DS3 – Distributed Storage and Solar Study

Final Report – February 2020

Acknowledgement

Northern Powergrid would first and foremost like to thank the tenants for accepting to participate in this innovation project. The project would not have been feasible without their participation.

Special thanks to the project partners Moixa for providing the hardware, software and the dataset and Gen Communities for managing all stakeholder engagement. The high level of engagement of both partners was key in delivering this ground breaking project.

Last but not least, a big thank you to Berneslai Homes for installing the batteries and resolving any operational issues on site and Element Energy who along with TNEI analysed the data and produced a series of insightful reports.

Definitions

This page provides an overview of definitions used in this report and gives a quick introduction to the battery charging schemes which are extensively used in the data analysis.

Definitions:

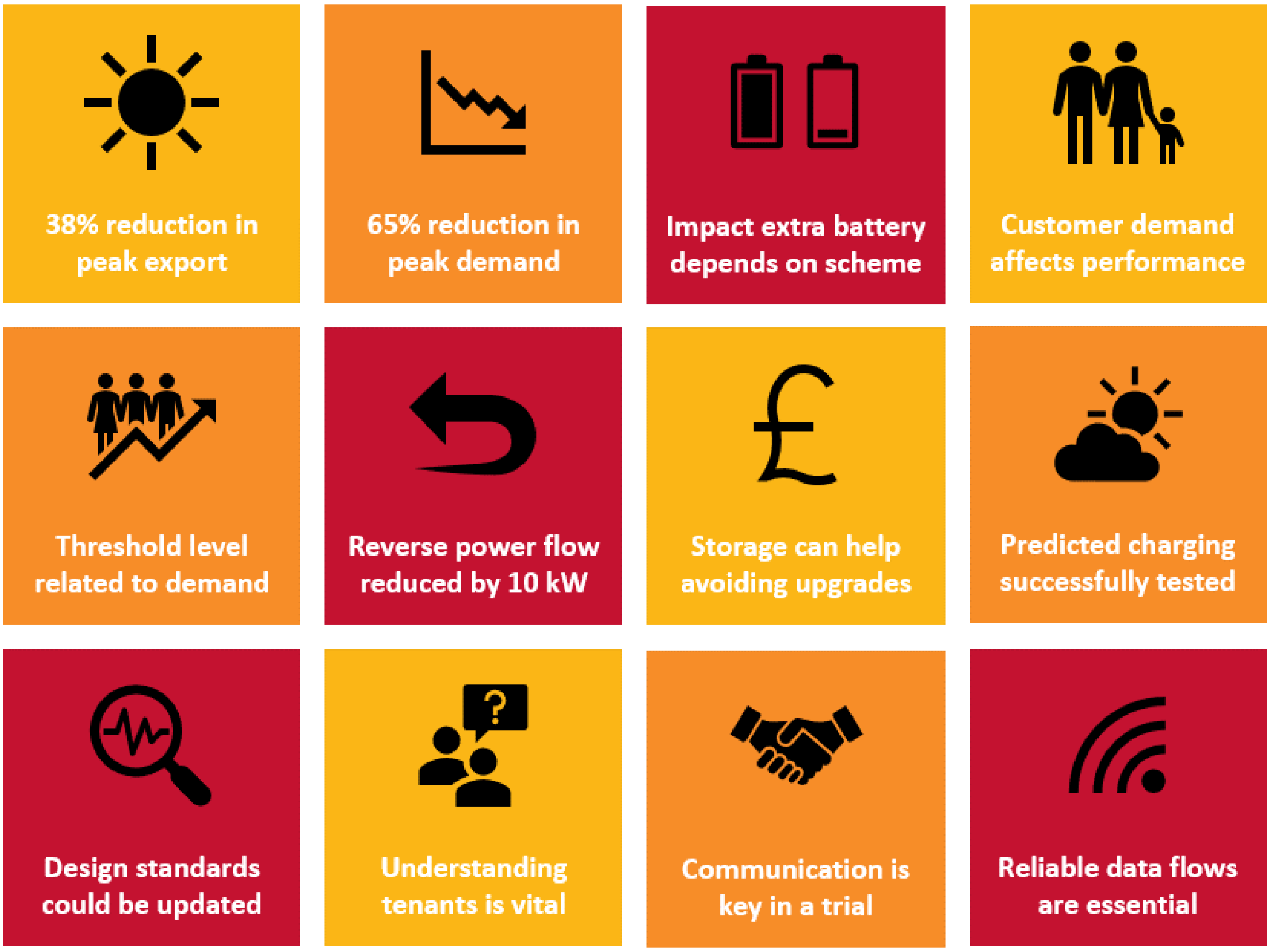
- **BESS**: Battery energy storage systems
- **CLNR**: Customer-Led Network Revolution project
- **DNO**: Distributed Network operator
- **DSO**: Distributed System Operator
- **DS3**: Distributed storage and solar study
- **Effectivity factor:** The share of their maximum charging rate at which batteries are expected to operate on average when controlled according to a certain charging scheme.
- **E7**: Economy 7 tariff (Energy tariff with cheaper rates for seven hours during the night).
- **IPSA**: TNEI's power system analysis software
- **LV**: Low voltage
- **NPg**: Northern Powergrid
- **PV**: Photovoltaic
- **SoC**: State of charge
- **Peak reduction ($R_{\%,peak}$):** Percentage reduction in import/export level at the time of peak demand (18:00) or peak generation (12:30).
- **Average Reduction ($R_{\%}$):** Average percentage reduction in import/export level over the high demand period (17:00-20:00) or the high generation period (10:00-16:00).

Charging schemes:

- **Demand-Led:** Batteries charge at their maximum level, but discharge is limited by consumption.
- **Maximum Impact:** Batteries charge and discharge at their maximum rate at set times.
- **No Impact:** Batteries are inactive to enable a baseline calculation.
- **Predicted Generation:** Batteries charge at their maximum rate only when it is predicted that generation will be high.
- **Threshold Charging**: Batteries (dis)charge based on excess demand/generation (above a set threshold).

Executive Summary

Growing levels of photovoltaic (PV) penetration on the low voltage (LV) electricity network are increasingly causing reverse power flows and voltage rise issues, limiting the number of PVs that can be connected without network reinforcement. Battery energy storage systems (BESS) may not only provide a solution for such issues but also for those associated with the expected increase in evening peak load caused by the electrification of heat and transport. The Distributed Storage and Solar Study (DS3) explored the potential for aggregator-controlled behind-the-meter BESS to address these issues by limiting reverse power flows and providing peak-shaving capability. As part of the project 40 domestic scale Moixa battery energy storage systems were installed in 36 households in Oxspring, Barnsley, of which 27 also had a PV system installed. The trial was run during the period 2017-2019 and was made up of four monitoring periods, winters of 2017/2018 and 2018/2019 and summers of 2017 and 2018.



Data Analysis

The DS3 trial was successful and produced outcomes which can be used to inform battery operating modes, network design policies as well as further innovation trials. Analysis of the data has shown that when operating the batteries according to the Maximum Impact scheme – forcing the batteries to (dis)charge between certain periods of time during the day – *excess peak demand and peak export could be reduced by an average of respectively 65% and 38%* (as shown in Figure 1). Reductions were even as high as 95% and 59% where batteries were twice the size (two batteries were installed per household).

The customer-focused charging schemes Demand-Led and Threshold Charging – which (dis)charged the batteries based on excess consumption and generation – had a smaller impact on the network with winter peak reductions of 36% and 29%, and summer export reductions of 21% and 20%, but is important to note that these charging schemes did not cause extra costs for the battery owners, and therefore essentially provided a *free benefit to the DNO*.

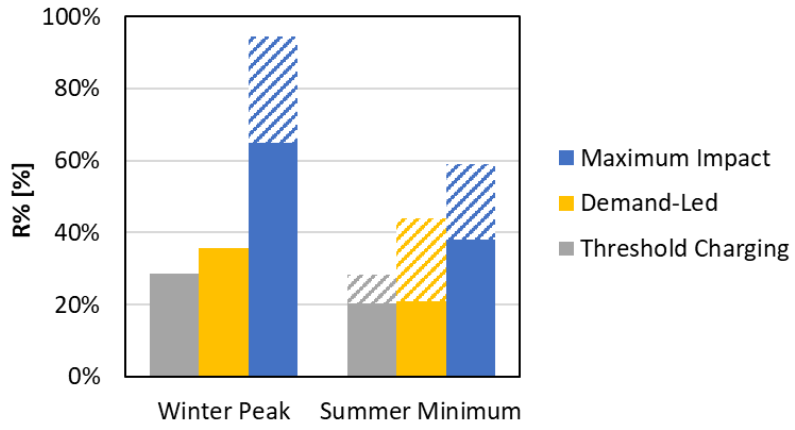


Figure 1: The percentage reduction (R%) of excess demand at the time of winter peak and excess generation at the time of summer minimum that can be achieved by operating the batteries according to the different schemes. The hatched areas indicate the further reduction that is achievable by having a second battery installed, which turned out to be negligible for the Threshold and Demand-Led schemes in winter because of the limited excess demand.

The *limited performance of these schemes was mostly caused by the low demand of the trial participants* – most of which could be described by the Experian Mosaic Elderly Needs class. In summer the low levels of demand (less than half of the typical demand levels of families with kids) in the evening meant the state of charge did not drop significantly, resulting in insufficient remaining capacity to store the excess generation the following day. On the other hand, in winter, the levels of PV generation were limited which meant the batteries could not discharge at the time of the evening peak because they did not have enough capacity available. In both cases, the schemes were also constrained by the threshold level set for the batteries, which required levels of excess demand or generation of 200 W before the batteries started operating. Preliminary data analysis revealed that as a result of this threshold many batteries were inactive, and therefore the threshold level was reduced to 100 W in early 2018.

In addition to the battery data, substation data was also monitored throughout the trial. For one of the substation's feeders (Way 4) to which 36 households were connected – 20 of which participating in the DS3 trial – operating the batteries according to *the Maximum Impact scheme caused a reduction of about 10 kW (approximately 50%) in both peak demand and reverse power flow*, significantly flattening the substation demand by shifting the load, as is shown in Figure 2.

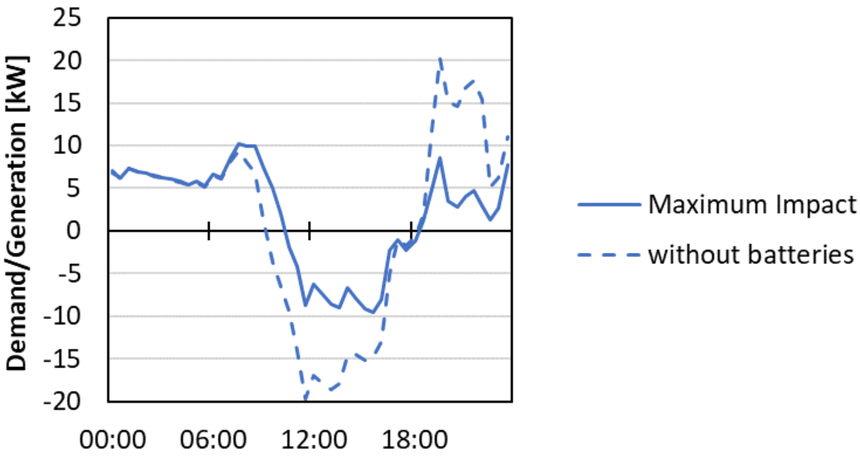


Figure 2: Demand on Way 4 for the Maximum Impact scheme as compared to the base case demand determined by subtracting the battery (dis)charging rate from the monitored substation demand (dashed blue line).

As strong reverse power flows only occurred on sunny days, a charging scheme was also designed and trialled to account for this. The *Predicted Charging scheme successfully managed to predict days with high levels of excess PV generation*, and ensured that only on these days all batteries were forced to charge in order to assist the network whilst *keeping costs for battery owners at a minimum*. The scheme even allowed for more detailed forecasting, forcing the batteries to assist the network only at specific times of the day, e.g. when only the afternoon was sunny.

Network Modelling

To further explore the impact of behind-the-meter storage, the network has also been modelled using Ipsa software, which enabled us to simulate a wider range of scenarios than would otherwise be possible. The modelling outcomes revealed that *domestic storage can not only assist in balancing the demand and generation*, levelling the power flow at the substation and keeping the voltage within a narrower band, *but is also capable of addressing issues along the feeder*, which can be of significant value to the DNO.

The model showed that for a 100% PV penetration level, a high battery penetration level (100%) of the 2 kWh / 0.4 kW batteries would allow the DNO to reduce the substation voltage enough to remove any potential voltage constraints along the feeder. However, it also revealed that on sunny *days the generation period was longer than the maximum battery charging period* (based on the maximum charging rate), as a result of which voltage constraints occurred when the batteries stopped working. To prevent this from happening, it is recommended that *more battery capacity should be installed than is minimally required*. As an example, the model showed that having 4.8 kWh / 1 kW batteries installed could reduce the substation voltage by 3.5 V (~1.4 %), meaning that they could also provide the required voltage reduction for a longer period. It should be noted that particularly when installing such a large amount of battery capacity, *the modelling results highlighted the importance of carefully considering and implementing the battery operating schemes*. When forced to (dis)charge at the same time, the batteries could cause significant unwanted reverse power flows or other detrimental effects, which could be easily avoided.

CBA

A cost-benefit analysis was performed to determine the economic feasibility of using BESS to resolve network constraints as opposed to conventional network reinforcement solutions. Typical costs were used to define reinforcement case studies, which provided an indication of the costs related to certain network upgrades, as well as of the amount of battery capacity that would be required to avoid or defer these upgrades. A methodology was developed to calculate the annual compensation that could be offered, which ranged from £26.81 - 244.35/kW/year if conventional reinforcements could be completely avoided, to £8.70 - 79.28/kW/year if they could only be deferred. With typical annualised costs of storage ranging from £41.46 - 119/89/kW/year for grid scale and domestic storage respectively, it was concluded that *there is potential for battery storage to be competitive with conventional reinforcements*, but that (in case uptake is DNO driven) most business cases are only profitable if reinforcements can be entirely avoided. Alternatively, when uptake is customer driven, the DNO can decide to *benefit for free* when batteries operate at the discretion of the customer, or to *use the annual compensation to incentivise customers* to operate their batteries according to the maximum impact scheme and increase the impact on the network.

It is important to note that as battery costs are still expected to fall, and additional revenues (e.g. by providing Firm Frequency Response) could be contracted, it is likely that some business cases which are non-profitable now might need to be reconsidered in a few years.

Review of design standards

The learnings from the data analysis also fed into a review of design standards, which demonstrated that there is a need to account for installed domestic storage on the network when developing the LV system. The trial revealed that even without forcing the batteries to operate according to a DNO-focussed scheme, the excess generation was reduced by an average of 0.175 kW, which suggests that *the minimum demand for households with BESS could safely be raised to 0.475 kW*.

This is strengthened by the fact that all households in this trial had low consumption levels (that negatively impacted the battery performance), and it is therefore likely that the batteries will be more effective when installed for any other subset of customers.

Lessons Learned

Finally, lessons learned from this trial are reported throughout the report and highlight the importance of knowing the tenants' load profile, ongoing communication between partners and reliable data flows and data access and availability. Communication issues and problems with battery availability occurring throughout the project were resolved by Energise Barnsley and Moixa, but often took more time or required more site visits than was anticipated. In many cases these issues related to the unfamiliarity of tenants with the technologies installed in their homes, but they were also caused by the fact that the batteries relied on the customers' broadband signal in order to communicate data collection. The resulting data gaps or anomalies complicated the analysis and required close collaboration between Element Energy and Moixa. Regular meetings between the project partners and the project lead Northern Powergrid resulted in successful completion of this insightful project.

Contents

1 Introduction

Behind-the-meter storage has the potential to address several of the issues related to high levels of PV penetration, including reverse power flows and voltage rises. However, few studies have been performed to quantify the actual impact in-home batteries can have on the network. These issues have been assessed in the Distributed Storage and Solar (DS3) project, through a trial of 36 domestic scale Moixa battery energy storage systems (BESS), 27 of which were installed in properties that also had a PV system installed.

Figure 3: Illustration of battery energy storage systems absorbing excess PV.

1.1 Project Description

The DS3 trial was run during the period 2017-2019 and was made up of four monitoring periods, winter 2017/18 and 2018/19 and summer 2017 and 2018. Throughout the trial, the batteries' monitoring systems recorded a broad range of parameters related to the battery (state of charge and power flows), the PV system (power generation) and the household (consumption) which were accessible through the Moixa GridShare web portal. To understand the impact of the batteries on the network based on a variety of use cases, a set of charging schemes were designed focussing on either the customer's or the DNO's benefit.

Besides capturing the household data (which was anonymised and password protected), the substation and LV feeders were also monitored, and a network simulation has been performed using the Ipsa power system analysis software – which used demand, PV and battery profiles constructed with the battery data. Ipsa provided results for voltage profiles, power flows and various other metrics. The substation and feeder monitoring data were used to validate the model and to directly analyse the impact PV and BESS can have on the distribution network. Once validated with the trial data, the network model allowed for a range of scenarios for BESS and PV penetration level to be modelled that could otherwise not be studied within this trial, as the model allowed us to simulate any combination of PV battery and penetration levels.

1.2 Learning Goals

A set of learning goals were defined at the start of the project as a means to guide the DS3 trial. These goals have informed the design of the battery charging schemes, the effective analysis of the large amount of data and in aligning the project's learning with the DNO's requirements.

By addressing these goals, NPg wishes to improve the understanding of the impact residential batteries can have on the network, determine the penetration levels required to achieve a significant impact and assess whether or not there is potential to avoid costly network reinforcements by using BESS.

Distributed Storage and Solar Study - Learning Goals

- ✓ Establish the extent to which residential batteries can be controlled to
    a. reduce the peak export from a PV installation;
    b. reduce the evening peak load.
- ✓ Identify the battery penetration needed to make a difference to network constraints caused by daytime PV output or evening peak loading.
- ✓ Determine whether an additional de-rating factor would be appropriate for design studies on PV installations that propose to have aggregator-controlled batteries at some properties.
- ✓ Determine whether it would be valid for design engineers to apply different design parameters to new housing estates without PV but equipped with aggregator-controlled batteries.
- ✓ To gain a DNO understanding of the Moixa Cloud aggregation platform, the potential revenue streams that such arrangements can secure commercially, how such arrangements impact on the DNO network and whether the DNO can interact with it to dynamically manage DNO constraints.
- ✓ To understand the network benefits (if any) of privately owned behind-the-meter storage compared with storage directly connected to the LV network as trialled on CLNR.

1.3 Report Structure

With the project now complete, all aspects of the DS3 project are discussed in this final report. Firstly, in Chapter 2 the focus is on the network and household information, and on the importance of engaging with customers. Based on that information, and on the learning goals outlined above, battery charging schemes were defined, which allowed us to investigate a range of use cases of residential batteries. A timeline is included to illustrate when the different charging schemes are trialled throughout the project.

The large amount of data monitored at both household and substation level is analysed in Chapter 3. The impact of the batteries on the network and their effectivity has been assessed at the time of winter evening peak as well as at the time of summer minimum and proved to vary significantly between the battery charging schemes.

Feeding the monitored network, battery, consumption and PV profiles into the Ipsa model, allowed us to simulate a wider range of scenarios, which is discussed in Chapter 4. The chapter assesses the impact of the behind-the-meter batteries at both substation and household level, revealing that not only the power flows and voltage at the substation can be controlled within narrower boundaries, but that also voltage profiles along the feeder can be improved. Distribution network losses were not investigated as part of this project but the dataset will be analysed separately to provide further insights.

Combining the learnings from both the battery data analysis and the network modelling with information on cost and benefits of conventional reinforcements and battery storage, enabled us to perform a cost-benefit analysis which is discussed in Chapter 5. Due to the typical longevity of network assets (over 45 years), , results reveal that although it is hard for storage to be cost-effective, it can be used as a short-term solution to defer reinforcement.

The understanding of the effectivity of the batteries at reducing network constraints also allowed us to make recommendations to amend existing Northern Powergrid design policies (LV Code of Practice) and potentially national standards (EREC P5) related to installation of PV and battery energy storage systems on LV networks, which is presented in Chapter 6.

Finally, in Chapter 7 the results from this trial and conclusions drawn are summarised and evaluated against the learning goals as defined above. A large set of lessons learned as part of the DS3 trial is presented, which will provide valuable information to similar trials or battery installations in the future.

2 Trial Design

This chapter discusses the data monitoring, tenant engagement, and research methodology, which were all key aspects of a successful trial. The final section introduces a timeline that gives an overview of the range of charging schemes that has been trialled.

2.1 Data Monitoring

The data that has been used for the analytical work can be divided in two segments – the data available at the household level from the Moixa monitoring system, and the network data (i.e. monitoring of the feeders of the distribution substation) provided by Northern Powergrid.

2.1.1 Household Information

Batteries are currently installed and functional in 36 of the Berneslai Homes properties, of which 27 houses have PV installed PV (26 systems of 2.7 kWp and 1 system of 3.78 kWp). The distribution of batteries over the homes is as follows:

- 17 homes have a battery with a capacity of 2 kWh / 0.4 kW;
- 15 homes have a battery with a capacity of 3 kWh / 0.4 kW;
- 1 home has two batteries, with a combined capacity of 4 kWh / 0.8 kW, i.e. 2 x 2 kWh;
- 3 homes have two batteries, with a combined capacity of 6 kWh / 0.8 kW i.e. 2 x 3 kWh.

Battery Specifications

The batteries operate to balance generation and consumption by storing excess generation and offsetting import. During operation, monitoring systems recorded a broad range of parameters related to the battery (state of charge and power flows), the PV system (power generation) and the household (consumption and export) which were accessible through Moixa's GridShare web portal. It should be noted that due to issues with battery installations and data monitoring, there were periods when only a subset of the battery fleet could be used as some batteries were inactive or unreliable because of communication issues.

The system is designed to balance consumption and generation by storing excess generation and offsetting import. Each battery is connected to the building's electrical systems via a DC/AC inverter. This inverter has a threshold – which is set at a certain level of electricity demand in excess of solar PV output (200W by default) – at which the unit starts pushing power back into the household. When the PV system is generating, the system will try to maintain a set (negative) wattage, attempting to maintain the export close to zero. The system was limited to not go below 20% State of Charge as this could negatively impact the performance of the battery.

PV Specifications

Of the 27 houses that have PV installed, 26 have a maximum power of 2.7 kWp. The PV of the remaining house has a capacity of 3.78 kWp. The PV modules installed are of the type *SolarWorld – Sunmodule Plus SW270 Mono,* which under standard test conditions each have a maximum power of 270 Wp, a maximum power point voltage of 30.9 V, a maximum power point current of 8.81 A and a module efficiency of 16.1%.

2.1.2 Network Information

Additional monitoring equipment installed at the distribution substation monitored the aggregated substation power flows and voltage. The distribution substation is configured as per Figure 4 and supplies a total of 119 customers.

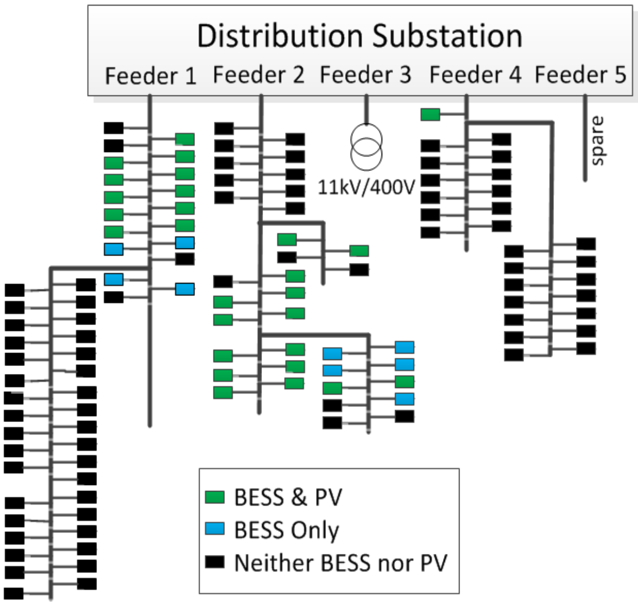


Figure 4: Network configuration indicating the households participating in the DS3 trial as well as all other households connected to the substation.

The network data is accessible through the NorTech iHost interface and information about the Transformer and the LV circuit has been made available by Northern Powergrid, as summarised below.

Transformer Details

- Size: 300 kVA
- Resistance R: 0.00948 Ω
- Reactance X: 0.266 Ω

LV Circuit Details

The distribution substation has five feeders, of which one (Feeder 5) is a spare and another is connected to the transformer (Feeder 3), so the area is fed by three feeders. Each feeder is a radial network (of which cable types and lengths are known) with a total of 119 customers connected. Except for one home (with PV and BESS), all properties in the trial are connected to two of those feeders (Way 3 and 4 on the iHost interface).

- Feeder 1 connects 55 households, of which 11 have PV and 15 have BESS.
- Feeder 2 connects 36 households, of which 15 have PV and 20 have BESS.

Monitoring parameters

Information on the power, voltage, current and reactive power of each feeder could be downloaded from the iHost interface, with a temporal resolution smaller than 1 minute, although a resolution of 30 minutes (averaged) has been used.

2.2 Tenant Engagement

The tenants involved in the Battery Storage collaboration agreement are all tenants of Berneslai Homes. The solar PV systems on their rooftops are owned by Energise Barnsley – a community benefit society registered with the Financial Conduct Authority, and were already installed prior to the project commencing.

Since currently there are no commercial benefits for having a BESS in a household without PV (other than those with an E7 tariff), participants without PV were offered an annual financial incentive (£75 per year) to participate in the trial.

2.2.1 Tenant Engagement Actions

The batteries were installed in Q1 and Q2 2017 after engaging with and informing the residents. A significant amount of site visits was required due to issues with broadband, communications, and battery installations, but Energise Barnsley ensured the tenants were properly informed (tenants were given a box of chocolates as thanks for their continued cooperation). Table 1 gives an overview of all steps undertaken regarding the tenant engagement in the DS3 project.

Table 1: Chronological overview of the steps undertaken regarding the tenant engagement.

Step	Description
1	Tenants had solar PV installed in December 2015. Tenants had a choice and could opt into the project if they wanted to receive solar PV, and benefit from the free use of electricity when the panels were generating.
2	Tenants received an 'Owl monitor', as part of the solar PV installation, and guidance on making the best use of the free electricity when the system was generating.
3	The tenants were familiar with Energise Barnsley and had an increased energy awareness ahead of the battery storage trial due to the installation of solar PV panels.
4	Tenant engagement and acceptance of the battery trial was foremost in the minds of Energise Barnsley when carrying out market research for the most suitable battery in terms of aesthetics including size and ease of install for this retired community living in bungalows with small kitchens and an outhouse. The tenants were approached and signed up by people they knew.
5	As a community organisation they had to choose a battery manufacturer who had adequate capital reserves for at least the duration of the project, and most likely for the duration of the product warranty.
6	When Moixa was selected and a collaboration agreement between all parties was agreed (Northern Powergrid, Moixa and Energise Barnsley) and an engagement plan was put in place and sent to Ofgem for approval along with a Data Protection Strategy.
7	A community hall near the properties was identified. Many of the residents in the trial use the club on a Wednesday afternoon.
8	First tenant engagement involved engaging with the tenant liaison officers from Berneslai Homes, who the tenants knew and trusted. The tenant liaison officers in turn could confidently speak with the tenants or answer their questions when asked.
9	An initial tenant information letter was sent in the post explaining the purpose of the project, what the tenants could expect, and notifying the tenants that an Energise Barnsley board member was going to visit the community centre with an actual battery for demonstration purposes. Tenants could also choose to receive a home visit, as some are homebound, or could not make the afternoon engagement session.
10	Key tenants were identified who could be community ambassadors for the project, and who were willing to talk to neighbours about the scheme.
11	An actual battery was demonstrated to the tenants either in their home, or in the community hall.
12	Tenants were given the opportunity to opt-in to the project.
13	In the 'opt in' agreement there was an explicit commitment to be part of the two-year trial, in agreeing to participate in tenant feedback, and for any additional visits engineers had to make.

14	The batteries were installed in Q1 and Q2 of 2017
15	As part of the project, tenants who did not have a landline or broadband, had the services installed, with Energise Barnsley becoming a white label internet service provider with Northern Powergrid covering the costs. Sixteen of the homes had a landline or broadband or both installed and paid for them. The percentage of homes without broadband was significantly higher compared to the national average.
16	Some tenants therefore had site visits from three different parties – a battery engineer, a BT landline engineer and a broadband engineer.
17	Communication with the tenants was either through the tenant liaison officers or via the telephone for repeat site visits, to iron out any installation problems.
18	Whist the batteries were out of sight (in the side house) and therefore out of mind, some tenants were also curious about what the battery was doing, and what savings they were likely to achieve per month, with some going in the side house checking if the lights were on.
19	Energise Barnsley had access to online battery charging and discharging data on behalf of the tenants. The data was not tenant friendly, and feedback went back from the tenants to Moixa simplify the data produced to equivalent monthly savings figures.
20	Two further community meetings were held to discuss initial findings from the project, and to gauge tenants' reactions and perceptions.
21	Tenants were all given a box of chocolates after seven months into the project as a thank you for their continued participation in the project.
22	At the end of the project the tenants were presented their total savings and were offered the opportunity to maintain the battery free of charge.

2.2.2 Learnings

Over the course of this project valuable lessons were learned regarding tenant engagement, particularly related to the specific demographics of the DS3 project participants. An overview of these lessons is provided in Table 2.

Table 2: Lessons learned regarding tenant engagement as part of the DS3 trial.

Understanding of Tenants
Issues occurred because tenants were not tech savvy
An important lesson learned during this study is that the fact that the tenants were not tech savvy made it hard to proactively identify issues and troubleshoot remotely. Tenants occasionally switched off their routers when they were not using it or unplugged the battery which shows education of tenants is necessary and important.
Tenants showed patience with the installation process
The tenants were patient as firmware updates to the batteries and communication issues meant that some tenants had multiple installation visits.
It is important to have tenant liaison officers that tenants know and trust
The tenants really valued having a familiar face as a main point of contact and appreciated being able to ask questions to somebody they trusted.
It is important to have tenant friendly data
The **project highlighted the importance of being able to show savings to customers in a simple and user-friendly format to help them understand the impact of the batteries and solar on their bills.**
Not everyone has broadband

Although it was anticipated that some tenants would require broadband connection, acquiring it for multiple properties and making arrangements for covering the costs took longer than expected.
Unexpected issues with property access
Despite having scheduled meetings in advance, in some cases there were unexpected issues with accessing the properties during the installation period. Some tenants forgot appointments or were out due to an emergency. Since this behaviour is unpredictable, it should be taken into account that delays during installation should be expected. Reminders could perhaps be a mitigation action.
Only a very small percentage of tenants was interested in viewing their battery usage
It turned out that only a very small percentage of the tenants were interested to view their battery usage, and potential savings on the online platform provided by Moixa, which is related to the tenants being elderly and not tech savvy. The tenants relied on Energise Barnsley to equate battery usage to potential electricity monthly bill savings. Energise Barnsley spent a significant amount of time trying to clean the data and analyse the battery savings and recommends that data should be metered instead of measured by clamps (or similar) so data is reliable and there is belief in the numbers so electricity savings data is easier to produce.
Batteries increase tenant savings, but retail price increases disguised savings
The savings from the solar electricity generation were significant for those tenants who actively tried and changed their energy behaviour to capture as much of the solar generation as possible through self-consumption. Levels of self-consumption of solar generation varied greatly within the project. The electricity savings from the battery can approximately contributed another 10 – 25% on top of the solar electricity savings. Even though the batteries did cause savings, it should be noted that from the tenants' perspective these savings were sometimes disguised by the increasing utility bills as a result of increasing retail prices.

2.3 Research Methodology

In order to address the learning goals introduced in Section 1.2 a set of questions was defined as part of this study to guide the analysis:

- To what extent does BESS enable a shift of excess demand or generation at peak times to other times of the day?
- How does this vary with household occupancy/underlying demand pattern?
- To what extent does the presence of BESS affect the variability of demand at network level?
- How does the operability of BESS vary between homes with BESS only and homes with PV + BESS installed?

In Chapter 3 these questions are addressed by analysing the battery and network data.

2.3.1 Key Metrics

For clarity and consistency some key metrics were defined at the start of the project. The key metrics are summarised in Table 3 and basically describe two effects; $R_{\%}$ and $R_{\%,peak}$ describe the extent to which the in-home battery is able to **reduce the excess import/export** of the house during peak demand/generation periods and the standard variation σ is a measure for the **variability of the load profile** at network level, which should decrease when all batteries are discharging during the peak demand and charging during the peak generation periods. The key metrics are discussed in more detail in Appendix A.

Table 3: Key metrics used to describe the monitored data.

Parameter	Description
$\boldsymbol{R_{\%}}$ [%]	Average percentage reduction in import/export level over the high demand period (17:00-20:00) or the high generation period (10:00-16:00).
$\boldsymbol{R_{\%,peak}}$ [%]	Percentage reduction in import/export level at the time of peak demand (18:00) or peak generation (12:30).
$\boldsymbol{\sigma}$ $[W]$	Variability in distribution substation demand expressed as the standard deviation, which is expected to decrease when more BESS is installed. To understand the impact the batteries have on flattening the profile during the day, the standard deviation is calculated for the time period 09:00 – 21:00.

2.3.2 Battery Utilisation

There are multiple reasons for installing BESS – which differ per type of battery owner. For domestic customers, having BESS to increase self-consumption of PV can significantly increase savings, and as tariffs become more flexible, using BESS to avoid times of high prices will become more relevant. For network operators, benefiting from either behind-the-meter storage or grid-scale storage can reduce their need for network upgrades. Particularly if constraints are only expected to occur a few times per year benefiting from BESS could offer a very cost-effective solution.

To accommodate these different use cases, there are multiple ways that the batteries could be operated, all with their own advantages (and disadvantages) for the DNO and the consumer. Some utilisation options are shown in Figure 5, ranked by their focus on the DNO or the consumer.

It is important to note here that this ranking does not necessarily coincide with the ranking of the financial benefits for both stakeholders. For example, the 'Maximise Self-Consumption' strategy may be aimed at maximising the profit for the consumer, but the fact that the benefits for the DNO are available without any further costs, still makes this an interesting option for the network operator. Similarly, if DNOs are willing to compensate consumers for control of their batteries, the reduction in self-consumption may be offset by a new form of income.

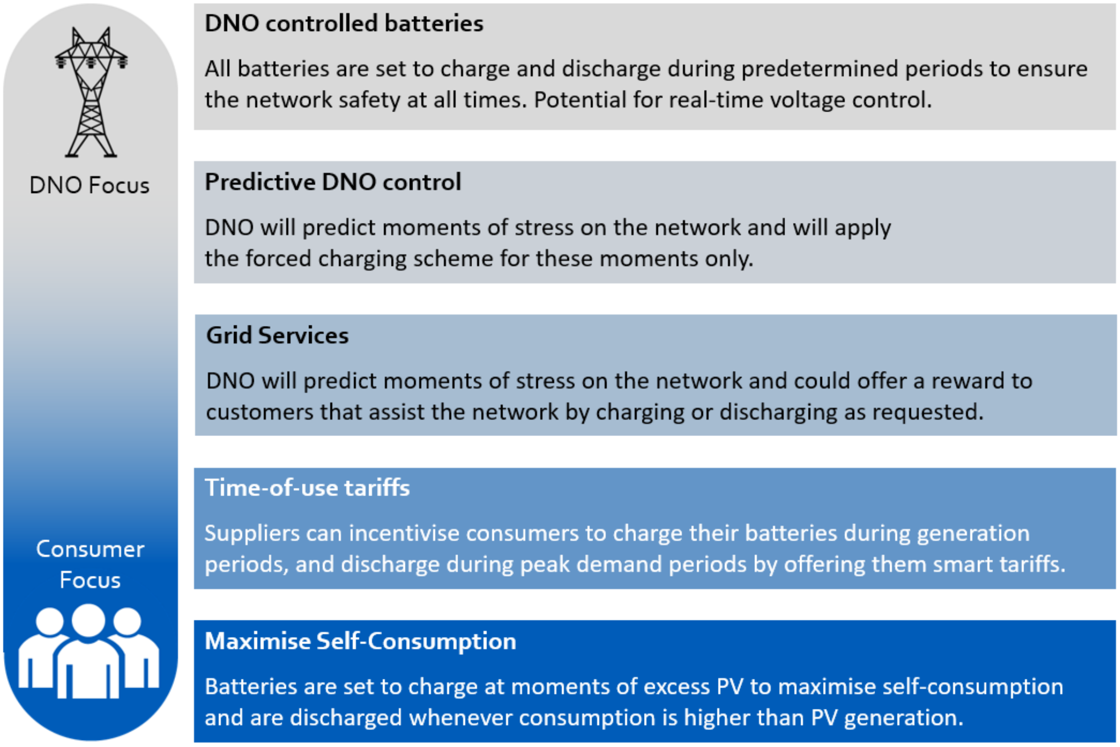


Figure 5: Overview of multiple battery utilisation options ranked by their focus.

2.3.3 Battery Charging Schemes

The battery utilisation options shown in Figure 5 require the batteries to be charged according to pre-defined battery charging schemes. The charging schemes trialled in this study are shown below, ordered from DNO to consumer focus.

- **Maximum Impact:** Batteries charge and discharge at their maximum rate at set times.
- **Predicted Generation:** Batteries charge at their maximum rate only when it is predicted that generation will be high.
- **Demand-Led:** Batteries charge at their maximum level, but discharge is limited by consumption.
- **Threshold Charging**: Batteries (dis)charge based on excess demand/generation (above a set threshold).
- **No Impact:** Batteries are inactive to enable a baseline calculation.

Most of these schemes have been trialled in both summer and winter, although it should be noted that the focus of the schemes differs based on the network constraints in each time of year (i.e. load in the winter and generation in the summer).

Summer

In summer, the Maximum Impact on the network has been achieved by force charging of all batteries during the period of peak generation and discharging them during the evening peak. However, to prevent causing extra costs[1] for the tenants, a more Demand-Led approach was also tested, for which the discharge rate was limited by the level of consumption of each household. Since assistance to the network is not always required, a more advanced Predicted Generation scheme has also been trialled which used weather forecasting to predict on which days it would be beneficial to the network to force charge all batteries of non-PV households.

The most consumer-based approach relies on the Threshold Charging scheme which ensures batteries are only charged based on the available excess PV generation, and discharged to supply the tenant's consumption. It should be noted that under this scheme non-PV homes were inactive.

Winter

The focus of the DNO in the winter is more on evening peak load than on generation. For a Maximum Impact on the network, in winter the batteries were forced to discharge during the evening peak. To ensure the batteries were fully charged before this time, they were forced to charge in the afternoon (10:00-16:00) (still benefiting from the excess PV generation in PV homes), although it should be noted that this charging could be shifted to any point during the day if that would be preferable.

To test the impact the batteries can still have on the network, even if no extra costs are implied for the tenants, the Demand-Led scheme was trialled in winter as well. For completeness the Threshold Charging scheme was also tested in winter, although it was expected that due to limited PV generation, the impact for both the customer and the network would be small.

