Distribution Network Voltage Control Using Energy Storage and Demand Side Response

J. Yi, P. Wang, P. C. Taylor, P. J. Davison, P. F. Lyons, D. Liang, S. Brown and D. Roberts

***Abstract*— This paper presents a new application of electrical energy storage (EES) systems and demand side response (DSR) operating collaboratively to enable voltage control within distribution networks. This work has been carried out as part of the Customer Led Network Revolution (CLNR) project which is funded by Ofgem's Low Carbon Networks Fund. Modelling and simulation work is presented, which demonstrates the operation of the control system. Field trials will be carried out in 2012, to implement and evaluate the control systems on the case study network.**

***Index Terms*—Electrical Energy Storage, Demand Side Response, Voltage Control, Electric Vehicle, Heat Pump**

I. Introduction

THE UK government's target for reducing CO_2 emissions by 26% before 2020 [1] is expected to lead to a continuous increase in the uptake of micro-generation and low carbon technologies (LCTs) within distribution networks. The anticipated electrification of the transport and heat sectors is likely to result in large concentrations of devices such as electric vehicles (EVs) and heat pumps (HPs), providing new challenges for distribution network operators (DNOs). In order to cope with these challenges, the UK regulator (Ofgem) has set up the Low Carbon Networks Fund (LCNF) to facilitate investigation into the impact of LCTs on the GB power system. The Customer Led Network Revolution (CLNR) project is the largest smart grid project funded by the LCNF thus far.

As part of the CLNR project, multiple smart grid technologies such as, electrical energy storage (EES) systems, enhanced automatic voltage control (EAVC), demand side response (DSR) and real time thermal ratings (RTTR) will be deployed upon real distribution networks in the north of England.

This deployment will facilitate investigation of these techniques as an alternative or complementary measure to network reinforcement, and aid identification of coordinated, optimal solutions to relieve future network constraints.

The research described in this paper represents preparatory work required to enable voltage control network field trials to be carried out. The network is currently operated well within the statutory and operational limits; however problems could potentially occur in the future, if proliferation of LCTs occurs.

A future scenario is presented, in which a high penetration of EVs and HPs within a localised cluster of 230 domestic customers, results in a steady-state voltage limit violation. A control scheme using EES in conjunction with DSR is proposed in order to solve the problem.

This paper begins by presenting background research where EES or DSR have been used to control voltage in distribution networks. The following section describes the rural test network in the CLNR project, development of the network model and field trial data which has been used to validate the model. Additionally the EES model, based on the real device that will be deployed in the network, and the DSR models, which utilise real data from industrial and commercial (I&C) DSR trials, are also detailed.

A study to determine the impacts of large concentrations of LCTs on the network is presented in the following section. The proposed voltage control system, which integrates the collaborative operation of EES and DSR, is then detailed. Finally, results illustrating the operation of the system are presented.

II. Background

A. Electrical Energy Storage

The benefits of EES systems, particularly for power flow management and voltage control, have been illustrated previously, by research at Durham University [3].

During the CLNR project, six EES systems will be installed at various voltage levels and locations, with output power ranging from 50kVA to 2.5MVA. Five of these will be installed on the LV side (0.4kV) of HV/LV transformers, or in more remote locations along the feeder. This will enable evaluation of the use of EES to mitigate both localised and upstream network constraints. The EES systems to be deployed feature lithium ion iron nano-phosphate batteries, manufactured by A123 Systems [4].

B. Demand Side Response

The application of DSR can yield numerous network benefits, such as reduction of the generation margin and improvements to the investment and operational efficiencies

This work was supported in part by Office of the gas and electricity market (Ofgem) under Low Carbon Network Fund

J. Yi, P. Wang, P. C. Taylor, P. J. Davison, P. F. Lyons and D. Liang are with the School of Engineering and Computing Sciences, Durham University, Durham, DH1 3LE UK (e-mail: Jialiang.Yi@durham.ac.uk)

S. Brown is with Northern Powergrid, Castleford, WF10 5DS UK (e-mail: Stuart.Brown@northernpowergrid.com)

D. Roberts is with EA Technology Limited, Chester, CH1 6ES UK (e-mail:David.Roberts@eatechnology.com)

978-1-4673-2597-4/12/$31.00 ©2012 IEEE

of both transmission and distribution systems [5]. In [6], it was demonstrated how DSR can also be used to solve distribution network voltage problems.

In the CLNR project, domestic, small and medium enterprise (SME) and I&C customers will participate in demand response programmes. However the initial trials introduced in this paper, consist of I&C customers only. These trials are designed to investigate DSR customers' flexibility and response characteristics. Three I&C customers have participated in the initial series of thirteen DSR trials. Nine out of the thirteen requests for demand response were successful.

Fig. 1 illustrates the half hourly energy consumption and average power consumption of customer A, during DSR trial A.1. The blue bar represents the half hourly consumption of customer A, obtained from meter readings, and the red trace represents the average real power consumption.

In this trial, the DSR command was issued from a control room at 14:50. On receiving the signal, a diesel generator was engaged, to supply power to meet the customer demand. The customer load was thus reduced by over 800kW for four hours. It should be noted however, that there was a delay of approximately 20 minutes before customer consumption was actually reduced.

