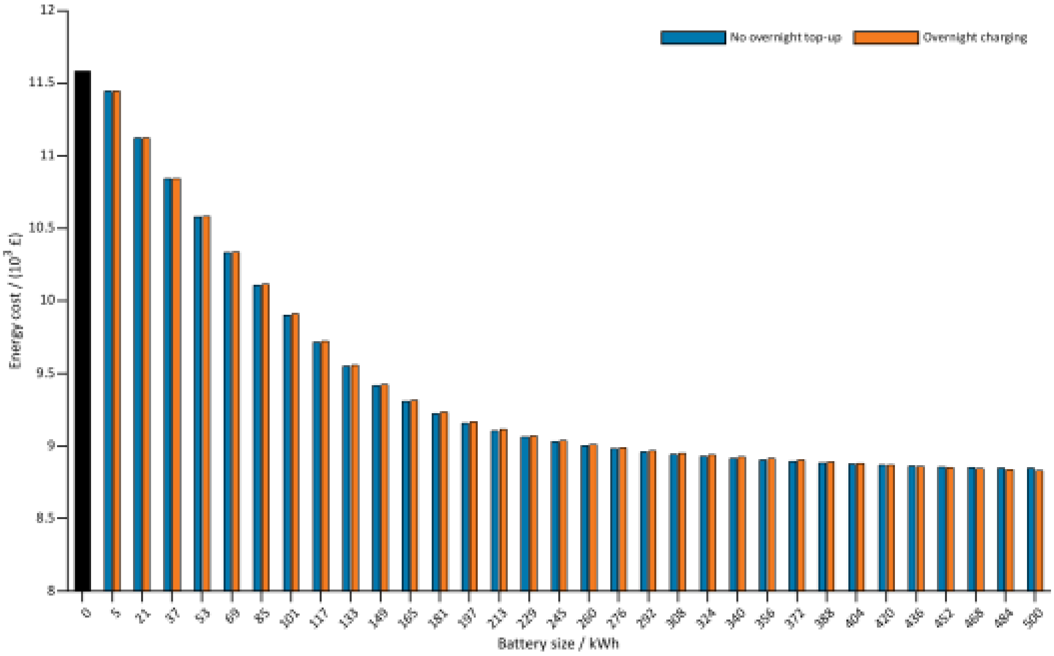


Figure 7: Annual energy cost for 50 EV vs battery size

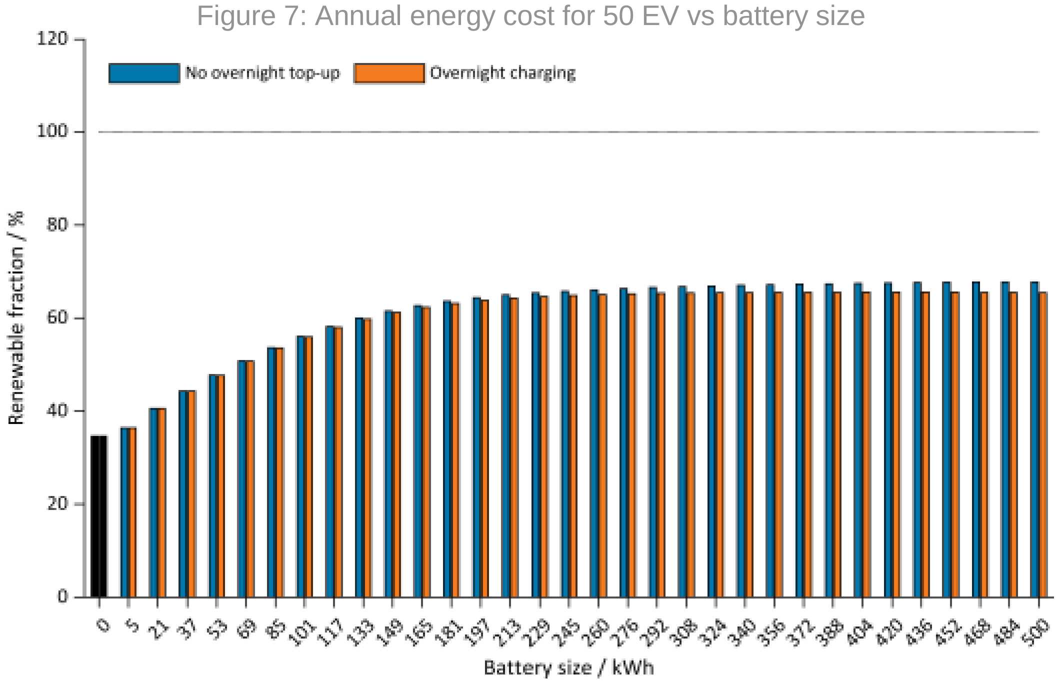


Figure 8: Renewable utilisation fraction for 50EV vs battery size.

Running costs drop with increasing battery capacity, but not as distinctly as seen in the previous two cases. The costs begin to level out at a battery capacity of approx. 300 kWh.

The graph of renewable utilisation fraction shows a similar, but inverted trend, with improvements in *F* tending to level off at battery capacities above 300 kWh. The renewable utilisation fractions are significantly lower than those seen in the 10 and 20 EV cases.

Analysis Considering Base Load and EV Charging

As has been mentioned previously, the substation servicing Duke Street car park has a significant base load demand of approx. 30 kW. This is an unusually high base load for a single building and merits further investigation by the owners.

The case that follows shows the impact on running costs and renewable utilisation fraction (*F*) associated with the battery servicing the base load in addition to EV charging.

1.1.6 Case: Servicing Base Load + EV Load - 10 Vehicles

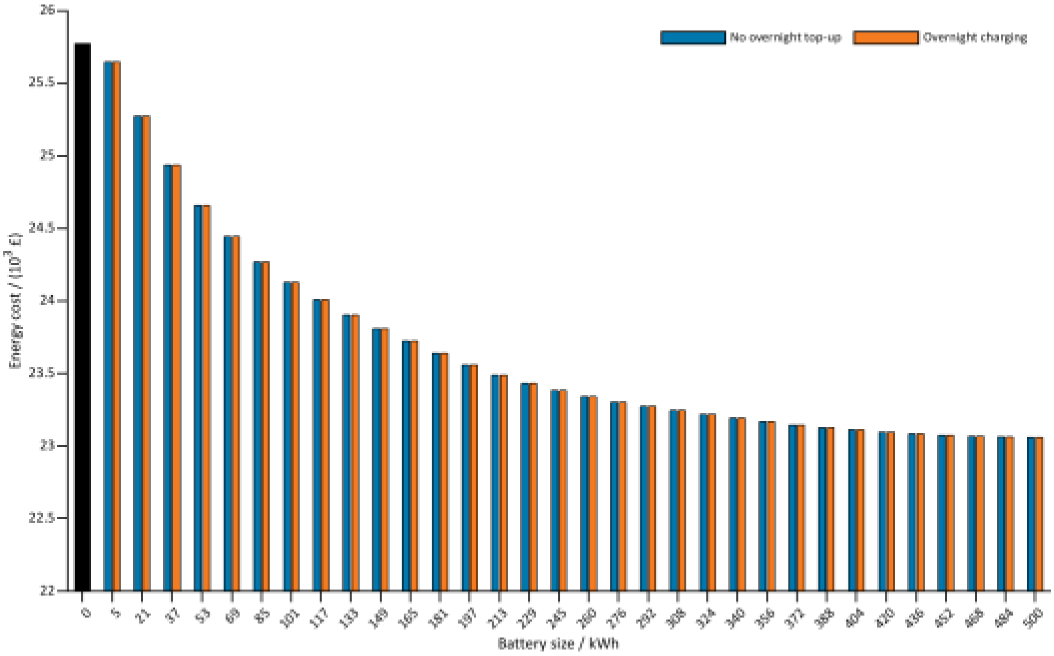


Figure 9: Annual energy cost for base load + 10 EV vs battery size

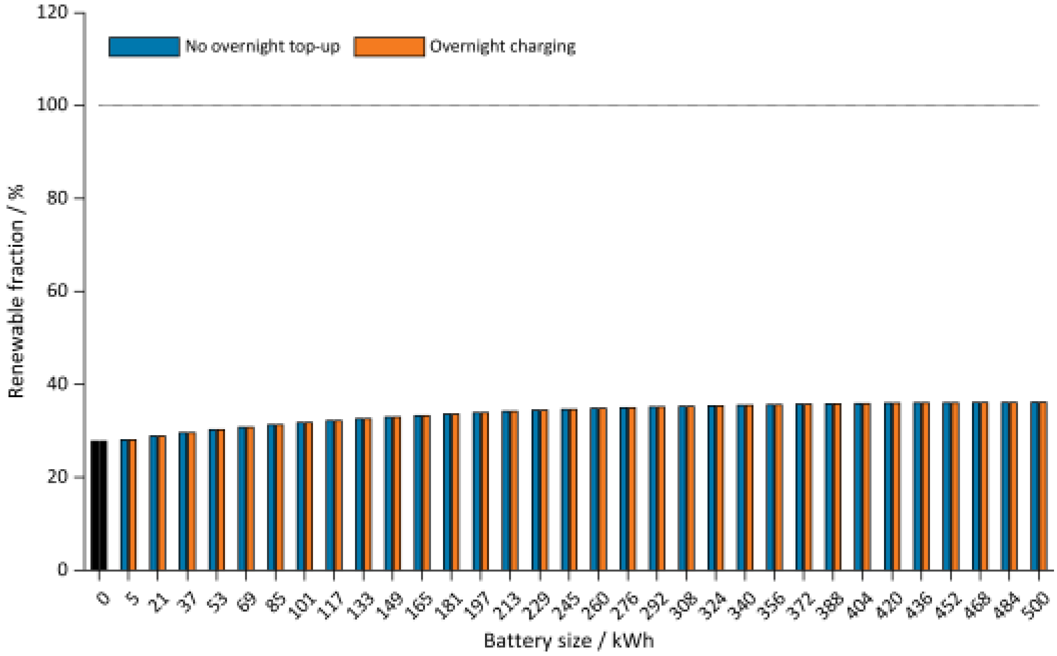


Figure 10: Renewable utilisation fraction for base load + 10EV vs battery size.