2.3.4 Timeline

The initial project scope anticipated that trials would be held over two summer and two winter periods, from winter 2016/17 to summer 2018. However, due to delays to the installation programme, the systems were not in place to collect data during the first winter period. As a result, summer 2017 was the first period for collection of trial data, and the project duration has been extended to include winter 2018/19 to make up for the delay and hence there was no impact on the trial results.

Within the summer and winter trial periods, the intention was to operate the battery systems under a variety of different control strategies, in order to understand the potential to optimise battery operation to provide network benefits and how this impacts on the benefit to the householders, including their ability to reduce their energy bills or exploit other revenue-generating opportunities.

An overview of the battery charging schemes that were trialled during this study is shown in Figure 6.

[1] Extra costs are the costs related to buying and storing electricity and exporting it back to the grid at a lower price without consuming it, as well as the battery degradation costs. These costs must be added on top of any costs incurred due to the efficiency loss of the batteries.

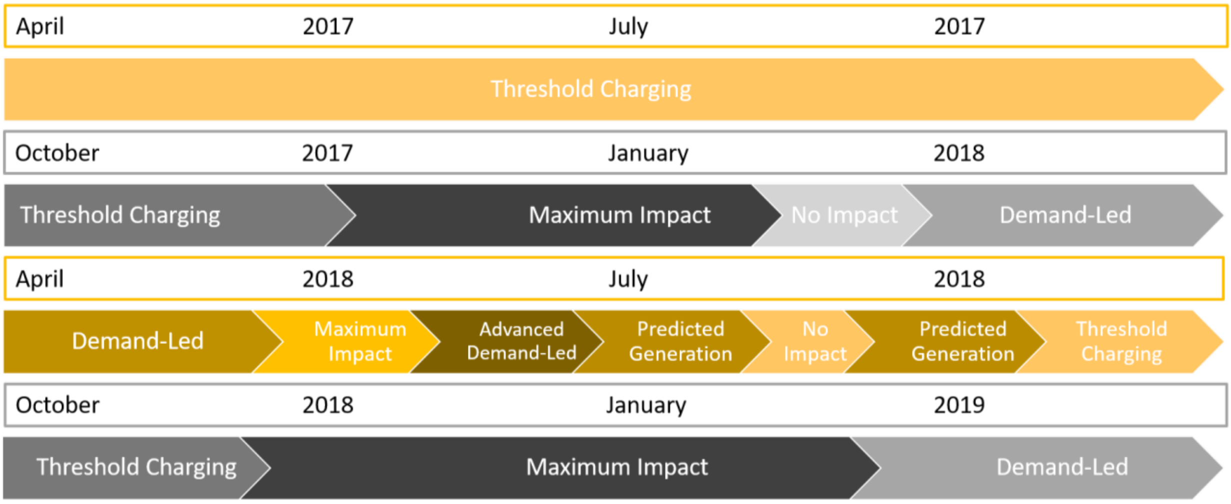


Figure 6: Overview of battery charging schemes as trialled during the DS3 project.

3 Data Analysis

This chapter describes the analysis of the data monitored during a two year period between 01/03/2017 – 14/04/2019 as part of the DS3 trial in order to answer the questions defined in Section 1.2. The data cleaning required to avoid skewed results is discussed, as well as the aggregation of data over subsets of batteries and time periods when certain charging schemes were trialled.

3.1 Data Availability

As mentioned in the introduction, the installation of the batteries was completed in Q1 of 2017, and these systems have been recording data since. However, in some of the households unexpected issues occurred which had to be resolved before the BESS unit could (reliably) provide data – in some cases the inverters needed to be replaced as well. Apart from these installation issues, a firmware update was rolled out in June 2017 to increase the accuracy of data monitoring. Although the firmware update was eventually completed successfully across all systems, it resulted in a temporary reduction in the number of systems communicating reliable data. Similarly, a change of the Moixa systems in August 2018 also caused a temporary reduction in reliable communication.

The availability of the data is visualised in Figure 7, by showing the amount of batteries for which non-zero consumption data was recorded, which has been used as a metric for battery data availability. It can be seen that the firmware update in June 2017 and the change in Moixa system in August 2018 caused a significant reduction in battery availability. Despite these issues, levels of around 80% availability were reached for a large part of the trail.

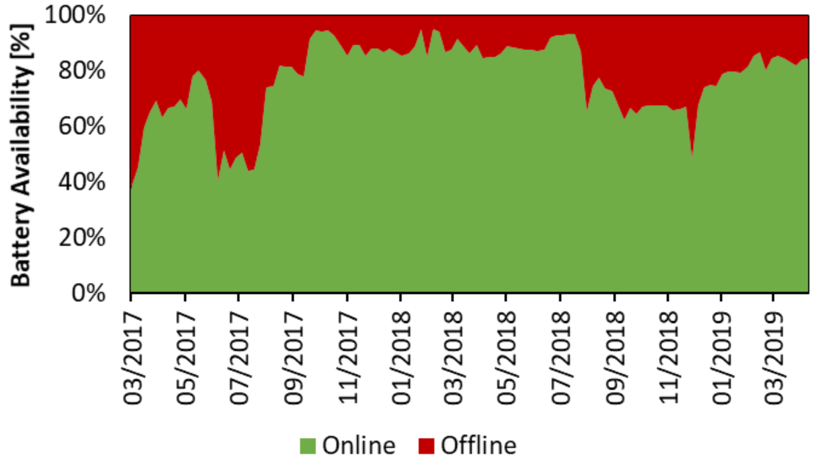


Figure 7: Overview of the battery data availability during the entire trial.

3.1.1 Data Cleaning

It should be noted here that at certain times (particularly after the firmware updates) some of the batteries were online but not operating according to the agreed charging scheme because of communication issues. As an example, during the winter of 2018/19 all batteries were set to operate according to the Maximum Impact scheme (i.e. having forced (dis)charging in the afternoon and evening) but aggregation over all the operating batteries (Figure 8) showed that the average battery (dis)charging rates were significantly smaller than in the winter of 2017/18. Since the batteries were supposed to operate similarly at both these times, this indicates that some of the batteries were indeed not operating as expected.

It is true that including the batteries that were not performing according to the planned scheme gives an interesting insight in the real-life performance of the batteries. However, since as an outcome of this trial we are mostly interested in the impact the batteries can have on the network if they are fully operational, we have attempted to clean the data to remove the influence of erroneous values caused by communication issues or batteries not operating according to the intended charging scheme. In order to do this, we have assessed the state of charge data of the batteries and have ignored days for which a battery was inactive for 12 hours or more. The time periods during which the batteries were forced to be in Idle mode were excluded from this data cleaning step. The resulting profiles in Figure 8 show that the charging rate for the cleaned 2018/19 data is closer to what would be expected for the Maximum Impact scheme, although it should be noted that despite the cleaning process, not all erroneous values were removed.

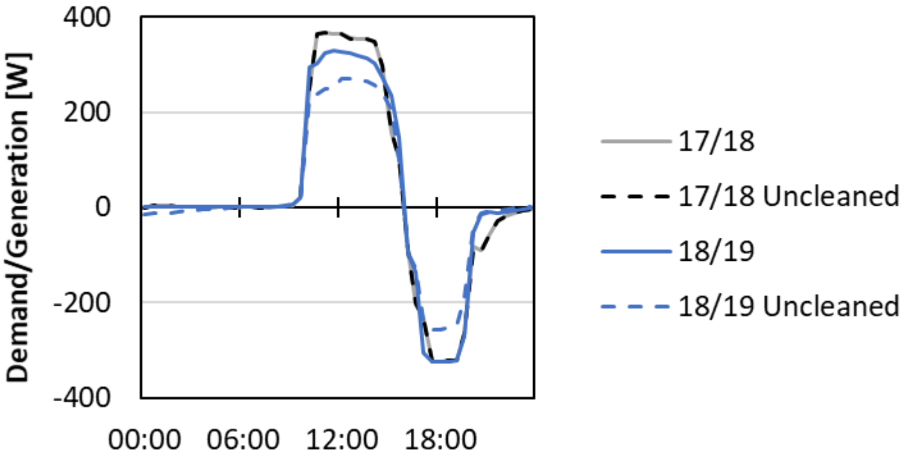


Figure 8: Battery charging rate during the Maximum Impact scheme in the winter of 17/18 and the winter of 18/19, prior to and after applying the data cleaning. Note that this graph includes both those households with one battery and those with two.

3.1.2 Aggregated profiles

As a first step in understanding the data, the PV and consumption profiles aggregated over all households and per month are shown in Figure 9. It can be seen that the PV generation profile is comparable for each month, albeit stronger in mid-summer, as would be expected. The individual PV profiles of each household are all very similar because all households are in the same neighbourhood and their solar panels are oriented in the same direction.

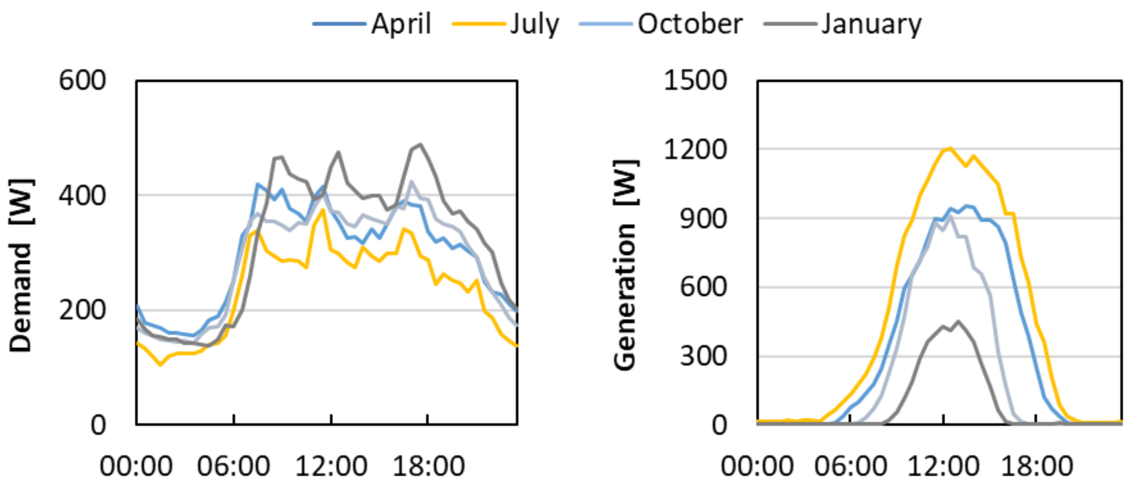


Figure 9: Aggregated consumption (left) and PV (right) profiles per property for all households with batteries for April, July, October and January. Based on these aggregated profiles the time of peak demand is determined to be 18:00 and the time of peak generation to be 12:30.

Figure 9 reveals that aggregated over all homes the consumption profiles are rather flat with no significant evening and morning peaks exist. However, there appears to be some increase in consumption towards the colder months.

Consumption behaviour differs strongly per customer type, and in order to check if the consumption profiles are sensible, they have been compared to data from the *General Load Customers analysis* of the *Customer Led Network Revolution* (*CLNR)* project, as is shown in Figure 10. In the CLNR project the consumption profiles of a wide range of households were collected and categorised according to the Mosaic system. Mosaic is a consumer classification[2] developed by Experian based on demographics, behaviours, preferences and lifestyles. The Mosaic classification system segments the population into 66 types, within 15 broader groups.

The tenants of the households participating in the DS3 project are mostly retired and apart from one household, all of them are gas heated. For this comparison the electrically heated household has been excluded, as the diurnal profiles and annual demands of the CLNR project (test cell TC1a) are based on gas heated households only[3].

In Figure 10 it can be seen that the average consumption profile as recorded by the batteries is very similar to the consumption profiles of the 'Elderly Needs' and the 'Active Retirement' classes, as would be expected based on the Mosaic class descriptions. The average daily consumption of the Berneslai homes households is 6.59 kWh, which corresponds to 2,405 kWh per year, which closely matches the 2,344 kWh per year expected for the 'Elderly Needs' class and the 2,777 kWh per year for the 'Active Retirement' Class.

To generalise the results of this study, the different consumption profiles expected in other types of households were considered. As an example, Figure 10 shows the average daily consumption profile of the 'Careers and Kids' class. If a battery were to be installed in such a household, its impact would be very

[2] http://www.experian.co.uk/marketing-services/products/mosaic-uk.html

[3] http://www.networkrevolution.co.uk/wp-content/uploads/2015/02/Insight-Report-TC1a.pdf

different as a result of the overall higher demand level and the significantly stronger evening peak. To test the impact of this, the Ipsa modelling tool was used to run scenarios in which the DS3 households were assumed to have 'Careers and Kids' demand profiles instead of their actual demand profiles.

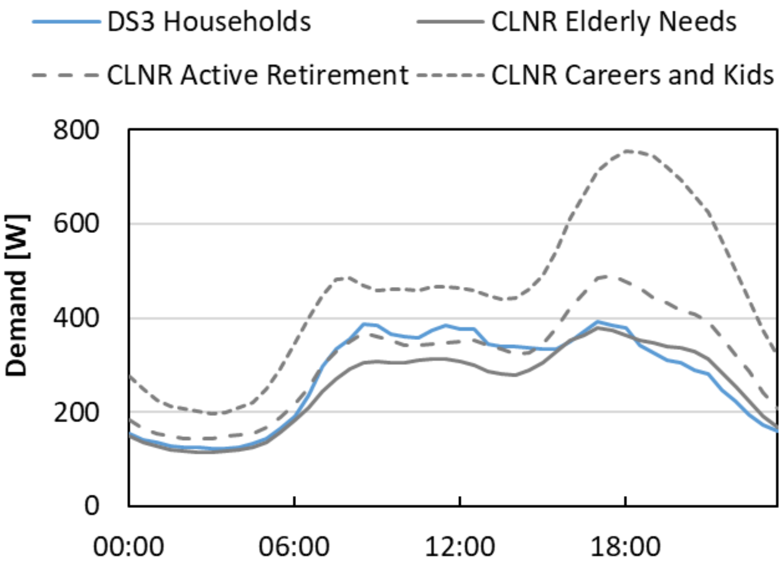


Figure 10: Average daily consumption profiles (accounting for both weekdays and weekends) of the DS3 households, and of the 'Elderly Needs', 'Active Retirement' and 'Careers and Kids' classes from the CLNR project. The average consumption profile of the households closely matches that of the CLNR Elderly Needs and Active Retirement classes, which would be expected because most of the tenants of the DS3 households are retired.

3.2 Winter Analysis

Over the course of the trial the schemes as discussed in Section 2.3.3 – Threshold Charging, Maximum Impact and Demand-Led – have been tested. Continuous inspection of the data throughout the project has allowed us to identify opportunities to improve the charging schemes to avoid issues or battery inactivity. The graphs presented below are based on the data recorded during the winters of 2017/2018 and 2018/2019, with the data cleaned as described in Section 3.1.1 above.

3.2.1 Threshold Charging

As the default mode of operation, this scheme (dis)charged based on excess generation or demand and therefore caused no extra costs to the owner. However, it should be noted that without any smart tariffs or incentives the threshold scheme is not applicable to households without PV as they will never be able to charge.

The scheme is only applicable to households with PV, but due to the high default charging threshold (200 W) in combination with the low overnight consumption levels observed in these households and the limited PV generation on some days, many BESS were often inactive. Limited fluctuation in the SoC of the batteries indicated that on average only a small portion of the BESS capacity was used, suggesting that for consumers with a low average consumption as well as for periods of limited PV generation, the threshold for battery operation should be lower to avoid the batteries remaining idle. A lower threshold was trialled during the second winter period and the average charging rate increased by approximately 33%, as shown in Figure 11.

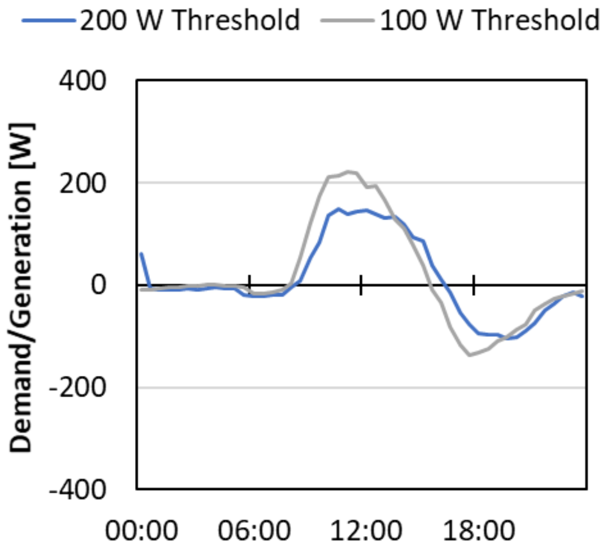


Figure 11: Threshold Charging – Average charging (demand) and discharging (generation) rates of the batteries in the PV households. The results are shown for the original threshold of 200 W (blue) and the new lower threshold of 100 W (grey) which is better suited to the demand of the DS3 households.

The profiles shown in Figure 12 are for all PV households with a single battery during the second winter of the trial, when the threshold was set to 100 W. On average during the high demand period the batteries managed to reduce the average demand in the evening period ($R_{\%}$) by 28% and demand at peak time ($R_{\%,peak}$) by 29%. This compares to 25% (on average and at peak) during the first winter when the threshold level was higher.

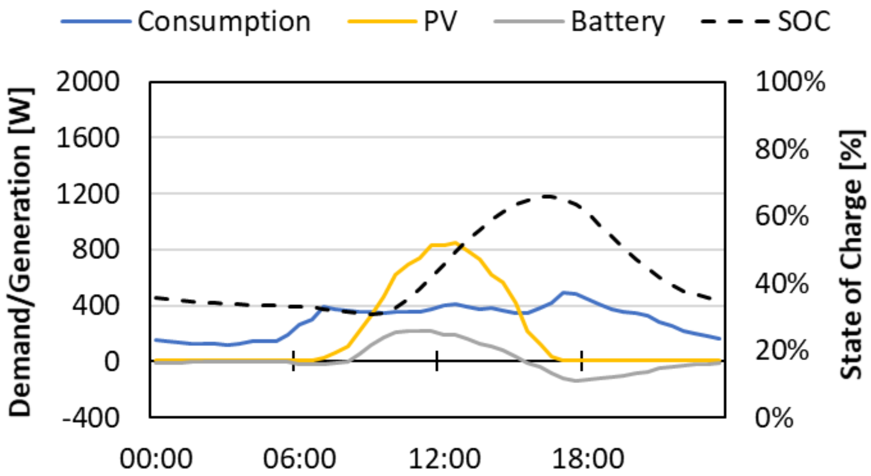


Figure 12: Threshold Charging – Data averaged over all single battery PV households during the winter of 2018/2019 when the threshold level was set to 100 W. Note that the grey battery (dis)charging profile in this figure is the same as the grey profile in Figure 11.

The impact on the network whilst operating the Threshold Charging scheme will be discussed in more detail in Section 3.2.5.

3.2.2 Maximum Impact

This scheme focused on the impact BESS can have on the network, without considering the optimal performance for the owner. If in the future such a scheme is deemed to be beneficial for distribution network operators, any costs incurred by the BESS owners may be compensated through a financial incentive. The scheme forces all batteries to charge during the day (10:00 - 16:00) and discharge during the evening peak (17:00 - 20:00). As per Figure 13, this scheme is useful during the winter when the average PV generation is low and hence the BESS might not have been charged fully unless they were forced to. The scheme therefore ensures that the BESS are charged and ready to support in the evening peak. Likewise, forcing the batteries to discharge reduces the evening peak significantly. The average discharge rate at the time of peak is about 300 W, indicating that many batteries were discharging at their maximum rate (420 W) for the majority of days.

By forcing the batteries to assist the network, import from the grid could be reduced by an average of 55% during the high demand period, doubling the impact that was achieved with the Threshold Charging scheme. At the time of peak demand, the reduction was as high as 60%.

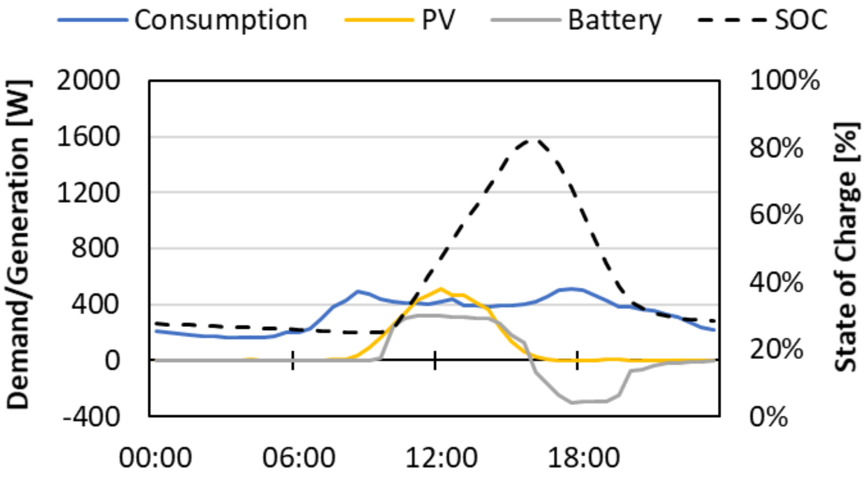


Figure 13: Maximum Impact – Data of all single battery households during both winters. The PV and non-PV households are not treated separately because their battery (dis)charging profile is very similar.

As was discussed in Section 2.1.1, two batteries were installed in some households to replicate a larger battery (capacity and rate), increasing the potential impact on the network. Figure 14 shows the difference in impact between households with one or two batteries when operated according to the Maximum Impact scheme. The increased impact on the network is clear, but it should be noted that in this case the amount of electricity imported and exported is large compared to the customer demand, and hence a larger incentive would be required.

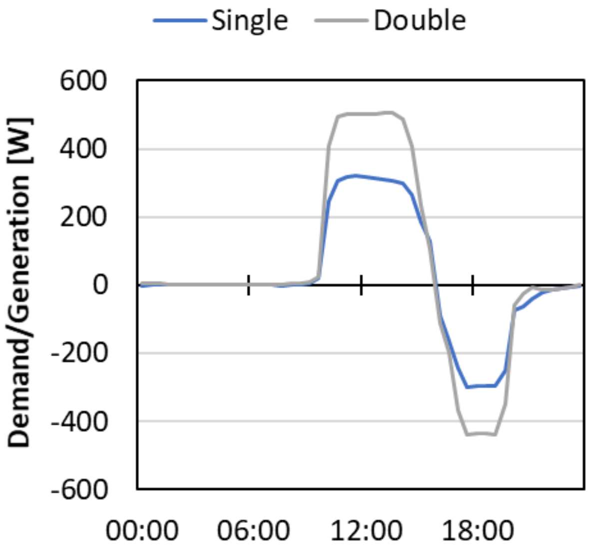


Figure 14: Maximum Impact – Scheme operated in both winters aggregated over the households that have one battery installed versus the households that have two batteries installed.

3.2.3 Demand-Led

The Demand-Led scheme is a combination of the Threshold Charging and the Maximum Impact schemes in that it ensures the BESS is fully charged before the evening peak but it only discharges based on excess consumption. Before running this scheme, the threshold level was reduced to 100 W to reflect the demand profile of the households in this trial. Figure 15 shows that even without forcing them to do so, due to the demand, many batteries discharge in the evening peak, reducing it by almost 39% (with an average reduction of 43% over the high demand period).

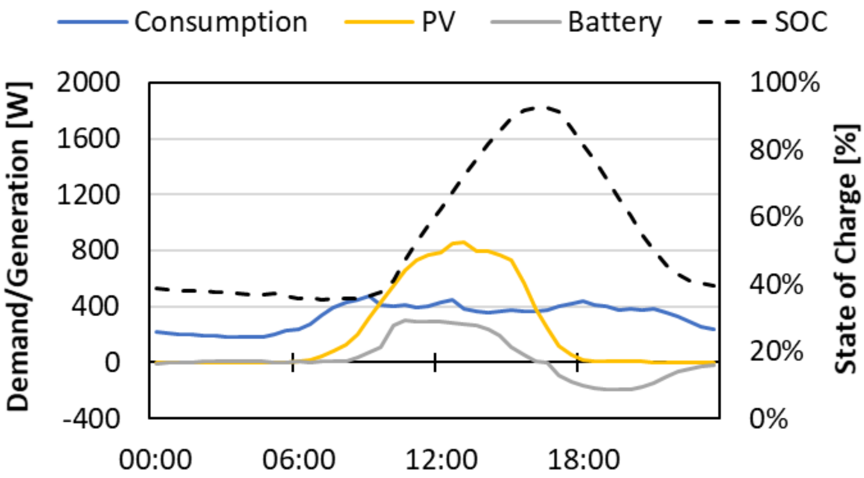


Figure 15: Demand-Led – Data of all single battery households during both winters. The PV and non-PV households are not treated separately because their battery (dis)charging profile is very similar.

It is worth noting here that despite the SoC not reaching 20% before the start of the generation period, due to the low levels of PV output experienced in the winter, there is adequate demand and available BESS capacity to ensure PV generation is not exported onto the grid. This suggests that during the winter period, forced discharge to ensure maximum battery capacity is available at the start of the PV generation period is not necessary to avoid reverse power flows.

We have also looked at the impact of having two batteries installed in the Demand-led scheme. As expected, Figure 16 shows that the charging rate in the afternoon is significantly larger, but interestingly because in this scheme the discharge in the evening is based on the excess demand, having two batteries installed in the DS3 households turned out to provide no extra benefit when operating the batteries in this way.

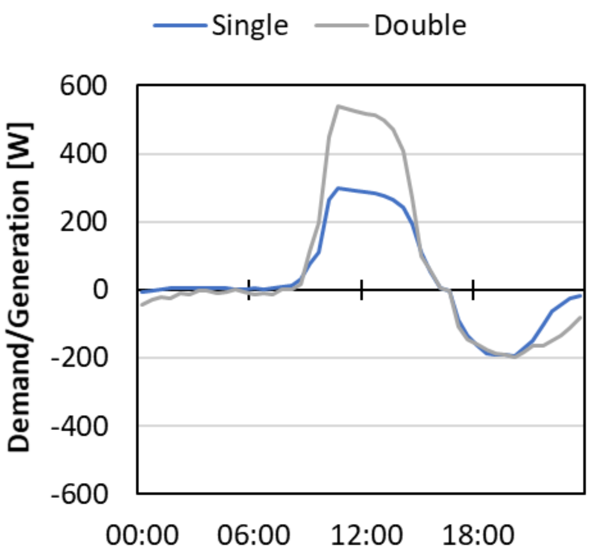


Figure 16: Demand-Led – Scheme operated in both winters aggregated over the households that have one battery installed versus the households that have two batteries installed.

3.2.4 Battery Impact

Since the weather conditions and household consumption behaviour varied at the times when the different charging schemes were trialled, the percentage reduction achieved by the batteries across the different schemes cannot be directly compared. Therefore, to be able to meaningfully compare the impact the batteries have had whilst operating according to the different schemes, the average PV and consumption profiles in January will be used as presented in Figure 9. This will avoid certain schemes having a seemingly small impact, simply because the excess demand on average was higher when that scheme was trialled.

Figure 17 shows that the import from the grid can be significantly reduced during the time of the winter peak demand by operating the batteries according to the different schemes. This comparison shows that for the DS3 households, the Maximum Impact scheme managed to have the largest impact, reducing the evening peak demand levels from 400 W to just over 100 W. It should be noted that for the Threshold Charging scheme the reduction (to 300 W) is only applicable to PV households.

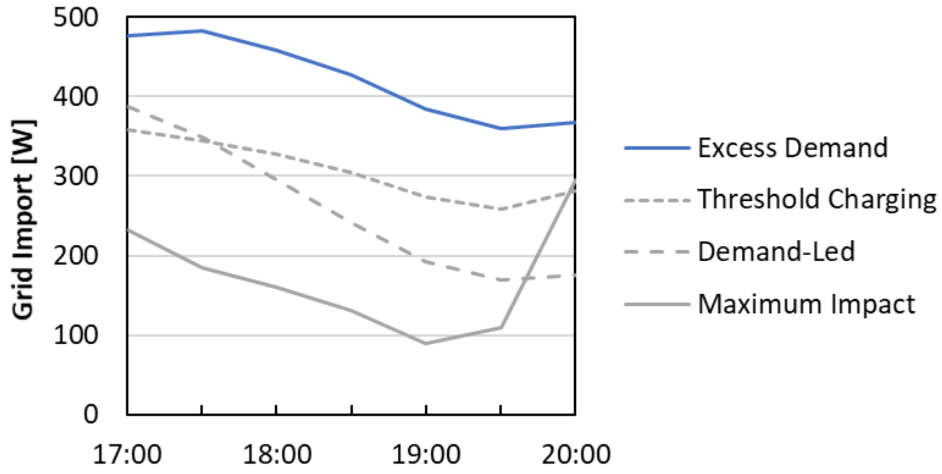


Figure 17: The average grid import per property before (blue) and after (grey) accounting for the impact of the BESS.

Calculating the reduction observed in Figure 17 as a percentage might give us a more intuitive understanding of the effect the BESS can have. For completeness the impact that can be achieved by having two batteries operating alongside each other was also calculated. Figure 18 shows that by operating the Maximum Impact scheme, the winter evening peak demand reduction ranges from 50-75% with a single battery (solid) and can even be as large as 76-100% when having two batteries installed (dashed). The impact of the other schemes is smaller, but importantly they could still cause reductions of around 25-50% without incurring extra costs for the customer or the DNOs. It should be noted here that adding a second battery did not add much value to the Demand-Led and Threshold Charging schemes, as in these cases demand levels were too low to effectively discharge both batteries.

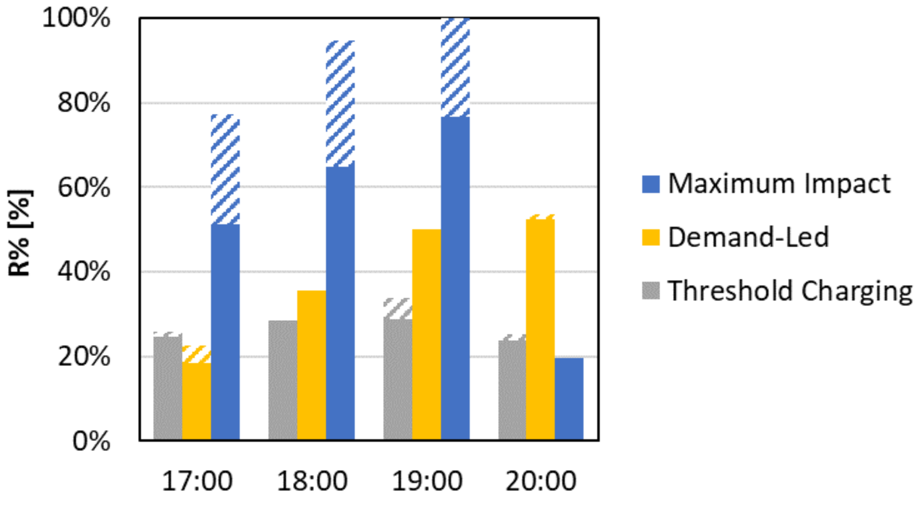


Figure 18: The percentage reduction of excess demand (averaged over half an hour) that can be achieved by operating the batteries according to the different schemes. The dashed area indicates the further reduction that is achievable by having a second battery installed. The reduction for the Threshold Charging scheme is only valid for the PV households as other households will probably not have a BESS due to the lack of incentives such as time-of-use tariffs.

It should be noted that the underlying demand pattern of the household has a strong impact on the achievable reductions. To illustrate this, the analysis shown in Figure 18 is repeated in Appendix B but based on a demand profile that corresponds to the Mosaic 'Careers and Kids' class.

3.2.5 Network Impact

As discussed in Section 2.1.2, substation data was also recorded as part of this trial. To study the impact of the batteries on the network, one of the two feeders supplying the households, Feeder 2, was analysed. Twenty of the 36 households on this feeder were participating in the DS3 trial. We have determined the base case (the substation demand of the feeder without battery intervention) in two ways; firstly by operating all batteries according to the No Impact scheme (i.e. putting all batteries in idle mode) during set time periods during the trial, and secondly by simply subtracting the total recorded battery (dis)charging rate from the substation demand. The former allowed to validate the analysis with real data. Both methods are represented in the figures in this section and in Section 3.3.5 by the solid grey line (idle mode) and the dashed blue line (subtracted battery impact).

Figure 19 shows that when operating the batteries according to the Maximum Impact scheme, the evening peak was significantly reduced. The small peak at 17:00 implies that the batteries should have started discharging slightly sooner, but the flatter demand profile throughout the day shows that the batteries could shift a large part of the evening load to the afternoon. It is worth noting that the fact that both methods for determining the base case provide similar results indicates that the conditions whilst trialling the two schemes (i.e. the No Impact and Maximum Impact scheme) were comparable.

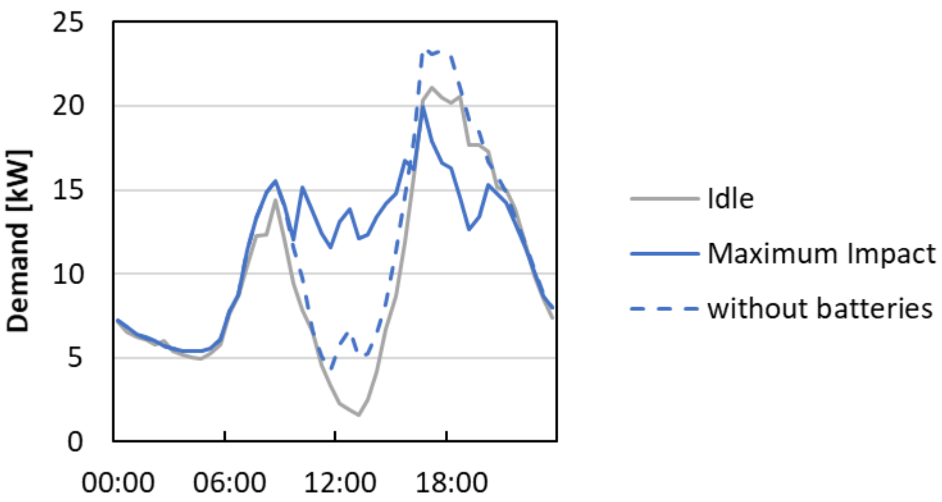


Figure 19: Feeder 2 – The substation demand for the Maximum Impact scheme compared to the base case substation demand *calculated* by subtracting the battery impact (dashed blue line) and *monitored* by operating all batteries in idle mode (grey line). Note that the difference between the base case substation demand profiles is mostly caused by the varying weather conditions during the time periods for which the schemes were trialled.

Similar to the Maximum Impact scheme, as per Figure 20, the Demand-Led charging scheme also managed to significantly reduce the evening peak. When considering the afternoon, it is important to highlight that there is a large difference between the *monitored* (Idle) and *calculated* (without batteries), which is caused by the high levels of PV generation at the time of the Demand-Led charging scheme as compared to the generation when the batteries were operated in Idle mode. Due to the differences in weather conditions, particularly in this case, it is more informative to look at what the demand would have been at the substation in the case that the battery impact is removed – which shows that operating the batteries according to the Demand-Led scheme has prevented reverse power flows from occurring on the network in the afternoon.

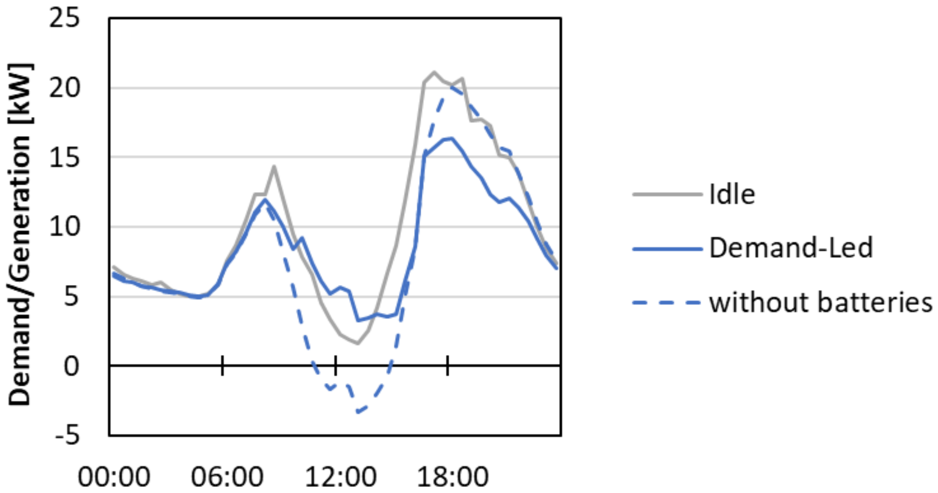


Figure 20: Feeder 2 – The substation demand for the Demand-Led scheme as compared to the base case substation demand *calculated* by subtracting the battery impact (dashed blue line) and *monitored* by operating all batteries in idle mode (grey line).

As we have seen in Section 3.2.4 the impact of Threshold Charging at household level was smallest of all schemes trialled. This is also shown in Figure 21, but the difference between the Threshold Charging and the Demand Led scheme above is larger than one might expect based on the difference at household level alone. The main reason for this is that the Threshold Charging scheme is only applicable to PV households, and hence at network level the total impact that can be achieved is smaller.

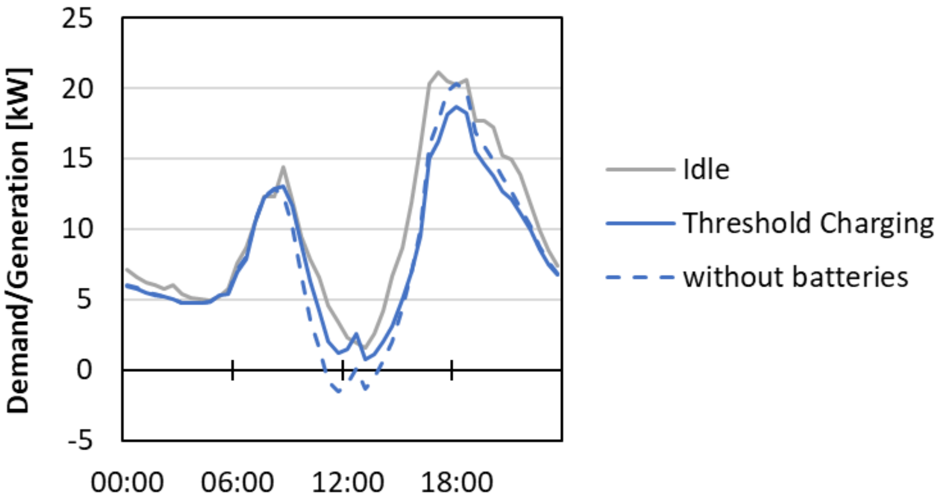


Figure 21: Feeder 2 – The substation demand for the Threshold Charging scheme as compared to the base case substation demand *calculated* by subtracting the battery impact (dashed blue line) and *monitored* by operating all batteries in idle mode (grey line).

By discharging in the evening and charging in the afternoon the batteries managed to supply a significant amount of substation load at periods of peak demand, effectively reducing it. To quantify the extent to which the batteries reduced the variability in demand during the day (an example of which is given for the Maximum Impact scheme in Figure 22), when operated according to the different charging schemes, the standard deviation of the substation demand has been calculated for the time period 09:00 – 21:00, as is shown in Figure 23.