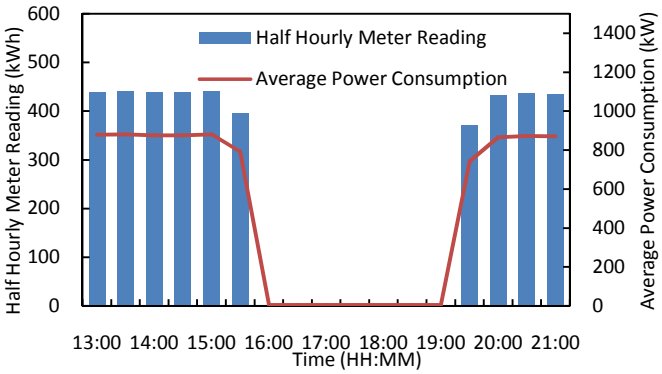

Fig. 1. I&C Customer A DSR profile in DSR trial A.1

In trial A.2, the DSR instruction was confirmed before 11:00 and DSR commenced at 15:00. The half hourly meter readings and average power are shown below in Fig. 2.

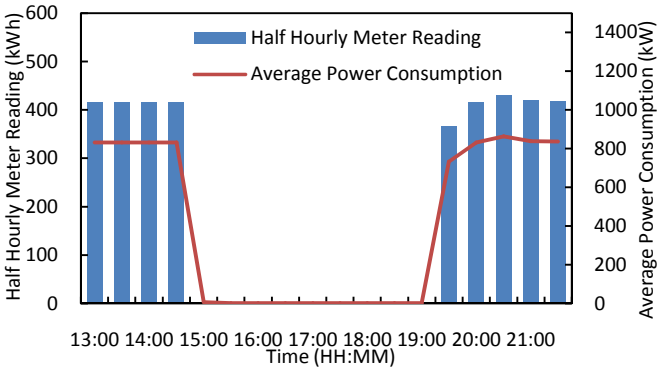

Fig. 2. I&C Customer A DSR profile in DSR trial A.2

Comparing Fig. 1 and Fig. 2, it can be seen that the response of A.1 is much slower than that in A.2. Due to the use of the diesel generator to supply the local load, power consumption was reduced to 2kW within 2 minutes and remained constant. Similarly, when the invoked DSR came to an end, load was restored within a 2 minute period.

The load of Customer B consists primarily of refrigeration. In contrast to customer A, the load was varied by reducing consumption as opposed to engaging on site backup generation. A DSR profile, for this customer, (DSR trial B.1) is illustrated in Fig. 3 DSR commenced at 15:00 and lasted until 19:00. During this period, the half hourly energy consumption of customer B was reduced from 1200kWh to approximately 600 kWh.

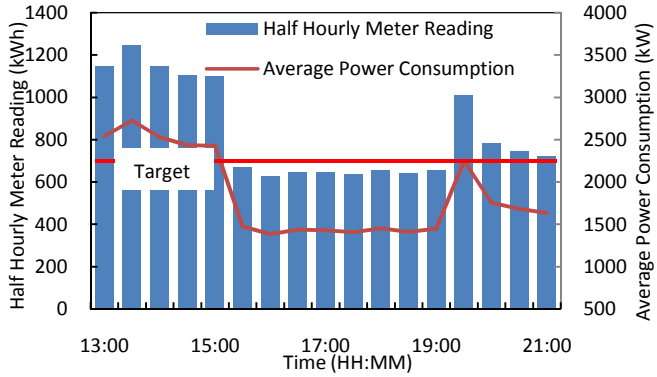

Fig. 3. I&C Customer B DSR profile in DSR trial B.1

As mentioned previously, not all trials resulted in a successful response from the customers. Reasons for unsuccessful DSR include; failure to respond, or an inability to reduce enough load to meet the target half hourly energy consumption. For example, in one trial, the diesel generator used on the site of customer A experienced failure and therefore the site was unable to respond.

The half hourly energy consumption and average power curves from trial B.2 are given in Fig. 4. The DSR command was confirmed before 11:00 and DSR started at 15:00. It can be seen that the half hourly energy consumption started to decrease and dropped from 1195.9kWh at 15:00 to 950.2kWh at 15:30. However the reduction was smaller than the agreed target and therefore the DSR was deemed to be unsuccessful. The load on the site did not drop below the target until 17:30, at which point the DSR was considered to be successful.