The results in this case are similar to the 50 EV case where the base load was not included, with costs levelling off at a slightly larger approx. 500kWh. An obvious "sweet spot" for cost reductions and renewable utilisation fraction is less evident than the 10 and 20 EV cases.

Including the 30 kW base load in the cost saving calculation resulted in more substantive savings compared to the equivalent case considered only EV charging. For example, in the case of 10 EVs being serviced (Figure 3), a battery of 105 kWh delivered a running cost saving of approx. £660. When the base load is accounted for in the running cost calculation, this rises to approx. £1.9K of running cost savings.

Note that in this case, there is no difference between the results from the two charging control strategies. This is because the grid top-up of the battery was configured to occur when there is no call on the battery. As the base load exists at all times, the battery will never charge from the grid during off-peak periods and only take charge from the PV array.

The picture for the renewable utilisation fraction is similar with a slow increase in utilisation with battery size. *F* levels off below 40% after battery size reaches approx. 500 kWh.

Battery Size and Peak Power Flows

The size of the battery and battery charging strategy has a significant effect on the peak imported power flows associated with vehicle charging. Figure 11 shows the peak power drawn[2] from the grid against battery size for a fleet of 50 EVs and for two different charging strategies.

For the no overnight top-up case of the battery from the grid, the reduction in peak imported power is non-linear but clearly downward with increasing battery size.

In the case of overnight top up a minimum of 60 kW is reached at a battery size of approx. 400 kWh. Up to 400kWh, the battery helps mitigate the peak power drawn by the vehicles. But, beyond this point, topping up the charge of an increasingly large battery causes the imported power to rise again in this case. Note that this increase could be avoided by limiting the top up charging rate.

1.1.7 Case: Peak Imported Power Servicing 50 EVs

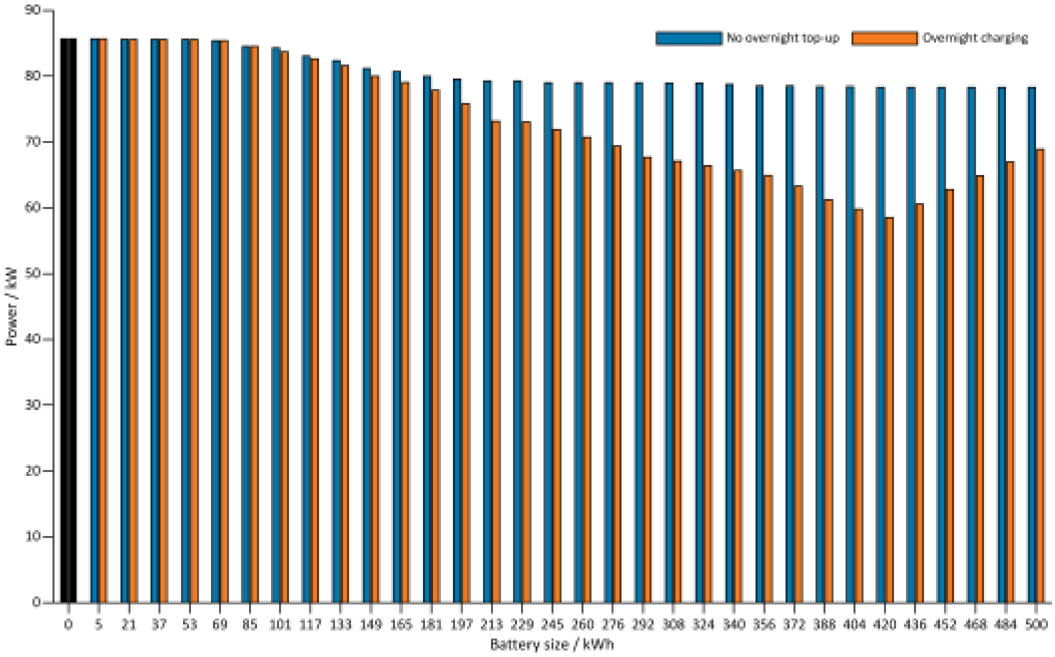


Figure 11: Change in peak imported power with battery size for 50EVs.

[2] The figure shows the imported power level corresponding to the 99th percentile imported power as this more clearly shows reduction with battery size. The corresponding figure for the absolute peak imported power shows a more eccentric but still declining trend.

1.1.8 Case: Peak Exported Power Servicing 50 EVs

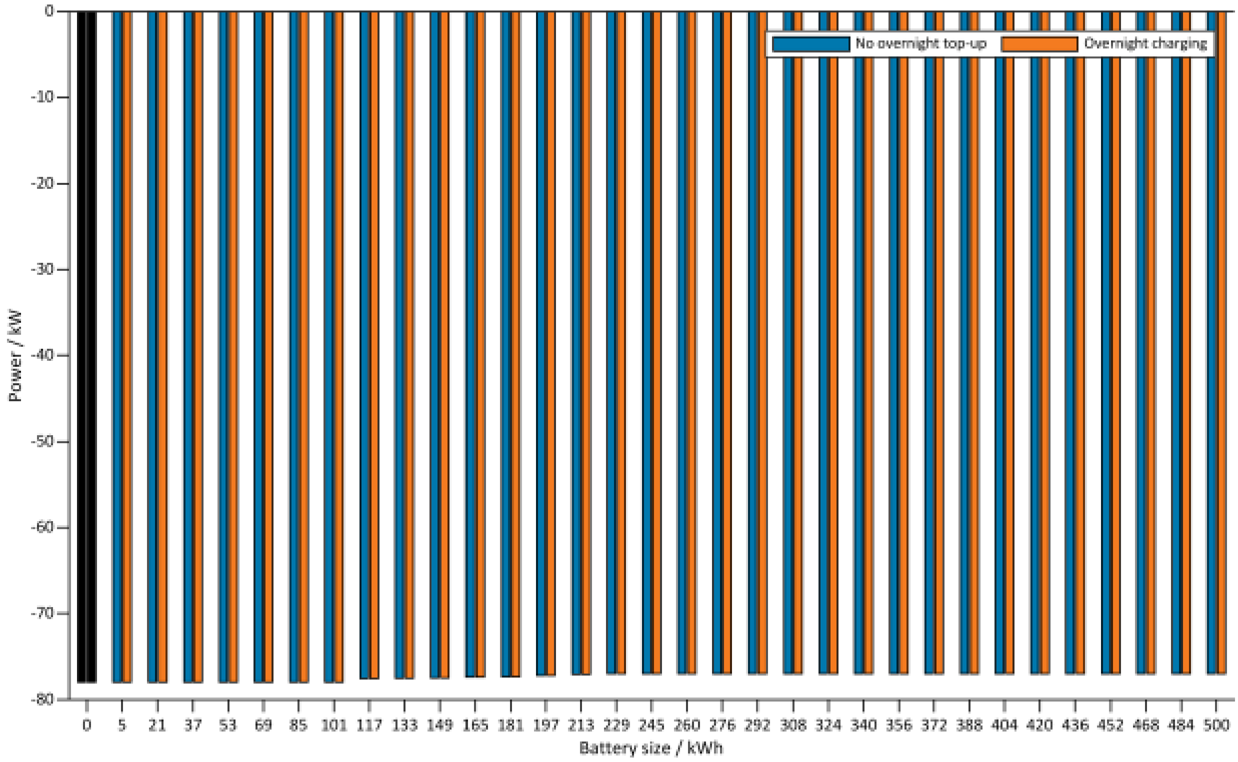


Figure 12: Change in peak exported power with battery size for 50 EVs.

The corresponding figure for peak power exported[3] to the network indicates that this is insensitive to battery size, with only a very slight reduction in power flow with battery size. This hints that when the peak output from the car park PV array occurs, the battery is already full and there is limited or no vehicle charging.

Both figures 11 and 12 show the peak power flows for vehicle charging only, base load is excluded.

Varying Connection Capacity charge

The previous results assume that the monthly connection capacity cost is charged at the present agreed capacity of 650 kVA. This results in an annual capacity charge of over £5600. However, adding a battery into the system can result in a significant drop in the peak demand. Consequently, in the results that follow, the peak demand has been calculated and the capacity charge adjusted to that level. The running costs reflect this revised capacity and capacity charge. NB The figures that follow do not account for base load.

[3] Again the figure shows the peak exported power corresponding to the 1st percentile value.