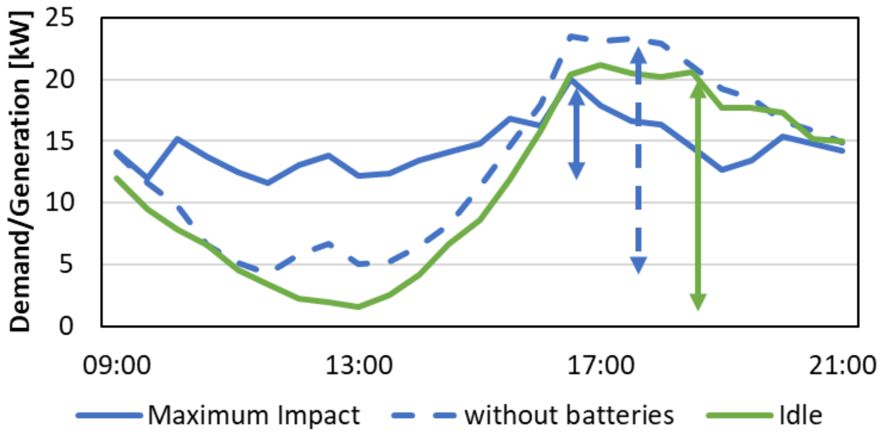


Figure 22: Example of the reduced variability in substation demand achieved by the batteries operated according to the Maximum Impact scheme. The arrows illustrate the standard deviation, which is shown in more detail and for all battery operating schemes in Figure 23.

The figure shows that the Maximum Impact scheme was very successful at flattening the profile, with a standard deviation of only about 2 kW, as compared to 6.5 kW if the batteries would have been inactive. It also reveals that the variability in demand would have been strongest for the Demand-Led scheme (without the battery impact), but that as a result of the batteries the variability was significantly reduced.

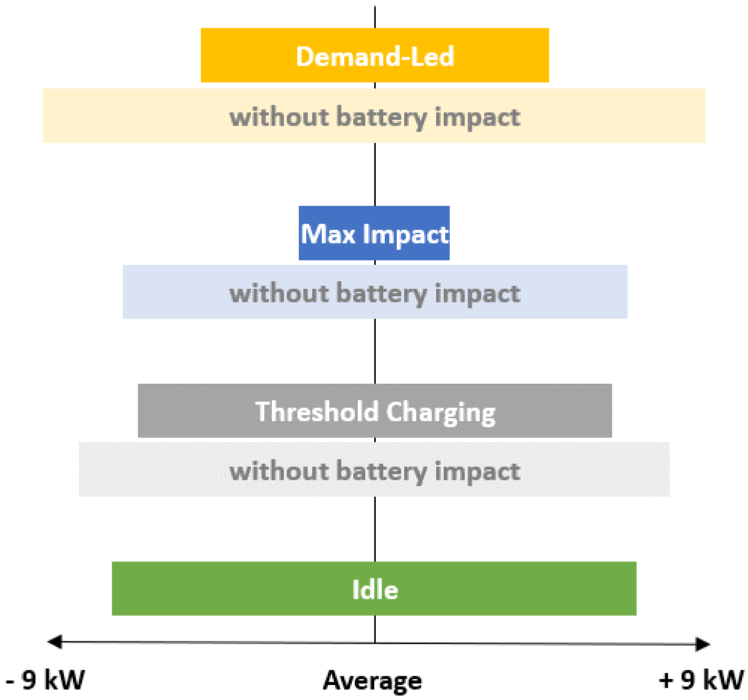


Figure 23: Standard deviation of the substation demand for all schemes operated in the winter.

3.3 Summer Analysis

The same charging schemes were trialled in the summers of 2017 and 2018, but then with a focus on reducing the generation exported to the network. In the summer of 2018, we have also tested a more dynamic predicted generation scheme which provides similar support to the network, whilst reducing the impact on the customer.

3.3.1 Threshold Charging

For the Threshold Charging scheme, reducing the threshold level proved to be even more important in the summer than in the winter period, as can be seen in Figure 24. At the time of peak generation, average battery charging rates of 225 W were achieved in the summer of 2018, as compared to 106 W in the summer of 2017.

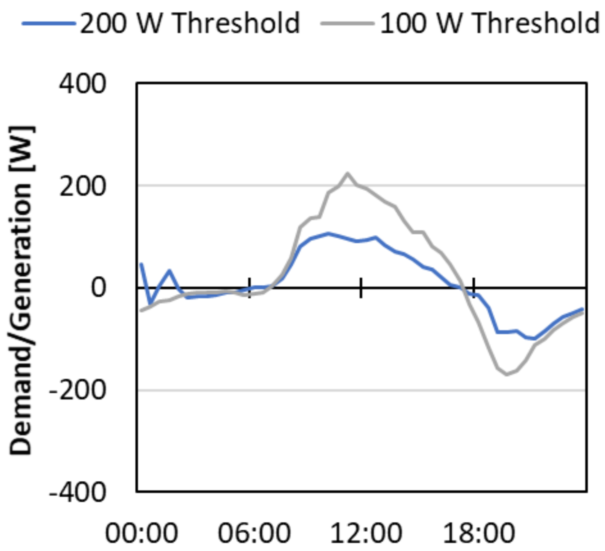


Figure 24: Threshold Charging **– Scheme operated in the summer with the original threshold of 200 W (blue) and the new lower threshold of 100 W (grey) which is better suited to the demand of the DS3 households.**

Figure 25 shows that even with the lower threshold, the batteries were not able to fully discharge whilst being operated according to the Threshold Charging scheme – in this case particularly because of the longer period of PV generation. As a result, not all batteries were able to charge over the entire afternoon, resulting in a generation peak reduction of 23%, and an average reduction during the generation period of 25%. This compares to a peak reduction of 12% (11% average reduction) when a 200 W threshold was used.

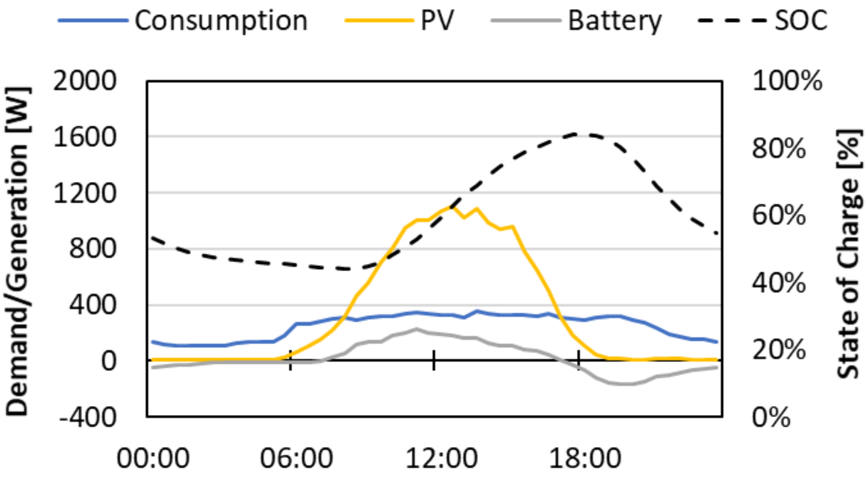


Figure 25: Threshold Charging – Data of all single battery PV households during the summer of 2018 when the threshold level was set to 100 W.

From a customer's perspective, this result indicates that households with such low levels of consumption, are unable to strongly increase their levels of self-consumption of PV generation by installing a battery and, therefore, might not benefit much from installing BESS. However, as discussed in Section 3.3.5 there may be a case for DNOs (or future DSOs) to incentivise customers to discharge their batteries overnight, as a significant impact on the network can be achieved if batteries have available capacity.

3.3.2 Maximum Impact

Trialling the Maximum Impact scheme in the summer allowed for the batteries to charge at nearly their maximum rate and to keep charging during most of the afternoon. The batteries quickly reduced to a low SoC in the evening by discharging at 420 W for a few hours which allowed them to absorb excess generation and assist the network on the next day. The resulting reduction achieved as a percentage was limited (22% on average and at peak) but it should be noted that this is caused by the particularly strong PV generation in this trial period – which is the main reason why in Figure 31 average consumption and generation profiles are used.

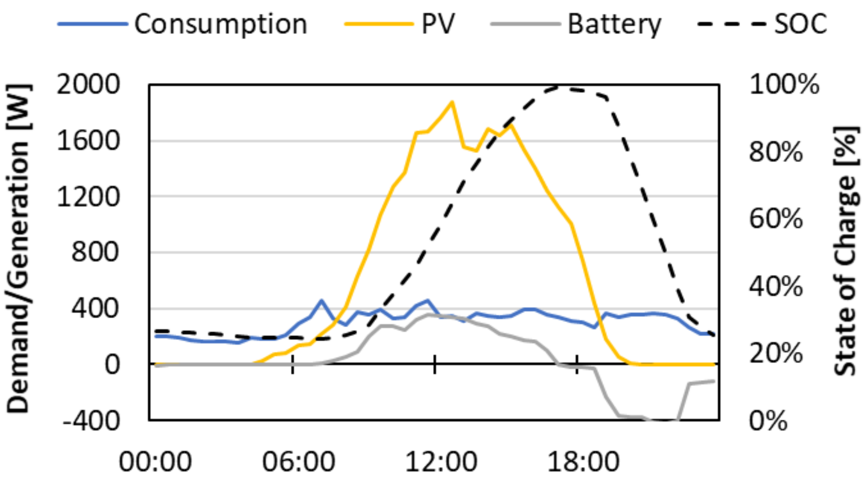


Figure 26: Maximum Impact – Data of all single battery households during the summer of 2018.

As discussed in Section 2.1.1, batteries with capacities of 2 and 3 kWh have been installed in the DS3 households. The aggregated battery monitoring data over the Maximum Impact (Summer) scheme has shown that the maximum (dis)charging rate is approximately the same for both battery types but, as expected, due to their larger capacity the 3 kWh batteries were able to (dis)charge over a somewhat longer period.

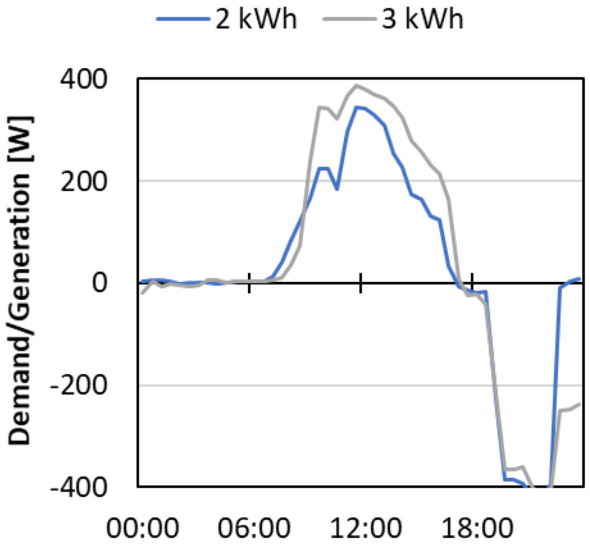


Figure 27: Maximum Impact – Scheme operated in the summer of 2018 aggregated over the single battery households that have a 2 kWh battery installed versus the households that have a 3 kWh battery installed.

3.3.3 Demand-Led

In the summer period, the effectivity of the Demand-Led scheme proved to be limited, particularly because of the long PV generation period and the low levels of demand – as was the case for the Threshold Charging scheme. Initially, the batteries assisted the network by absorbing PV generation, but early in the afternoon maximum capacities were reached and the average charging rate decreased significantly. The batteries managed to reduce excess PV by 24% (on average and at peak).

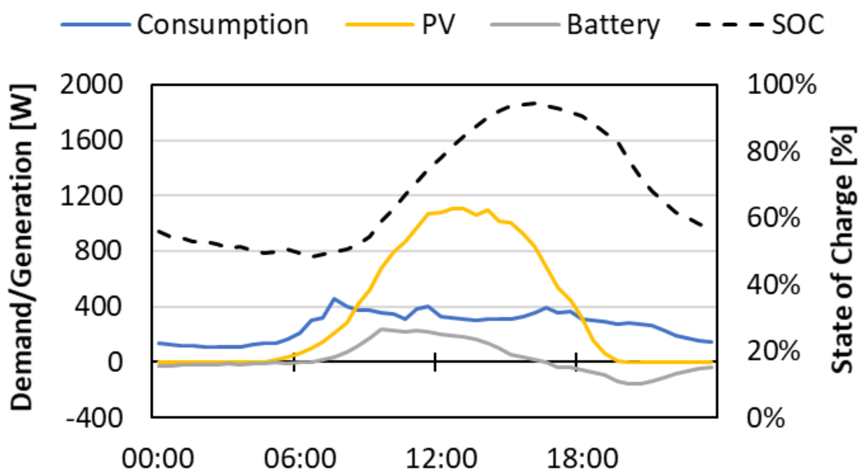


Figure 28: Demand-Led – Data of all single battery PV households during the summer of 2018.

When the batteries were operated according to the Demand-Led scheme in the summer period, a difference between the charging behaviour in households with and without PV was observed, as is shown in Figure 29. Apart from the Threshold Charging scheme (where the difference in effectivity for PV and non-PV households is obvious), this was the first time this difference was significant. The relatively long period of PV generation on a summer day meant excess demand during the evening peak was limited, resulting in a low battery discharge rate and a high state of charge ahead of the subsequent period of PV generation.

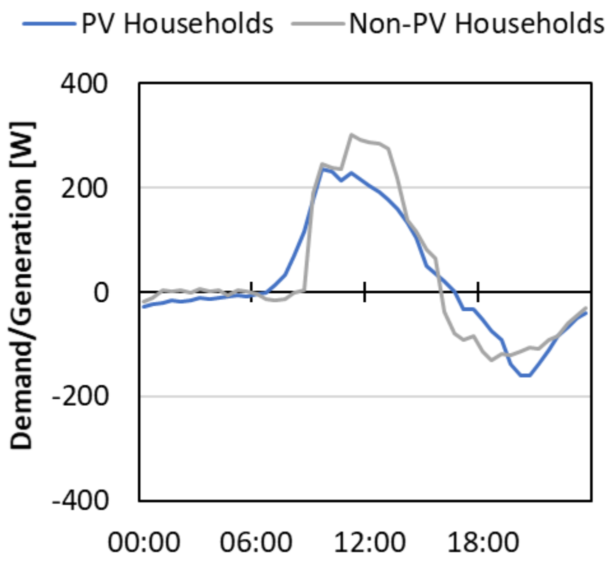


Figure 29: Demand-Led **– Scheme operated in the summer aggregated over the single battery PV households and the non-PV households (all single battery).**

Interestingly, even though in this scheme the battery charging rate in the evening was limited, the somewhat longer discharging period in households that had two batteries installed allowed both batteries to have a large impact on the network at the start of the generation period. The steep decrease in charging rate from 12:00 onwards shows that many batteries started reaching 100% SoC, but still a significant reduction at the peak time (71%) was achieved without forcing the batteries to charge.

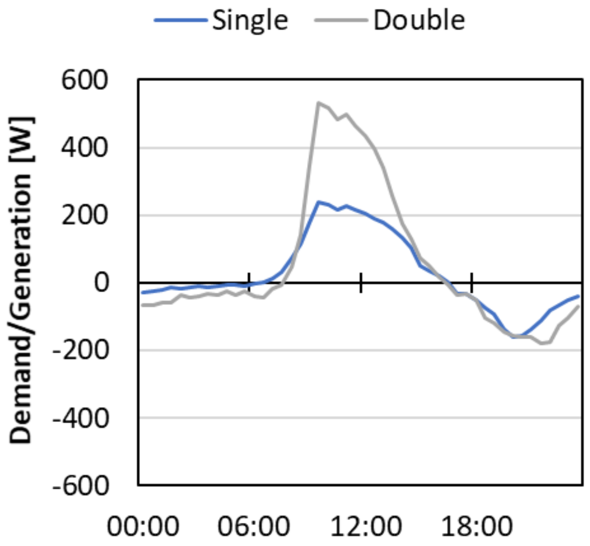


Figure 30: Demand-Led – Scheme operated in the summer aggregated over the PV households that have one battery installed versus the PV households that have two batteries installed.

3.3.4 Battery Impact

In this section we assess the impact the batteries can have at household level when using the average consumption and PV profiles (similarly to the analysis presented in Section 3.2.4, but for July in this case). Where on average the excess generation at peak time was about 900 W, the schemes managed to reduce this significantly to levels of 550-700 W.

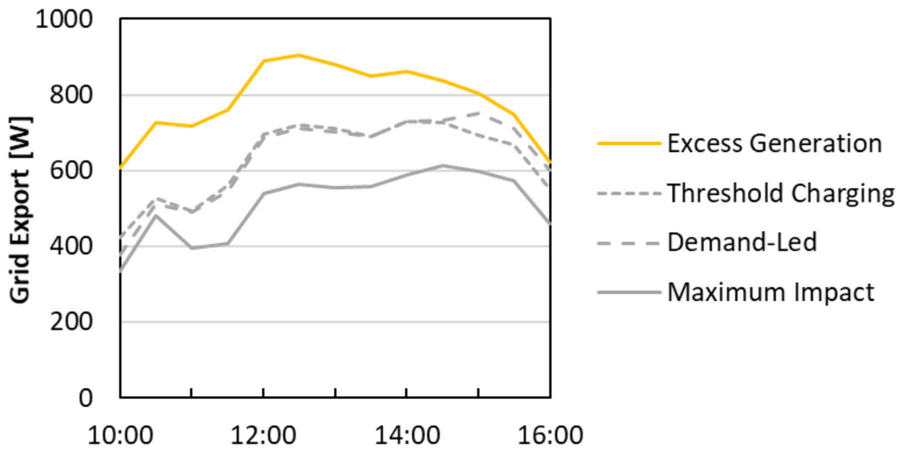


Figure 31: The remaining grid export before (yellow) and after (grey) accounting for the impact of the BESS.

Displayed as a percentage (Figure 32), at peak time reductions of about 50% were achieved by the Maximum Impact scheme (70% when two batteries were installed). Interestingly, the schemes for which the batteries discharged based on excess demand (Threshold Charging and Demand-Led) both suffered from reaching full capacities too soon when charging during the subsequent charging period, which is reflected by the strong downward trend for these schemes in Figure 32. When operating according to these two schemes it could be beneficial (for the network operator) to only allow the batteries to start charging from 12:00 onwards.

As a similar trend can be seen (albeit to a lesser extent) for the Maximum Impact scheme, we have also included the reduction achieved in the late afternoon (16:00) for the households that had a 3 kWh battery installed. It can be seen that because of their larger capacity, these batteries were able to assist the network for a longer period of time.

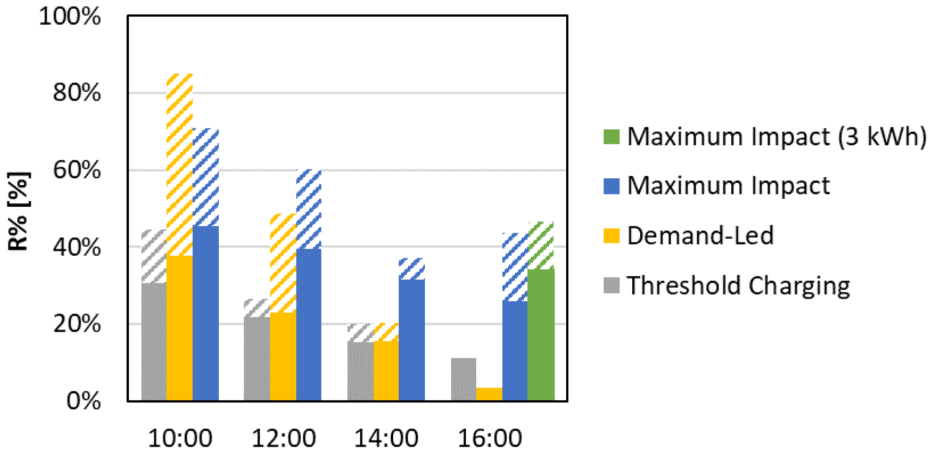


Figure 32: The percentage reduction of excess generation (averaged over half an hour) that can be achieved by operating the batteries according to the different schemes. The dashed area indicates the further reduction that is achievable by having a second battery installed. The reduction for the Threshold Charging scheme is only valid for the PV households. The impact achieved by 3 kWh batteries operated according to the Maximum Impact scheme is shown in green.

As before, the impact of having a household with a higher demand is shown in Figure 95 in Appendix B.

3.3.5 Network Impact

At substation level, the batteries have had a large impact during the summer period. Figure 33 shows that at the time of peak generation (12:00), the batteries managed to halve the reverse power flow of Feeder 2 from nearly 20 kW to 10 kW. Equally, the dashed blue line suggests that by discharging in the evening (to assist the network in the afternoon on the next day), the batteries actually managed to significantly reduce the evening peak demand as well. As a high evening peak demand was not observed in the DS3 households, this therefore implies that the batteries installed in the DS3 households assisted in reducing a potential high demand issue caused by the 16 other households connected to the feeder.

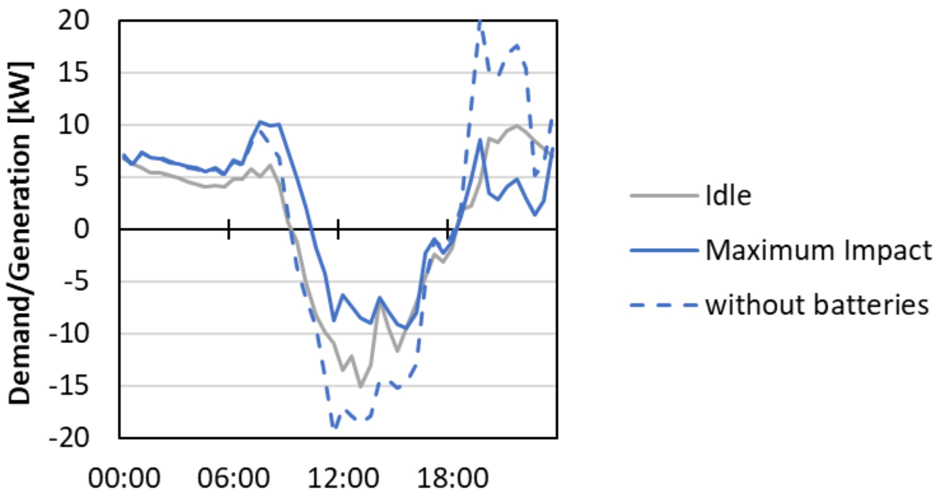


Figure 33: Feeder 2 – The total feeder demand for the Maximum Impact scheme as compared to the base case feeder demand *calculated* by subtracting the battery impact (dashed blue line) and *monitored* by operating all batteries in idle mode (grey line).

The impact of the batteries on the network when operated according to the Demand-Led scheme in summer was smaller than for the Maximum Impact scheme because of the limited discharging during the evening peak. Figure 34 shows that at peak time the reverse power flow was still reduced by about 5 kW, but that particularly later in the afternoon the batteries were not capable of assisting the network. To improve this scheme a shorter time period for forced charging could be selected (e.g. 11:00 – 16:00) as the figure also shows that the batteries were already forced to charge before there was significant excess generation, and were therefore ineffectively using their available capacity (i.e. from a DNOs perspective).

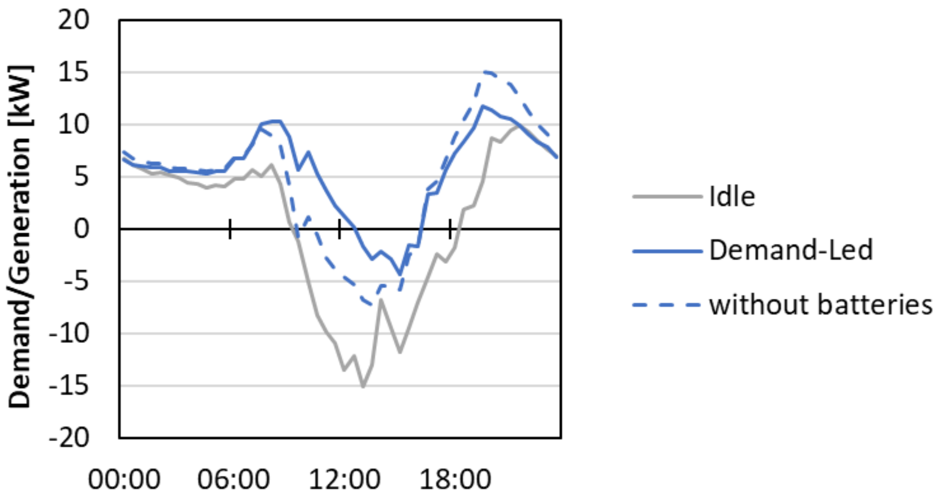


Figure 34: Feeder 2 – The total feeder demand for the Demand-Led scheme as compared to the base case feeder demand *calculated* by subtracting the battery impact (dashed blue line) and *monitored* by operating all batteries in idle mode (grey line).

For the same reasons as in winter, the impact of the batteries when operated according to the Threshold Charging scheme was limited (Figure 35). Only batteries in PV households were able to operate successfully, and even these batteries did not discharge enough to be able to significantly assist the network in the afternoon the following day.

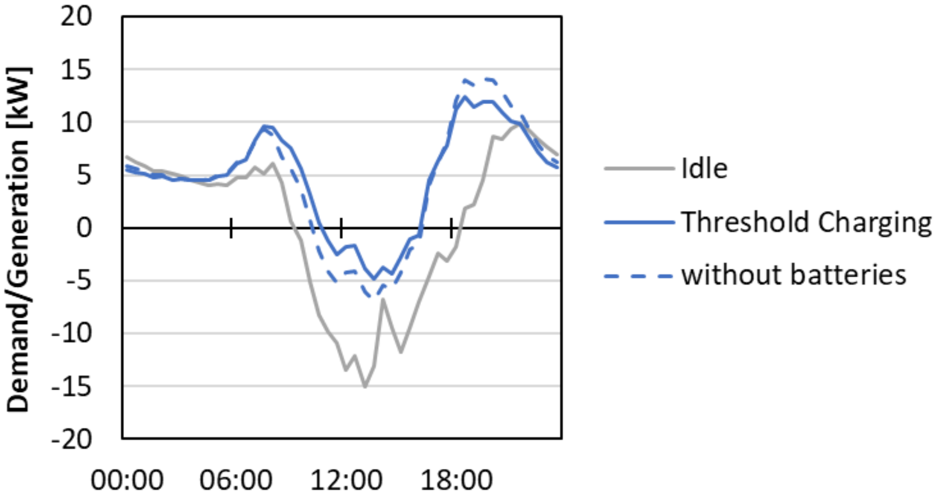


Figure 35: Feeder 2 – The total feeder demand for the Threshold Charging scheme as compared to the base case feeder demand *calculated* by subtracting the battery impact (dashed blue line) and *monitored* by operating all batteries in idle mode (grey line).

We can conclude that in order to achieve large impacts on the network with batteries installed in households like the ones in this trial the DNO will have to incentivise the customer, as a customer focused scheme like Threshold Charging (Figure 35) will not give reductions as large as a DNO focused scheme like Maximum Impact (Figure 33). However, the fact that the reverse power flow in Figure 34 and Figure 35 would have been limited even if the batteries were inactive, also shows that the DNO would not have to incentivise the customer at all times, essentially benefiting for free.

This also can be concluded from Figure 36, in which the standard deviation of the feeder demand is displayed for Feeder 2. It clearly shows that the Maximum Impact scheme managed to cause the biggest change in the variability of demand, but it also reveals that for the other schemes the initial spread in data was limited, and hence network assistance was not necessarily required.

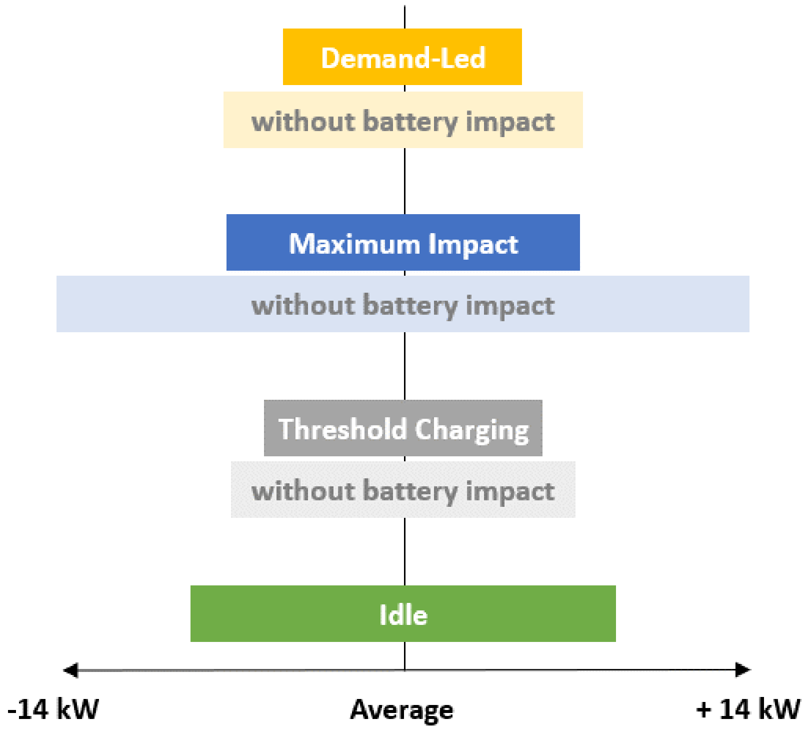


Figure 36: Standard deviation of the substation demand for all schemes operated in the summer. The fact that the standard deviation without batteries significantly differs across the schemes should be accounted for when determining the impact of a scheme.

All these results indicate that only when large amounts of excess PV (or excess demand during the winter evening peak) are expected the DNO would require the batteries to assist the network. To accommodate for this, an advanced charging scheme was designed – the Predicted Generation scheme – which only forced batteries to assist the network at times when the network operator expects to need it. A cost-benefit analysis comparing conventional and alternative reinforcements is discussed in Chapter 5.

3.3.6 Predicted Generation

This scheme used weather forecasts to determine the expected cloudiness in the area a day ahead and set the BESS (dis)charging scheme accordingly. In this scheme, all units were forced to discharge overnight, and set in threshold mode throughout the day. This meant that batteries in PV homes would charge based on excess generation and batteries in non-PV homes would be inactive (hence incur no additional costs to the owner nor cause any degradation). On sunny or partly cloudy days, the batteries in non-PV homes were forced to charge at their maximum rate to help the network when the impact of PVs was expected to be the largest. The PV generation in Figure 37 shows that the scheme was able to make correct predictions, and Figure 38 shows that the batteries in non-PV households were engaged on sunny days to reduce the amount of excess generation.

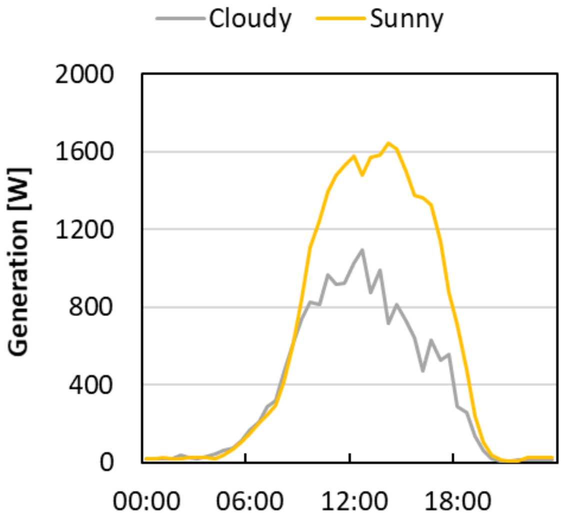


Figure 37: Predicted Generation – PV profiles of single battery households aggregated over cloudy and sunny days.

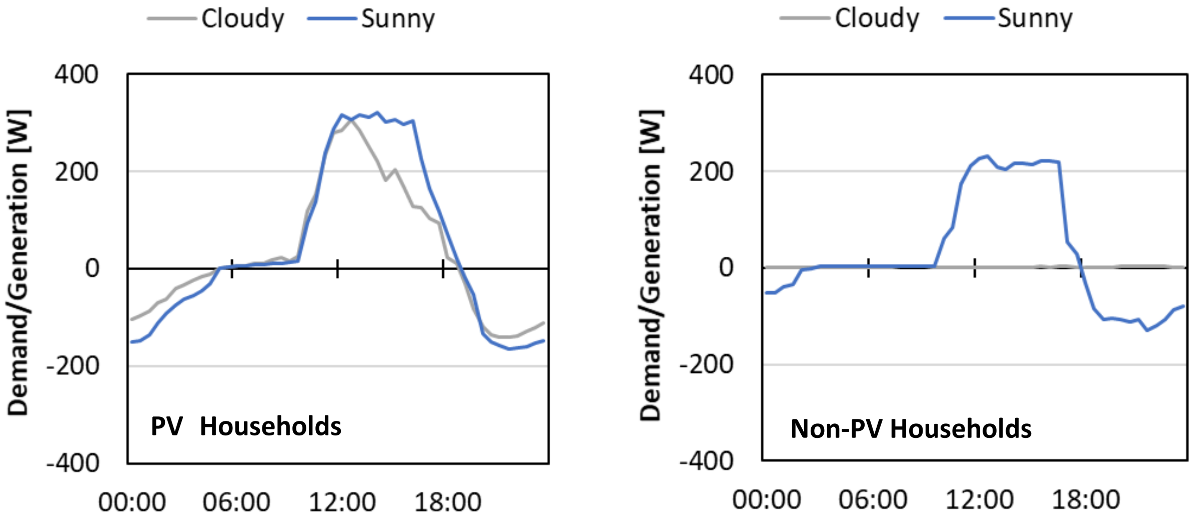


Figure 38: Predicted Generation – Battery charging profiles of single battery households with PV (left) and without PV (right) aggregated over sunny and cloudy days.

In addition to this, the 1-hour granularity of the cloudiness prediction throughout the day enabled batteries to be set to charge for only part of the day. Although this only seemed applicable to a few days within the period during which this scheme was trialled, analysis suggests that such a targeted scheme is equally useful and could be beneficial when considering aspects such as BESS degradation and owner reimbursement costs. Where predictions indicated that it would only be sunny in the afternoon, the batteries forced to charge then were able to achieve a similar impact on the network by charging only in the afternoon as opposed to charging over the entire period (10:00-16:00), as is shown in Figure 39.

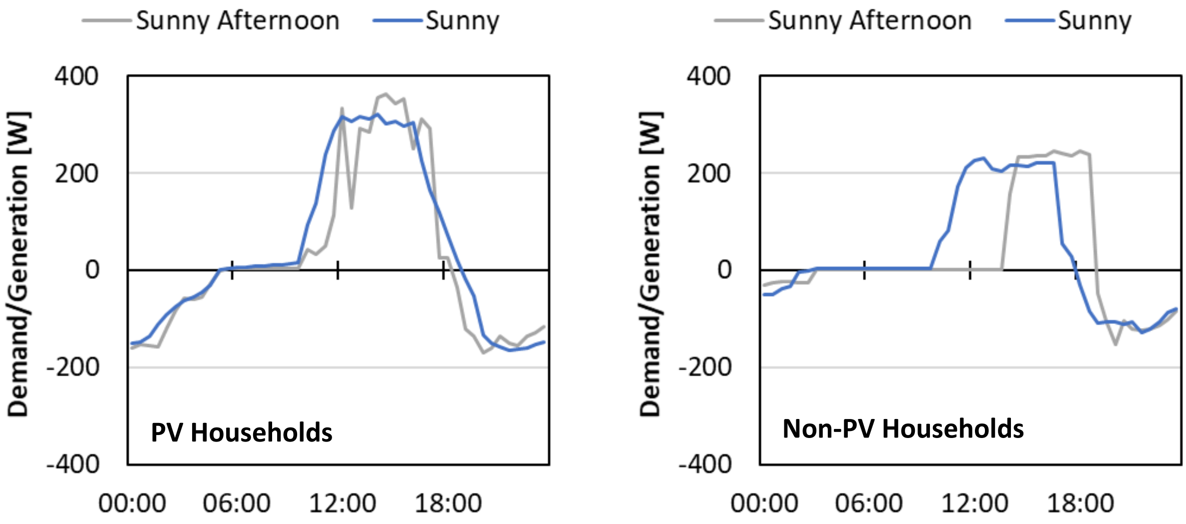


Figure 39: Predicted Generation – Battery charging profiles of single battery households with PV (left) and without PV (right) aggregated over sunny days and days for which only the afternoon was predicted to be sunny.

Analysis of the substation level data recorded during the Predicted Charging (Afternoon) scheme (Figure 40) clearly shows that compared to a typical summer day (grey line), the peak generation only occurred late in the afternoon, and that the batteries were able to successfully reduce the reverse power flow as can be seen by respectively the dashed and the solid blue lines. This result highlights two important findings; firstly that it was possible to predict on which day (and even at which time of the day) the batteries in the non-PV households were required to assist – and to manage their charging accordingly, and secondly that the Threshold Charging scheme for the PV households can be very successful, as long as the batteries discharge overnight – either based on their own excess demand, or by incentivising their discharge.

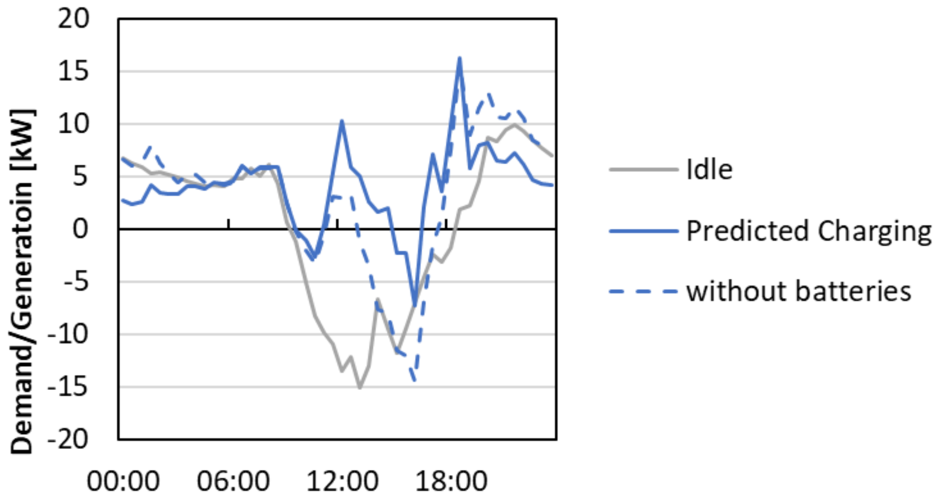


Figure 40: Feeder 2 – The total feeder demand – comparing the Predicted Charging (Afternoon) scheme with the base case feeder demand. The dashed line indicates what the network demand would have been without the battery impact.

3.4 Battery Degradation Tests

Near the end of the trial we have attempted to estimate the degradation that the battery modules have sustained during more than 2 years of operation. To minimise the impact on the tenants and general impact on the project, the tests were run in situ rather than in the lab, which means that the batteries could only be discharged to 23V (minimum operational voltage) instead of 15V (true minimum voltage). In order to compensate for this, tests were performed in lab conditions to determine how much energy could be squeezed out of a battery between the minimum operational voltage and the true minimum voltage.

During the assessment 20 40 Ah battery modules (part of 2 kWh units) and 20 60 Ah battery modules (part of 3 kWh units) were repeatedly (3 times) charged and discharged up to maximum capacity. We then measured the current of discharge from the battery (A) over time (h) to calculate the capacity in Ah and corrected for the fact that the batteries could not be discharged to the true minimum voltage. After 2 years, the average remaining capacity was estimated to be about 95% for 2kWh units, and 92% for 3 kWh units, as is shown in Figure 41.

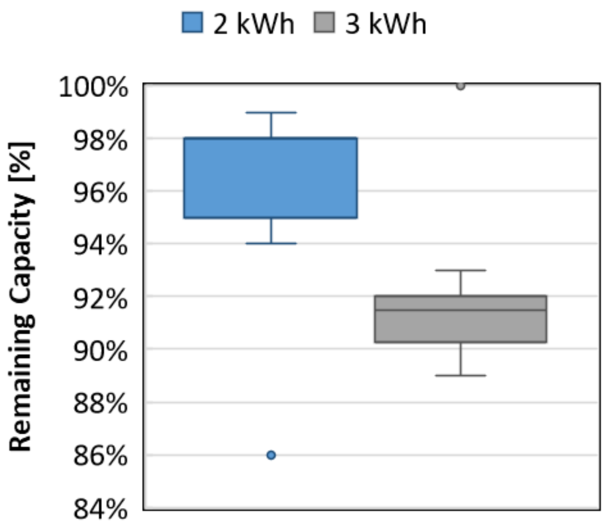


Figure 41: Overview of the degradation of the batteries trialled in the DS3 project after over two years of operation.

4 Network Model

In addition to analysing the impact of BESS on the network based on the recorded household and network data, the LV network was also modelled by TNEI using Ipsa software. This enabled us to explore scenarios which could otherwise not be studied within this trial and assisted in evaluating the network impact from a range of different PV and battery penetration combinations.

4.1 Model Design

The selected LV network was modelled as an unbalanced network model in Ipsa. The network data for cables and transformers was provided by Northern Powergrid and both monitored and synthesised customer generation/demand data was used to populate the model (data from 26/01/2018 and 21/06/2018 has been used because data quality was optimal for these days). Three different load elements were connected at relevant nodes to represent separate demand, generation and battery profiles of customers (where applicable). A node is an Ipsa representation of any busbar where a customer, lines or a transformer are joined.

The direction of power flow across the customer meter was represented as follows:

- Positive numbers indicate consumption of power by the customer and import from the Northern Powergrid network; e.g. demand (consumption) profiles.
- Negative numbers indicate production of power by the customer and export to the Northern Powergrid network; e.g. PV generation profiles.

The number of PV units and batteries across the test network are as follows:

PV:

Way 1: 1 (Phase B=1)

Way 3: 11 (Phase A=5, Phase B=2, Phase C=4)

Way 4: 15 (Phase A=5, Phase B=6, Phase C=4)

Batteries:

Way 1: 1 (Phase B=1)

Way 3: 18 (Phase A=8, Phase B=3, Phase C=7)

Way 4: 21 (Phase A=9, Phase B=7, Phase C=5)

Note that the names of these feeders are based on the names as provided by the NorTech iHost interface, and correspond to Feeder 4 (Way 1), Feeder 1 (Way 3) and Feeder 2 (Way 4) as shown in Figure 4.

The battery profiles had a mix of both positive and negative power flows depending on the state of charging and discharging. These profiles were compiled based on measurement data taken at each of the customer points of supply (with PV and/or battery units). For those customer units without data measurement (not part of the trial), the consumption profiles were estimated using the data gathered at the LV substation[4].

These profiles were fed to the Ipsa load elements at the required time steps (e.g. every 5 minutes for 24 hours) using a python script. Once profiles were assigned for each of the customer units, the load flow simulation was carried out at the required points in time. The load flow activity in Ipsa provided results for voltage profiles and power flows (active and reactive power). With the model we have been able to run a wide range of studies to help us understand the impact of the battery and PV systems on the power flows and voltages at substation level as well as along the feeders and mains.

4.2 Ipsa 2

Ipsa 2 is the power system analysis software program that was used to undertake the modelling and studies. Ipsa was developed by TNEI and remains part of the TNEI group. The software provides flexibility for modelling networks for load flow, short circuit analysis, and various other studies. It also interfaces well with python scripting which facilitates quick calculation and allows the use of different load profiles for time-series output results. Another important characteristic of Ipsa is the capability to model unbalanced networks which allows the modelling of the electrical networks down to single houses. This functionality can assess the effect of generation and loading per phase which can then be correlated with the aggregate results at substation level.

4.3 Model Validation

Using the profiles constructed with the Moixa data, a scripted model was used to produce the power flows across the LV network which was then validated at substation level based on the data available through the NorTech iHost interface, as described in Section 2.1.2.

Measurement data recorded on 05/11/2017 was used for validation. Figure 42 shows the active power measurement for phase A in Way 3, along with Ipsa load flow results. It can be seen that the measurement results closely match the Ipsa load flow results.

[4] The aggregated power measurement from the measurement-available customer units was subtracted from the power flow measurement at each of the LV feeders. The average of the difference was assigned for the consumption profiles of the customer units without power measurement (along the respective feeders).

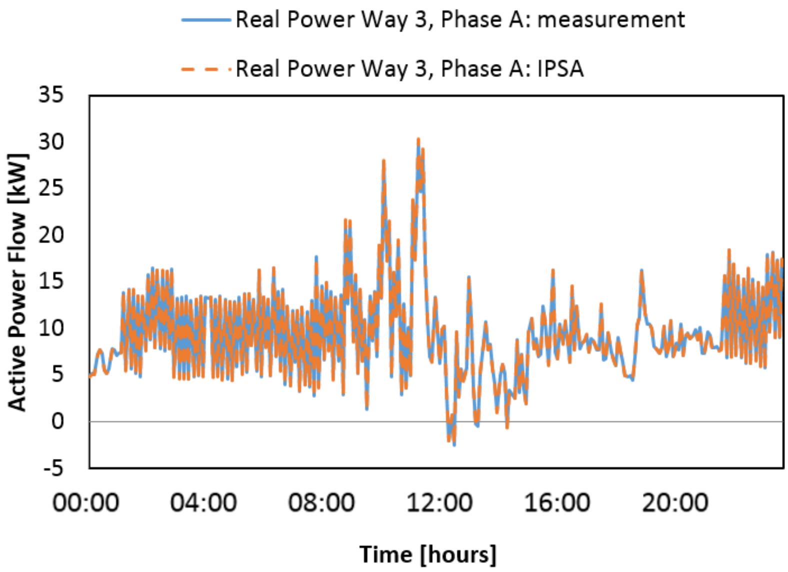


Figure 42: The variation of active power flow with time at feeder Way 3.

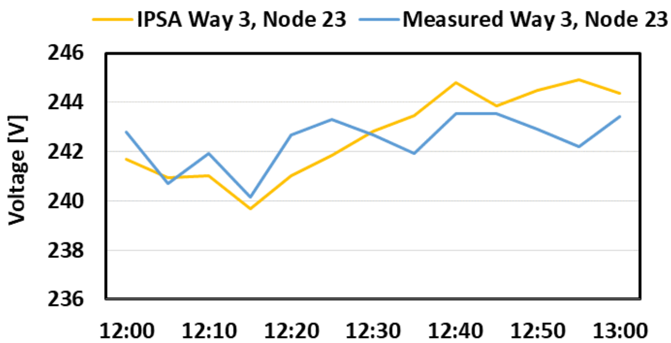


Figure 43: The variation of voltage at Node 23 in Way 3.

Figure 43 shows the measured voltage at Node 23 in Way 3 along with Ipsa network simulated results, for the time period from 12:00 hours to 13:00 hours. Node 23 is a node where it was found that the voltage fluctuations were considerable compared to the rest of the network.

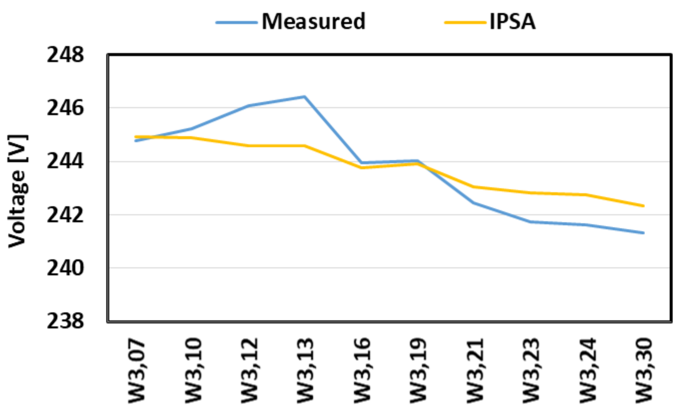


Figure 44: Voltage profile of measured voltages and Ipsa results at nodes on Way 3 at 12:00.

Figure 44 shows the measured voltages at measurement-available nodes along with Ipsa network simulated results in Way 3 at 12:00. It can be seen that the Ipsa network model shows a close trend with the measurement data. The small discrepancy in the voltage profiles can be attributed to the following factors:

- Lack of measurement data along the feeder, i.e. power measurements were not carried out for all the households in the study area.
- Reactive power measurement at individual households was not given.
- Resistance was reduced for those feeders which have an R:X ratio greater than 9 to aid convergence of the power flow in Ipsa.

The results shown have an absolute error of less than 3% which indicates that the model is suitable for the purpose of this project.

Based on improved measurement data from the Moixa batteries at a later stage of the project, the IPSA model was recalibrated to improve the accuracy of the results. Data was used for 26-01-2018 (typical winter day) and 21-06-2018 (typical summer day) and was selected based on the quality of the data and the connectivity of the batteries. Figure 45 and Figure 46 present the absolute error in % between the measured voltage at the substation and the simulated voltage in IPSA over the course of a summer and a winter day. The error remains well below 2% in the three phases during the summer, as seen in Figure 45. During winter, the error tends to be slightly higher (> 2%), as shows in Figure 46.

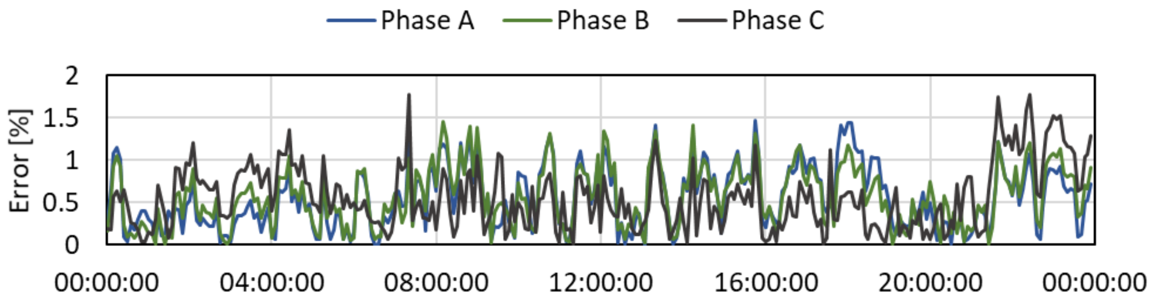


Figure 45: Percentage error between measured voltage at the substation and IPSA simulation on 21st June.

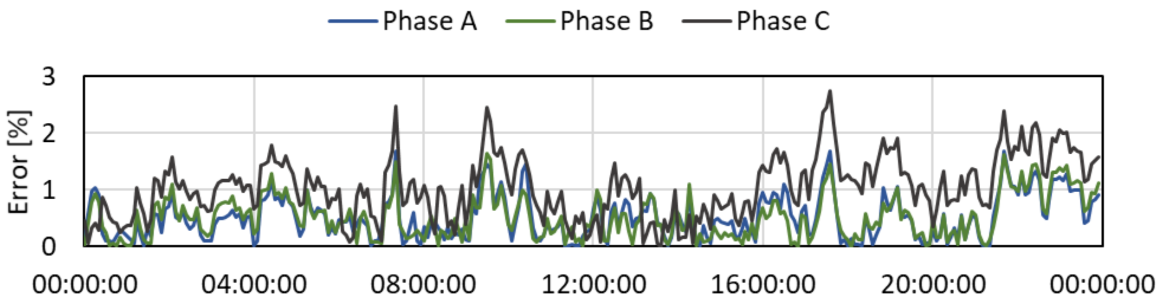


Figure 46: Percentage error between measured voltage at the substation and IPSA simulation on 26th January.

4.4 Scenario Modelling

Once validated, the Ipsa model was used to analyse a range of selected scenarios of interest that were not accessible based on the household measurements in the trial alone. The scenarios are separated in summer and winter scenarios, each with their corresponding profiles for demand and generation. For both times of year, each scenario has a different level of battery penetration (i.e. none, actual penetration, and 100% penetration).

Within each scenario, a number of case studies were used to vary the load classification, level of PV penetration, and the size of the batteries. The case studies are compared against one another which is discussed in Section 4.5 and 4.6.

4.4.1 Larger battery capacities and varying levels of battery penetration

Batteries with different capacities, as shown in Figure 47, have been simulated, which allows us to quantify the impact of battery size on the metrics. The network model was used to extend the learnings of the measured data, by adapting the battery profiles so that they represent larger battery capacities or higher levels of penetration.

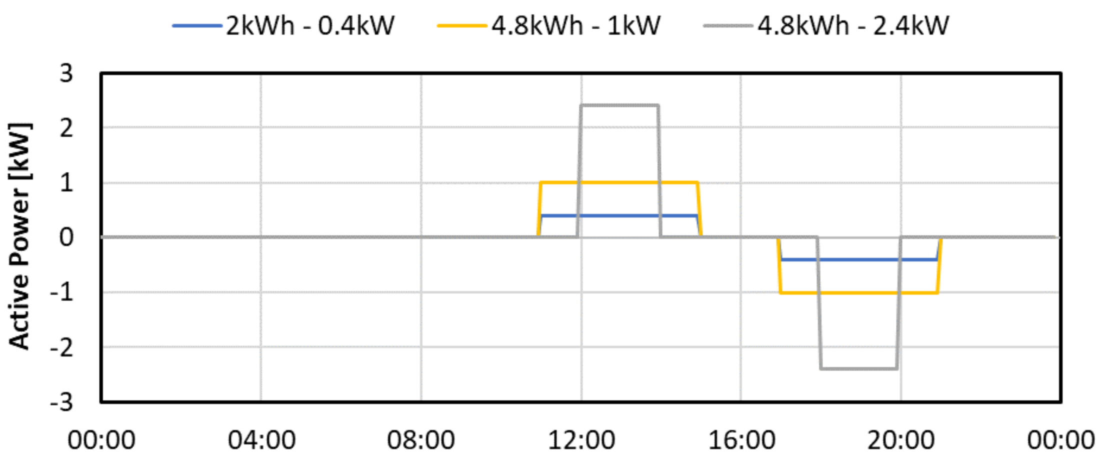


Figure 47: Three different battery types used in the case studies.

To represent the different levels of battery penetration, in Scenario 2 the actual penetration is used, which means the 40 batteries are allocated to the 36 households as in the trial, and no batteries are allocated to the other households. In Scenario 3 we assume that all 119 households that are connected to the substation have a battery installed.

To avoid the impact of the trialled charging schemes on the battery profiles, for all scenarios the battery charging rates as in Figure 47 are used, based on the size of the batteries as indicated for each case study.

4.4.2 Higher levels of PV penetration and PV clustering

The trial data allows us to study the impact of PV but the Ipsa model strongly enhances our capability to investigate this impact since it allows us to analyse any PV penetration level. However, due to the limited time and budget of the project only three PV penetration levels have been selected for the analysis, i.e. 0%, Actual penetration and 100% penetration.

For the Actual PV penetration level, PV is allocated to the 27 households in the trial that had PV installed, whilst no PV is installed to all other households. When we assume a PV penetration level of 100%, it means all 119 households are given PV.

In the case of PV generation, for the 27 households with PV that were part of the trial their actual monitored PV generation has been used. When assigning PV to the remaining households, a typical PV generation profile (as shown in Figure 48) was taken from the monitored dataset (i.e. the PV profile on 21-06-2018 from one property was selected based on data quality and representativeness), which was then used for all these households.

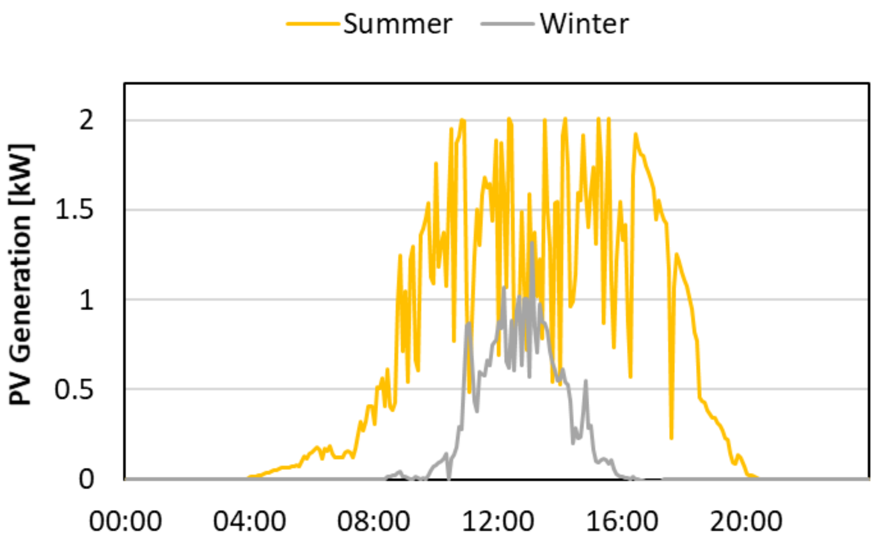


Figure 48: Typical PV generation profiles for the summer and winter. These profiles are used for all households that were not participating in the trial and for the households in the trail that did not have PV installed.

4.5 Summer Minimum Scenarios

The Summer Minimum scenarios modelled are described in the table below. For each of the three high-level scenarios, defined by the level of battery penetration (No batteries, Actual battery penetration and 100% battery penetration), a number of cases are defined, where the individual cases differ in terms of the assumed demand pattern ('Actual' versus 'Careers and Kids') and the battery size (the Summer Minimum loading level is assumed in all cases).

Scenarios for Summer Minimum

	Scenario 1	Scenario 2	Scenario 3
	No Battery Penetration	**Actual Battery Penetration**	**100% Battery Penetration**
Loading level **Demand** **Battery size**	Case 1: 0% PV Penetration Summer Minimum Actual -	Not modelled because no network problems expected with 0% PV penetration	
Loading level **Demand** **Battery size**	Case 2: 0% PV Penetration Summer Minimum Careers and Kids -		
Loading level **Demand** **Battery size**	Case 3: Actual PV Penetration Summer Minimum Actual -	Case 1: Actual PV Penetration Summer Minimum Actual 2kWh / 0.4 kW	Case 1: Actual PV Penetration Summer Minimum Actual 2kWh / 0.4 kW
Loading level **Demand** **Battery size**	Case 3b: Actual PV Penetration Summer Minimum Careers and Kids -	No larger battery modelled because scenario is expected to be similar to the 100% battery penetration scenario.	Case 2: Actual PV Penetration Summer Minimum Actual 4.8 kWh / 1 kW
Loading level **Demand** **Battery size**	Case 4: 100% PV Penetration Summer Minimum Actual -	Case 2: 100% PV Penetration Summer Minimum Actual 2kWh / 0.4 kW	Case 3: 100% PV Penetration Summer Minimum Actual 2kWh / 0.4 kW
Loading level **Demand** **Battery size**	Case 5: 100% PV Penetration Summer Minimum Careers and Kids -	No larger battery modelled because scenario is expected to be similar to the 100% battery penetration scenario.	Case 4: 100% PV Penetration Summer Minimum Actual 4.8 kWh / 1 kW
Loading level **Demand** **Battery size**	Not modelled because we are mostly interested in changes in demand levels for the scenario with 100% PV and 100% battery penetration.		Case 3b: 100% PV Penetration Summer Minimum Careers and Kids 2kWh / 0.4 kW
Loading level **Demand** **Battery size**			Case 4b: 100% PV Penetration Summer Minimum Careers and Kids 4.8 kWh / 1 kW

4.5.1 Results for Scenario 1 with Summer minimum loads

Base case: modelling the network without PV or batteries (Scenario 1, Cases 1 and 2)

The measured load data ('Actual') closely resembles the 'Elderly Needs' Mosaic class as shown in Figure 10. The 'Careers and Kids' Mosaic class has a higher demand and a different load profile to the 'Elderly Needs' class. Results for simulations run for both of these classes are shown in Figure 49. The maximum summer demand on the substation is less than 100 kW in both cases for the 119 households connected to the substation, with peak periods around 07:00 and 20:00.

It should be noted here that the 'Careers and Kids' load profile has only been applied to the households which were participating in the trial as no information was available on the tenants of the other households connected to the substation. This explains why some additional load is expected (12 kW at 20:00) when modelling the 'Careers and Kids' households, but why the difference is not as large as one would expect based on the difference seen in Figure 10. To put it in perspective, the impact on the network caused by the change in Mosaic class is comparable to the impact of the batteries based on the actual battery penetration (i.e. 16 kW) but significantly smaller than the impact made by PV based on the actual PV penetration (approximately 40 kW throughout the afternoon). It is particularly when we assume 100% penetration of batteries and PV that the difference caused by the change in Mosaic class becomes less significant.

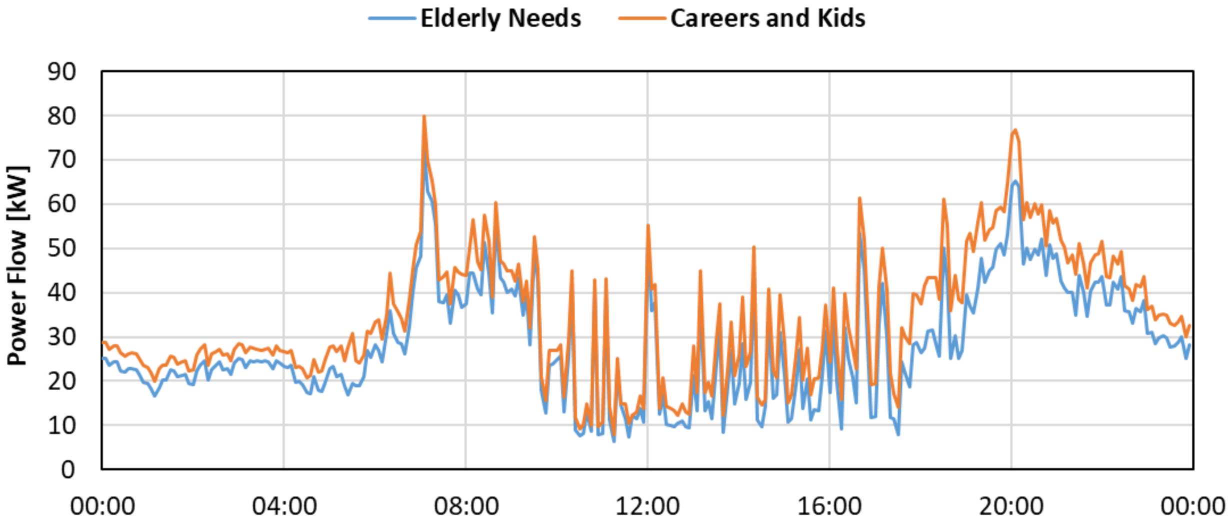


Figure 49: Total demand (3 phase) at the substation.

As is evident from Figure 50 the higher demand of the 'Careers and Kids' customer type also has limited impact on the substation voltage (0.66 V at 20:00), with the maximum difference well below 1% at peak time (around 20:00).

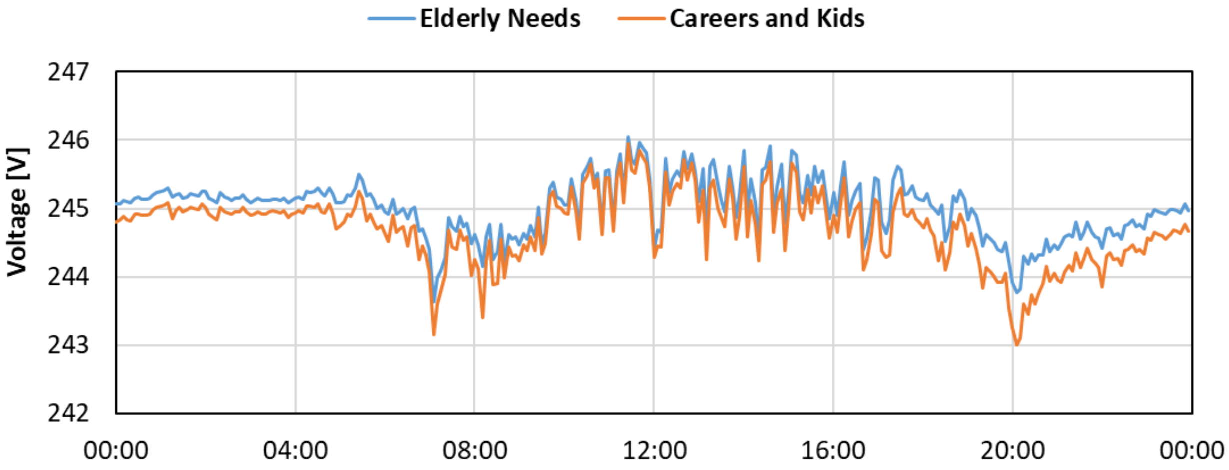


Figure 50: Substation voltage over time (phase A).

Actual installed capacity PV case, with no batteries (Scenario 1, Cases 3 and 3b)

Cases 1 and 2 have no PV generation simulated. Case 3 has PV penetration modelled to accurately reflect the capacity which is installed in the trial (27 households have PV), and actual measurements used as inputs to the simulation. Case 3b has the same generation installed, but with the 'Careers and Kids' load profile used.

With the actual PV penetration (approximately 40 kW throughout the afternoon), the total generation exceeds the demand at the substation between 10:00 and 17:30 causing reverse power flow through the secondary transformer in Case 3 and 3b, as can be seen in Figure 51.

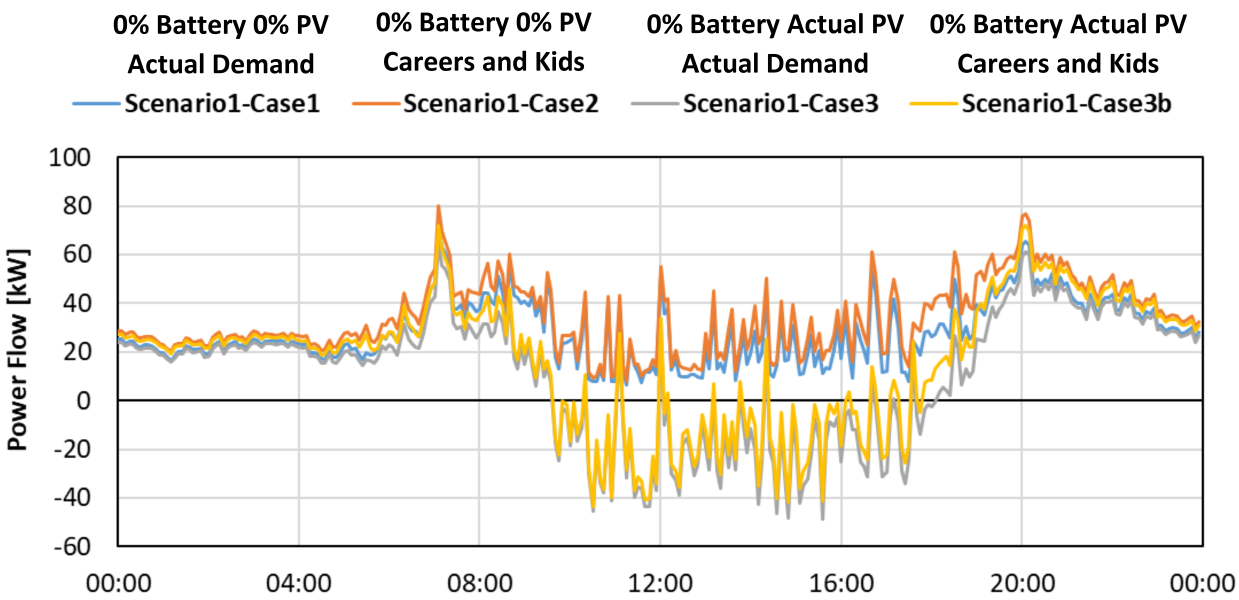


Figure 51: Power flow at the substation.

The high level of generation also has a significant impact on the voltage at the substation (approximately 1.1 V throughout the afternoon), although with the actual penetration level the voltage at the substation is nowhere near the limit (253 V) yet.

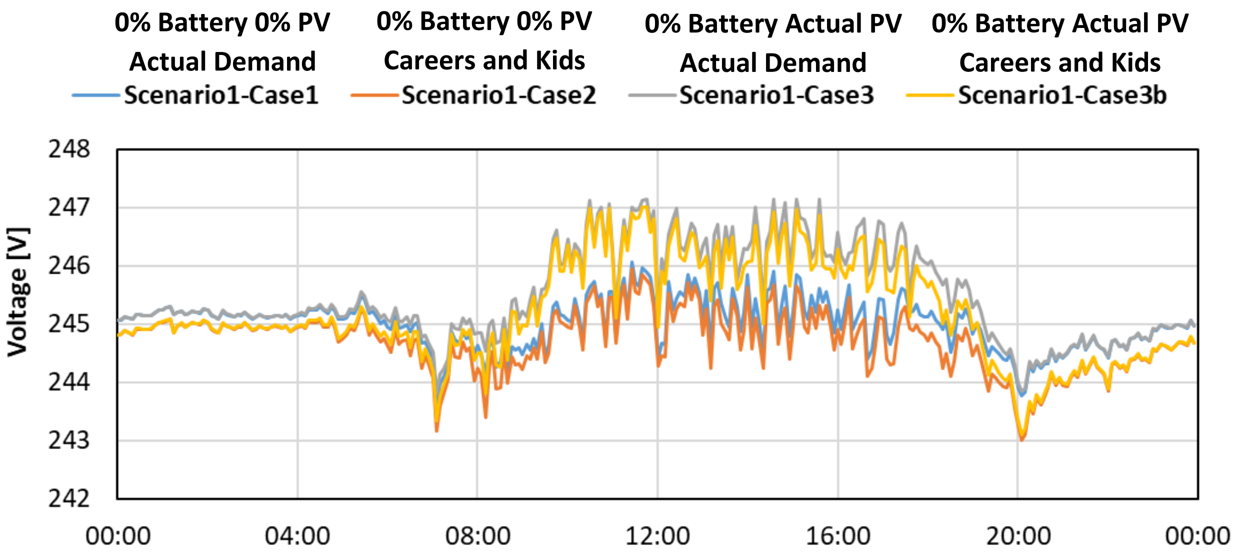


Figure 52: Impact of PV generation on substation voltage.

These results show that having ‘Careers and Kids’ instead of ‘Elderly Needs’ customers on the network reduces the voltage, but the impact is only limited – particularly when compared to the impact of the PV generation. It should again be noted however, that the ‘Careers and Kids’ profile only has been modelled for the households participating in the trial.

100% PV penetration case, with no batteries (Scenario 1, Cases 4 and 5)

In Case 4 and 5, all the households are considered to have installed solar PV generation. Since limited measurements are available (only 36 households), the remaining households are considered to have identical generation profiles: a typical profile (displayed in Figure 48) from the set of measurements is used for this purpose. Case 4 uses the measured load profile, while Case 5 uses the ‘Careers and Kids’ profile.

As expected, with more generation on the network, an even higher reverse power flow is observed at the substation during daylight hours. Consequently, the substation voltage is affected more dramatically (reaching values near 253 V), and the value remains high during the entire period of excess generation.

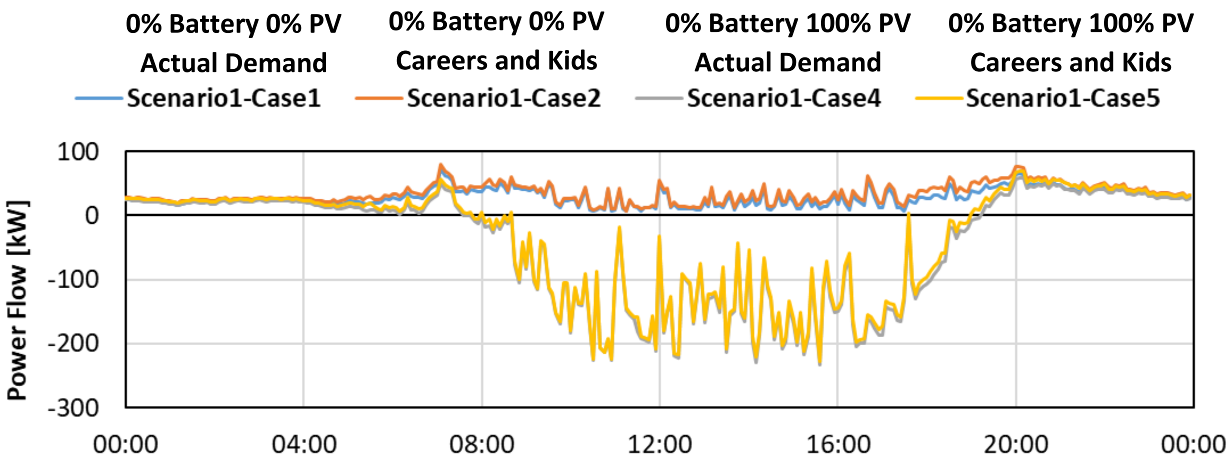


Figure 53: Impact of PV generation on power flow at the substation.

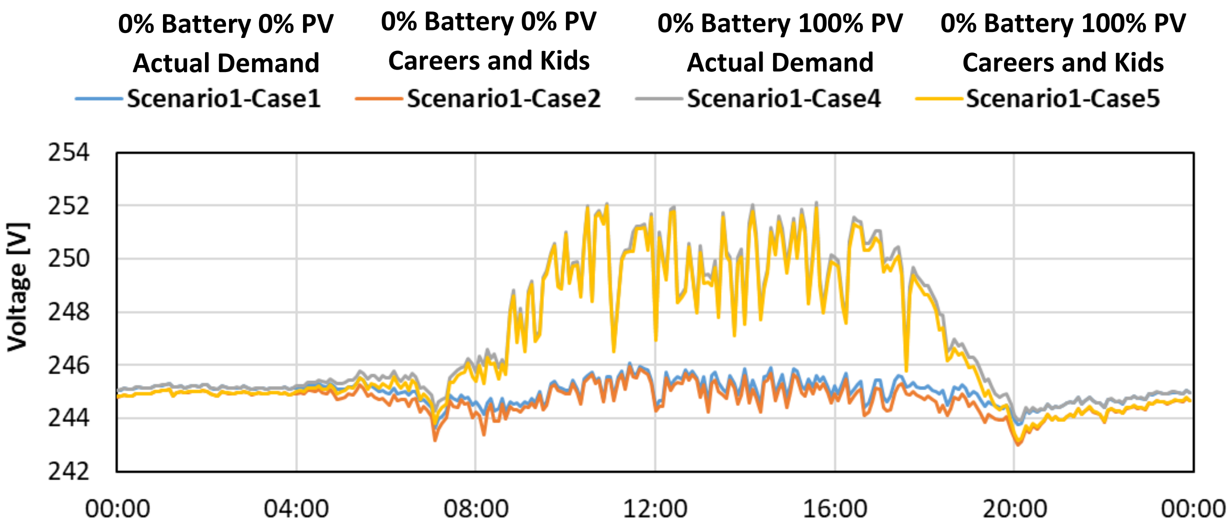


Figure 54: Impact of PV generation on substation voltage.

It should be noted here that even though the voltage at the substation does not exceed the limit, it is likely that the voltage along the feeder will. This will be discussed in more detail in Section 4.7.

4.5.2 Results for Scenario 2 with Summer minimum loads

One of the main objectives of this study is to establish the extent to which residential batteries can be controlled to reduce the peak PV generation. The results above have shown and quantified that increasing levels of PV generation do indeed cause a significant increase in voltage at the substation. Scenario 2 considers the impact of the actual battery penetration (i.e. 36 households have batteries) on the network. A battery of size 2 kWh is considered for all the case studies under Scenario 2 with a (dis)charging value of 0.4 kW, as shown in Figure 47.

Since the purpose here is to study the best-case impact due to high battery penetration, a standard 'block' shape profile is considered for all customers, rather than the actual monitored battery data (as this would have been affected by the charging schemes used at the time the data was collected).

Actual PV and battery penetration case, with batteries sized at 2 kWh / 0.4 kW (Scenario 2, Case 1)

This case (Scenario 2 Case 1) is the closest simulation to the actual installation in the trial, since it considers actual PV penetration levels, actual battery penetration levels and battery sizes reflective of the actual installed capacity. The charging of the batteries during the peak PV generation time has a positive impact on the power flow (16 kW, i.e. 40 x 0.4 kW) and the voltage (reducing it by 0.6 V – as shows in Figure 56) at the substation. Effectively, each kW of battery capacity has reduced the substation voltage by 0.0375 V. Importantly, since the generation period is longer than the maximum charging period of the batteries (when charging at their maximum rate) the batteries are incapable of reducing the export during the entire afternoon.

As expected, the modelled block shape profile shows the importance of operating the batteries according to an appropriate charging scheme, as forcing the batteries to discharge too early (i.e. whilst PV generation is still significant) has actually made the response of the network poorer. When operating the batteries according to the Maximum Impact scheme, this is something that needs to be carefully considered. The issue can be easily avoided by using a Threshold Charging scheme, although in this case the data analysis in Chapter 3 has shown that the batteries might not discharge enough to operate effectively the next day.

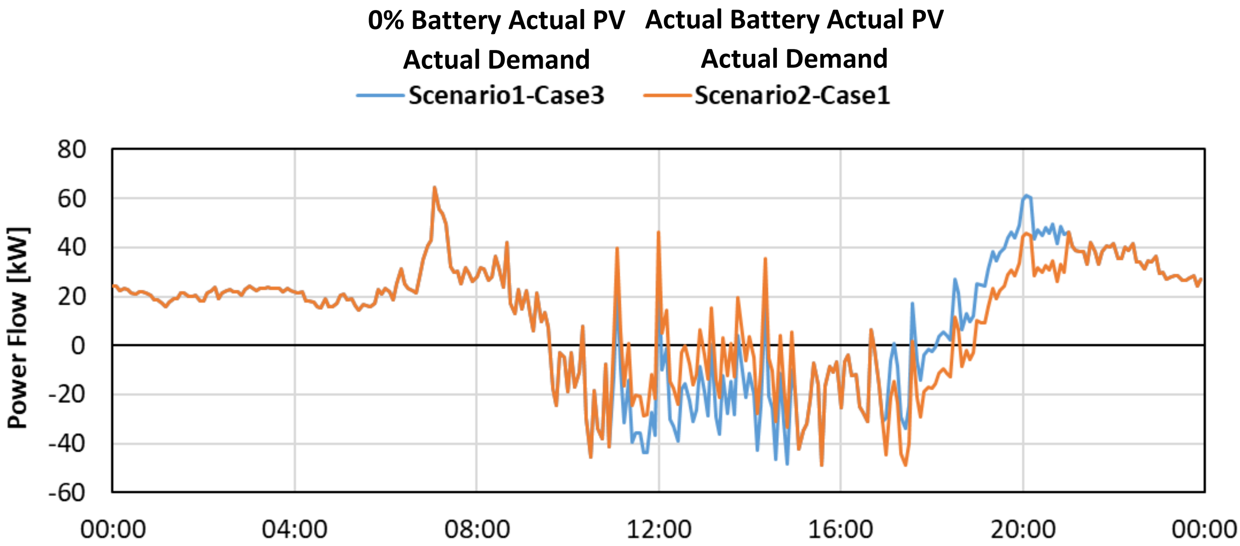


Figure 55: Impact of battery (dis)charging on substation power flow.