1.1.9 Case: Servicing EV Load Only – Altered Capacity Charge – 10 Vehicles

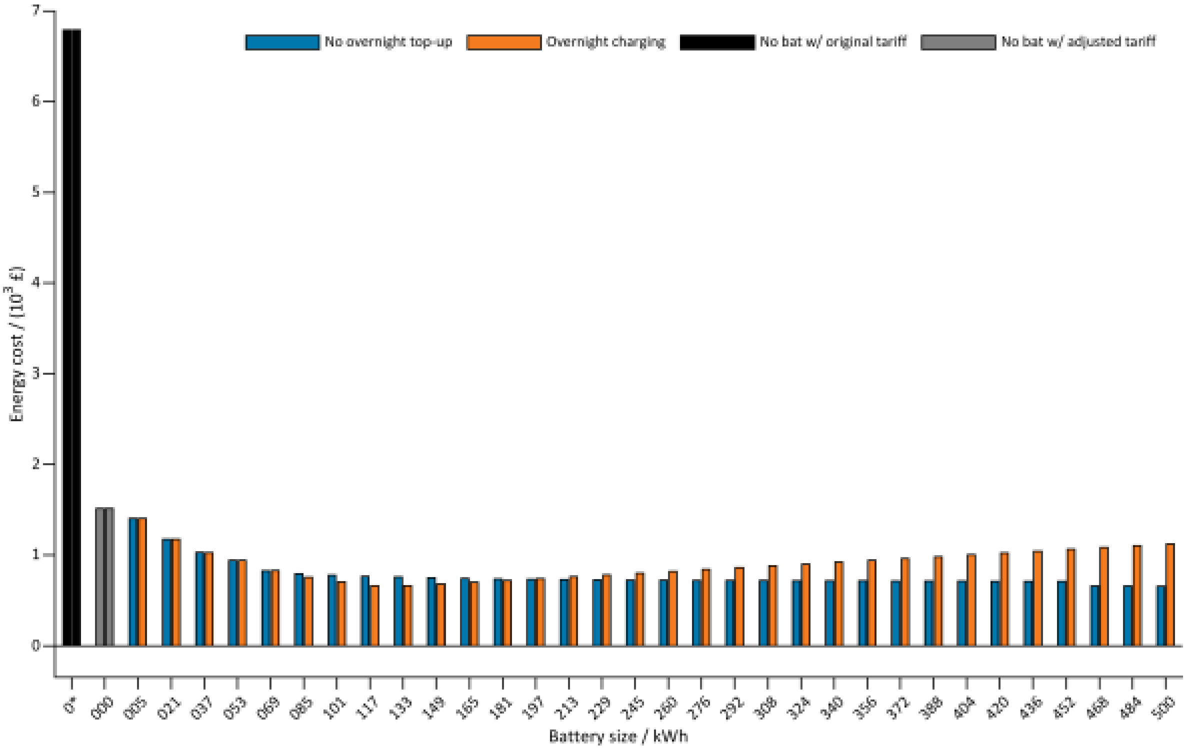


Figure 13: Annual energy cost for 10 EV with new tariff vs battery size

The results show an even steeper drop off in costs compared to previous examples, however cost reductions again level off around 100 kWh battery capacity for the no overnight top up case and approx. 150kWh for the case with battery top up overnight. In this case the overnight top up results in the cheaper running costs as the battery can make a bigger contribution to PV charging during the day than the case where the battery is only charged from the PV array. This results in lower peak demand and so a lower capacity cost.

Note however that even where there was no battery but adjusting the capacity charge to the level predicted resulted in a very significant drop in costs.

1.1.10 Case: Servicing EV Load Only – Altered Capacity Charge – 20 Vehicles

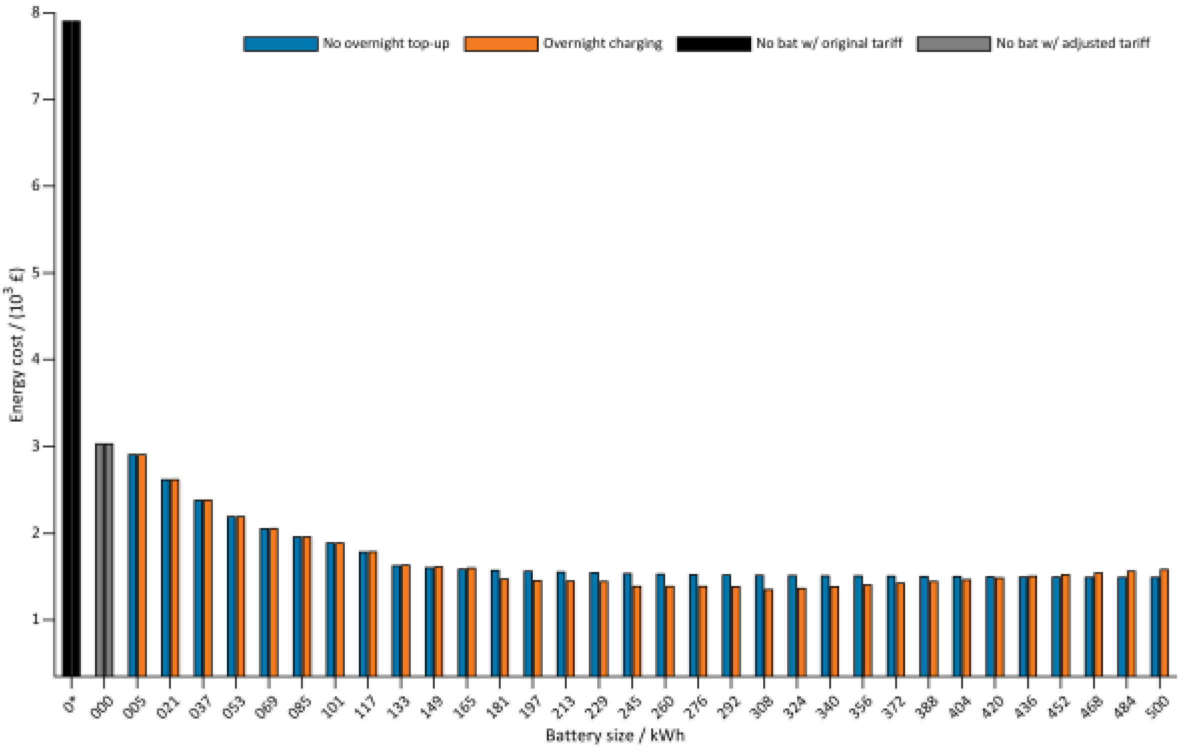


Figure 14: Annual energy cost for 20 EV with new tariff vs battery size

A similar pattern is evident in the 20 EV case with the no top-up running costs levelling off around 200 kWh and the case with top up levelling off around 250 kWh battery capacity. Again the running costs associated with overnight charging are lower than where the battery is charged only from the PV array.

1.1.11 Case: Servicing EV Load Only – Altered Capacity Charge – 50 Vehicles

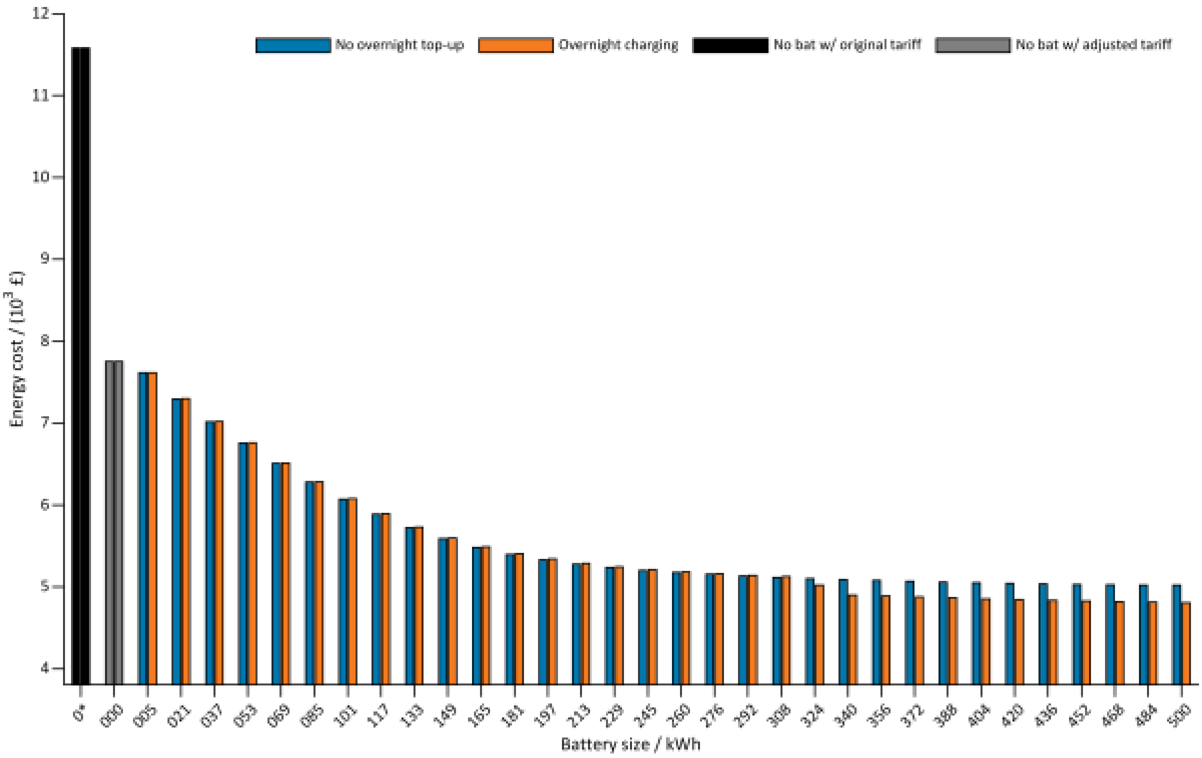


Figure 15: Annual energy cost for 50 EV with new tariff vs battery size

The 50 EV case shows a less distinct fall in running costs and a gradual levelling off in running cost reductions as battery size increases. Costs associated with overnight top up are lower than charging the battery with the PV output alone, for the reasons stated previously.