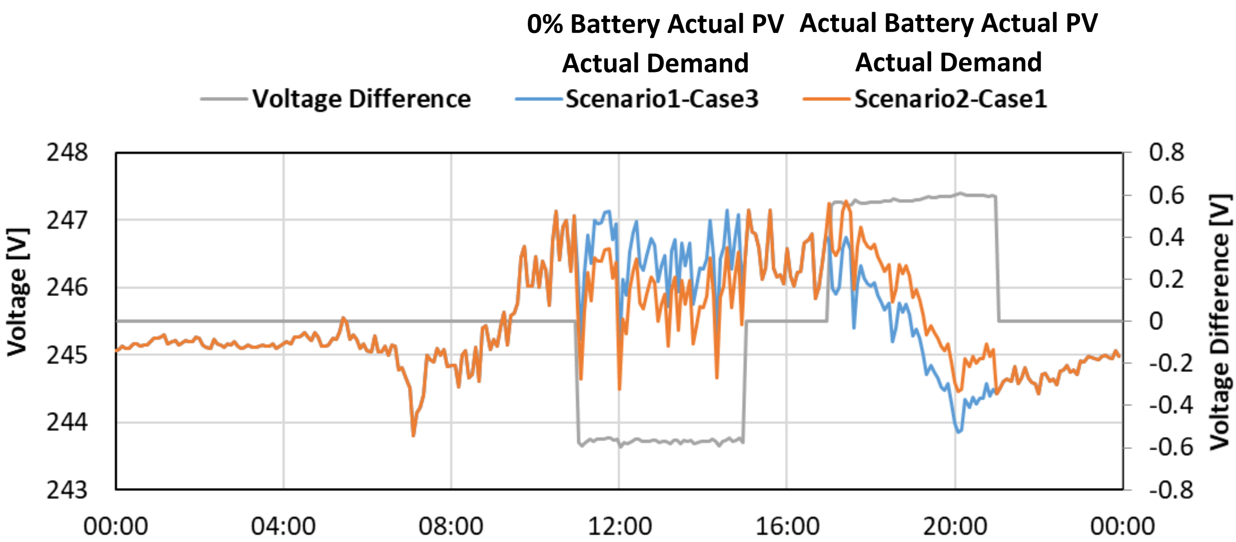


Figure 56: Impact of battery (dis)charging on substation voltage.

100% PV and actual battery penetration, with batteries sized at 2kWh / 0.4kW (Scenario 2, Case 2)

With the battery penetration unchanged, the change in power flow (16 kW) and voltage (0.6 V) is the same as in the previous section, although it should be noted that the relative impact is much smaller because of the significantly stronger PV generation.

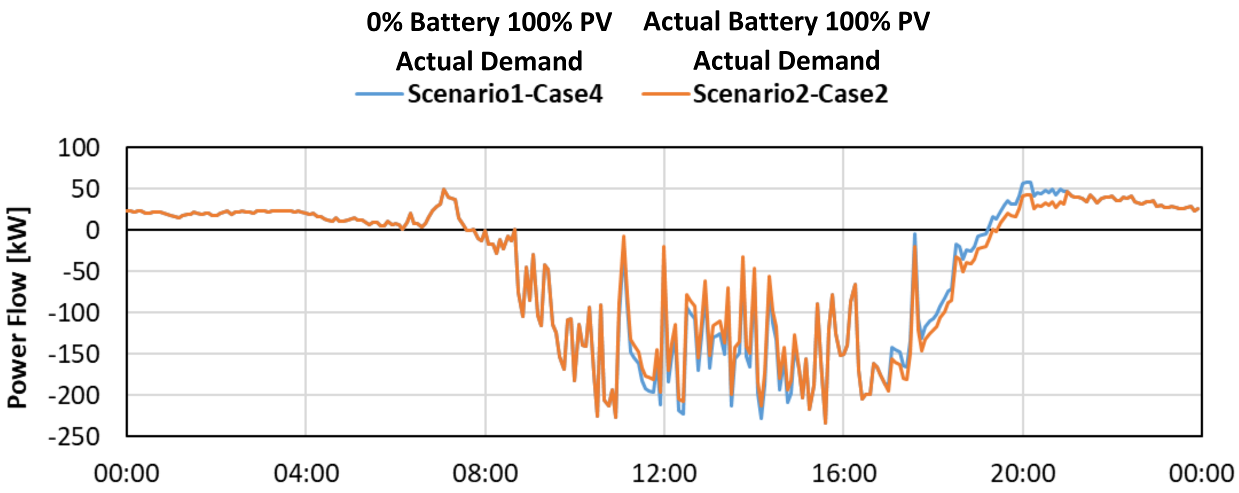


Figure 57: Impact of battery (dis)charging on substation power flow.

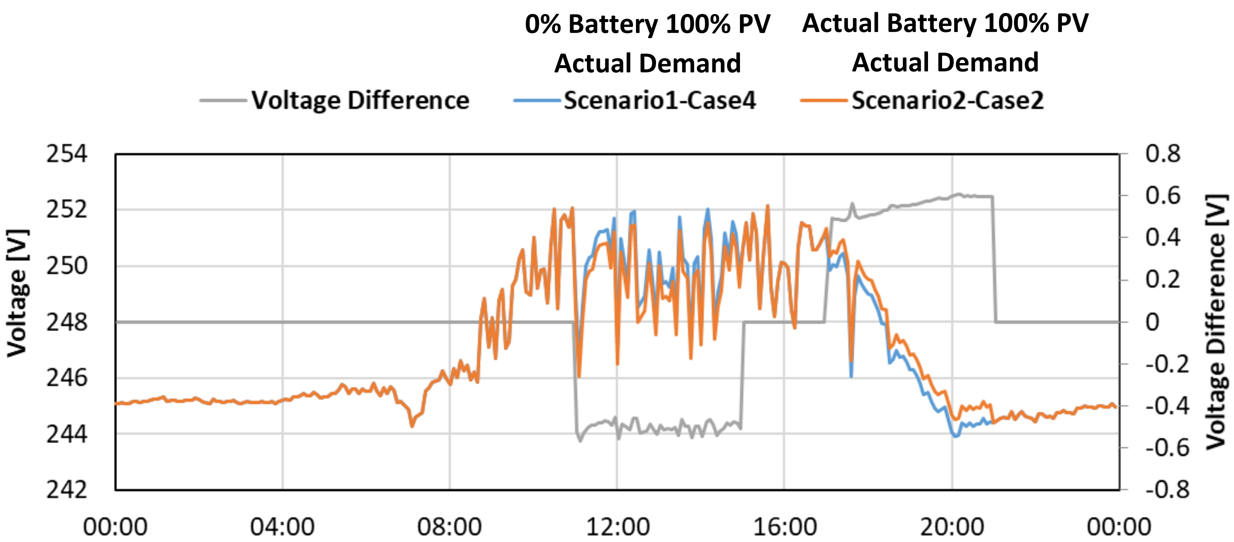


Figure 58: Impact of battery (dis)charging on substation voltage.

4.5.3 Results for Scenario 3 with Summer minimum loads

The previous section, and in particular Figure 58, has shown that the impact of the batteries on the substation is limited when only 16 kW is installed, especially when high levels of generation are modelled. Therefore, in Scenario 3 we assume that all 119 households connected to the substation will have storage (i.e. 47.6 kW).

Actual PV penetration and 100% battery penetration, with batteries sized at 2 kWh/0.4 kW (Scenario 3, Case 1)

In the graphs below, the results of Scenario 3 Case 1 (actual PV penetration, with 100% battery penetration) are compared with Scenario 1 Case 3 (actual PV penetration, without batteries). With the high battery penetration, the batteries managed to significantly reduce the reverse power flow and maintained the voltage close to the target value of around 245 V during the time of high generation, reducing it by 1.5 V (~0.6 %). It should however be noted that the generation period was longer than the battery charging period, and therefore the voltage could not be reduced throughout the entire afternoon. Furthermore, by discharging the batteries in the evening, a significant increase in voltage was caused, which shows the importance of distributing the times at which the batteries charge more evenly throughout the evening/night if high levels of battery penetration are reached.

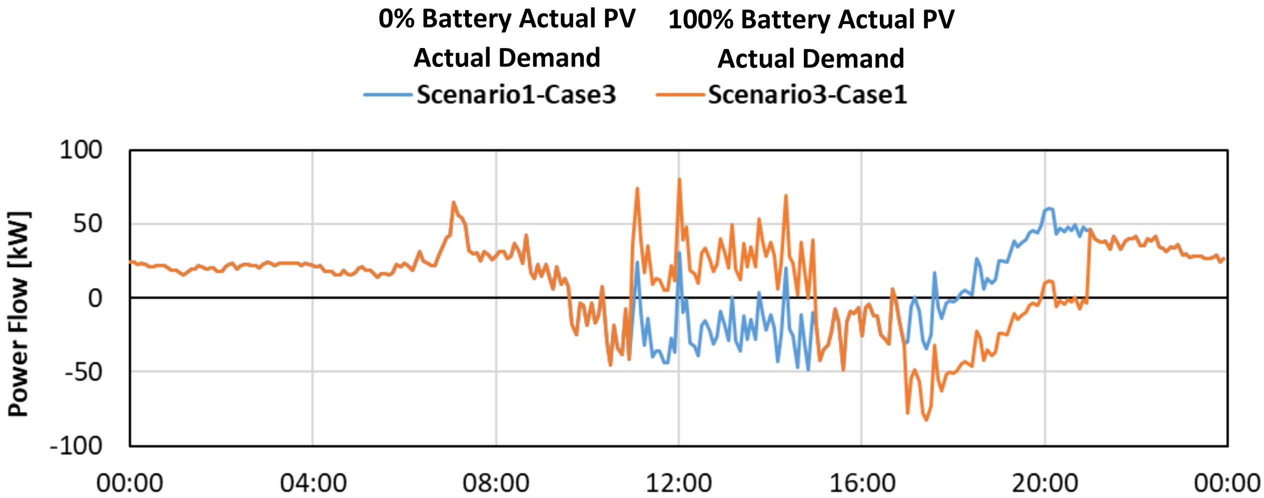


Figure 59: Impact of 100% battery penetration on the aggregate active power flow.

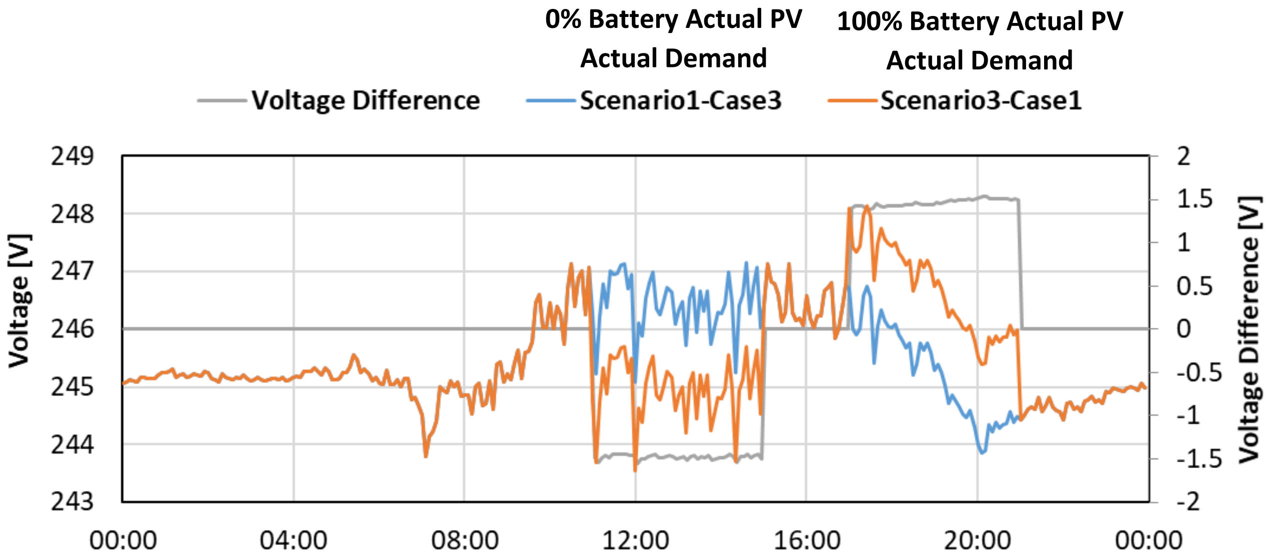


Figure 60: Impact of 100% battery penetration on the substation voltage.

Actual PV penetration and 100% battery penetration, with batteries sized at 4.8 kWh/1 kW (Scenario 3, Case 2)

Like the previous case comparison, this section considers 100% battery penetration, however this time a larger battery type is simulated. As expected, batteries with 1 kW (dis)charging rate have a considerably bigger impact on the operation of the network. In fact, the modelling shows that in this case having 100% battery penetration is too much for this substation (with the current PV penetration level) as the batteries could unnecessarily cause a significant demand in the afternoon and a reverse power flow in the evening. This could also lead to significant changes in the substation voltage although it should be noted that the voltage would still remain within the statutory limit of 253 V and 216.2 V, as shown in Figure 62.

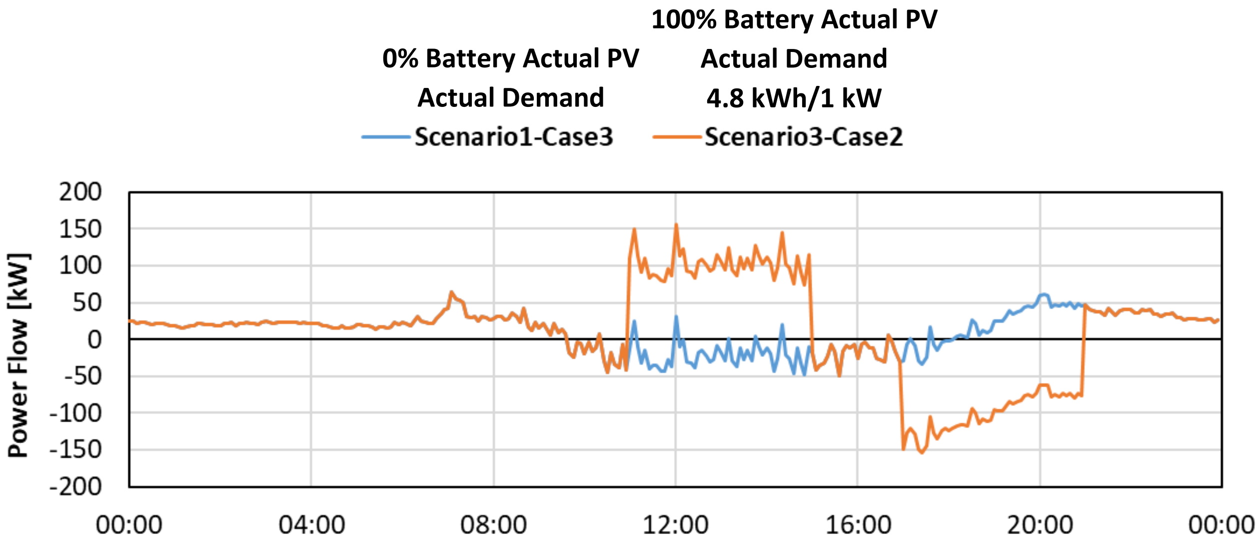


Figure 61: Impact of 100% penetration of large batteries (4.8kWh/1kW) on aggregate power flow.

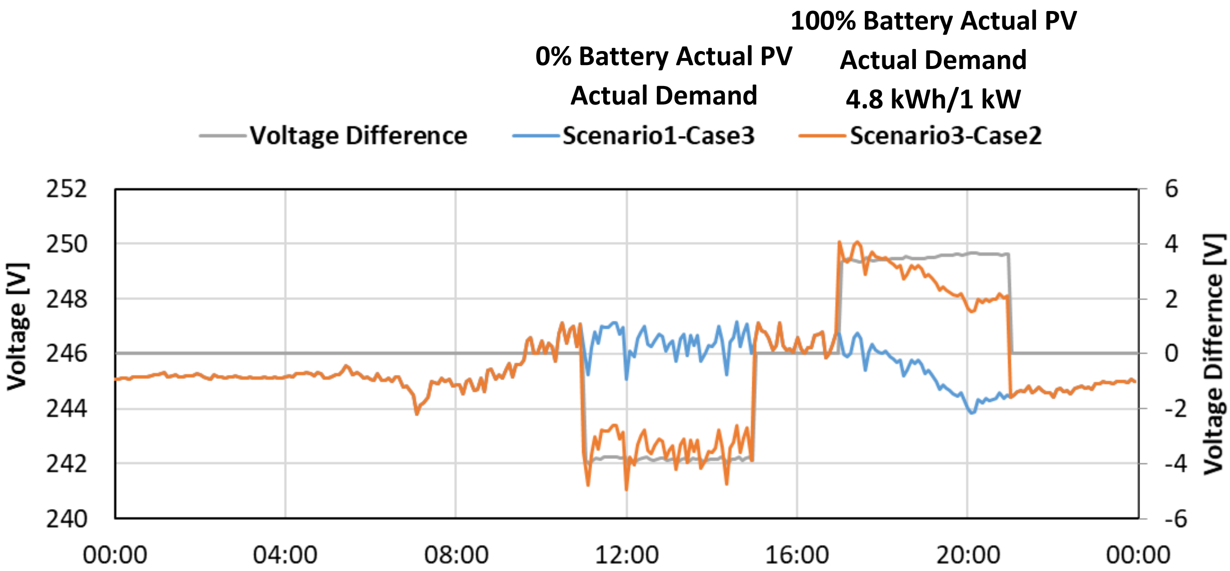


Figure 62: Impact of 100% penetration of large batteries (4.8kWh/1kW) on substation voltage.

100% PV and battery penetration, with batteries sized at 2 kWh / 0.4 kW (Scenario 3, Case 3)

In this section we will assess if the strong increase in voltage as a result of a high PV penetration level (as in Figure 54) can be offset by a high penetration level of batteries. In Figure 63, a comparison is made where 100% PV penetration is considered for both cases while the battery penetration is increased from 0% (Scenario 1 Case 4) to 100% (Scenario 3 Case 3). The batteries manage to reduce the voltage by approximately 1.5 V (~0.6 %) towards about 250 V, taking it further away from the limit 253 V, although it should again be noted that since the batteries are charging at their maximum rate, they would not be able to significantly reduce the voltage throughout the entire afternoon.

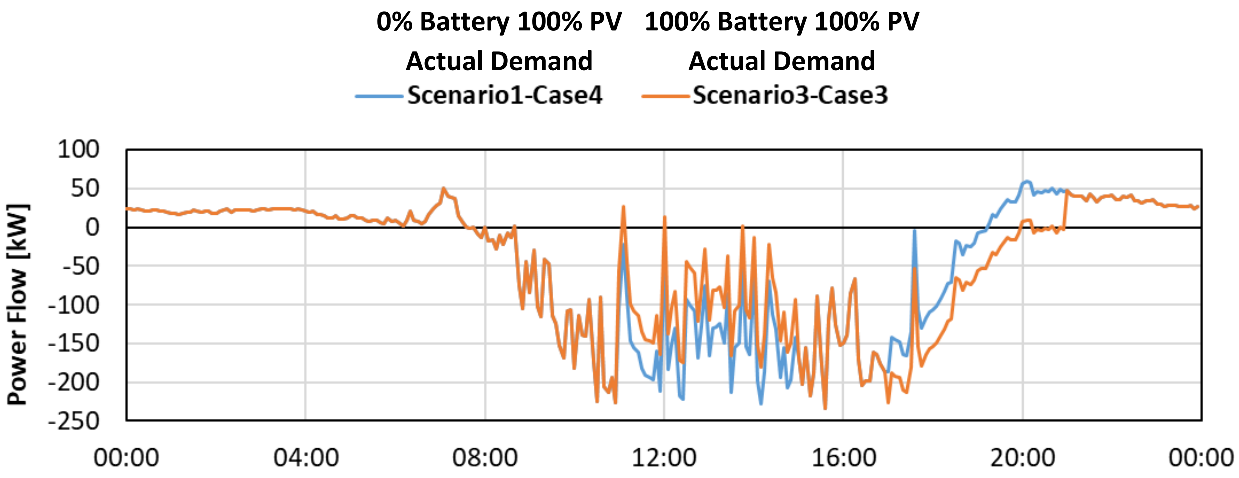


Figure 63: Impact of 2 kWh battery penetration with a (dis)charging rate of 0.4kW on power flow through the secondary transformer.

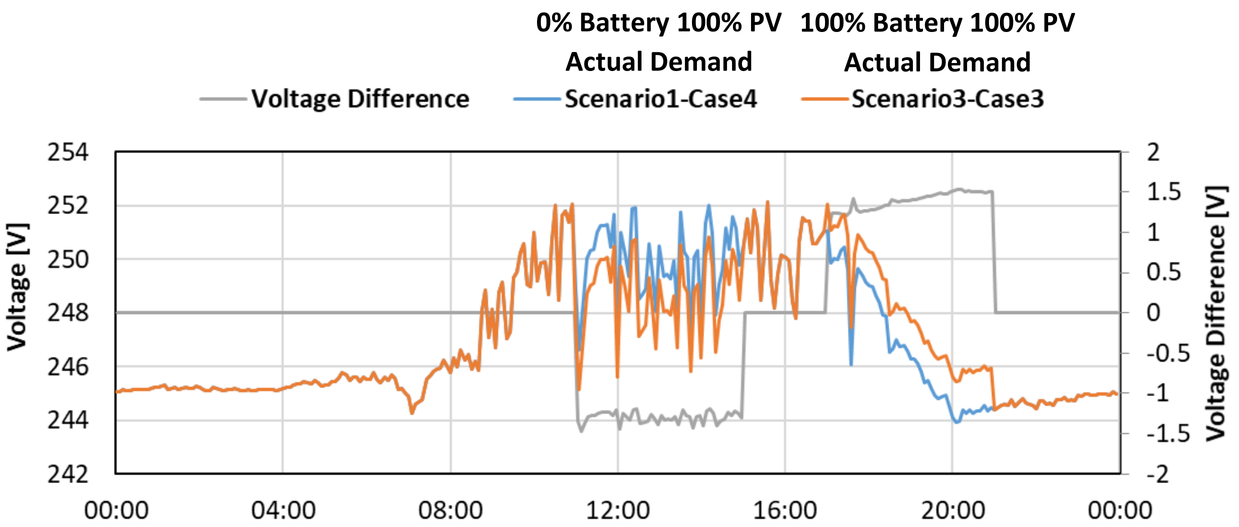


Figure 64: Impact of 2 kWh battery penetration with a (dis)charging rate of 0.4 kW on substation voltage.

100% PV and large battery penetration, with batteries sized at 4.8 kWh / 1 kW (Scenario 3, Case 4)

While Figure 64 showed that the batteries could have a significant impact on the voltage, it also highlighted that this impact can only be maintained for a period shorter than the generation period. In Figure 66 it can be seen that the 4.8 kWh / 1 kW batteries can have a very strong impact on the network (potentially stronger than required), meaning that:

- It could be decided to operate these batteries at a lower rate (e.g. 0.7 kW) for a longer period of time, meaning they are able to resolve potential voltage constraints throughout the entire afternoon.
- A voltage constraint can be resolved by a smaller battery penetration level, meaning that less uptake of domestic storage will be required which will affect the business case for using storage instead of investing in conventional network reinforcements, as will be discussed in Chapter 5.

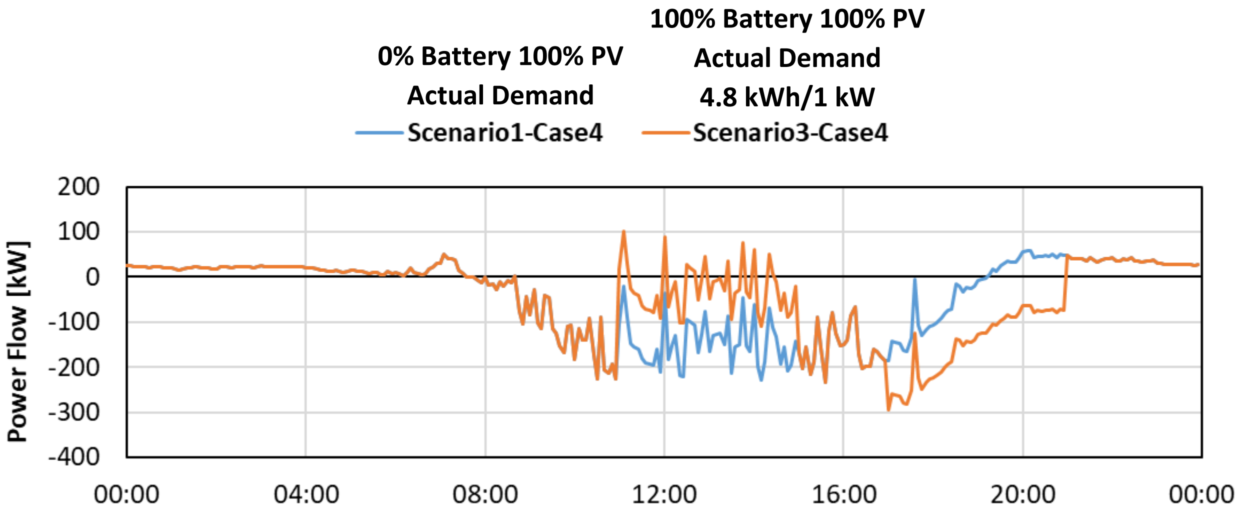


Figure 65: Impact of 4.8 kWh battery penetration with a (dis)charging rate of 1 kW on power flow through the secondary transformer. To avoid strong reverse power flows late in the afternoon it could be decided to charge the batteries at a lower rate over a longer period of time in summer.

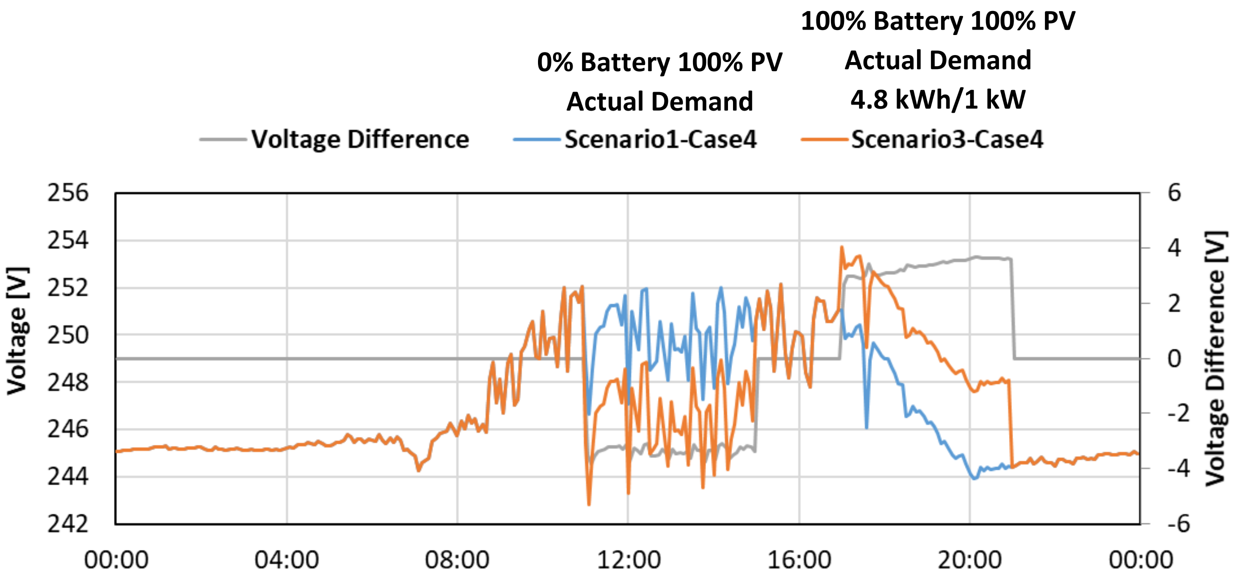


Figure 66: Impact of 4.8 kWh battery penetration with a (dis)charging rate of 1 kW on substation voltage. To avoid a voltage peak late in the afternoon it could be decided to charge the batteries at a lower rate over a longer period of time in summer.

For completeness Figure 67 shows the difference in substation voltage for the 100% battery 100% PV scenario when modelling the two different customer categories. Because in this case only the households participating in the trial have been considered the difference is fairly small, with the voltage being only 0.2 – 0.3 V lower when modelling the 'Careers and Kids' demand profile.

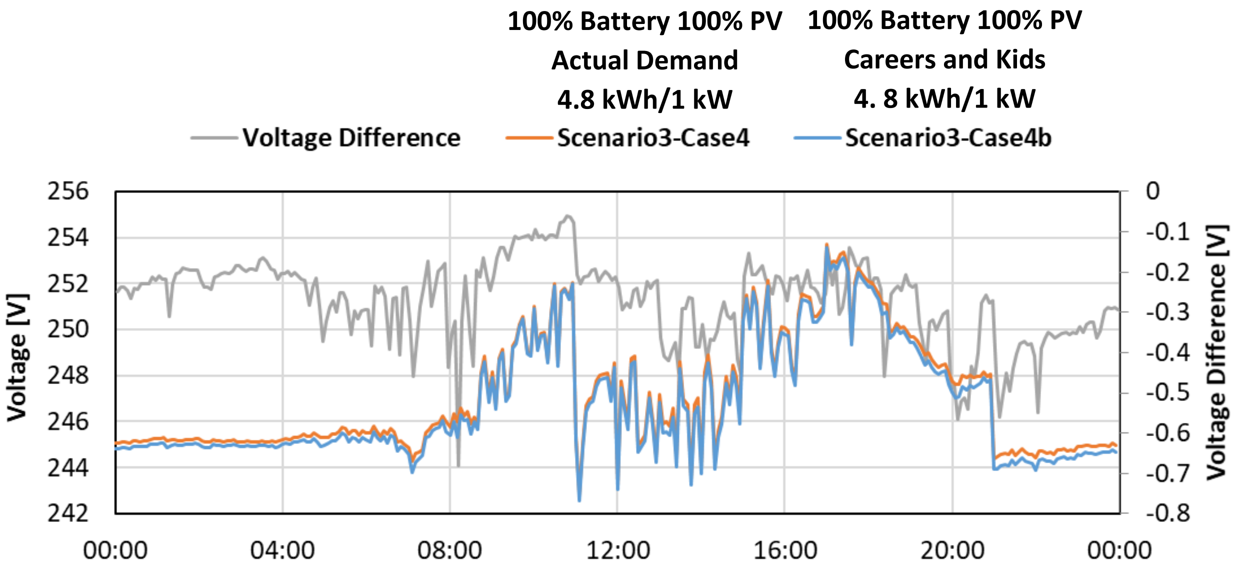


Figure 67: Difference in substation voltage for the two modelled customer categories.

4.6 Winter Peak Scenarios

The scenarios modelled at time of winter peak demand are described below. Again, there are three scenarios differing by the level of battery penetration and a number of cases defined for each scenario, which differ in terms of the assumed demand pattern and size of batteries installed (Winter Peak loading level for all cases).

Scenarios for Winter Peak

	Scenario 1	Scenario 2	Scenario 3
	No Battery Penetration	**Actual Battery Penetration**	**100% Battery Penetration**
	Case 1: 0% PV Penetration	**Case 1: 0% PV Penetration**	**Case 1: 0% PV Penetration**
Loading level	Winter Peak	Winter Peak	Winter Peak
Demand Pattern	Actual	Actual	Actual
Battery size	-	2kWh / 0.4 kW	2kWh / 0.4 kW
	Case 2: 0% PV Penetration	No larger battery modelled because scenario is expected to be similar to 100% battery penetration scenario.	**Case 2: 0% PV Penetration**
Loading level	Winter Peak		Winter Peak
Demand Pattern	Careers and Kids		Actual
Battery size	-		4.8 kWh / 1 kW
	Not modelled because we are mostly interested in changes in demand levels for the scenario with 100% battery penetration.		**Case 3: 0% PV Penetration**
Loading level			Winter Peak
Demand Pattern			Careers and Kids
Battery size			4.8 kWh / 1 kW
			Case 4: 0% PV Penetration
Loading level			Winter Peak
Demand Pattern			Careers and Kids
Battery size			4.8 kWh / 2.3 kW

4.6.1 Results for Scenario 1 with Winter peak loads

Base case: modelling the network without PV or batteries (Scenario 1, Cases 1 and 2)

The base demand on the secondary substation during winter months is almost two times higher than in summer. Although the peak demand occurs at a similar time of day in winter and summer months (around 19:00), the magnitude of the peak is very different.

As before, because of the lack of household information of the other houses in the trial, in the model the demand profile is only adjusted for the 36 households participating in the trial. As the difference in peak demand between the 'Careers and Kids' and the 'Elderly Needs' customer classes (as in Figure 10) is approximately 400 W, the demand for the 'Careers and Kids' scenario is about 14.4 kW (i.e. 36 x 0.4 kW) higher at peak time.

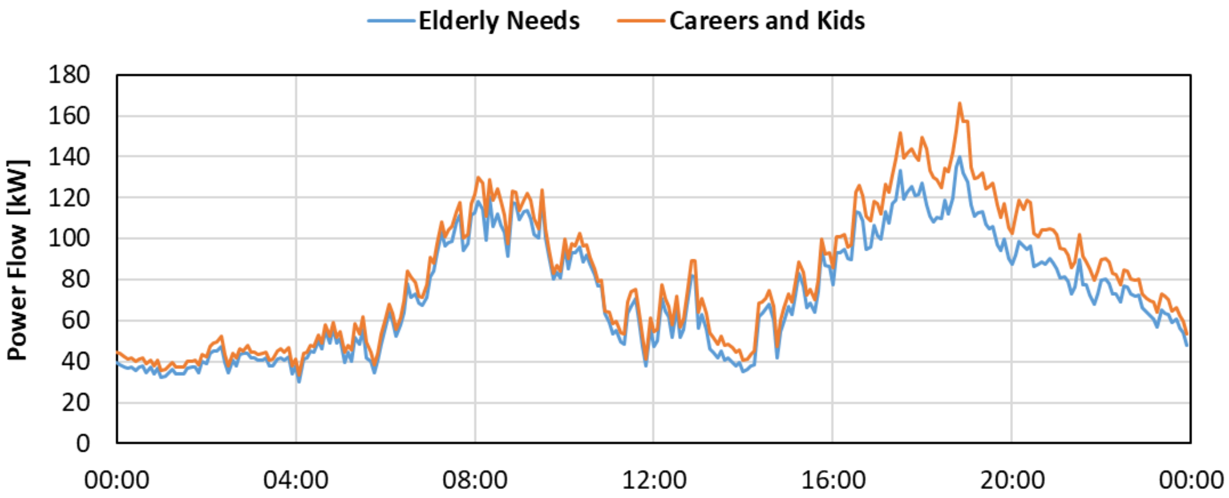


Figure 68: Substation demand when no PV generation and battery storage are present in the network.

The effect is reflected on the substation voltage where the voltage dips below 240 V at the peak hour for the case of 'Careers and Kids'. However, the difference in voltage between the two results is minimal, again owing to only a limited number of customers considered to be of 'Career and Kids' profile, while the other loads are unchanged from the original profile.

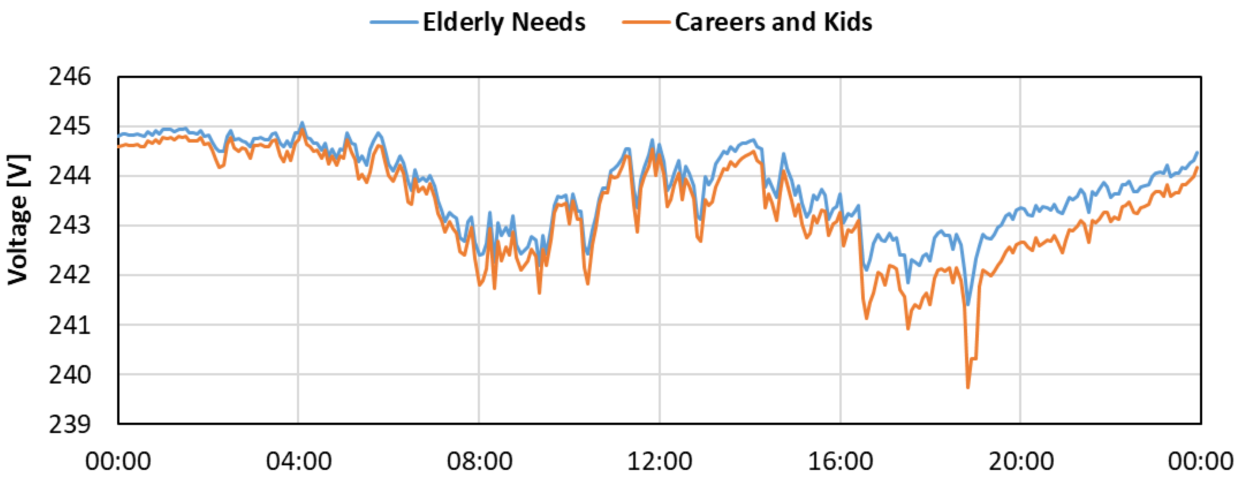


Figure 69: Substation voltage when no PV generation and battery storage are present in the network.

4.6.2 Results for Scenario 2 with Winter Peak Loads

No PV, Actual battery penetration, with batteries sized at 2 kWh/0.4 kW (Scenario 2, Case 1)

The battery profile considered in these studies charges between 11:00 and 15:30 and discharges between 17:30 and 21:00. During charging, the overall demand on the substation increases by a certain margin, as shown in Figure 70, while during the evening, discharging helps to shave the network peak demand.

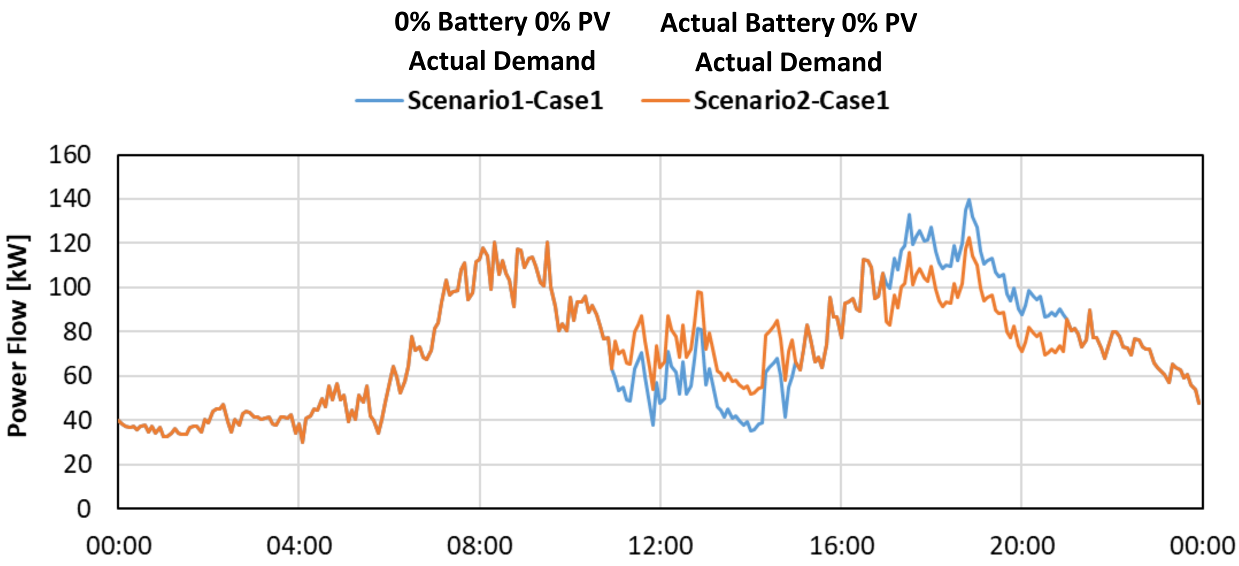


Figure 70: Impact of batteries on total demand when no PV generation is present in the network.