1.1.12 Case: Servicing Base Load + EV Load– Altered Capacity Charge – 10 Vehicles

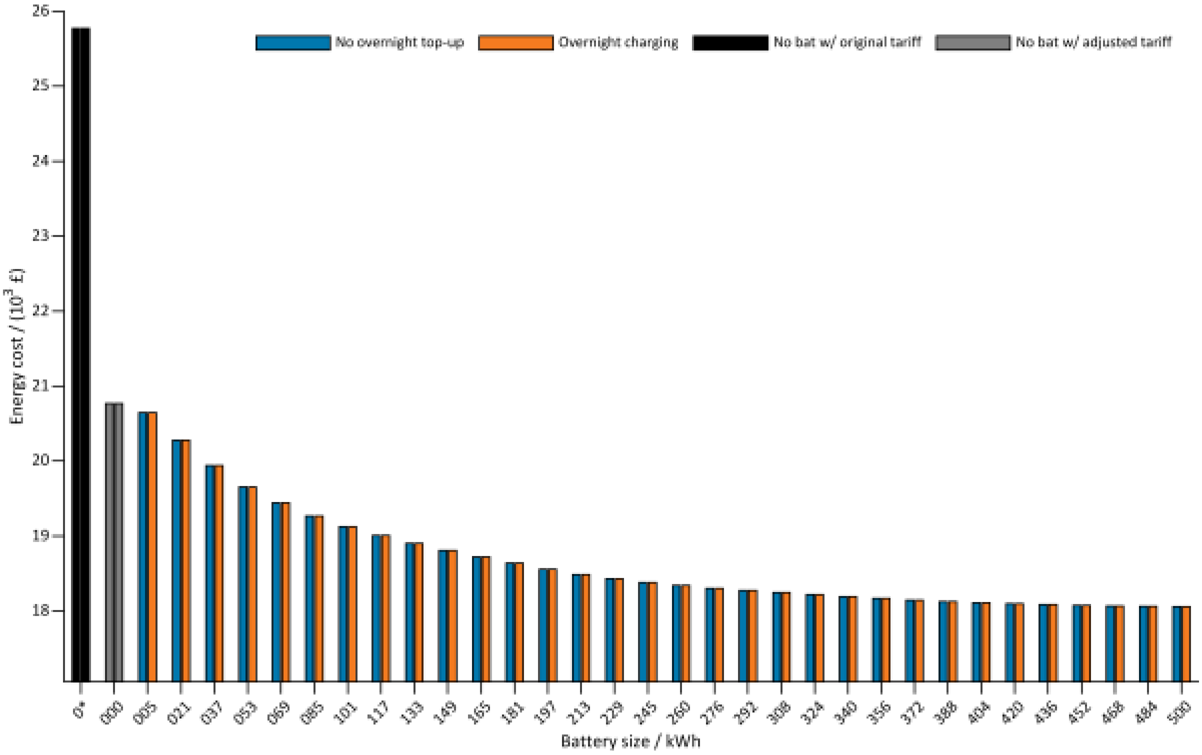


Figure 16: Annual energy cost for Load + 10 EV with new tariff vs battery size

Finally, again considering the case where the base load and the EV charging load are serviced by the battery, there is still a dramatic initial drop in running cost, with a gradual levelling off in costs as battery size increases.

Conclusions

A model of the Duke Street car park EV charging and battery storage system has been developed and applied to analysing the performance of different battery capacities under a range of operating conditions.

Considering running costs and the renewable utilisation fraction, for the EV charging load only:

- A (rough) rule of thumb appears to be that 6-10 kWh of battery capacity per EV serviced delivers the large majority of potential running cost savings and renewable utilisation fraction, whilst minimising the size of the battery required[4].
- Cost savings and renewable energy utilisation fraction both level off at higher battery capacities.
- The optimal battery size is less distinct with larger EV loads, but increasing battery size increased both savings and renewable utilisation fraction.
- Overnight battery top up to 100% SOC results in higher running costs for the 10 and 20 EV cases.

[4] Note that this rule-of-thumb assumes that the EV charging model used in the simulations reflects how vehicles will charge once the battery is installed. The charging model was derived from real kerbside charging data and car park charging characteristics may differ in terms of the timing of charge and the charge duration.

- In the 50 EV case overnight top up results in lower running costs, as it prevents the need to draw power at later periods of high electricity costs to maintain minimum battery SOC (20%).

Including the car park base load in the calculations resulted in less distinct cost reductions.
The magnitude of cost savings was greater when base load was included; however renewable utilisation fraction was significantly lower.
Peak imported power decreases with increasing battery size charging from PV alone. However, top up charging shows a clear minimum demand (e.g. approx. 60kW at a capacity of 400kWh, servicing a fleet of 50EVs).
Peak exported power is relatively insensitive to battery size, hinting that when the car park PV array is producing peak power (e.g. midday in high summer) the battery is already full and there is little or no charging load.
The greatest cost savings occurred if the assumed connection capacity (and associated charge) was reduced to the levels of peak demand predicted by the model. This reduction in cost occurred with or without a battery.
When capacity charges were adjusted to mirror the predicted peak demand, overnight top-up resulted in lower running costs than charging the battery from PV alone.

References

Hand J and Kelly N J (2017) Further analysis of Duke St car park power flows with a PV array and ducted wind turbines, RUGGEDISED project report ESRU-RUG-002.

Appendix 2 – University of Strathclyde Modelling Report

Smart Energy Networks: Analysis and Design of Glasgow's Smart Street

Overview

A modelling frame work is in development, which will enable that the performance of the various components of the Glasgow smart street in RUGGEDISED can be simulated. This will aid in their design, procurement and operation. The framework comprises a core suite of energy modelling tools, but which can be linked in future to geographical information systems (GIS) and decision support platforms.

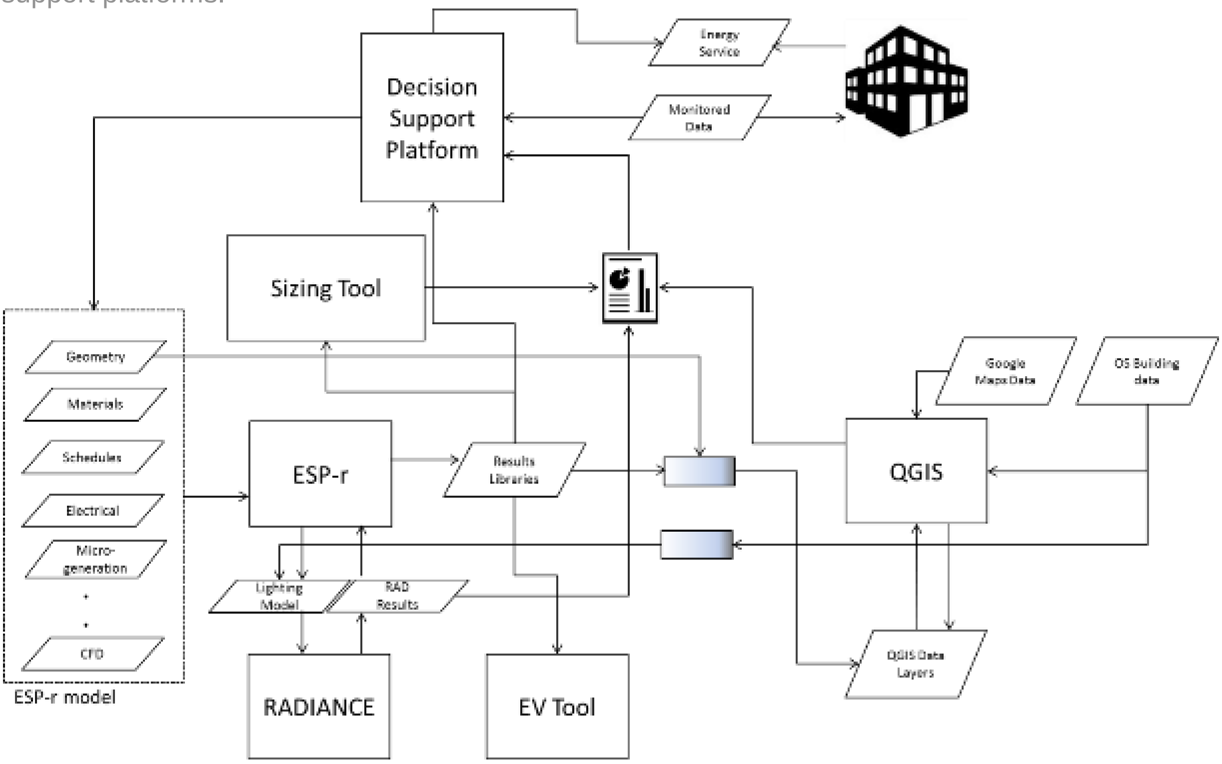


Figure 1: RUGGEDISED modelling platform.

The following sections outline the different elements of the smart street that have been modelled to date.

Duke St Car Park

The Duke Street car park will be refurbished as part of RUGGEDISED with a 200kW PV array, electric vehicle (EV) charge points and battery installed. Currently, the battery and PV array are in the process of being procured and negotiations are underway with the utilities to allow the connection of the system to the electricity network.

Modelling

Modelling is being used both to inform design decisions and provide information to the utilities and City planners. To-date, a model of the car park has been developed on the ESP-r building simulation tool; this is shown in Figure 2. ESP-r calculates the dynamic performance of buildings over a simulated period. The tool can be used to calculate the performance of any building at any location, as long as appropriate climate data is available. Simulation of the car park model and array allows the performance of the PV array to be quantified.

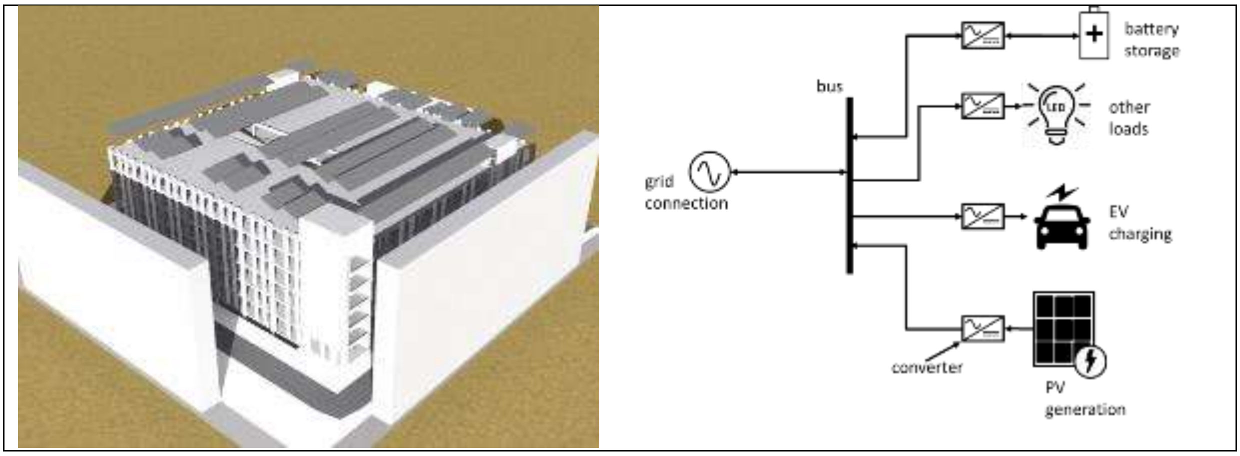


Figure 2: the Duke St car park simulation model and basic system schematic.

Photovoltaic Installation

For Duke St, the power output of the PV array was determined at half hour intervals over the course of a simulated year, using Glasgow climate data. Output from this simulation is shown in Figure 2.

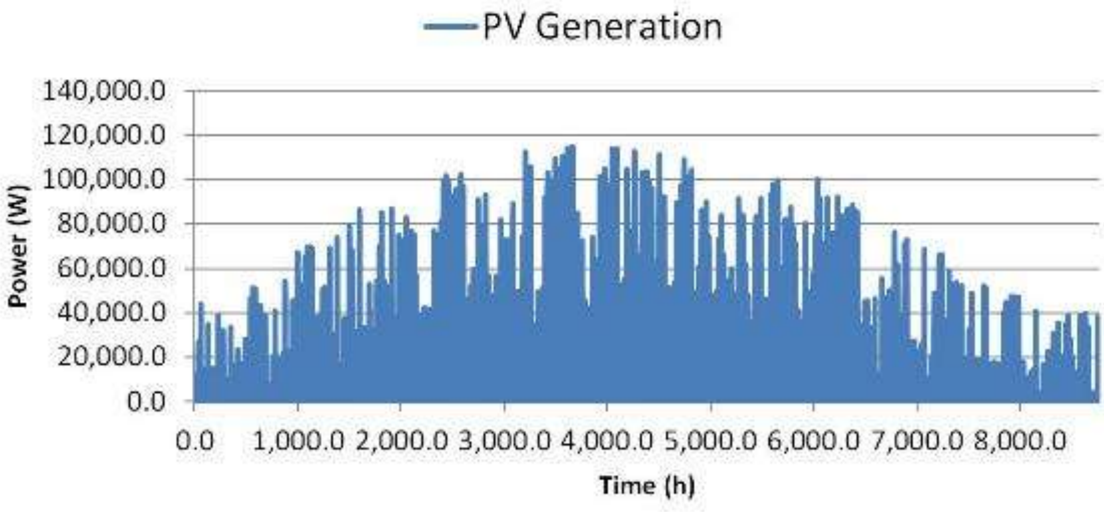


Figure 2: simulated PV output from the ESP-r model.

Figure 2 shows that although the PV array is rated at 200 kW, in reality, the installation does not produce more than 120 kW; this is because PV will typically operate in conditions that are very different from those under which the power rating was derived. The image also highlights the huge inter-day and seasonal variation in output at higher northern latitudes (Glasgow c. 56ºN).

Electrical Demand

A prototype tool to calculate the electrical demand associated with electric vehicle (EV) charging at the car park has been developed for RUGGEDISED. The tool uses charge point data supplied by Transport Scotland (TS) to generate charging profiles for a fleet of EVs. The TS data was used to generate charging probabilities as shown in Figure 3. The tool then uses this information to generate stochastic half hourly charging profiles, such as shown in Figure 3.

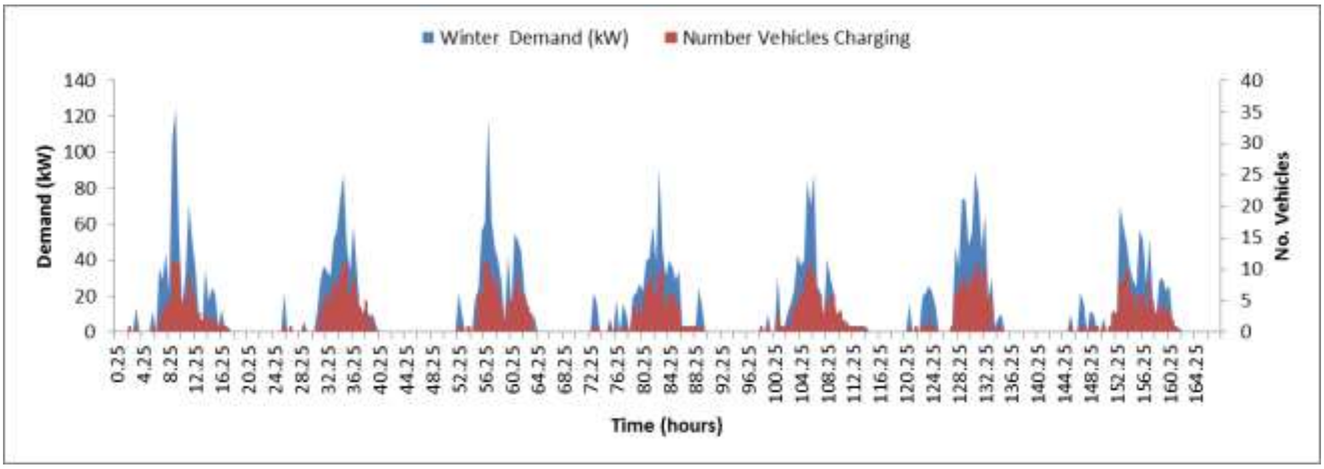


Figure 3: EV charging profiles generated by the EV charging tool.

Battery and Sizing

Using the demand and supply profiles generated by the car park and EV models, a battery sizing exercise was undertaken; this was done for different objective functions including maximising the quantity of renewable energy used locally for battery charging (and minimising import from the network) and minimising the overall cost of the battery installation. This was done for a range of EV fleet sizes and two different battery charging strategies: charging using available renewable energy and charging with renewable plus off-peak electricity.

Illustrative results from this process are shown in Figure 5, 6 and 7.