Although the difference in the two cases is not huge, increased penetration of battery storage is expected to help shift the energy usage from peak periods into times of lower load. Similar effects can be observed in the substation voltage, which exhibit a narrower range (Figure 71) if battery storage is installed.

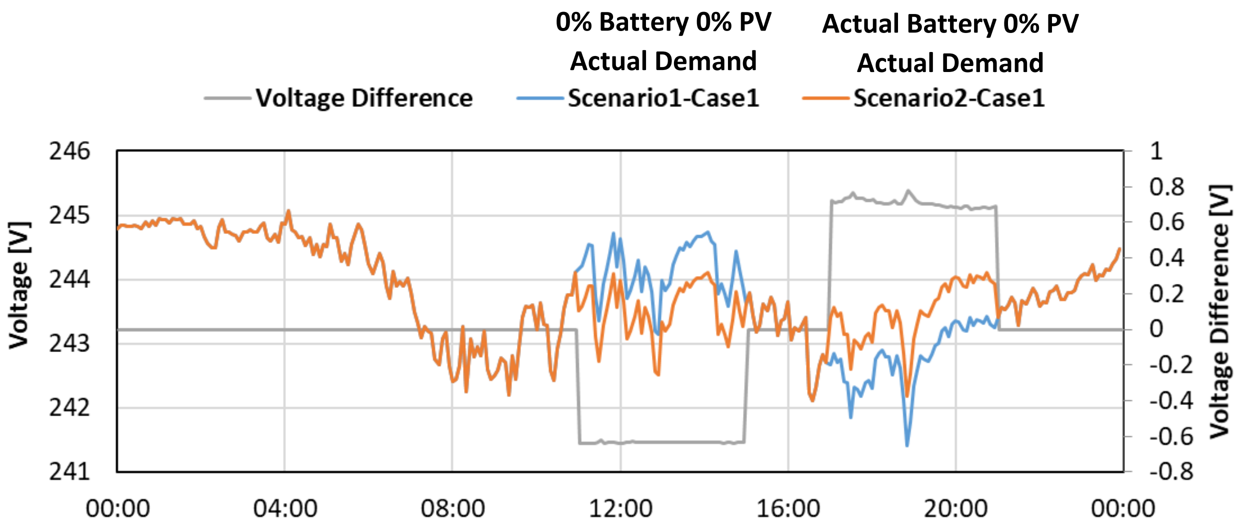


Figure 71: Impact of batteries on substation voltage when no PV generation is present in the network.

4.6.3 Results for Scenario 3 with Winter Peak Loads

No PV, 100% battery penetration, with batteries sized at 2 kWh / 0.4 kW (Scenario 3, Cases 1)

In contrast to the previous set of results, this case simulates all households having battery storage (Scenario 3 Case 1), with no PV generation is present in the network.

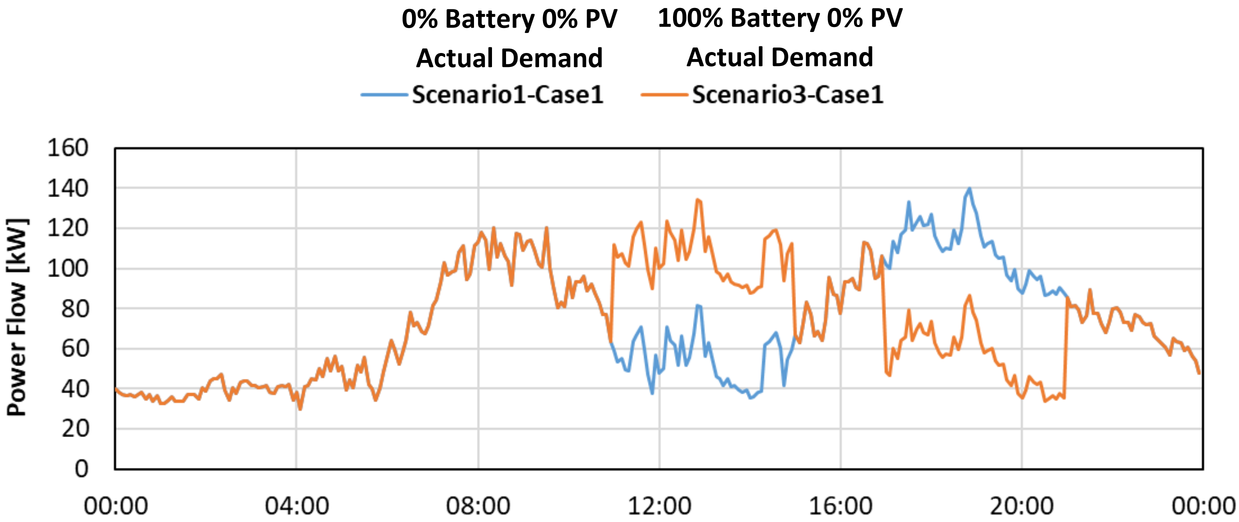


Figure 72: Impact of storage on the peak demand when every household has a battery of size 2 kWh / 0.4 kW.

Having more batteries in the network, all with identical charging profiles, means the demand increases significantly during the afternoon hours, becoming comparable to the evening peak demand without batteries. This is also evident in Figure 73, where the voltage at the substation drops more than that of in Scenario 1 Case 1. When all the batteries start discharging in the evening the total demand on the substation reduces significantly, which in turn leads to a rise in voltage.

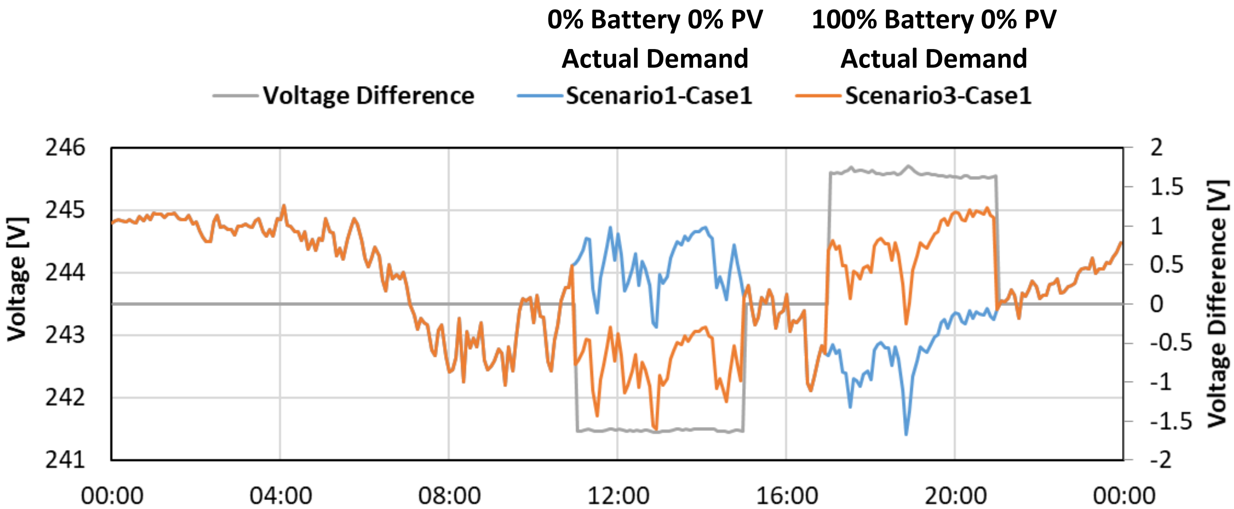


Figure 73: Impact of storage on the voltage when every household has a battery of size 2 kWh / 0.4 kW.

No PV, 100% battery penetration, sized at 4.8 kWh / 1 kW (Scenario 3, Cases 2 and 3)

Since Figure 72 revealed that high levels of battery penetration (based on a 2 kWh / 0.4 kW battery) would already cause levels of demand in the afternoon higher than the original peak demand, this section is only included for completeness, and should be considered as an example of an overly high battery penetration level that could cause constraints on the network if controlled improperly.

It can be concluded from Figure 74 that such a high level of battery penetration is capable of providing nearly the entire peak demand, which is significantly more than would be required, and hence fewer batteries could be installed, or the batteries could be discharged at a lower rate over a longer period of time. Furthermore, it shows that if all batteries were forced to charge at the same time, unnecessarily high demands could be caused, which in winter could easily be avoided by charging the batteries according to a smarter scheme which would spread the charging of multiple batteries in the same region over an entire day, making sure enough capacity is available to assist in reducing the evening peak.

As before, the impact of changing the demand profiles to a 'Careers and Kids' customer class is small.

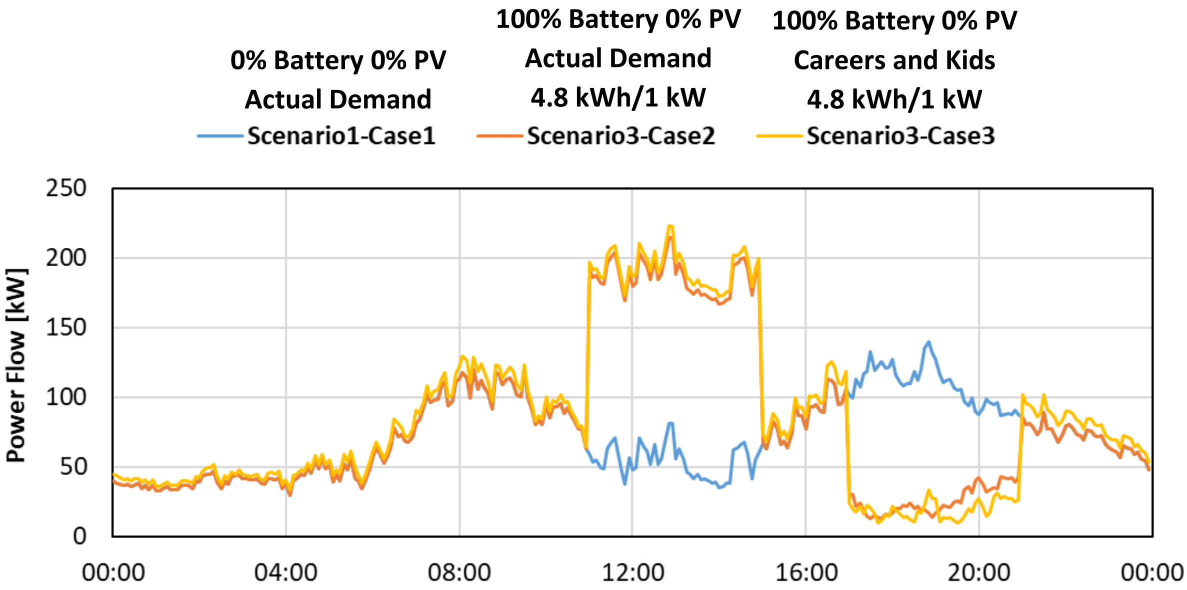


Figure 74: Impact of storage on the peak demand when every household have a battery of size 4.8 kWh/1 kW.

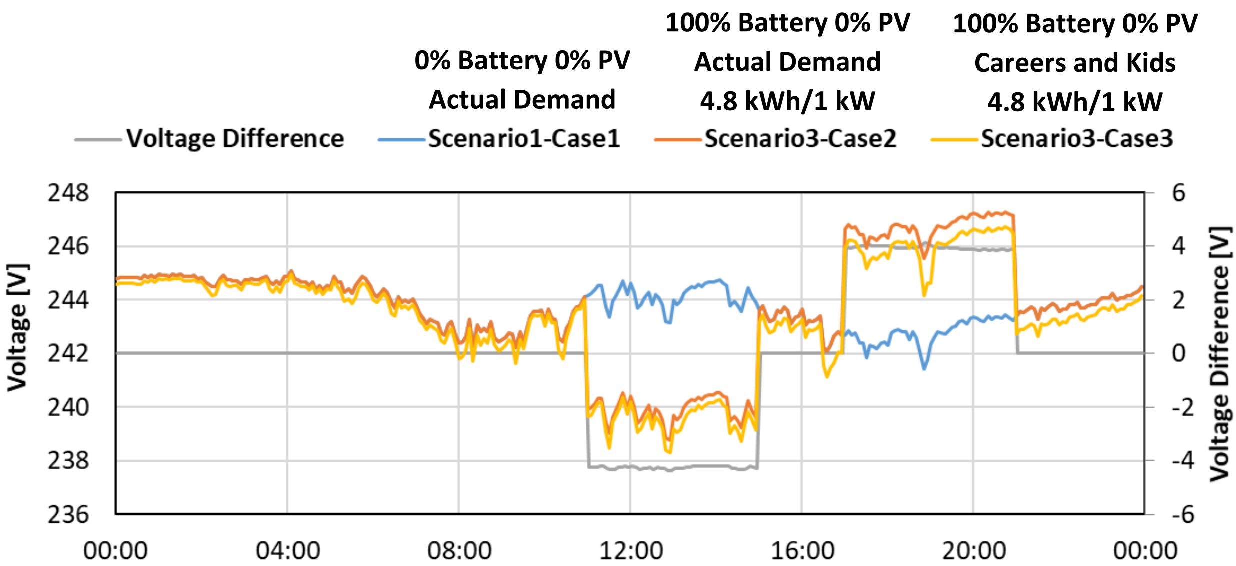


Figure 75: Impact of storage on the substation voltage when every household has a battery of size 4.8 kWh/1 kW. The voltage difference shown represents the difference between Scenario 1 - Case 1 and Scenario 3 - Case 2.

4.7 Feeder and service voltage analysis

To improve the understanding of the impact of the batteries on the voltage across the feeders in the network, the model has also been used to provide voltage at node level. The section below discusses the voltage profile across feeder Way 4 as a whole, as well as for a specific service cable.

Way 4 has 15 service joints supplying 36 customers. A schematic representation is presented in Figure 76. This particular mains feeder is selected for this analysis as the majority of the households (20) have measurements available.

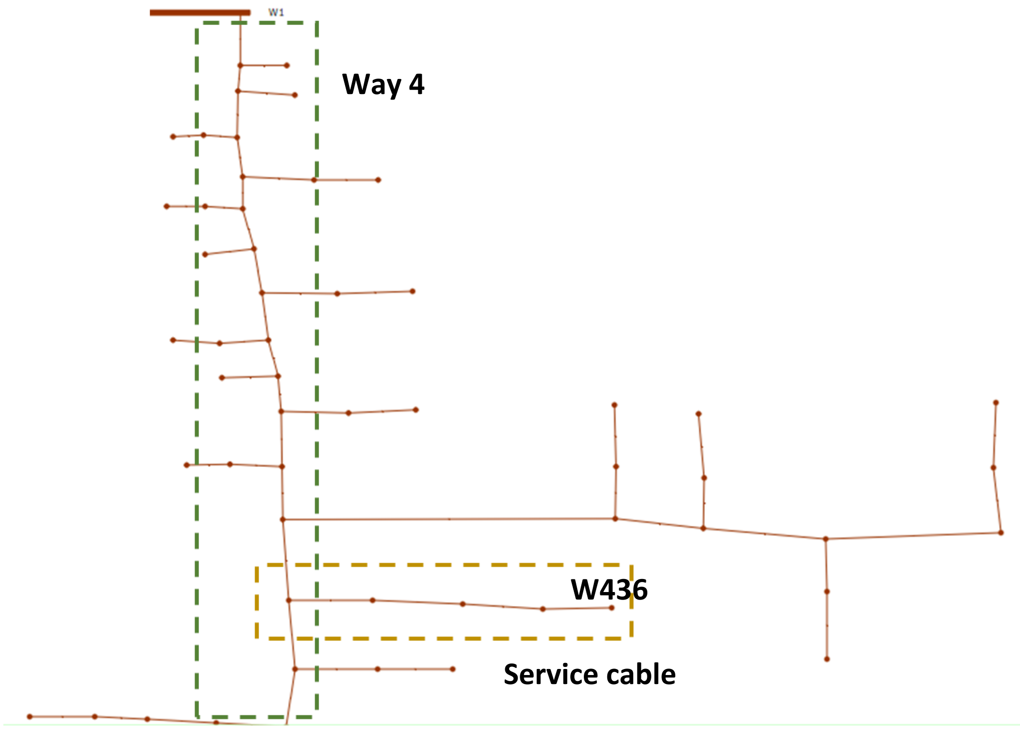


Figure 76: Schematic showing the mains feeder (way 4) and the service cables.

4.7.1 Modelled profiles

The base case (no PV and no battery) voltage profile is compared to four scenarios with varying levels of PV and battery penetration. Figure 77 – Figure 79 shows the total amount of modelled PV generation, consumption and battery (dis)charge rate for all households in Way 4, for the different scenarios and case studies.

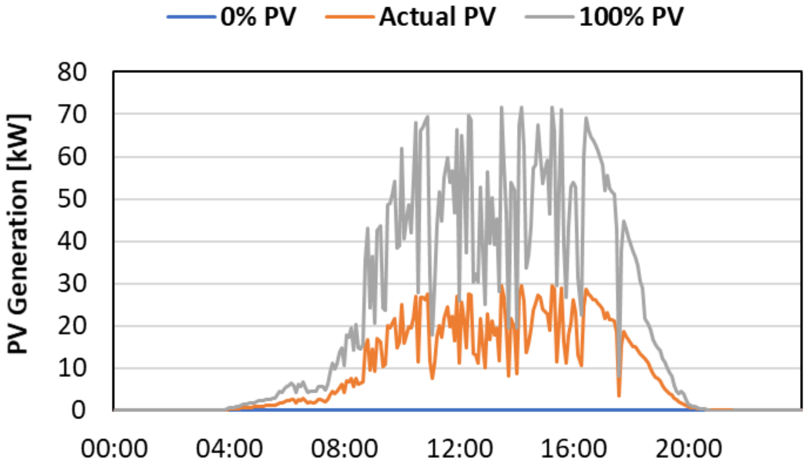


Figure 77: Total amount of generated PV modelled for the different scenarios for all households in Way 4. In the Actual PV case 15 out of 36 households have PV installed.

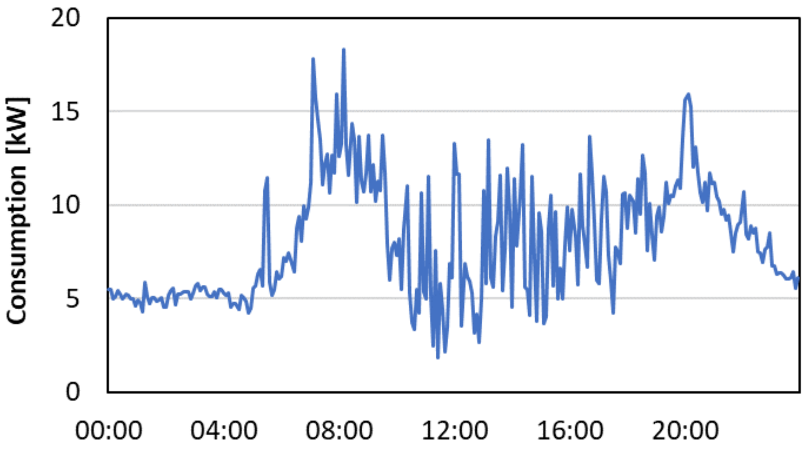


Figure 78: Total consumption modelled for all households in Way 4.

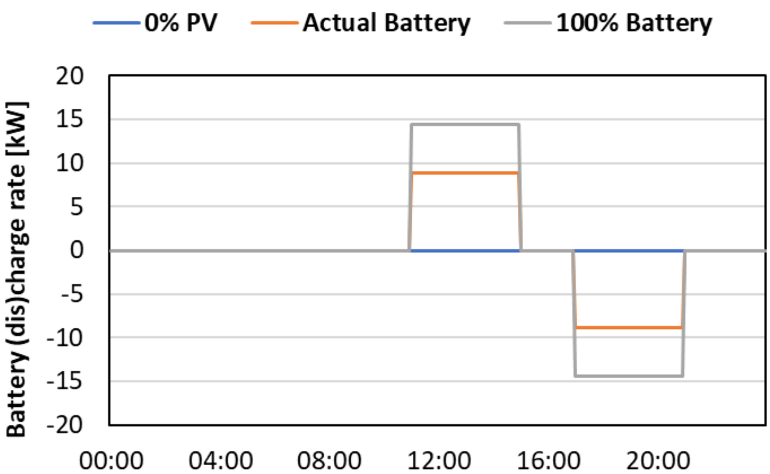


Figure 79: Total battery (dis)charge rate modelled for the different scenarios for all households in Way 4. In the Actual battery case 20 out of 36 households have batteries installed.

As discussed before, in summer PV generation is high throughout the entire afternoon, and as the batteries only are able to charge or discharge for a limited amount of time, the net demand/generation in Figure 80 shows that on sunny summer days voltage issues can be expected to be stronger outside of the time during which the batteries are assumed to operate, which will be discussed in more detail below.

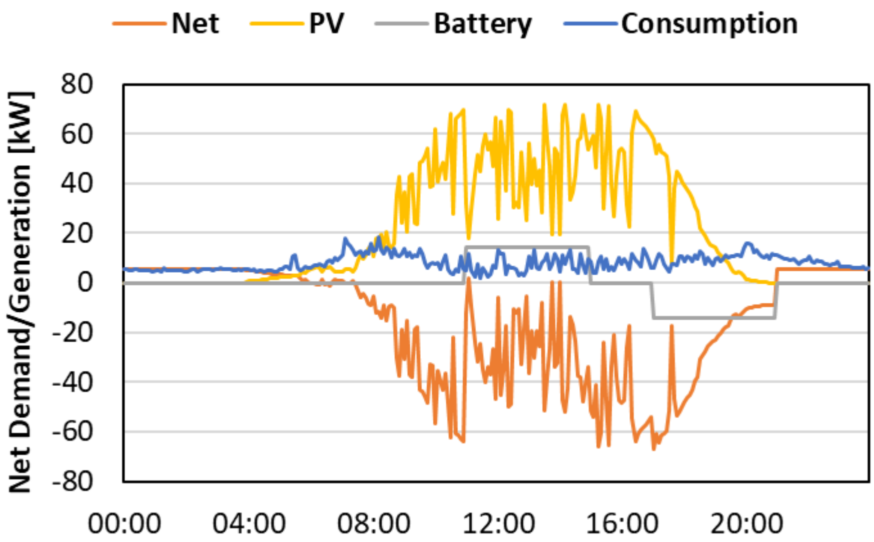


Figure 80: Overview of the total PV, battery and consumption in Way 4 (assuming 100% penetration of PV and batteries) and the corresponding net demand/generation.

4.7.2 Voltage impact snapshots

To create a better understanding of the impact of PV and batteries on the network for varying conditions, the modelling results for the different scenarios for four typical moments during a summer day are presented below. It should be noted that the times 13:30 and 15:15 have been selected because the profiles above indicate PV generation can be at its maximum throughout the entire afternoon and picking timestamps for which generation was at its peak therefore gives us the most representative understanding of a sunny day. We appreciate that the PV generation period might be shorter for an average day but want to focus on the most constrained conditions in this section.

The four typical times that are explored are:

- **Midnight** (24:00) – At midnight both the PV and the battery have no impact and the network response is guided by the demands only.
- **Midday** (13:30) – Peak PV generation during this period along with charging of all the batteries at their maximum capacity. Network response depends on PVs, batteries and household demands.
- **Afternoon** (15:15) – Generation is still nearly at peak, but all the batteries are fully charged, and their response is zero i.e. no import/export. Network voltage profile is guided by the demands and the PV generation only.
- **Evening** (20:00) – All the batteries are discharging and there is hardly any PV generation (1.5 kW) in the network, network response is mostly a function of demand and battery.

Note that for convenience the total consumption for all households in Way 4, as well as the total PV generation and battery discharge rate (for the case of 100% penetration) are included in the titles of the figures below for the specified time.

Midnight

Figure 81 shows that due to the limited load at midnight (and the inactive PV and battery systems) the voltage is nearly constant across the mains feeder with only a very small drop. Even at the end of the service cable (Figure 84) the voltage has only dropped by 0.2 V. It should be noted that in this case the voltage profiles from the six case studies overlap due to identical network conditions (i.e. no impact of PV and battery).

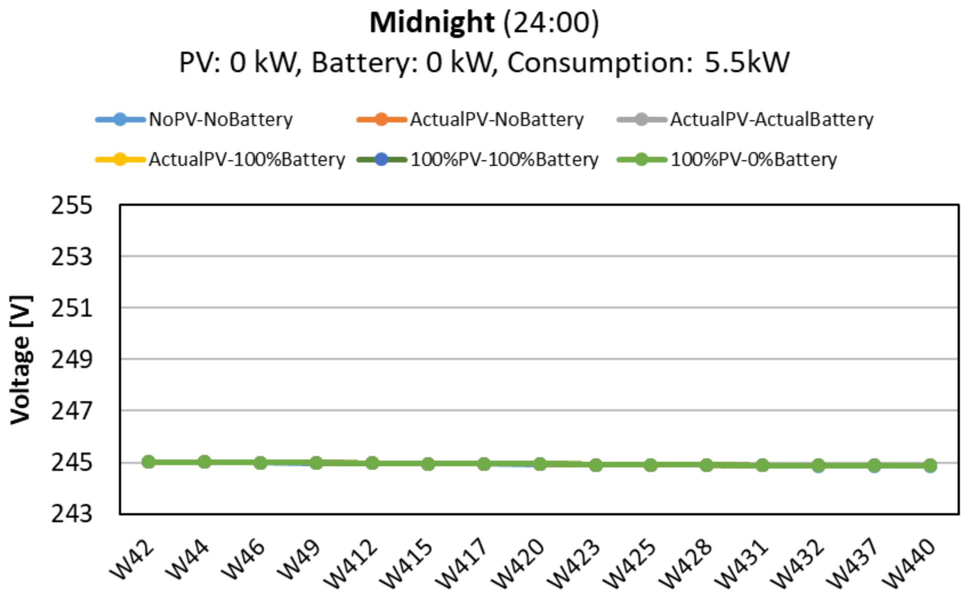


Figure 81: Way 4 feeder voltage profile during summer minimum demand conditions at midnight (24:00).

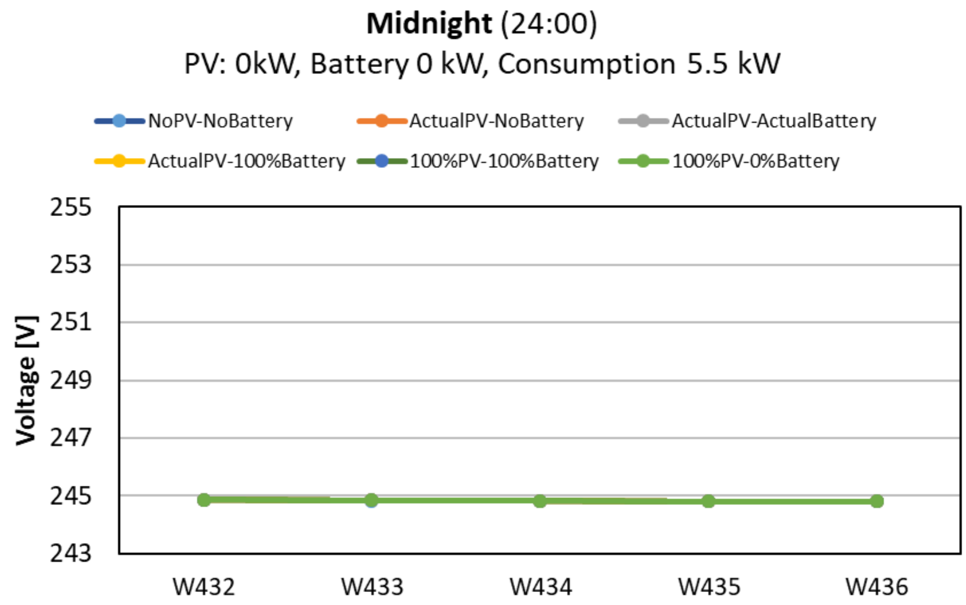


Figure 82: Service cable voltage profile during summer minimum demand conditions at midnight (24:00).

Midday

Figure 83 (Midday) shows a much wider voltage range on the mains feeder. In case all households would have PV systems installed, a 100% PV penetration (71.6 kW) would cause voltage constraints from W420 onwards. The impact of batteries becomes apparent from this figure, as voltage constraints could be resolved by installing batteries in all households (the voltage could be 1.8 V lower at node W440).

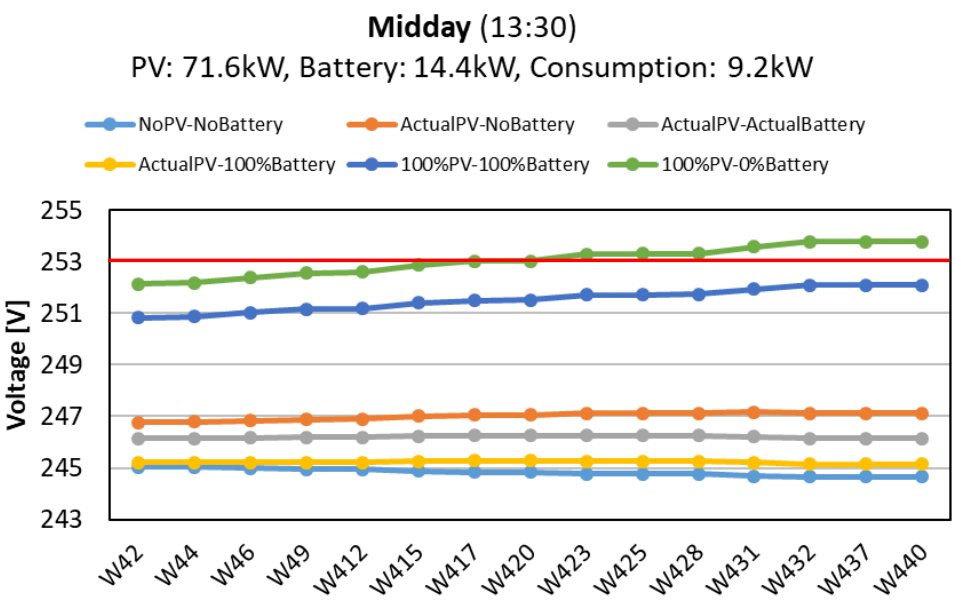


Figure 83: Way 4 feeder voltage profile during summer minimum demand conditions at midday (13:30).

For the service cable constraints are even more significant, and the voltage could increase up to 254.7 V. Similar to the mains case, the impact of battery storage could just about resolve the network constraints.

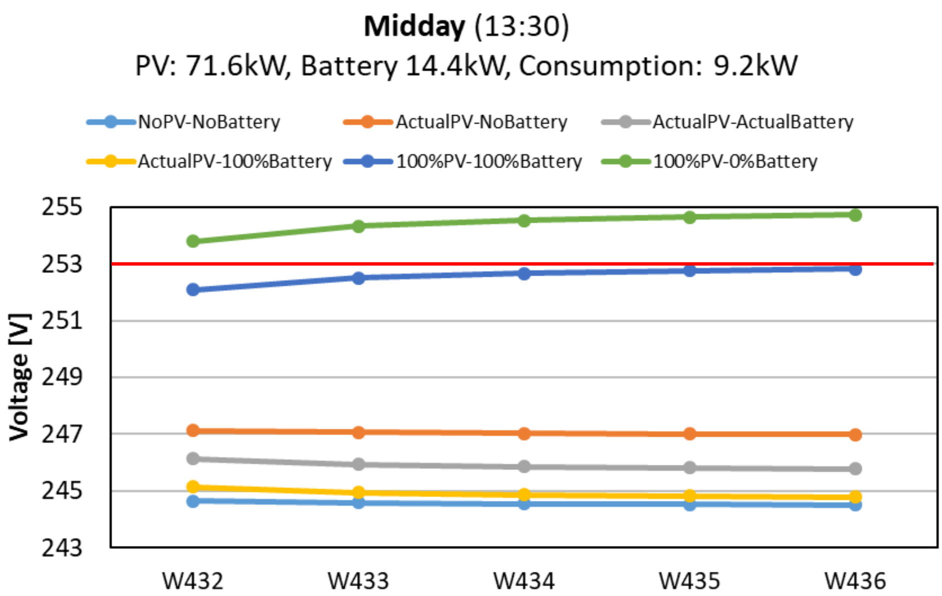


Figure 84: Service cable voltage profile during summer minimum demand conditions at midday (13:30).

Afternoon

In the afternoon (15:15), generation levels are still the same as at midday, but due to the limited capacity of the batteries, they are unable to assist the network. Therefore, there is less difference across the scenarios in Figure 85, as the battery penetration level has no impact and consequently the scenarios with the same PV penetration level overlap.

It should be concluded from these figures that constraints on the network might occur in summer even if batteries are installed when the period over which the batteries can charge is too short compared to the period of generation. This highlights the importance of the ratio between the battery charging rate and the capacity (particularly from the DNO's perspective), as well as sizing the battery appropriately based on the installed PV capacity and the household consumption.

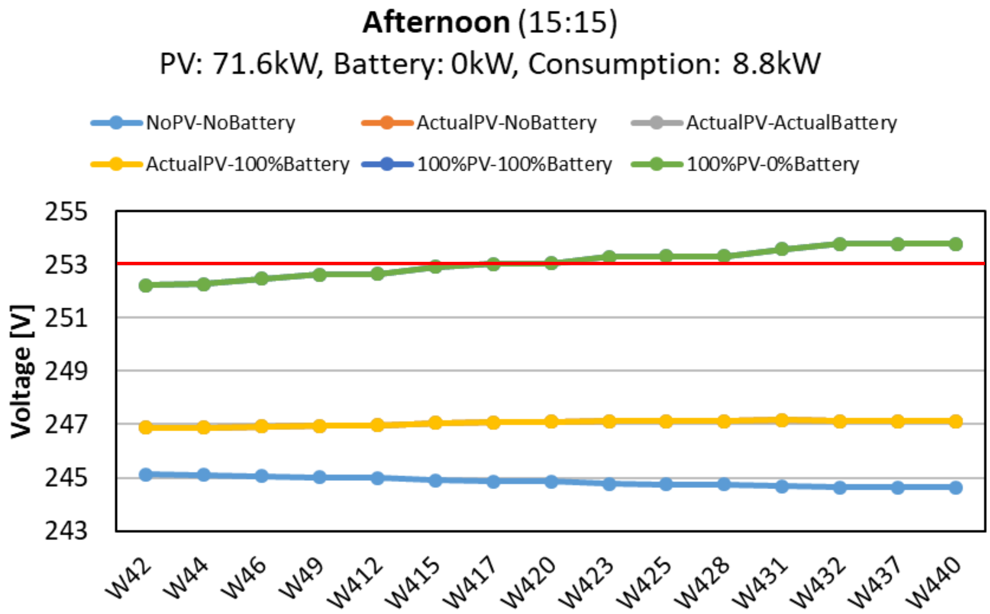


Figure 85: Way 4 feeder voltage profile during summer minimum demand conditions in the afternoon (15:15).

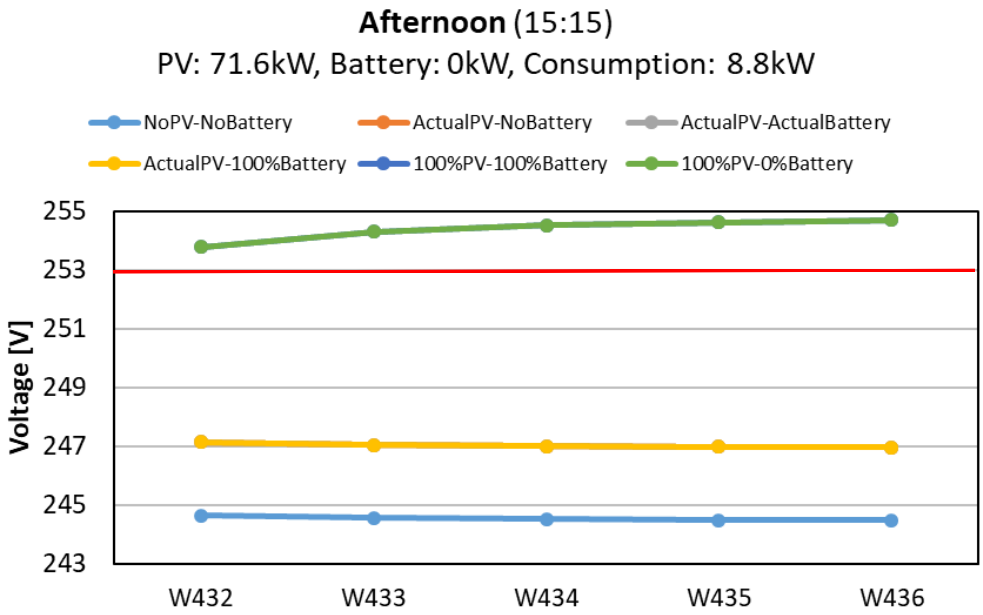


Figure 86: Service cable voltage profile during summer minimum demand conditions in the afternoon (15:15).

Evening

Figure 87 presents the feeder voltage profile during the evening peak demand (20:00). As the PV generation is almost negligible, the difference between the scenarios is caused by the varying impact of the batteries. It should be noted that without any PV and battery activity, the voltage at the end of the feeder at 20:00 is significantly lower (1.3 V) than for the other times of the day because of the higher level of consumption.

The figures show that assuming 100% battery penetration has a significant impact on the network, as the voltage increases by about 2 V as compared to not having storage, which could avoid constraints caused by evening peak demand.