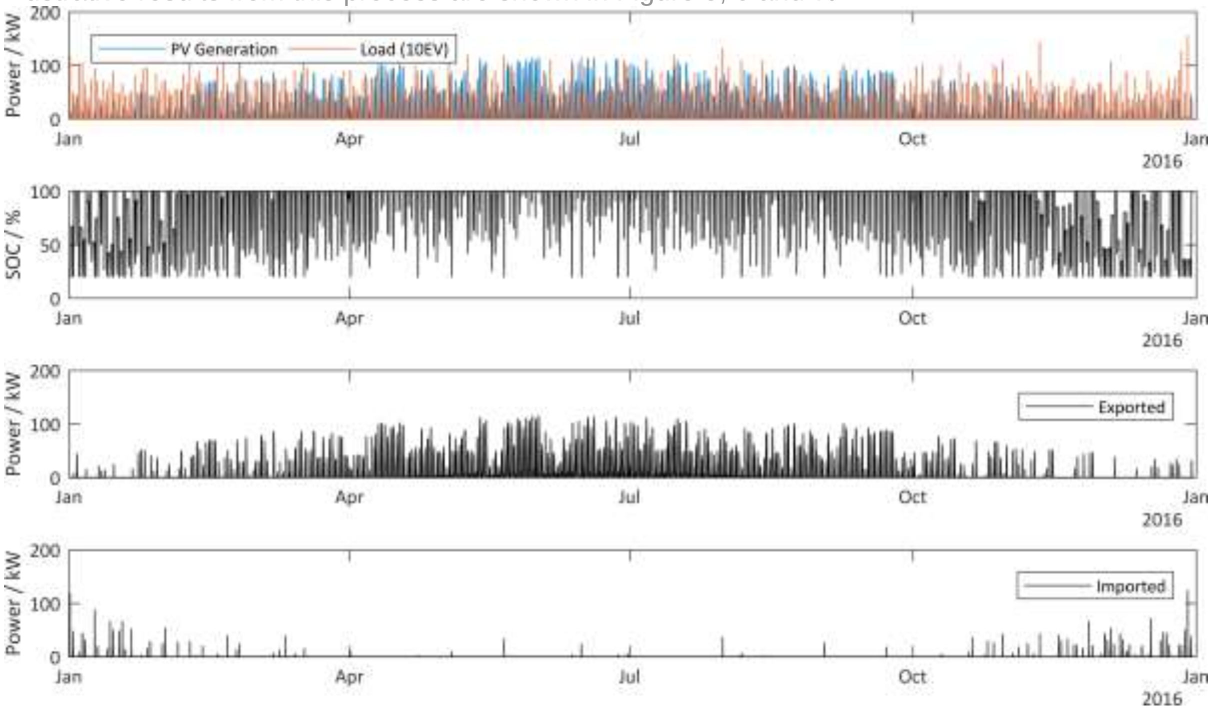


Figure 5: output from the PV/EV/battery simulation

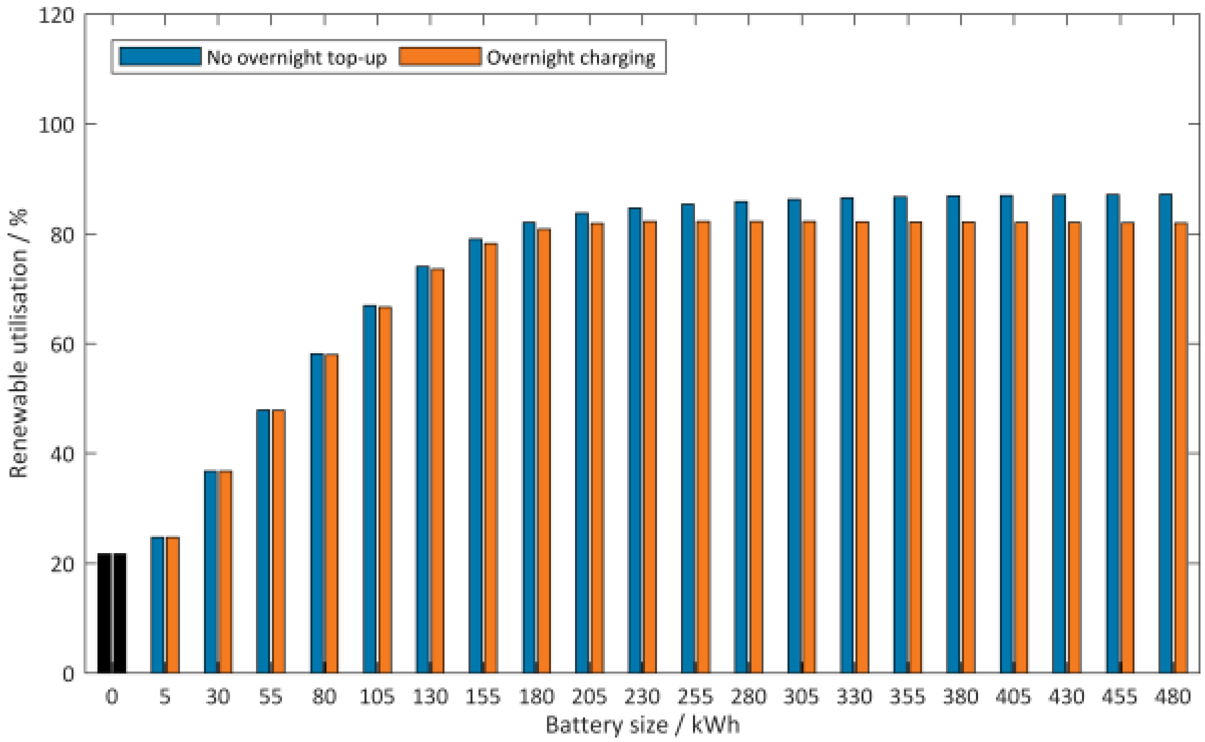


Figure 6: variation in renewable energy fraction with battery size and charging strategies (20 EV fleet)

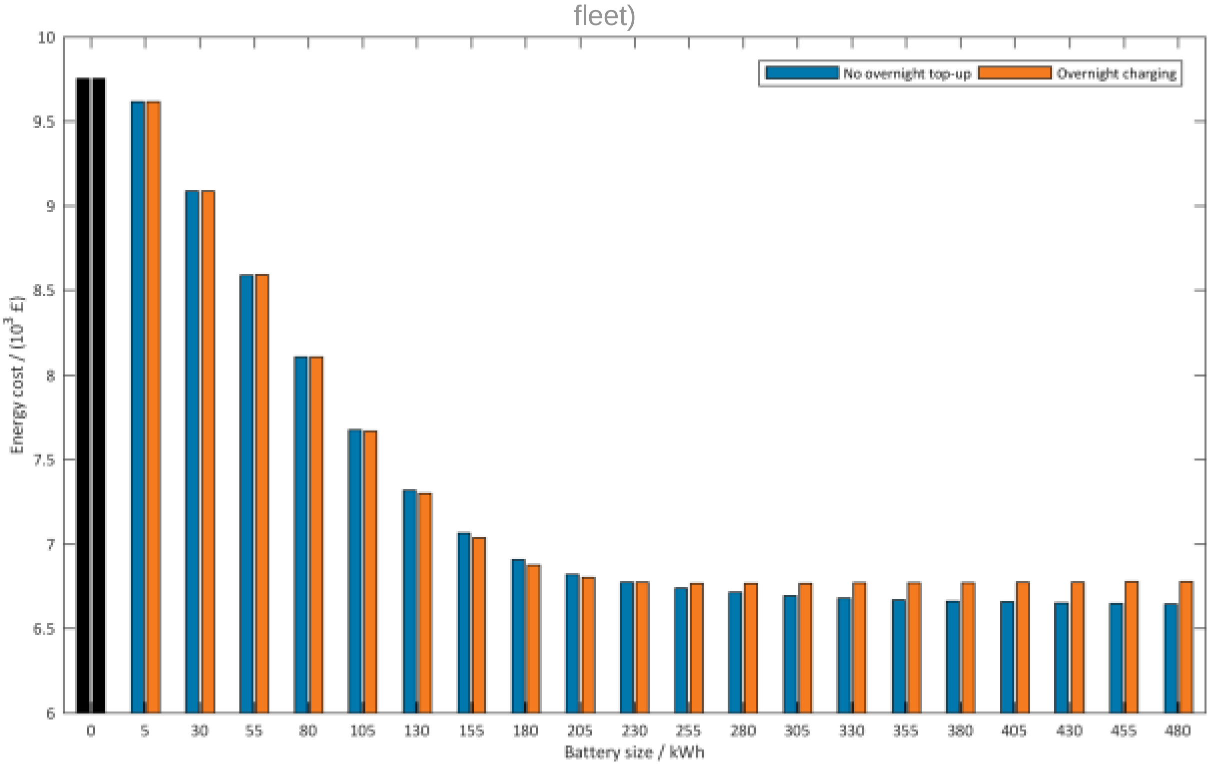


Figure 7: variation in annual energy costs with battery size and charging strategies (20 EV fleet)

Charge Point Analysis

The capabilities of the EV tool have been extended recently to assess charge point use, occupancy and congestion.

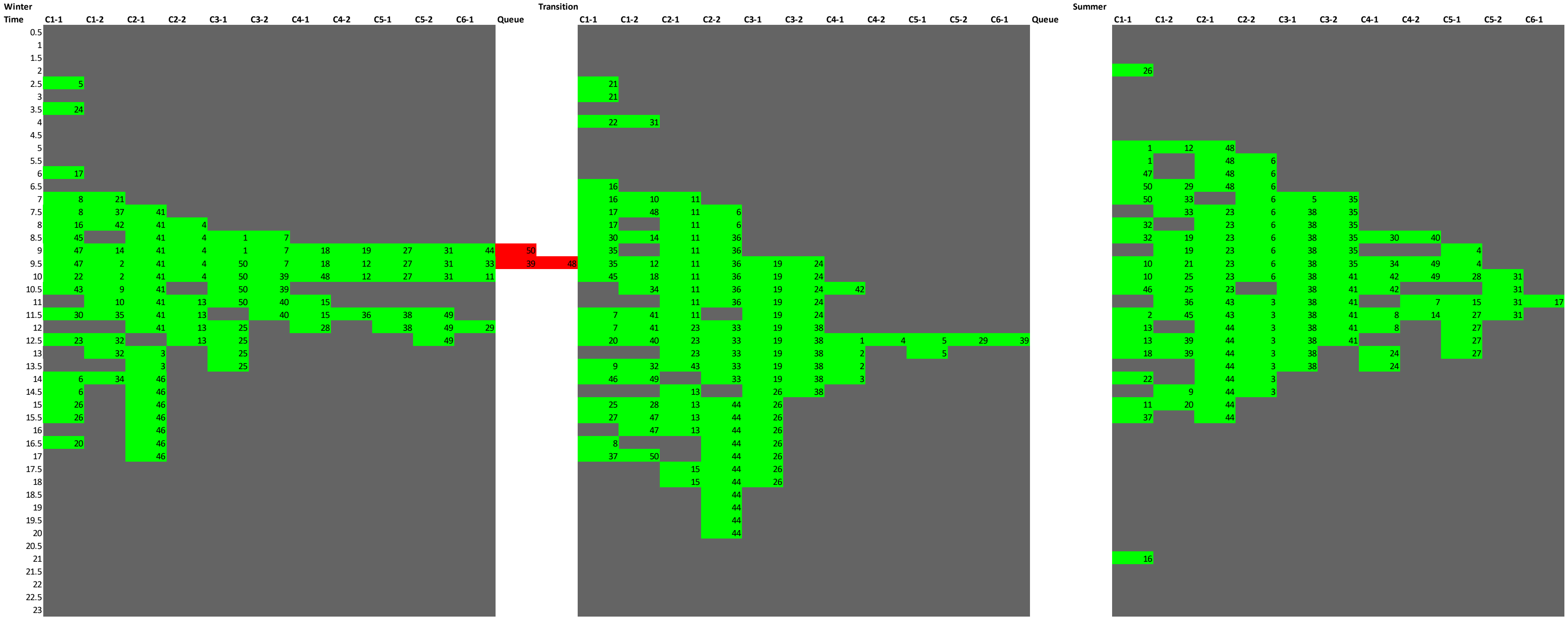


Figure8: charger occupancy (green) and queueing (red) over 24 hours for a day in winter, transition and summer.

Again, this uses a probabilistic approach to determine whether an EV charge point in the Duke St car park is vacant or occupied with a vehicle, and how many vehicles are awaiting charging. This can be done for any population of vehicles and combination of charge points. Sample output from the tool is shown in Figure 8.

Drygate Flats

The Drygate flats date from the 1960s and have been refurbished with improved glazing and external insulation within the last 15 years. Currently, the flats are heated using off-peak electric storage heating and this will be revamped as part of RUGGEDISED project. The heating is being retrofitted with an improved heating charge control system that should improve its performance and the thermal comfort of the occupants. In addition, a communal battery system is being fitted, which should enable more low-cost, off-peak electricity to be used for charging the heating system leading to a reduction in energy costs and emissions associated with heating.

The improved heating controllers and an improved WIFI communication system is currently being installed in the flats by contractors, with the battery procurement process has begun, with likely suppliers identified.

Modelling

An ESP-r simulation model of a complete floor of flats in the Drygate housing scheme have been created as shown in Figure 9. This will be used to produce heat and power demand data that can assist in sizing the communal battery and planning future improvements.

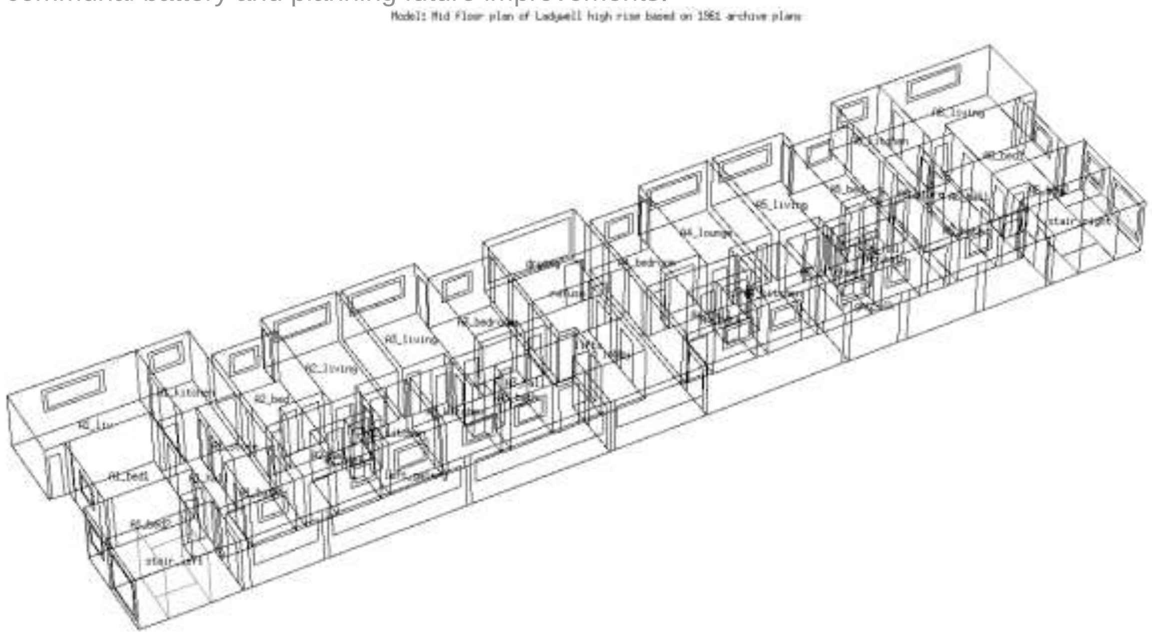


Figure 9: ESP-r model of one floor of the Drygate flats.

District Heating

The ESP-r tool can already model buildings and systems associated with buildings such as heating and cooling systems. For RUGGEDISED, the tool has been further developed to allow it to model the heat transfer and flows associated with a district heating networks; this required that an algorithm to deal with heat exchange between two buried piped was added to the code.

A model of the heating system that is currently being installed at the University of Strathclyde has been developed and illustrative output from this model is shown in Figure 10.

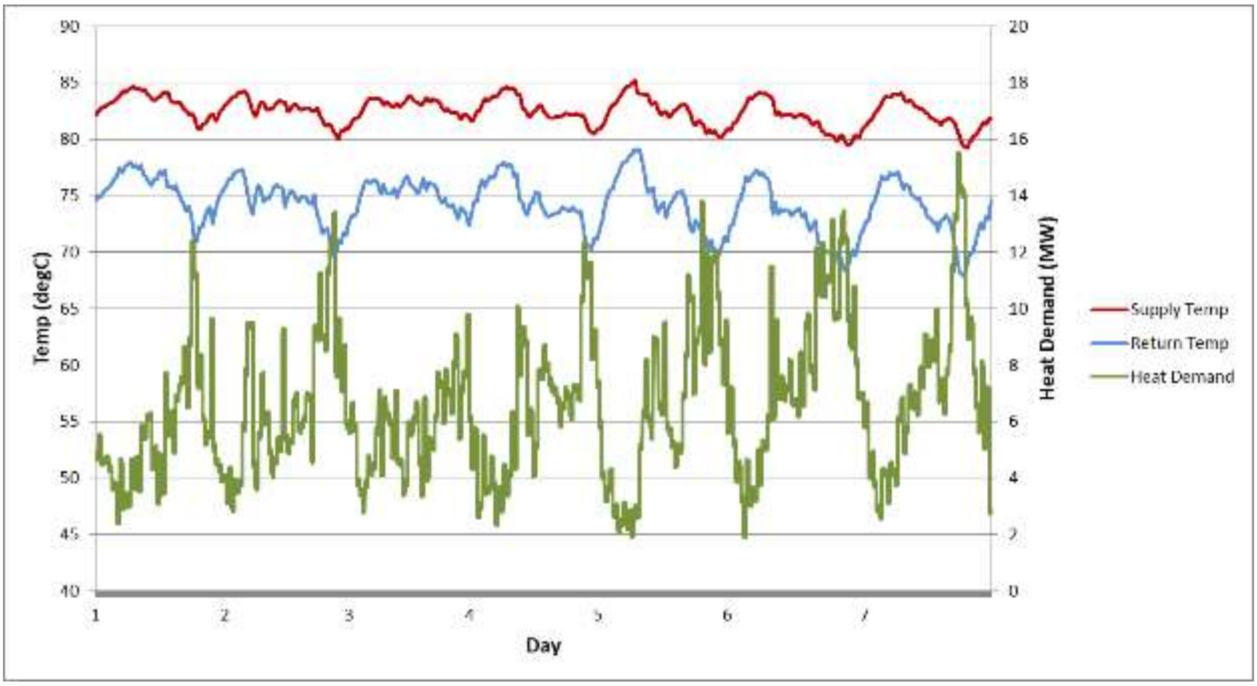


Figure 10: variation in flow and return temperatures with load changes over a winter week.

The model was used to explore a range of issues, including the impact of extension of the network to other (non-University) buildings in the City Centre and options for replacement of the CHP/boiler system with zero-carbon alternatives in the medium term.

Smart Street

The ultimate aim of the Glasgow team's modelling activities is to have a suite of tools, models and analytical techniques that can assist planners and policy makers in further developing the Glasgow Smart street, and which could also be applied to assist the development of similar projects elsewhere in Europe.

Achievements

- ESP-r Model of Duke St. Car Park and PV array completed.
- Performance simulation of array completed.
- Battery sizing algorithm and method developed and applied to Duke St. car park.
- EV charging data from Transport Scotland analysed and charging probabilities derived.
- EV demand and charge point analysis tool developed.
- ESP-r modified to enable detailed thermal simulation of district heat networks.

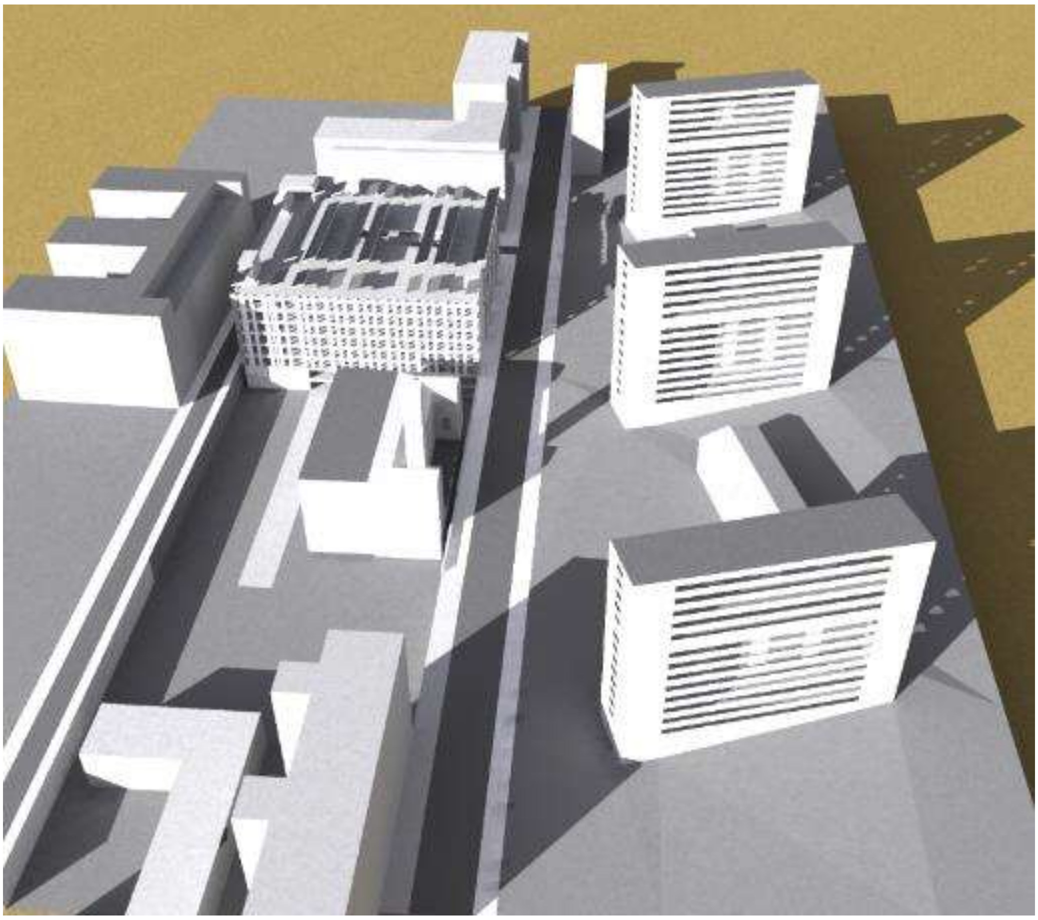


Figure 10: Radiance visualisation of Duke St.