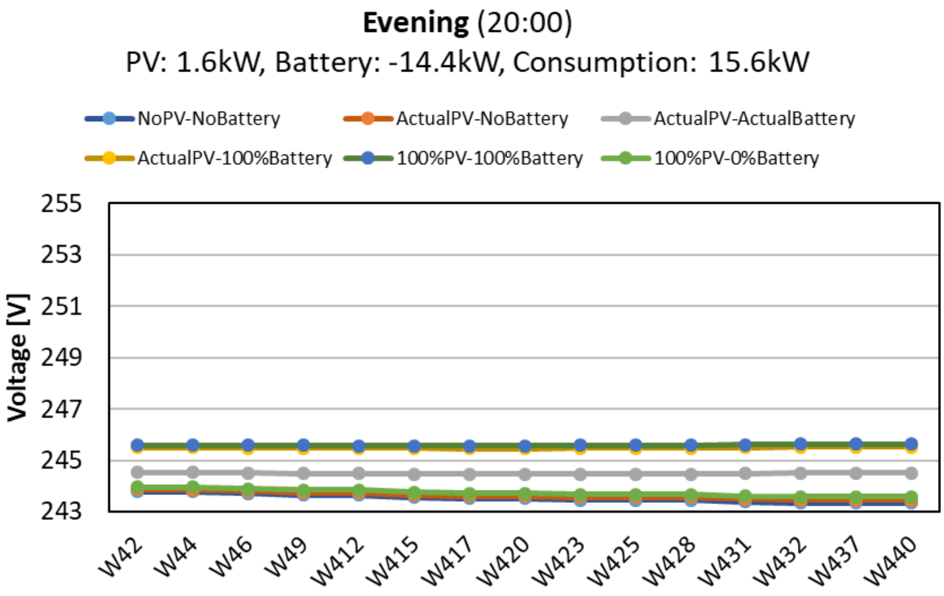


Figure 87: Way 4 feeder voltage profile during summer minimum demand conditions in the evening (20:00).

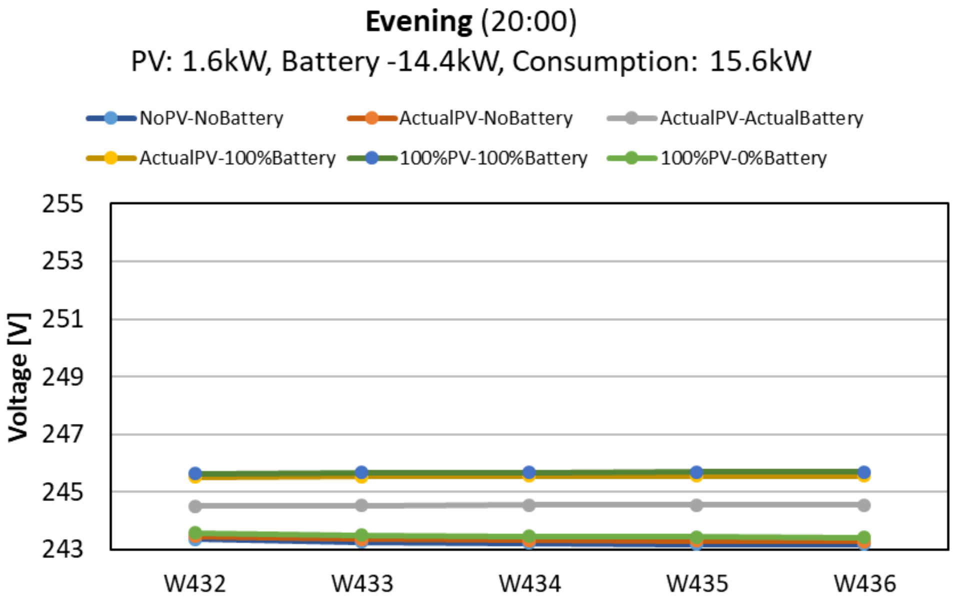


Figure 88: Service cable voltage profile during summer minimum demand conditions in the evening (20:00).

4.7.3 Understanding the impact of generation and storage on the voltage

By plotting the voltage against the net generation (PV generation – battery charge rate) at all times of the day, we can derive the relation between these two parameters. In Figure 89 each blue dot represents the voltage at the end of the service cable (W436) for each modelled half hour as well as the net generation on Way 4 at that time. The data shown is for the 100% PV – 100% Battery and the 100% PV – 0% Battery scenarios as these show the widest range of net generation, ranging from 0 kW at times of no generation to over 70 kW at times of peak generation (without batteries).

The trendline indicates that the initial voltage level (without the impact of any PV or batteries) at the end of the service cable is 244.53 V, and that for each additional kW of net generation on Way 4 an increase of

0.15 V should be expected. This implies that a voltage constraint would be reached for 64.5 kW of net generation. Note that the variation around the trendline is caused by the variability in demand across the day, which causes a standard deviation of about 0.52 V around the trend.

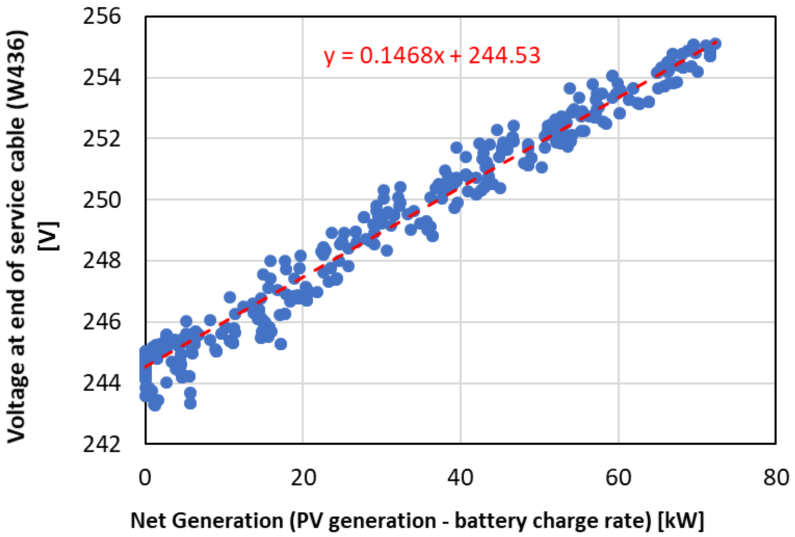


Figure 89: Voltage at the end of the service cable as a function of the net generation.

4.8 Modelling Outcomes

Within both the Summer minimum and the Winter Peak demand scenarios, we can conclude that the presence of batteries on the network assists in balancing demand and generation, thus levelling the power flow at the substation and along the feeder, keeping the voltage within a narrower band. Although each network configuration is unique, the modelling outcomes still provide useful insights into the impact of storage on the network.

Summer Minimum

At the time of summer minimum demand, the modelling revealed that high levels of PV penetration (100%) would cause strong reverse power flows (200 kW) and high substation voltage levels (252 V) close to the limit (253 V) – causing constraints along the feeder. The current level of installed battery capacity would be able to assist the network by slightly reducing the peak voltage, although it should be noted that since the batteries would need to charge at their maximum rate, they would not be able to reduce the voltage during the entire generation period. As expected, a higher battery penetration level (100%) has a more significant impact, meaning that either larger constraints could be resolved or voltage could be reduced for a longer period. For completeness larger battery systems (4.8 kWh / 1 kW) were also modelled, which would be capable of reducing the voltage even more at peak generation time based on a penetration level of 100%. We should note here that for such a high battery penetration of strong batteries it should also be carefully considered when the batteries would discharge, as they could easily cause a strong increase in the voltage level during the evening peak (when demand is low and PV might still be generation to some extent).

The minimum battery penetration required to make a difference to network constraints caused by excess PV generation depends on the type and size of batteries installed, the level of voltage violation and by how much DNO would like to reduce it by. However, the modelling has highlighted the importance of installing more battery capacity than would minimally be required at the time of peak, as on sunny summer days the period of strong generation can be longer than the typical charging period of batteries (when charging at their maximum rate), and hence batteries should be set to charge at a lower rate to ensure they are able to assist the network throughout the entire afternoon.

Winter Peak

The modelling showed that in winter less penetration of storage is required for a significant impact, as the high demand levels in winter are less likely to cause constraints than the high levels of PV generation in summer. The current level of battery penetration would increase the voltage during the evening peak slightly (and slightly reduce it in the afternoon when generation is highest) which would assist in flattening the substation voltage throughout the day to some extent. A battery penetration level of 100% would have a much larger impact and would already be capable of bringing the voltage back to the base level of about 245 V but could also increase the afternoon demand to evening peak levels, which should be avoided by using appropriate charging schemes. The larger batteries have been included in the analysis, but as their impact is larger than would be required, a significantly lower penetration level of these batteries would suffice.

Feeder Analysis

Although the results shown for this feeder are mostly applicable to this type of cable (impedance and length) and demand profile, the general learnings are still valid. The feeder analysis has shown that constraints are likely to occur in service cables. The ability of the batteries to reduce the voltage to within boundaries was shown, but the length of the generation period again highlighted that the charging schemes of the batteries should be carefully considered as the batteries are likely to reach full capacity ahead of the end of the generation period, which would cause significant constraints later in the afternoon.

A more detailed analysis of the voltage as a function of the net generation (PV generation – battery charge rate) on the feeder has taught us that for the voltage at the of end of this service cable we can assume that each additional kW of net generation will cause an increase of 0.15 V. For the modelled feeder this implied that constraints would be reached for 64.5 kW of net generation.

5 Cost-Benefit Analysis

The aims of this Cost-Benefit Analysis (CBA) is to determine the economic feasibility of using battery storage to provide flexibility and resolve network constraints as opposed to conventional network reinforcement. The analysis considers two different scenarios:

- Storage is used to entirely avoid the need for conventional reinforcement; and
- Storage is used as an interim to defer reinforcement for a period of time.

5.1 Conventional Reinforcements

To understand the typical costs related to conventional network reinforcements Table 4 sets out average unit costs for a variety of potential network investments, based on the RIIO-ED1 network price control – which sets the output that DNOs need to deliver for their consumers and the associated revenues they are allowed to collect. By means of example, a number of reinforcement use cases have been created for which the associated costs, based upon the costs in Table 4 below, are outlined and presented in columns A and B of Table 5.

Table 4: Typical unit costs for conventional network reinforcements

ED1 average unit costs (2019/20 prices)		
Description	**Unit**	**ED1 allowed cost [£]**
LV Main (overhead) Conductor	km	£16,826
LV Service (overhead)	each	£435
LV Poles	each	£1,614
LV Main (underground Plastic)	km	£107,435
LV Service (underground)	each	£1,403
LV Pillar (indoor)	each	£8,848
LV Pillar (outdoor at Substation)	each	£9,717
LV Board (wall mounted)	each	£11,259
6.6/11kV Switchgear - Other (pole mounted)	each	£2,123
6.6/11kV RMU (Ring Main Unit)	each	£14,216
6.6/11kV Transformer (pole mounted)	each	£4,105
6.6/11kV Transformer (ground mounted)	each	£13,593

As per Table 5, costs vary strongly depending on the scale of the reinforcement works required, but it should be noted that the expected amount of required battery capacity to resolve potential constraints is related to the project scale as well. To account for this, column D of Table 5 shows an estimated battery capacity required to avoid or defer the conventional upgrade. For example, instead of reinforcing a LV service cable to accommodate high levels of generation or peak demand, if a 1 kW battery could absorb a significant part of the PV generation and provide most of the evening peak instead, it may allow the DNO to avoid or at least defer such investment.

Table 5: Example reinforcement use cases

A	B	C	D	E	F
Use cases	**Reinforcement Cases**	**Cost [£] (Ceiling price)**	**Estimated required battery capacity [kW]**	**Available compensation when avoiding reinforcement [£/kW/h]**	**Available compensation when deferring reinforcement [£/kW/h]**
1	1x LV Service (UG)	£1,403	1	£0.19	£0.06
2	10x LV Service (UG)	£14,030	10	£0.19	£0.06
3	10x LV Service (UG) 100m LV Main (UG Plastic)	£24,774	10	£0.34	£0.11
4	1x 6.6/11kV Transformer (GM)	£13,593	50	£0.04	£0.01
5	50x LV Service (UG) 100m LV Main (UG Plastic) 1x 6.6/11kV Transformer (GM)	£94,487	50	£0.26	£0.08

Based on the cost of the conventional reinforcement and the estimated required battery capacity that could resolve the constraint, the potential compensation that could be provided to battery owners/aggregators can be calculated and is shown in columns E and F of Table 5. These values have been calculated using the methodologies described in Table 8 and Table 9 (Appendix D) for completely avoiding and deferring reinforcement works respectively. The following assumptions were made for both methodologies:

- Discount rate of 4%;
- Network assets have a lifetime of 45 years;
- Flexibility services are required for 10 years[5];
- The DNO flexibility services requirements are:
    - 243 days per year[6];
    - 3 hours per day; and
    - at maximum capacity.

[5] The annualised cost savings for completely avoiding reinforcement are expected to be higher than those of deferring reinforcement as the investment would eventually need to be made sometime in the future.

[6] Available for evening peak demand reduction in November, December, January and February. Availability for mid-day generation reduction in May, June, July, August.

- The available compensation for flexibility services should not cost more than the cost of conventional reinforcement.

The compensation the DNO is willing to pay in the examples presented above may be deemed conservative as in practice, it is unlikely that the DNO would need to call for flexibility on all 243 days of the year. However, the compensation is calculated as such to ensure that in a worst case scenario (i.e. flexibility is required for 243 days in a year), the total cost of flexibility services will not exceed the annualised equivalent savings achieved by avoiding reinforcement or else the latter would be more cost effective and hence a better solution.

A number of reinforcement use cases were created to calculate indicative compensation amount for flexibility services that would resolve the same network constraints and are presented in Table 5. The available compensation ranges between £0.04 - 0.34/kW/h (where the conventional reinforcement can be completely avoided) and between £0.01 - 0.11/kW/h (where the conventional reinforcement can only be deferred for a period of time). It is important to note that in both cases flexibility services were assumed to be needed for a fixed period of time (10 years). In the "avoiding reinforcement" case, this assumes that in the long term (beyond the 10 year period) any reinforcement works will be avoided by other means (e.g. ToU tariffs) rather than through the procurement of flexibility services. Where flexibility services will be required for the full 45 year period, the compensation amount will be significantly less.

Based on these values, the maximum annual compensation available to a battery owner / aggregator (i.e. hourly compensation x 243 days x 3 hours per day) would be as follows:

- **Avoiding Reinforcement:** £26.81 - 244.35/kW/year
- **Deferring Reinforcement:** £8.70 - 79.28/kW/year

As stated earlier, the compensation payment may be deemed conservative as in practice it is unlikely that the DNO would need to call for flexibility on all 243 days of the year. For example, if the DNO expected that services would only be needed for half the time (i.e. 121 days) the maximum available compensation would double.

5.2 Alternative reinforcements drivers

For this study two types of battery storage have been studied, grid scale battery storage and domestic battery storage. To reflect different business cases, the following drivers behind battery storage installations were also considered:

- **DNO driven** – storage is installed for the main purpose of alleviating network constraints. This type of storage would most likely not have been installed otherwise (i.e. services provided to the DNO are a key part of the business case for investment in the batteries); and
- **Customer driven** – storage is installed to either bring savings for domestic customers by increasing their level of self-consumption, or to reduce costs for large I&C customers (e.g. by avoiding Triad charges. This type of storage is expected to be installed regardless of a DNO incentive.

5.2.1 DNO driven installation

Where storage is used to avoid or defer network reinforcement, the annual ceiling price for any DNO flexibility services should not exceed the equivalent annualised savings achieved by avoiding (or deferring) these works. For the five use cases presented in Table 5, the maximum price for the provision of flexibility services depends on the level of reinforcement required and whether it can be avoided or deferred. Where the reinforcement can be avoided, the compensation ranges between £26.81 and 244.35/kW/year (based on a 10-year flexibility requirement). On the contrary, where the reinforcement can only be deferred for 10 years the maximum compensation range reduced to £8.70 and 79.28/kW/year. The difference in price is due to the fact that in the deferral case, the full asset cost will still need to be paid after the deferral years. Table 6 compares the upper limits to the annualised costs of installing domestic or grid scale storage, which allows the calculation of the potential revenues.

As expected, the potential revenues depend strongly on the amount of reinforcement required. For example, in Case 4, where only a relatively small investment is needed for a large amount of additional capacity, the business case for batteries may be deemed poor, even when using the upper limit for the available compensation. However, where high network upgrade costs can be avoided by relatively limited amounts of storage, such as in Case 3, the business case is much more promising as the maximum available compensation is significantly larger than the cost of storage. Therefore, as the ratio between capacity required and reinforcement cost increases, the compensation decreases. Having said this, where storage can only defer rather than entirely avoid reinforcement works, the business case is more challenging, particularly for domestic scale storage where the cost per kW of storage capacity is high (see Table 5). If the cost of domestic scale storage would come down to the levels of grid scale storage, its business case would significantly improve.

With this in mind, the option for battery owners/aggregators to stack revenue, by bidding in the Firm Frequency Response markets for example, could provide them with additional revenue and hence improve the business case for them. Even though the value of these services has come down significantly in recent years, with an average price of £3.66/MW/h[7] in March 2019 this would equal to £32.06/kW/year based on full-year availability. These revenues can stack on top of any compensation offered by the local DNO.

In conclusion, there is potential for battery storage to be economically competitive with conventional reinforcement solutions, but only for certain types of network upgrades and where reinforcement can be entirely avoided and compensation is only required for a limited amount of time (although there could be some potential for grid scale storage to defer investments if the utilisation rate is expected to be high). Finally, the declining trend on the cost of battery combined with the potential of revenue stacking by bidding in other markets such as Frequency Response for additional income, would further improve their business case and make them economically viable alternatives.

[7] https://www.auroraer.com/insight/gb-ffr-market-summary-march-2019/

				Case 3: 10x service + 100m LV Main		Case 4: Transformer upgrade	
				Annual Compensation/kW			
				Avoid	Defer	Avoid	Defer
Storage Type	Cost/kW	Lifetime	Annual Cost/kW [8]	£244.35	£79.28	£26.81	£8.70
				Annual revenue (Compensation - Storage cost)			
Grid scale battery	£461 [9]	15	£41.46	£202.89	£37.82	-£14.65	-£32.76
Domestic battery	£1333 [10]	15	£119.89	£124.46	-£40.61	-£93.08	-£111.19

Table 6: Overview of the annual costs of DNO driven storage and the potential annual compensation available per kW for two of the reinforcement cases, combined to show the potential revenues for the different business cases of reinforcement being avoided or deferred.

5.2.2 Customer driven installation

As part of the DS3 study several battery charging profiles have been tested which allowed to determine the impact domestic storage can have on the network for different use cases. It was found that even when the batteries were operated purely at the discretion of the customer (Threshold Charging scheme), they were still contributing to a reduction in reverse power flow and peak load. Trials of a different charging scheme (Maximum Impact scheme) showed that their impact could be enhanced if customers were incentivised to operate their batteries according to a more optimal (from the DNO perspective) charging pattern. Figure 90, which shows the effectiveness of the batteries when operated according to different charging schemes in terms of the rate at which they discharged at the time of winter peak (max. 420 W) and charged at the time of peak generation in summer (max. 350 W), as a percentage of their maximum (dis)charging rates.

It should be noted that the batteries were not always operating according to the planned charging schedule and were only discharging at approximately 75% of their maximum rate at the time of winter peak (for the Maximum Impact scheme), something that might have skewed the results slightly. However, given the

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[8] Energy losses are not included in the annual costs per kW as it is assumed that batteries will only need to operate a few times per year when assisting the network, and losses are therefore expected to be small. The annual cost is based on an interest rate of 4%.

[9] Schmidt, O., Hawkes, A., Gambhir, A. & Staffell, I. The future cost of electrical energy storage based on experience rates. Nat. Energy 2, 17110 (2017).

This Imperial College paper states that the battery pack makes up 30% of the costs of a 1 kW/1 kWh system which, assuming a recent battery pack cost of €158/kWh (Bloomberg 2018 - $176/kWh: https://about.bnef.com/blog/behind-scenes-take-lithium-ion-battery-prices/) results in a cost of €369/kW for the power related part of the system. With an exchange rate of £1/€1.144 this gives us an estimate of £461/kW for the total system cost (assuming 70% of costs are caused by the power related part).

[10] Assuming the Moixa wholesale price (£2,900/unit) for an order larger than 100 units for their 2.4 kW / 4.8 kWh battery plus installation costs of £300/unit results in a cost of £1333/kW. This does not include VAT.

limited PV generation and low levels of demand, the lower effectivity demonstrated by batteries operating according to the Threshold Charging scheme is as expected.

For simplicity, the CBA uses an effectivity factor of 100% for DNO incentivised operation, and an effectivity factor of 50% for customer-controlled operation. However, results assuming effectivity factors of 75% and 33% respectively were undertaken as a sensitivity to test the impact of these reduced performances on the business case. These results are included in Table 7.

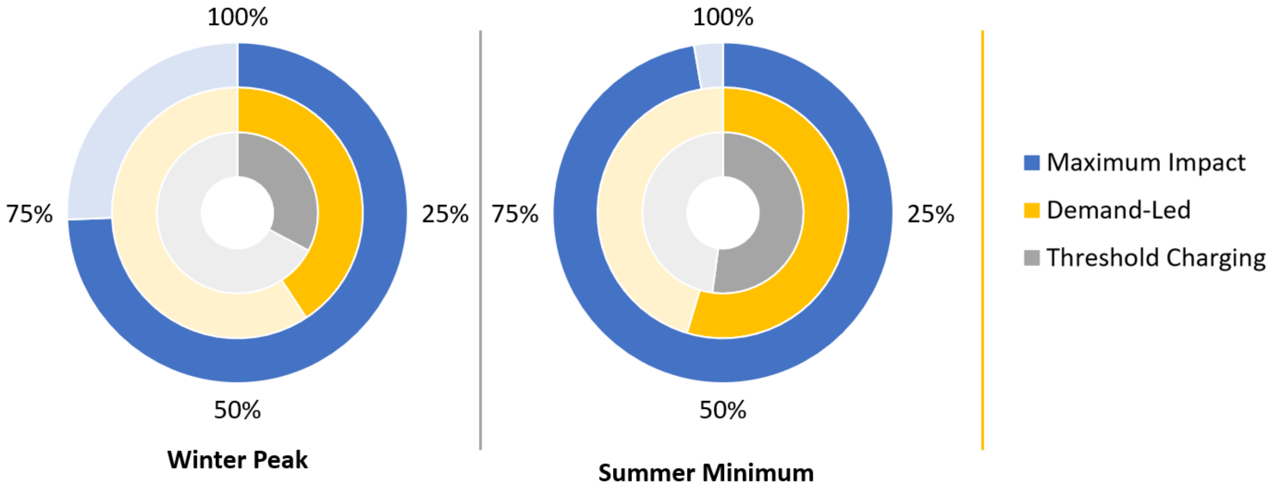

Figure 90: Effectivity Factors – Percentage of the maximum (dis)charging rate achieved by the batteries when operated according to the different schemes. Note that at the time of winter peak 100% corresponds to 420 W and at the time of summer minimum it corresponds to 350 W.

In the case of the customer driven installation, the customers have invested in the batteries for their own purposes, therefore any payment offered by the DNO needs to be adequate to incentivise the customers to use their assets to provide services to the DNO (i.e. by operating according to the Maximum Impact scheme) and to compensate the customer for any losses incurred as a result of providing those services (e.g. additional battery degradation and energy losses), which is accounted for in the 'Costs per cycle per kW' section in Table 7. It is worth noting that customer driven uptake will only result in enough battery capacity being available to provide DNO services if the customers deem that there is a sufficiently attractive case for purchasing domestic battery storage, either by just increasing self-consumption of locally generated energy, arbitrage or through the provision of services, something that is currently unproven. Furthermore, since the impact of customer-controlled storage (i.e. following a threshold charging scheme without DNO incentive) is much less than that of a DNO incentivised operation, based on the 50% effectivity factor, it would require twice as much capacity to have the same impact on the network. Having said this, the trial showed that customer-controlled operation could deliver some benefits to networks regardless. If these benefits are deemed adequate and could deliver deferral or avoidance of network reinforcement, the government and/or the local DNOs could potentially offer an upfront capital support (e.g. through a subsidy) rather than paying for a service, to stimulate the market and incentivise householders to invest in batteries.

Since if enough capacity is available storage could defer network investments in both use cases, the ceiling price for flexibility will be determined by the equivalent annualised savings of avoided conventional reinforcements, as described in Section 5.1.

	DNO incentivised operation		Customer-controlled operation	
	Case 3: 10x service + 100m LV Main	Case 4: Transformer upgrade	Case 3: 10x service + 100m LV Main	Case 4: Transformer upgrade
Effectivity Factor	100%	100%	50%	50%
Required Capacity [kW]	10	50	20	100
Maximum incentive per kW per year	A: £244.35 D: £79.28	A: £26.81 D: £8.70	**A: £122.18** **D: £39.64**	**A: £13.41** **D: £4.35**
Sensitivity: Maximum incentive per kW per year (based on 75% and 33% effectivity)	A: £183.26 D: £59.46	A: £20.11 D: £6.53	A: £80.64 D: £26.16	A: £8.85 D: £2.87
Costs per cycle per kW				
Battery Degradation[11]	£0.34		£0.00	
Energy Losses[12]	£0.02		£0.00	
Reduced self-consumption[13]	£0.13		£0.00	
Total additional costs per cycle	£0.49		£0.00	
Incentive Options				
Number of expected cycles	243		N/A	
Maximum incentive per cycle	**A: £1.05** **D: £0.33**	**A: £0.11** **D: £0.04**	N/A	
Potential revenue per cycle	A: £0.56 D: N/A	A: N/A D: N/A	N/A	

Table 7: Overview of the potential incentive (per kW per year or per kW per cycle) that a DNO could offer battery owners based on the avoided (A) or deferred (D) costs of conventional reinforcements for two different case studies.

[11] For the battery degradation, a battery cost of £4,450 (including VAT) for a 4.8 kWh/2.4 kW battery was assumed. After removing VAT that results in i.e. £1,545/kW. With a lifetime of approximately 4500 cycles, this results in £0.34 per kW per cycle. As it is likely that the customer would – to a lesser depth of discharge – operate their battery even if not requested by the DNO, and because the battery is expected to have leftover value after 4500 cycles, this figure provides an upper limit of the costs.

[12] Assuming a loss percentage of the battery of 10%, an electricity price of £0.13/kWh and a 4.8 kWh battery with a minimum state of charge of 20% results in £0.02 per kW per cycle.

[13] Since the trial revealed that customer-controlled batteries only had an effectivity factor of about 50%, it is assumed here that forcing the batteries to (dis)charge will mean that approximately half of the energy stored in the battery will not be self-consumed – resulting in a cost of £0.13 per kW per cycle. It should be noted however that this also enables the customers to store more PV generation on the next day, meaning the figure provided is an upper limit of the costs.

Table 7 indicates that the business case for the DNO-incentivised operation of customer owned storage is only promising if high network upgrade costs can be avoided (and flexibility is required for a fixed period of time) – allowing the DNO to offer up to £1.05 per kW per cycle to the battery owner. Where the upgrade can only be deferred or it is not as costly, the costs and losses related to operating the battery might outweigh the incentive the DNO can offer (up to £0.33 per kW per cycle). However, it should be noted that the battery operating costs provided are upper limits, so it is not unlikely that battery owners would be willing to operate their battery differently for a smaller compensation, if that operating scheme aligns with how they would otherwise operate them.

The table also shows that the DNO could potentially offer up to £122.18 per kW per year in some form of capital support to customers, if it is clear that such support would encourage the uptake of storage capacity in the constrained area and that customer-controlled battery operation would resolve the constraint. Interestingly, even if conventional reinforcement could only be deferred, a compensation could still be offered (£39.64 per kW per year) to also encourage uptake. As discussed earlier, where a relatively cheap conventional reinforcement is considered, it is unlikely that capital support will be adequate to stimulate enough storage uptake to resolve the constraint.

5.3 CBA Learnings

Performing the cost-benefit analysis has provided us with more insight into the commercial opportunities of using battery storage to defer network reinforcements. More specifically, we have learned that:

- There is potential for DNO driven installation of storage, but only in cases where a limited amount of storage could allow the DNO to avoid high cost network upgrades.
- In case uptake of storage is DNO driven, the business case for grid scale storage is significantly better than for domestic batteries due to the lower costs per kW. The installation of grid scale storage could be profitable even if it only allows for the deferral of a high cost conventional reinforcement.
- DNO can decide to incentivise customers to operate their batteries according to the maximum impact scheme, but only if:
    - a high cost conventional reinforcement can be avoided,
    - the battery owner would have operated their battery even if not incentivised by the DNO (i.e. the DNO is not solely responsible for the battery degradation)
- The DNO can benefit for free when batteries operate at the discretion of the customer as they can still assist the network at 50% of their maximum rate. It should be noted however that in this case twice as much battery capacity is required to be installed.
- The DNO can choose to offer some form of upfront capital support to stimulate the uptake of storage in the constrained area and exploit such benefit without the requirement to provide any further incentives.
- In some cases, the DNO incentive derived from avoided or deferred network reinforcements alone might not justify the investment in storage, but additional revenues (e.g. providing Firm Frequency Response) could contribute to the business case.
- Finally, it should be stated here that since battery costs are still expected to fall, some of the business cases which are only marginally non-profitable at the moment, might need to be reconsidered in a few years as their competitiveness is expected to improve.

6 Review of Engineering Recommendations & Design Standards

Due to the wide variety of charging schemes trialled, and the large amount of battery and network data monitored, there is an opportunity for the findings of the DS3 trial to inform relevant design policies and standards associated with the impact of PV systems and BESS on LV network. This chapter we will therefore assess whether the potential to amend the design standards so they could account for the impact storage can have on the network.

6.1 Description of standards

When designing an LV system, apart from establishing the capacity required to meet peak demands, where applicable, it is also necessary to assess potential constraints caused by high levels of PV generation at times of low demand. Northern Powergrid's Code of Practice for the Development of the LV System[14] states that the 'CLNR project concluded that it is difficult to derive a single combined net load profile to cater for network diversities across a group of customers' and therefore 'the effect of load on the system and export from PV generation need to be considered separately'.

To assess this impact of export from PV generation on the LV network, the code of practice suggests that a diversity factor should be applied to the nominal rated capacity of each PV installation, based on the number of PVs connected to the part of the LV system being assessed as well as on the relative orientation of these PV systems. The diversity factor ranges from 0.9 (for a large set of randomly oriented PV systems) up to 1.1 (for a small set of aligned installations). More importantly for this work, the code of practice suggests that a minimum demand of 0.3 kW per domestic premises should be assumed when doing so. This test ensures that the network voltage will remain within statutory limits even at the worst-case scenario (i.e. minimum demand, maximum generation).

6.2 Assessment of battery suitability

This trial assessed the suitability of batteries to assist the network at the time of minimum demand. Figure 90 has shown that the effectivity factor of domestic storage at the time of summer minimum ranges from 50% (Threshold Charging) to 100% (Maximum Impact) which based on the 0.35 kW maximum charging rate of the battery implies that in the worst case effectively (i.e. 50%) an additional minimum demand of 0.175 kW (0.35 kW * 0.5) could be assumed per domestic premise with BESS and PV on top of the currently assumed value of 0.3 kW, taking the total to 0.475 kW. In case a DNO intends to actively control the batteries, the minimum demand could even be assumed to be as high as 0.65 kW.

An important note that should be made here is that the impact of the Threshold Charging scheme in summer was mostly limited by the low evening demand of the tenants participating in the trial. A percentage significantly higher than 50% peak reduction should be achievable with batteries operating according to the Threshold Charging scheme in households with more consumption (Figure 10).

Interestingly, even though it was shown that a battery with a larger capacity and charging rate could have a much larger impact on the network (as is discussed in Section 4.5.3) in this case accounting for the

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[14] IMP/001/911 Code of Practice for the Economic Development of the LV System. Version 6.0. Date of Issue: Nov. 2018

household consumption level is even more important. For example, a larger battery for the participants of this trial – when operated according the Threshold Charging scheme – would only have reduced the effectivity factor, rather than increase the impact on the network. Crucially, an oversized battery could even completely nullify the impact on the network at the time of summer minimum, because the battery will only be able to partially discharge (due to the low household demand) and the higher charger rate could mean it can actually become fully charged earlier in the day (before the PV peak occurs on the network). This stresses the importance of assessing the household consumption levels when accounting for installed battery capacity in the network design – and when installing the battery in the first place.

6.3 Recommendation

In conclusion, the trial has demonstrated the need to account for installed domestic storage on the network when developing the LV system. Although it is important for any Engineering Recommendations and Design Standards to be robust, the fact that even for households with low levels of consumption the battery could reduce the excess generation by 0.175 kW would safely suggest that the minimum demand for households with BESS, where the battery is properly sized[15], can be raised to 0.475 kW. This is strengthened by the fact that participants of this trial could mostly be categorised according to the Mosaic Elderly Needs class, which describes customers with the lowest consumption level in the UK, and therefore it is likely that any other subset of customers will have a higher evening demand which will improve the effectivity of the Threshold Charging scheme in summer and hence would increase the 'effective' minimum demand even further.

In the case that the installed batteries are oversized compared to the consumption levels of the households (i.e. such that the battery does not fully discharge), larger benefits for the network could be achieved by incentivising customers to operate their batteries according to the Maximum Impact scheme – forcing them to (dis)charge – or according to the Predictive Charging scheme – which should be able to provide the same benefits whilst minimising the costs for the battery owner. However, when designing the LV system, the DNO will need to consider whether it will have the financial means to incentivise customers to operate their batteries in such a way. Budget for such incentives might be made available by deferring conventional network reinforcements (as discussed in Section 5.2.2).

[15] The maximum charging rate of the installed battery is the most important parameter to consider when assessing the minimum demand. This study has shown that households with low levels of demand will discharge the battery enough in the evening to enable a charge rate at peak time of 0.175 kW, but only because the batteries in the trial had a maximum charging rate of 0.35 kW. If, for example, a battery would be capable of charging at a rate of 1 kW, it would very likely reach its full capacity before the time of peak generation (if set to maximise self-consumption), in which case using a DNO focused charging scheme would become necessary.

7 Conclusions

Several learning goals were defined at the outset of the project, which were designed to guide the trials. Therefore, in this section we will use the main results of the data analysis and modelling to evaluate whether all learning goals have been successfully addressed by the trial.

7.1 Battery Performance

The impact of the batteries on the household import and export levels observed in Chapter 3 has allowed us to address the first learning goal.

Learning Goal

✓ Establish the extent to which residential batteries can be controlled to
- ➢ Reduce the peak export from a PV installation
- ➢ Reduce the evening peak load

Findings

1. DNO-focussed schemes can double network impact
   - ➢ By controlling the batteries to ensure they are empty ahead of a generation period and fully charged before the evening peak, batteries can be used much more effectively

2. Customer demand has big impact on battery performance
   - ➢ Evening peak and overnight demand should match battery size
   - ➢ The battery's threshold level may prevent the batteries from operating when customer demand is low therefore it should be set accordingly

Trials showed that although residential batteries can have a strong impact on the network, their effectivity varies significantly depending on the type of customers as well as their mode of operation (i.e. charging scheme), as is shown in Figure 91. The impact of the customer-focused charging schemes (ranging from 22% for the Threshold Charging scheme in summer to 36% for the Demand-Led scheme in winter – for households with one battery) was mainly limited by the low consumption levels of the participants in the trial, which either directly affected the discharging rate of the batteries at the time of winter peak, or indirectly reduced the available charging capacity and hence charging rate at the time of summer minimum as a result of limited available capacity. Due to this low demand, the added benefit of installing a second battery in a number of properties (i.e. double the capacity and rate of charge/discharge) was also small.

Finding 1

The DNO-focused scheme, whereby the batteries were forced to (dis)charge, resulted in a much stronger reduction of excess demand and generation. At the time of winter peak, reductions were around 65% for households with one battery, and even as high as 95% if two batteries were installed.

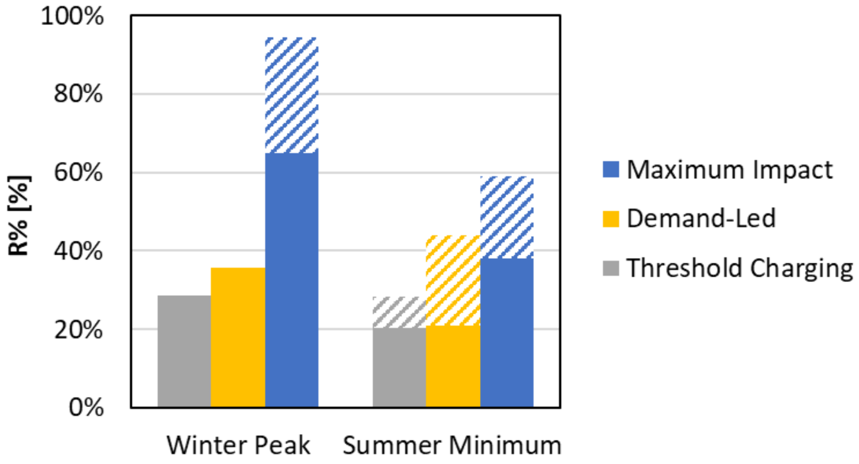

Figure 91: The percentage reduction of excess demand at the time of winter peak and excess generation at the time of summer minimum that can be achieved by operating the batteries according to the different schemes. The hatched areas indicate the further reduction that is achievable by having a second battery installed.

Finding 2

Additionally, during the early stages of the trial it was also found that the threshold level set for the batteries (i.e. the level of excess demand/generation above which the batteries start operating) was too high for the participants of the trial. For optimal battery operation and hence optimal benefit, the threshold value should therefore be reflective of the customers' demand profile.

7.2 Network Impact

The results above describe the impact residential batteries can have at household level. Analysis of the substation data together with modelling a variety of scenarios allowed to understand the extent to which batteries can make a difference to network constraints.

Learning Goal

✓ Identify the battery penetration needed to make a difference to network constraints caused by daytime PV output or evening peak loading

Findings

3. Batteries can make a big difference to network constraints, but required penetration depends on operating scheme
   - a. Low variability in substation demand has been achieved with a penetration level of 55%
   - b. In customer-focussed schemes twice as much kW should be installed than in DNO-focussed schemes

4. There is no need to force batteries to operate when predicted generation or demand is small
   - Advanced charging schemes were tested and were successful in forcing the batteries to charge on particularly sunny days

7.2.1 Trial Outcomes

Finding 3a

One of the substation feeders in the DS3 trial had 36 households connected to it of which 15 (or 42%) had PV installed, and 20 (or 55%) had battery storage. Analysis of the monitored substation data for this feeder revealed that the batteries had a very significant impact on the network, but also that the impact was strongest when they were forced to (dis)charge. Figure 92 shows that the Maximum Impact scheme managed to reduce the peak demand and reverse power flows from about 20 kW to levels of about 10 kW (50% reduction).

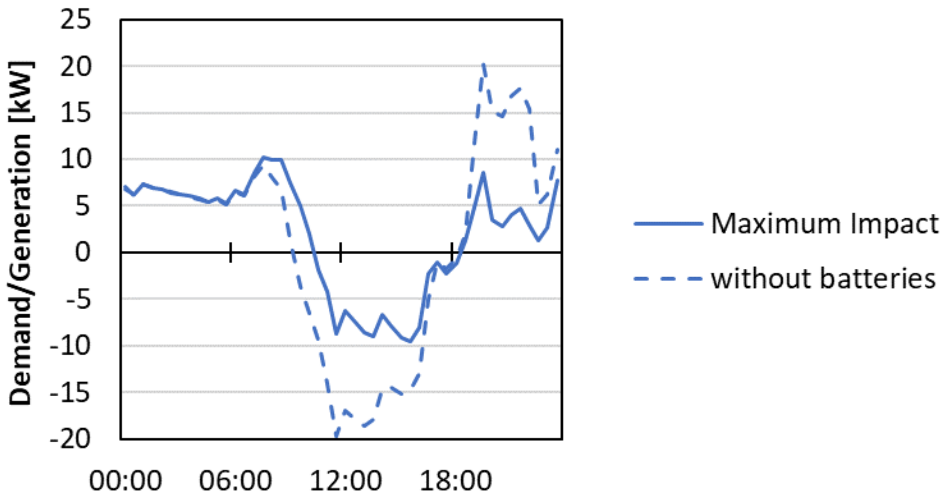

Figure 92: The substation demand for the Maximum Impact scheme as compared to the base case substation demand determined by subtracting the battery (dis)charging rate from the monitored substation demand (dashed blue line).

As the batteries reduce the peak demand and generation, they shift load to periods of low demand (and/or high generation), essentially flattening the substation demand profile. Figure 93 shows variability of the demand (with and without the impact of the batteries), expressed in terms of the standard deviation during the period 09:00 – 21:00. Based on this figure, and the results in Section 3.2.5 and 3.3.5, the following two conclusions can be drawn regarding the impact of residential batteries on the network:

Finding 3b

1. The impact of batteries on the network is significantly larger when batteries are forced to charge or discharge (i.e. operate).

Finding 4

2. The batteries only really need to be forced to charge on days when high peak demand or large amounts of generation is expected (as in Figure 40).

The importance of these conclusions is illustrated by the Maximum Impact scheme in Figure 93. During summer, the scheme indeed managed to reduce strong reverse power flows towards average levels – something the other schemes would have been incapable of – but in winter the scheme may have been unnecessarily impactful, at the expense of extra costs for the battery owner (i.e. degradation costs and losses).

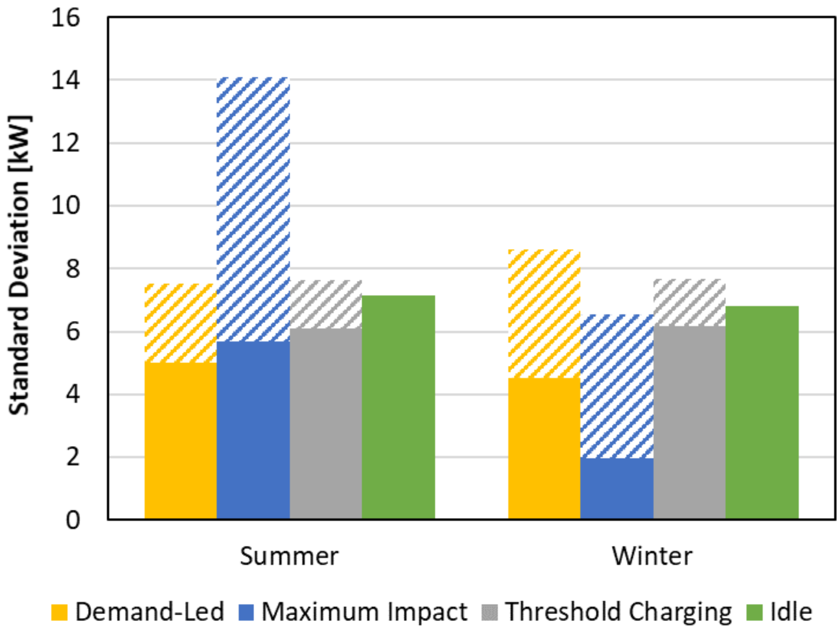

Figure 93: Standard deviation in substation demand with batteries operated according to the different schemes. The hatched areas indicate what the standard deviation would have been if the batteries would have been inactive.

In conclusion, residential battery storage can have a large impact on the network, but the battery penetration level required to make a difference to network constraints strongly depends on the charging scheme. Based on the effectivity factor of 1 for a DNO focussed scheme (e.g. Maximum Impact) an additional 1 kW of extra PV generation could be installed for each kW of battery storage available. For customer focused schemes, an effectivity factor of 0.5 should be used, which means 2 kW of storage would be required for each additional kW of PV generation.

7.2.2 Model Outcomes

Modelling the network using Ipsa software has enabled us to explore scenarios and their corresponding network impacts which could otherwise not be studied within this trial. This has helped understand better the network benefits of privately owned behind-the-meter storage.

Learning Goal

- ✓ To understand the network benefits (if any) of privately owned behind-the-meter storage compared with storage directly connected to the LV network as trialled on CLNR.

Findings

5. Batteries can manage voltage problems
   - ➢ High levels of battery penetration (2 kWh / 0.4 kW systems) could improve the voltage by 1.5 V (~0.6 %)
   - ➢ For larger batteries (4.8 kWh / 1 kW systems) the impact could be as large as 3.5 V (~1.4 %)

6. Battery capacity and charging rate should be correctly sized to assist the network throughout the entire afternoon
   - ➢ A larger battery capacity could be beneficial for the DNO, but for effective use of the battery, the capacity should not be much larger than the daily customer demand
   - ➢ If the charging rate is too high compared to battery capacity the battery can be full before the end of the generation period, although it can also be decided to force the battery to charge at a limited rate

7. Behind-the-meter batteries have the advantage over network connected storage that they can assist the network at node level
   - ➢ The model has shown that installing batteries along a feeder can help resolving voltage constraints at the end of a service cable

Finding 5

The modelling of Summer Minimum and Winter Peak demand scenarios led to the conclusion that the presence of domestic batteries on the network assists in balancing the demand and generation, levelling the power flow at the substation and keeping the voltage within a narrower band. The model showed that high levels of battery penetration could reduce or increase the voltage by about 1.5 V (~0.6 %) for 2 kWh / 0.4 kW systems or 3.5 V (~1.4 %) for 4.8 kWh / 1 kW systems, which could give the DNO flexibility, although it should be noted that the charging schemes should be carefully considered to avoid any unwanted reverse power flows or evening peak demands.

Finding 6

Through modelling it was found that the 2 kWh / 0.4 kW batteries were not always capable of resolving the network constraints throughout the entire afternoon and therefore larger batteries in terms of capacity (kWh) should be considered. However, it should be noted that for effective use of the battery the capacity should not be much larger than the daily customer demand. To ensure the batteries are able to assist the network during the entire generation period, the battery charging rate should not be too high compared to the battery capacity, although the DNO could also decide to incentivise customers to charge their batteries at a limited rate.

Finding 7

Previously, the CLNR project revealed that grid scale storage is able to have a similar effect on the substation power flow and voltage as behind-the-meter storage. However, analysis of the voltage at node level as part of this this project (Section 4.7) complements that of CLNR by indicating that the behind-the-meter storage is capable of addressing issues along the feeder as well. The modelled feeder profiles showed that high levels of PV penetration will lead to increasing voltages toward the end of the feeder or at nodes where a cluster of PV generation is connected, and batteries would be able to manage this.

7.3 Financial Impact

To explore the opportunities of using (aggregated) storage for the purpose of assisting the DNO network and understanding the possibilities for dynamically managing constraints, the following learning goal was defined at the start of the project.

Learning Goal

- ✓ To gain a DNO understanding of the Moixa Cloud aggregation platform, the potential revenue streams that such arrangements can secure commercially, how such arrangements impact on the DNO network and whether the DNO can interact with it to dynamically manage DNO constraints.

Findings

8. Where the DNO can avoid or defer conventional reinforcements, the following indicative compensation could be offered to storage owners, depending on the use case:
    - £27 – 244/kW/year if entirely avoided
    - £9 – 79/kW/year if deferred by 10 years

9. DNO driven installation of storage only is only feasible when high cost conventional reinforcements can be completely avoided which at the moment is highly unlikely.
    - With the decreasing cost of storage, the business case for storage to replace lower cost reinforcements will improve in the future
    - Additional revenues based on e.g. the Firm Frequency Response market can make the business case more profitable
    - The business case for grid scale storage is significantly better than for domestic batteries due to the lower costs per kW. The installation of grid scale storage could be profitable even if it only allows for the deferral of a high cost conventional reinforcement

10. Customer driven installation is economically feasible
    - The DNO can benefit for free from customers who have installed domestic storage to increase their self-consumption as the charging behaviour of their batteries naturally aligns with network constraints
    - Capital support could be offered to increase the natural uptake of storage to increase the network impact
    - The battery effectivity can be improved by incentivising customers to fully charge and discharge their batteries at certain times
    - Battery degradation costs can be significant, so if the DNO would need to pay the entire degradation costs, only high cost reinforcements could be replaced by domestic storage

11. Predicted charging can reduce costs
    - By accurately predicting days on which constraints are expected,

7.3.1 Cost-benefit analysis

Finding 8
To understand the compensation a DNO could offer for flexibility services if these would allow the DNO to avoid or defer conventional reinforcements, typical costs related to a variety of network reinforcements were used to define a set of reinforcement use cases. These use cases provide an indication of the costs related to certain network upgrades, as well as the indicative battery capacity that would be required to avoid or defer these upgrades. A methodology was set out in Section 5.1 to calculate the annual compensation that could be offered which ranges from £26.81 – 244.35/kW/year if conventional reinforcements could be avoided, to £8.70 - 79.28/kW/year if they could only be deferred.

When assessing the cost-effectiveness of installing battery storage on the network to defer network upgrades, two alternative reinforcement drivers were considered; DNO driven installations, with the main purpose of alleviating network constraints; and customer driven installations, which have the focus of reducing costs for domestic and I&C customers by increasing self-consumption or avoiding network charges.

Finding 9
With the current annualised costs of storage of £41/kW and £120/kW for grid-scale and domestic storage respectively, it was shown that there is potential for DNO driven installation of storage, but in most cases only if the conventional reinforcement can be avoided. There is some potential for grid scale storage when deferring investments, but only if the utilisation rate of the storage is expected to be high. For both these cases, it should be noted that additional revenues based on e.g. the Firm Frequency Response market would be required to make the business case more profitable.

Finding 10
Instead of investing in DNO driven installation, there would be potential for the DNO to incentivise its customers to operate their batteries based on a DNO focused charging scheme. However the costs related to battery degradation can be significant, and therefore the business case will only work if either a high cost conventional reinforcement can be avoided, or if the battery owner would have operated their battery

even if not incentivised by the DNO (meaning the DNO would not be solely responsible for the battery degradation).

As this work showed that batteries operated at the discretion of the customer still assisted the network at 50% of their maximum rate, the DNO could also decide to offer some form of capital support to stimulate uptake. However, in this case twice as much battery capacity would be required to resolve a similar constraint (due to its limited contribution).

7.3.2 Predicted Charging

Finding 11
To address the question whether the DNO will also be able to use the Moixa GridShare platform to address network constraints dynamically, in June 2018 an advanced charging scheme – Predicted Charging – was trialled. This scheme proved that the Moixa GridShare platform can be used to control the batteries in such a way that they assist the network by absorbing particularly high levels of PV generation at specific times during a day. This scheme allowed for a reduction of the costs incurred by customers, whilst still achieving a similar impact on the network.

7.4 Review Design Standards

The learnings of this trial have allowed to make a recommendation to amend the Northern Powergrid design standards used for the design of the LV system when accounting for PV and BESS, as was set out in the following learning goals for households with and without PV.

7.4.1 Households with PV

Learning Goal

✓ Determine whether an additional de-rating factor would be appropriate for design studies on PV installations that propose to have aggregator-controlled batteries at some properties.

Findings

12. A higher minimum demand can be assumed for domestic premises with PV and storage
    - ➢ Without any incentives the minimum demand can be assumed to be 0.475 kW (58% increase)
    - ➢ With aggregator-controlled batteries, the minimum demand could be as high as 0.65 kW (125% increase)

Analysis of the battery data has indicated that even when not incentivised the batteries of domestic customers assisted the network at approximately 50% of their maximum rate at the time of summer minimum (Figure 90). As battery activity was mostly constrained by low levels of demand (which was typical for the participants of this trial), it is expected that percentages significantly higher than 50% could be achieved for households with a larger demand. In the case of batteries forced to charge by an aggregator, an effectivity factor of 100% could be reached, although this would incur extra costs for a DNO.

Finding 12
When designing an LV system, the impact is that instead of assuming a minimum demand of 0.3 kW for each domestic premises, a value of 0.475 kW could be used for properties with domestic storage installed (58% increase), if the batteries are right-sized. The minimum demand could even be assumed to be as high as 0.65 kW (125% increase) if the batteries would be actively controlled.

An important finding is that the assessment of the impact of residential battery storage on the network (particularly when not incentivised) needs to take into consideration whether the battery capacity, the maximum charging rate, and the threshold level are reflective of the demand levels of the household.

7.4.2 Households without PV

Learning Goal

- ✓ Determine whether it would be valid for design engineers to apply different design parameters to new housing estates without PV but equipped with aggregator-controlled batteries.

Findings

13. There currently is no reason to install batteries in households without PV (apart from security of supply)
    - ➢ Without smart tariffs, batteries will be inactive and therefore have no impact on the network

14. The uptake of domestic batteries could be stimulated by DNOs by offering capital support
    - ➢ For homes without PV the DNO would need to force the batteries to operate to avoid inactivity
    - ➢ For homes with PV the DNO could benefit from the batteries without forcing them to charge

Finding 13
Operating the batteries according to the different charging schemes quickly revealed that batteries in households without PV remained inactive if not forced to (dis)charge. They could have the same network impact as batteries in households with PV, but due to the lack of time-of-use tariffs (and without incentives or access to other revenues) there is no reason for the user to operate the battery.

Finding 14
More generally, it is unlikely that with the current costs of residential storage and the lack of financial benefits there will be significant uptake of BESS in households without PV. However, the CBA in Chapter 5 indicated that in the case that network reinforcement could be avoided by incentivising customers, DNOs could offer a significant compensation (£47 – 430 per kW per year) to owners of domestic battery storage, which could potentially stimulate the uptake of storage in constrained areas.

7.5 Lessons Learned

The DS3 project has provided many valuable learnings to all partners involved in the trial, ranging from battery data quality and impact on the distribution network to tenant understanding. These lessons are summarised here. For completeness, the lessons learned regarding the tenant engagement, as listed in Section 2.2.2, are repeated here.

7.5.1 Data Analysis

Working with large datasets, particularly in trials, will almost always cause some complications. The importance of having reliable and consistent data streams in place has been highlighted during this trial, as well as the fact that deadlines in a trial should be responsive to trial issues. An overview of the lessons learned related to the data analysis and network modelling is provided below.

Data quality and availability
Data is not always perfect
Data captured from the battery systems is not always perfect and there might be missing or anomalous data points.
Connectivity issues can complicate data transfer
Due to connectivity issues with the web interface, it was not always possible to download the very large datasets of short time-step monitored data. This reduced flexibility when performing the preliminary analysis and slowed the process of producing results. It should be ensured that efficient processes are in place to transfer the data.
Reporting deadlines should have some flexibility to respond to trial issues
Due to installation issues, the number of batteries online and reporting reliable data was low in the initial phase of the project. As a result, we were unable to draw accurate conclusions based on the early data analysis. The constantly evolving nature of the dataset has meant it has been necessary to repeat some analyses as the dataset improved, resulting in some duplication of effort. This highlights the importance of retaining some flexibility regarding the deadlines for reporting and data analysis, to account for the practical issues with the trials.

Automated Data Analysis
Ensure datasets will be in a consistent format
The project data was provided from different sources and in multiple formats, which caused difficulties due to system migrations. Agreeing on a standard format where possible at the start of the project can avoid issues.
Being able to easily recreate results is very useful
Particularly during a trial, it is important to be able to have insight in the data at multiple times throughout the project. Python code was developed to easily reproduce outputs, but it had to be adapted many times because of changes in the data format and the battery IDs. This shows there is value in designing a more flexible tool when changes are expected to occur throughout a project.
Accurately define parameters at the beginning of a project
Spending a significant amount of time at the outset to define parameters to describe the impact that the

batteries have on the network has proven to be useful. These parameters have informed discussion and provided a consistent basis for assessment of the batteries' performance throughout the project.
Data cleaning is vital
A data cleaning procedure was implemented to ensure reliable data analysis by ignoring missing or anomalous data points when calculating the average battery performance. Battery performance could easily be over- or underestimated if the data is not cleaned. In any project, a significant amount of time should be allowed for this.

Network Modeling
Having accurate measurement data important for model performance
The accuracy of the network model strongly depends on the measurement data provided. In the initial calibration of the model, data was missing for some households, and therefore the model was recalibrated at a later stage of the project. It would have been more efficient to await better battery data quality before developing and modeling the network.
Reactive power measurement was not provided separately for consumption
The reactive power consumption data of each household is important to accurately model the power flow and in turn the voltage profile down the feeder. The power factor was assumed to be unity. This can have an impact on voltage profile and power flow since it is more realistic to have the actual power factor. The overall power factor is between 0.95-0.97.
Some data points were missing
The data that was missing was either assumed to be zero or interpolated for completion. This approach is valid for PV as the output is predictable. It is not necessarily true for domestic demand. The quality of the data must be considered for the validation of the model and for future analysis.
Consider conventions on power flow
Convention on power flow should be considered (positive/negative power flow) for better understanding of the data since batteries and/or PV are connected to the households.

7.5.2 Project Management

In a long-term trial like DS3 delays can be caused by a variety of reasons, but clear communication and regular meetings can ensure the project remains focused on the goal it set out to achieve. Lessons learned regarding the project management of the DS3 project are listed here.

Clear Communication
Frequent and clear communication between the project team is important
Installation issues and firmware updates meant that some of the monitored parameters were not reporting reliable data. Some time was spent on analysis and attempts to understand unreliable data, which could have been avoided by more frequent communication between all parties.
Simplify modifications of battery control strategies
As part of the trial a range of battery charging schemes has been trialed and it was not always clear which scheme was implemented and when operation had started. For a next trial it would be useful to introduce a procedure for requesting changes to the charging schemes, and to automatically record the date of the implementation. This will ensure that changes to the charging strategy can be clearly linked

with the data analysis.

Project Management
Professional leadership
Appointing effective and proven project management teams who are familiar with the subject matter was critical for such an early-stage technology pilot.
Regular meetings
Monthly update meetings are important and weekly meetings for busier periods such as customer recruitment and installation.
Roles & responsibility
This must be clearly established by the project partners across all project participants from the outset.
Cross-collaboration
Project partners are encouraged to share their own best practices during the project.
Goal focused
Project managers must continuously reinforce the goals of the project at every meeting to keep project partners engaged and focused on timely delivery. Where possible, it is also important to maintain the same team members throughout the project for consistency.

7.5.3 Battery Installation

Since the start of the project a lot of experience has been gained regarding the installation of smart batteries, particularly related to data communications and the training and experience of installers. A variety of issues was resolved throughout the project, and the lessons learned in the process are treated below.

Battery Installation
Rapid fitting
Installation of the Moixa Smart Battery within 2 – 3 hours is feasible. It is important for provider (in this case Moixa) to understand the customer prior to engagement so product is right fit for tenant (both physically, as well as connection to internet, energy usage, etc.)
Compact size
The size allows the system to be installed in many locations which broadens the range of properties that are suitable for installation.
Trades coordination
Although PVs were already installed, simultaneous installation of all components (PV, battery, broadband) decreases customer disruption.
Installer experience
It can be concluded from this project that training and experience are vital, and it is worth double checking the contractor's understanding of what is expected, and the work they deliver. Moixa has overhauled how they engage, train and manage installers through the new Moixa Accredited Installer program.

Data communications
Good connectivity is key, and 3G cannot be depended upon to give a consistent service. Greater customer engagement and education to ensure customers do not switch their internet off.
Internet over power line communications can be unstable and interfere with other equipment
It turned out that the internet connection over power line communications could be unstable and caused interference with other equipment of similar nature. This prevented data transmission and remote battery control.
Problems with installation of the meters
Some of the meters were installed incorrectly (e.g. having their polarity reversed), which emphasised the need to ensure installers fully understand the work requirements prior commencing the installation process. By auditing the first few installations, trainers should be able to pick up any abnormalities which will prevent installers having to go back to sort out any wrongdoing.
Accidental activation of the bypass button
It seems that in some cases the bypass function was activated accidentally – putting the battery in standby mode – when the button cover was shut. As a result of this the battery was unknowingly not generating savings for the customer nor assisting the network. Moixa has reviewed the bypass button to see if they can prevent this issue from happening again in the future.

7.5.4 Tenant Engagement

The DS3 project has provided many learnings regarding tenant engagement, some of which are specifically related to the type of participants of the trial. The elderly tenants were not tech savvy which complicated remote troubleshooting and caused unexpected issues with property access. However, it should be noted that the tenants were always welcoming and engaged with the project.

It was also learned that customer communication should be appropriate of the audience, and that making use of existing networks often is more effective than relying on online communication only. Crucially, the project also stressed the importance of correctly sizing batteries based on the type of household and resident for optimal battery performance.

Based on these learnings, Moixa has further developed its Moixa GridShare dashboard to improve tenant visualisation and allow for group visualisation (enabling the grouping of multiple assets). Furthermore, they have improved the internal data collection and reporting to allow for data analysis across different assets (including individual assets across changing tenants) which was uncovered to be of importance through this project.

Understanding of Tenants
Issues occurred because tenants were not tech savvy
An important lesson learned during this study is that the fact that the tenants were not tech savvy made it hard to proactively identify issues and troubleshoot remotely. Tenants occasionally switched off their routers when they were not using it or unplugged the battery which shows education of tenants is necessary and important.
Tenants showed patience with the installation process
The tenants were patient as firmware updates to the batteries and communication issues meant that some tenants had multiple installation visits.

Not everyone has broadband

Although it was anticipated that some tenants would require broadband connection, acquiring it for multiple properties and making arrangements for covering the costs took longer than expected.

Unexpected issues with property access

Despite having scheduled meetings in advance, in some cases there were unexpected issues with accessing the properties during the installation period. Some tenants forgot appointments or were out due to an emergency. Since this behaviour is unpredictable, it should be taken into account that delays during installation should be expected. Reminders could perhaps be a mitigation action.

Only a very small percentage of tenants was interested in viewing their battery usage

It turned out that only a very small percentage of the tenants were interested to view their battery usage, and potential savings on the online platform provided by Moixa, which is related to the tenants being elderly and not tech savvy. The tenants relied on Energise Barnsley to equate battery usage to potential electricity monthly bill savings.

Energise Barnsley spent a significant amount of time trying to clean the data and analyse the battery savings and recommends that data should be metered instead of measured by clamps (or similar) so data is reliable and there is belief in the numbers so electricity savings data is easier to produce.

Batteries increase tenant savings, but retail price increases disguised savings

The savings from the solar electricity generation were significant for those tenants who actively tried and changed their energy behaviour to capture as much of the solar generation as possible through self-consumption. Levels of self-consumption of solar generation varied greatly within the project. The electricity savings from the battery approximately contributed another 10 – 25% on top of the solar electricity savings.

Even though the batteries did cause savings, it should be noted that from the tenants' perspective these savings were sometimes disguised by the increasing utility bills as a result of increasing retail prices.

Customer Recruitment

Allow time

A period of 3 to 6 months is needed to properly engage customers.

Understand individuals

A customer relationship management driven approach and rigorous customer management is essential to capture all the details that will improve the tenant experience.

Expectation management

Clear information in paper and email format upfront is essential to build trust between customer and technology.

Resident suitability

Energy audits are essential to ensure battery 'rightsizing'.

Onboarding takes time

Plan in extra time for unexpected events, particularly uncertainty around customer availability.

Household suitability
Medium to high electricity consumption with a peak in usage in the morning and evening. Ideally the household would use little power during the daytime. Tenant energy profile can be attained first with energy monitors or smart meter data or using information on demographics or archetypes.
Tenant Engagement
Customer communication
Language should suit and be appropriate for the audience.
Do not rely on online only
Information communicated in letters and direct telephone conversations was much more effective than when sent by email only. It is therefore important to know the audience.
Work with the social landlord
In this project we successfully worked together with Energy engagement officers and tenant liaison officers who did a lot to aid contacting tenants and addressing initial concerns. They also attended all the briefing meetings.
Use existing networks
Leverage community action groups and tenants' liaison officers to benefit from existing trust and relationships.
Battery location
Battery location is important; cupboards and storage areas are best. Some customers preferred to see their battery's light to know it was working. Others prefer the battery to be out of sight. Engage with customers and install accordingly.
Performance and savings
It is critical to explain the relationship between a customer's energy profile, the battery behavior and the expected savings. This must be established during customer recruitment.
Who is the tenant
Access to the customer Moixa dashboard is linked to the tenant's email so communication of when a property changes hands is essential.

7.6 Further work

The DS3 project has been successfully delivered and has generated many valuable learnings and insights. During the course of the project, a substantial dataset of residential electricity demand, PV generation and battery (dis)charge behaviour has been collected. While detailed analysis of this data has been undertaken within this project to comprehensively address the project's objectives and learning goals, there are opportunities to extract additional value from this data and derive further insights through a variety of further analyses. Furthermore, the analysis of the data collected in this project and consideration of the project learnings have revealed that future trials could be designed to explore certain interesting aspects in more detail.

7.6.1 Further Analysis

There are significant opportunities for further analysis of the existing data and exploration of the models developed:

- **CBA Model**: The cost-benefit analysis in this work outlines a range of options available to DNOs to invest in battery storage, but there is potential to explore this in more detail by assessing a broader range of scenarios, including consideration of regulatory impacts and more extensive analysis of the customers costs and benefits.
- **Network Model:** The Ipsa model has already been used to study a large variety of scenarios but could still provide many more insights in the performance of the network by simulating more (constrained) network configurations, varying network parameters (e.g. cable types) or analysing specific scenarios in more detail.
- **Monitored Data:** The network and battery data recorded as part of this trial has been analysed in great detail, but as there are so many combinations of charging schemes, time periods, customer types, battery capacities and installed PV generation, more analysis can still be done to e.g. assess the impact of batteries on the network on a specific day, determine the battery effectivity for a smaller subset of customers, or analyse the impact of the batteries on the feeder that had less trial participants connected to it. Furthermore, there is potential to combine the monitored data with other available datasets (e.g. on demand patterns or network constraints), to broaden the scope of the analysis.

7.6.2 Future Trials

Potential new projects to explore in more detail interesting aspects that have been revealed as part of the DS3 project could include:

- **Battery Rightsizing:** The DS3 project has highlighted the importance of installing battery capacity that is reflective of the household's consumption level and demand profile. A correct battery size will affect the costs and savings for the customers as well as the impact that the battery will have on the network. A future trial could be done based on a wide variety of households, in which the effectivity of the battery can be analysed. The outputs of this trial can also feed into the review of the Engineering Recommendations and Design Standards, as this project revealed that the minimum battery impact relies on the appropriateness of the size of the battery.
- **Dynamic Control:** By trialling the Predicted Generation scheme we have shown that it is possible to operate batteries in such a way that they have a large impact on the network whilst the costs for the battery owners is minimised. However, the scheme was only trialled for a limited amount of time, so future trials could explore the scheme over a longer period or could even trial more advanced schemes based on machine learning.
- **Business Case Trial:** The CBA has highlighted a range of business cases available to the DNO, but there would be value in trialling the operation of these business models in practice, within the current regulatory environment and market conditions, as well as trialling how changes to the regulatory and commercial framework could improve the business case. For example the CBA has shown that the value derived from deferred network reinforcement alone is unlikely to be sufficient to justify investment in behind-the-meter battery storage, hence it would be valuable to trial how support to the DNO can be combined with other potential revenue streams for domestic battery storage, for example via Moixa's GridShare or other aggregator platforms.
- **Batteries and Time-of-use tariffs:** A further aspect of testing the business case, given that the trial has highlighted that the business case for battery storage can be difficult based on the income of increased self-consumption alone, would be to explore in a future trial how advanced charging schemes can optimise savings for the customer when combining battery storage with PV generation and time of use tariffs.

Appendix A: Key Metrics

Parameter	Description
$\boldsymbol{R_{\%}}$ [%]	Average percentage reduction in import/export level over the high demand period (17:00-20:00) or the high generation period (10:00-16:00).
$\boldsymbol{R_{\%,peak}}$ [%]	Percentage reduction in import/export level at the time of peak demand (18:00) or peak generation (12:30).
$\boldsymbol{\sigma}$ $[W]$	Variability in distribution substation demand expressed as the standard deviation, which is expected to decrease when more BESS is installed. To understand the impact the batteries have on flattening the profile during the day, the standard deviation is calculated for the time period 09:00 – 21:00.

$\boldsymbol{\sigma}$

Standard deviation of the substation demand:

$$\sigma = \begin{matrix} standard \\ deviation \end{matrix} = \sqrt{\frac{\sum_{l=1}^{L}\left(\overline{P_{grid,l}} - \overline{P_{grid,avg}}\right)^2}{L}}$$

where L is the amount of time steps (48 half-hourly periods) and $\overline{P_{grid,avg}}$ the average demand level for the feeder. The standard deviation is calculated for the time period 09:00 – 21:00.

Summer

$\boldsymbol{R_{\%}}$

Fraction of the export $(P_{pv} - C_{tot})$ that is stored in the battery (P_{bat}):

$$R_{\%}[\text{Export}] = \frac{P_{bat}}{P_{pv} - C_{tot}}$$

$R_{\%,peak}$ when calculated at the time of peak: 12:30.

Winter

$\boldsymbol{R_{\%}}$

Fraction of the total import $(C_{tot} - P_{pv})$ that is provided by the battery (P_{bat}):

$$R_{\%}[\text{Import}] = \frac{P_{bat}}{C_{tot} - P_{pv}}.$$

$R_{\%,peak}$ when calculated at the time of peak: 18:00.

Appendix B: Battery Impact for Careers and Kids Households

When assessing the reduction of excess demand or generation the batteries can achieve the demand profile of the household owner has a large impact. Figure 94 and Figure 95 repeat the percentage reduction as shown in respectively Figure 18 and Figure 32, with as only difference the assumed demand profile. In the figures below a demand corresponding with the Mosaic class 'Careers and Kids' (as in Figure 10) has been used instead of the original consumption pattern, revealing that at the time of winter peak the achievable reduction is limited due to the significantly higher demand, whereas at the time of summer minimum the impact the battery can have is much stronger.

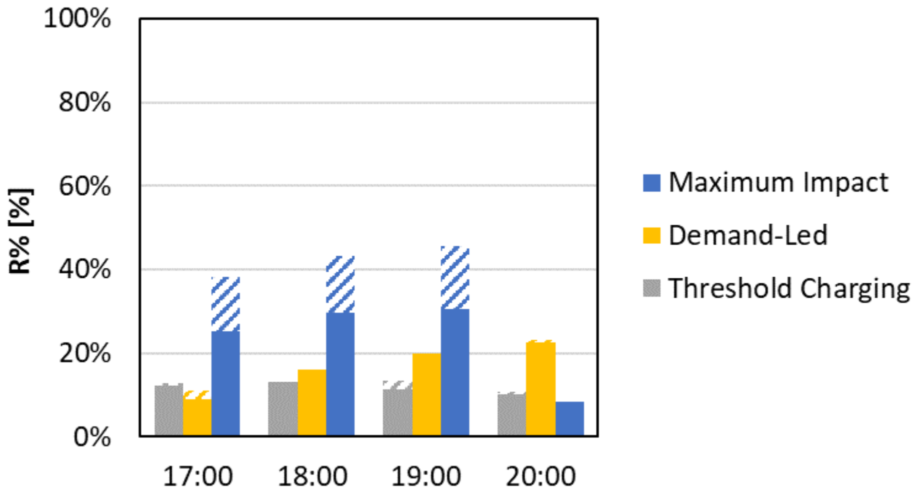

Figure 94: The percentage of reduction of excess demand that can be achieved by operating the batteries according to the different schemes when using the 'Careers and Kids' demand profile. The dashed area indicates the further reduction that is achievable by having a second battery installed. The reduction for the Threshold Charging scheme is only valid for the PV households.

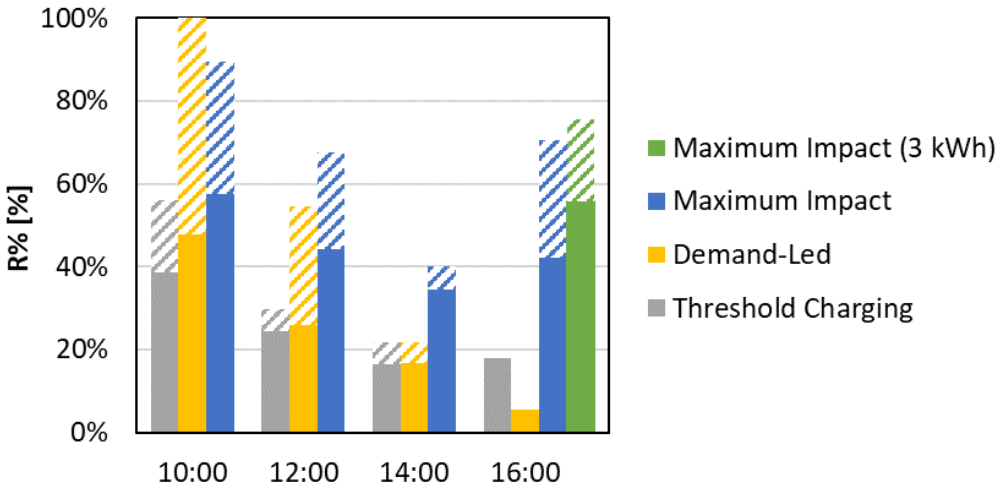

Figure 95: The percentage of reduction of excess generation that can be achieved by operating the batteries according to the different schemes when using the 'Careers and Kids' demand profile. The dashed area indicates the further reduction that is achievable by having a second battery installed. The reduction for the Threshold Charging scheme is only valid for the PV households. The impact achieved at 16:00 by 3 kWh batteries operated according to the Maximum Impact scheme is shown in green.

Appendix C: Network Model

1) The following changes were considered when constructing the network. These changes are done to match the GIS connection map and the given excel parameters.

- **Way 2 cable layout:**

  Original data (provided in LV Skeleton_protected.xlsx):

32	33	7	35c Al/Cu	1	B
32	33	4	35c Al/Cu	1	B
33	34	4	35c Al/Cu	1	B
34	35	4	35c Al/Cu	1	B
35	36	4	35c Al/Cu	1	B
3	4	48	0.3Al	0	3Ph

  Modified data (marked in red):

32	33a.0	7	35c Al/Cu	1	B
33a.0	33b.0	4	35c Al/Cu	1	B
33b.0	34	4	35c Al/Cu	1	B
34	35	4	35c Al/Cu	1	B
35	36	4	35c Al/Cu	1	B
31	37	20	0.3Cu	0	3Ph

- **Way 3 cable layout:**

  Original data (provided in LV Skeleton_protected.xlsx):

76	78	14	35c Al/Cu	1	R	4 Fox Fields		

  Modified data (marked in red):

77	78	14	35c Al/Cu	1	R	4 Fox Fields	0	

2) The cable parameter table given in LV Skeleton_protected.xlsx was updated as below.

Cable Types	R(ohms)	X (ohms)	Neutral Resistance (ohms)
185wf	0.205	0.068	0.164
120wf	0.315	0.068	0.253
70wf	0.55	0.071	0.443
0.3Al	0.197	0.068	0.152
0.15Al	0.394	0.07	0.312
0.0225	0.774	0.086	0.774
35c Al/Cu	0.72	0.08	0.72
25c Al/Cu	0.72	0.08	0.72
35wf	0.67	0.078	0.67
0.3Cu	0.128	0.073	0.128
0.0225Cu	0.711	0.079	0.711
0.2Cu	0.197	0.072	0.197
0.04Cu	0.72	0.08	0.72

The parameters for the cables that were not given in LV Skeleton_protected.xlsx were obtained from TNEI in-house parameters. The resistance of the cables for which R/X ratio is greater than 9 was reduced to 9 to avoid simulation errors.

Appendix D: Cost-benefit Analysis Methodology

Table 8: Methodology for calculating potential budget for flexibility services by avoiding reinforcements.

1	**Avoid reinforcement –** Assumes reinforcement will be completely avoided (e.g. via energy efficiency scheme or time-of-use tariffs)	**Worked Example**
1.1	a. Calculate cost of avoided reinforcement	a. £20,000
1.2	b. Calculate the equivalent annual budget for flexibility services using a representative discount factor over 10 years c. A safety margin could be added either on 1.2.b to take account of any error in flexibility requirement (e.g. 80%)	b. £2,465.82 @4% over 10 years c. £2,465.82 x 0.8 = £1,972.66 for 10 years
1.3	d. 1.2.c determines the annual savings for avoiding reinforcement and hence the potential ceiling price for flexibility e. This ceiling price could be offered as a mixture of availability and/or utilisation. Typically, for reinforcement avoidance/deferral, the availability compensation will be £0.00	d. Annual flexibility cost should be less than 1.2.c e. £0.00 availability, all for utilisation
1.4	f. Availability is calculated in kW (capacity). Proportion of savings allocated to availability divided by the number of days availability is required and then the capacity required in each day g. Utilisation is calculated in kWh (energy). Proportion of savings allocated to utilisation divided by the number of hours in a year that service may be required for	f. £0.00 / 243 days = £0.00 / 50kW g. £1,972.66 / 243days = £8.12 per day. We need 50kW for 3 hours each day £8.12 / (50kWx 3hrs per day) = £0.05 per kW/h
1.5	h. The above does not take into consideration: - Upfront flexibility set-up costs. These will increase expenses and hence reduce savings. - On-going flexibility operational costs. This will reduce the annualised savings. - Both costs above will likely be small as they will be spread across a number of sites. - Flexibility reliability; any additional flexibility that needs to be acquired to deliver required capacity. This will decrease the flexibility compensation per kW as more will have to be acquired to deliver what is needed.	

Table 9: Methodology for calculating potential budget for flexibility services by deferring reinforcements.

2	**Defer reinforcement –** Assumes reinforcement will be required after a number of years	**Worked Example**
2.1	a. Calculate cost of reinforcement b. Calculate the savings incurred by avoiding reinforcement for x years	a. £20,000 b. $£20{,}000 * \left(1 - \left(\frac{1}{1+0.04}\right)^{10}\right) = £6{,}488.72$
2.2	c. Calculate the equivalent annual budget for flexibility services using a representative discount factor over 10 years d. A safety margin could be added either on 2.2.b or on 2.2.c (depending on length of flexibility need) to take account of any error in flexibility requirement (e.g. 80%)	c. £800.00 @4% over 10 years d. £800.00 x 0.8 = £640.00 for 10 years
2.3	e. 2.2.d determines the annual savings for avoiding reinforcement and hence the potential ceiling price for flexibility f. This ceiling price could be offered as a mixture of availability and/or utilisation. Typically, for reinforcement deferral, there might be a low availability compensation	e. Annual flexibility cost should be less than 2.2.d f. £0.00 availability, all for utilisation
2.4	g. Availability is calculated in kW (capacity). Proportion of savings allocated to availability divided by the number of days availability is required and then the capacity required in each day h. Utilisation is calculated in kWh (energy). Proportion of savings allocated to utilisation divided by the number of hours in a year that service may be required for	g. £0.00 / 243 days = £0.00 / 50kW h. £640.00 / 243days = £2.63 per day. We need 50kW for 3 hours each day £2.63 / (50kWx 3hrs per day) = £0.02 per kW/h
2.5	i. The above does not take into consideration: - Upfront flexibility set-up costs. These will increase expenses and hence reduce savings. - On-going flexibility operational costs. This will reduce the annualised savings. - Both costs above will likely be small as they will be spread across a number of sites. - Flexibility reliability; any additional flexibility that needs to be acquired to deliver required capacity. This will decrease the flexibility compensation per kW as more will have to be acquired to deliver what is needed.	