Challenges

There are a number of challenges facing the development of the Glasgow smart street, both technical and administrative some of these are as follows:

- The electricity network in the centre of Glasgow is already heavily loaded in many places and the addition of new sources of generation such as CHP, PV and batteries can breach design limits. Work is needed to develop new, more flexible design approaches to facilitate the connection of low-carbon generation.
- Conventional district heat energy sources such as CHP risk becoming stranded assets as the electricity system of the UK rapidly decarbonises, work is required now to identify alternative ultra-low or zero carbon heat sources that could be retrofitted to existing heat networks in the future.
- District heat networks in the UK are typically owned and operate within a single organisation, what is being proposed in Glasgow is distribution of heat between multiple organisations. New technical and contracting models need to be developed to support this.
- The installation of generation and storage as part of RUGGEDISED opens the possibility of trading energy within a virtual energy network. The mechanisms by which this could be done, communications required, financial models and implications for the real (constrained) energy network need to be properly explored.
- Finally the means to maximise the benefits flowing from the elements of the smart street for end users such as Drygate flat residents, car park owners and EV users need to be fully explored and explained.

Appendix 3 – Heriot Watt Report, Domestic Battery Storage Update

Ruggedised – Community Scale Storage project
Project Update 6th September 2019

Project Review

The task list for the RUGGEDISED project is shown in the table below.

Sub task	Description
1	**Energy system and building audit.** This will define the overall system requirements that will inform the specification of (a) the storage system and (b) the control strategy
2	**Energy storage technology specification** Identify supply partner, procure and deploy systems in the candidate dwellings of the field trial
3	**Develop control strategy.** This will involve development of forecast algorithms to inform charge/discharge cycles. These will include weather and renewable energy generation, building demand, EV operation, overall network conditions and ancillary service conditions. These parameters will be defined in task 1. The control strategy will also be developed cognisant of the system selected to supply the energy storage technology
4	**Field trial management & data analysis** The field trial will run for 18 months to ensure that seasonal variation in supply and demand is considered. Field trial data will be analysed periodically (e.g. monthly) and performance of the system compared to overall system requirements defined in sub-task 1. Control strategies will be developed to ensure that field trial performance matches system requirements
5	**Replication** Using a bottom-up, stock modelling approach, the applicability and subsequent impact of the optimised energy storage approach will be determined. Control strategy may be iterated at this point to produce greater universality of the approach.

- The completion of sub task 2 has been beset with issues associated with battery supplier and barriers to the preferred install location.
- The battery supply issues have been overcome by specifying a productionised battery system from Sonnenbatterie, able to operate over a broad suite of environmental conditions.
- The issues presented by the preferred location, in the basement of Gibson Heights tower block could not be overcome (asbestos, outdated electricals, fire detection, exposure, etc) and an alternative location within the Smart Street zone had to be sought.
- Preferred location is now in the concierge office, adjacent to the tower block.
- The identified area has restricted space and the battery capacity has therefore to be constrained.
- The installed system will be of 45kWh capacity and 9.9kW charge/discharge rate.

Implications of Procurement Changes to task delivery

Issue A): Battery charge/discharge rate

The charge/discharge rate is significantly lower than the product offering from Denchi – reduction from 50kW to 9.9kW. Notwithstanding that the business use case discussed below can be assessed and reported as intended.

1.1.13 Risk Statement

The reduction in capacity will not adversely affect the project outcomes. The principal purpose of the battery system is two-fold:

a) To provide actual operating data that is in turn used to verify the modelling assumptions, in respect of the charge pattern and time interval profile of use within the domestic demand management of electric storage heating.
b) Performance data that will be critical in developing replicable business models will include installation requirements, latency, on-board safety control constraints and operations and communication availability.
c) Quantifying the above into financial cost/benefit for both operator (Wheatley or other) and resident.
d) To allow HWU to develop and test a multi-objective control platform

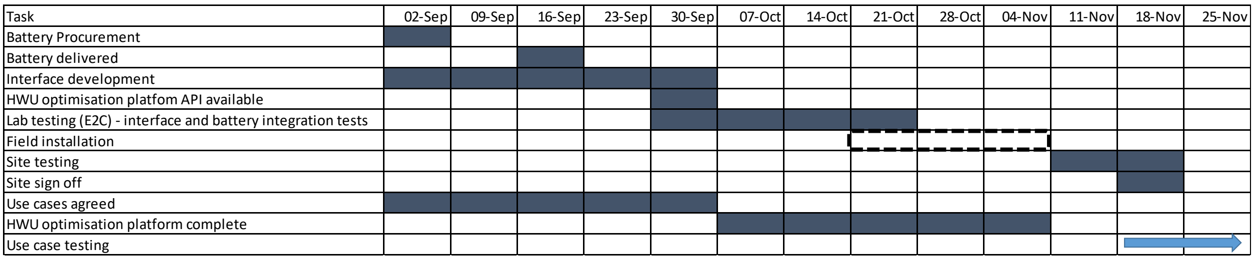
The reduction in capacity will not have an impact on delivery of these aims.
It should be noted, that the battery system deployed in RUGGEDISED was always going to be limited due to constraints in space for the option of individual dwellings or the alternatives of a consolidated battery 'behind' or on the 'DN' side of the meter. These limitations will form part of the use case report as they would likely prevail in many social housing retrofit scenarios. The business modelling approach (task 5) will report on cost-optimal sizing, and whether community storage with multi-objective control represents a replicable, cost effective method of contributing towards increased energy affordability.

Issue B): Change in location

1.1.14 Risk Statement

The original location, whilst physically connected to the residential block was not embedded within the residential block electricity supply. It was on the DN side of the meter. For it to have been otherwise would have required the creation of a single MPAN for the tower block, thereby removing the entity of customer MPANs and individual electricity retail accounts.
The change in location does not therefore represent an issue with respect to project task delivery.
The issues the project team have faced in installing batteries on-site at the tower block have prompted an additional task to be added to the Replication phase. Working with Wheatley Group we propose that a number of residential sites be surveyed to understand whether the issues faced on this site are anomalous. The ease and practicality of installation will form a key aspect of the replication assessment.

Updated Project Plan



Use Case Discussion

The overarching aim of the project is to explore the extent to which Community Energy Storage solutions can be used to increase energy affordability of the community.
The HWU optimisation platform is a battery control system that will seek to maximise the revenue that can be generated by the battery where control is pointed at more than one plausible revenue stream.
The revenue stream that are being considered at the moment are:

Price arbitrage

Charging the battery when cost of supply is low and discharging when cost of supply is high. This can be facilitated by using the Octopus Agile dynamic time of use tariff as a control signal. Charge and discharge cycles can be pointed towards either modelled tower block demand or monitored demand from the concierge office.

Peak shaving

Coincident to the evaluation of the battery, V-Charge are installing modified control equipment to individual dwellings in the tower block. This control equipment will alter the timing of the charge cycle of legacy electrical storage heaters to improve the thermal comfort outcomes of the residents. This change in control approach will result in a loss of load diversity in the tower block, potentially resulting in coincident peak loading and commensurate issues in the Distribution Grid. The battery will be controlled to discharge during these periods to minimise this impact.

Creation of a renewable virtual power plant

The battery can be controlled to increase the firmness of generation output from intermittent, renewable assets, allowing these to than participate in the capacity market. The battery will thus be controlled to charge and discharge is response to forecasted output from a designated renewable asset.

Other plausible revenue streams will be considered during the project lifetime.

The HWU platform will create charge and discharge signals for the battery that maximises revenue from each available source using a genetic algorithm. In so doing, it will identify periods where the battery capacity is not required for each of these services, and release this capacity to Siemens for use in the Ruggedised Smart Grid.

It should be noted that the battery has not been sized to produce optimal performance, rather, its function is to develop & test the optimal scheduling platform and then to provide field test data.

Energy affordability - Modelling the Benefits

The data generated in the field trial experiment along with the demand side management (VCharge / Connected Response) data on charge requirement, will be used in a modelling environment to investigate a cost optimal community energy storage solution based on the revenue streams evaluated and hierarchy of services / supply requirements. The output from the modelling exercise will be used, in conjunction with Wheatley Group to investigate (i) whether a plausible business case can be made for community energy storage and (ii) how benefits accrued from the optimal solution can be socialised to improve energy outcomes of the community and (iii) the regulatory and social housing asset management context that may inform decisions. These will take into account energy affordability and thermal comfort.