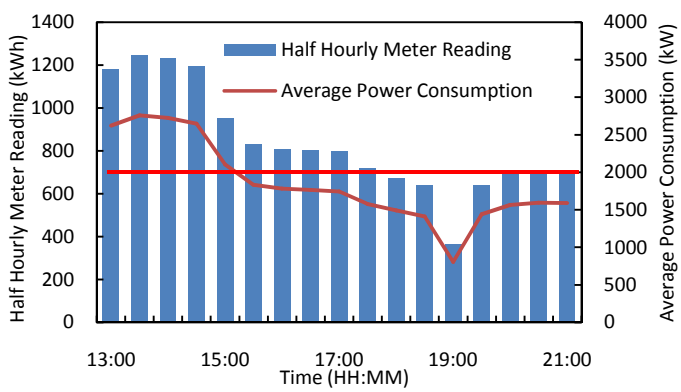

Fig. 4. I&C Customer B DSR profile in DSR trial B.2

C. Collaborative Use of Electrical Energy Storage and Demand Side Response

Due to the varying characteristics of different energy storage technologies, hybrid energy storage systems have been

proposed in previous literature. The combination of various storage technologies can provide improved performance when compared to a single technology. For example, in comparison to flywheels and capacitors, battery energy storage systems (BESS) have a lower self-discharge rate and a higher energy capacity, making them more suited to longer term storage. A similar size of flywheel and capacitor can offer a faster response however a limited capacity. In [7], a hybrid energy storage system composed of a lead acid battery and an electrical double layer capacitor (EDLC) was built and tested. This system was shown to be able to maintain DC bus voltage at a constant value in the presence of fluctuating PV generation. A coordinated control algorithm for a combined storage system was developed in [8]. A fast response storage unit with limited capacity and a slow response storage unit, with much larger capacity were controlled in a coordinated manner, to give an increased performance.

Energy storage and DSR have been used together for optimising network capacity [9] and cost reductions [10] previously. In this work, the two techniques are used collaboratively for voltage control purposes.

The ramp rate of the EES systems that are to be deployed is 20ms from zero to maximum power export [4]. In contrast, as seen in the previous section, the I&C DSR can react within two minutes and provide a response for a number of hours. This response is however conditional upon pre-arrangement of the necessary DSR. The fast response capability of the EES systems means that they are able to react in a far shorter timescale than even the fastest of the DSR facilities available. However a limitation of EES, relative to the DSR service, is that its capability to export real power is for a limited duration, dependent on the discharge current, initial state-of-charge (SOC) and the energy capacity of the battery bank. In contrast, where the local consumption during DSR is provided by a distributed generator, a diesel generator in this case, the duration of the DSR service can be as long as is required by the supervisory control system, albeit with an accompanying cost. It can also be seen also that DSR response is not guaranteed, (only nine of the thirteen DSR trials resulted in a response from the customers) and delays in the response are common. Moreover, when DSR relies on a thermal store e.g. refrigeration it is subject to some of the same limitations as EES e.g. limited time duration.

III. Case Study Network

A. Case Study Network

A typical rural network in Northumberland, England, owned by Northern Powergrid has been selected as the case study network. Fig. 5 shows the schematic diagram and the smart grid technologies which are to be installed.

As can be seen in Fig. 5, a mechanically switched capacitor bank and two in-line regulators are already deployed on this system for voltage control purposes and at present, operate according to the standard DNO voltage control practice. DSR customers A and B, and the LCT cluster with associated EES system are located towards the remote end of one of the 20kV feeders. The apparent power rating and the capacity of the energy storage system, are 100kVA and 200kWh, respectively. As previously mentioned there are 230 customers within the LCT cluster, and the penetration of EV and HP ownership is higher than in the remaining network.

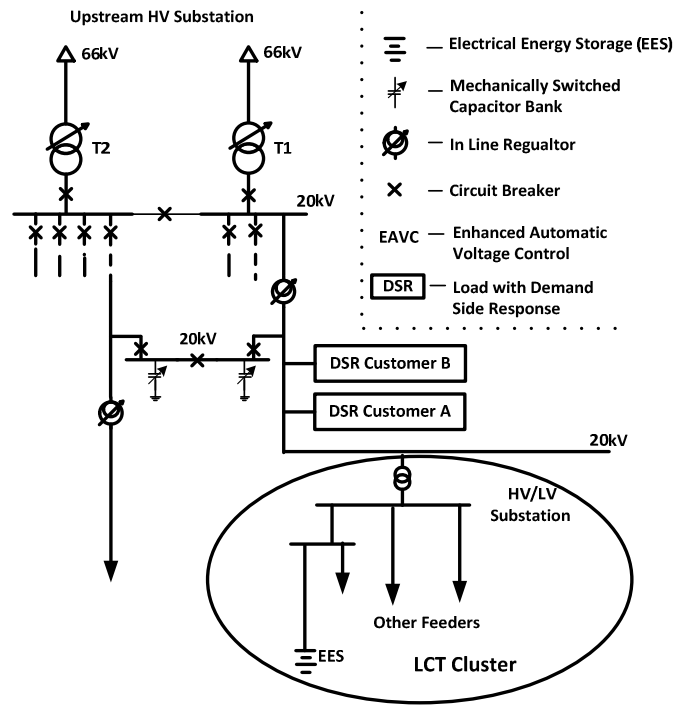

Fig. 5. Schematic diagram of the 20kV case-study network.

The demand profile of this distribution network, measured by the present SCADA system, is illustrated in Fig. 6. The blue trace indicates the typical load profile during a winter day, when the highest load was recorded, in the period from December 2010 to January 2012. The peak demand which occurs between 02:00 and 03:00 is due to electrical storage heating and a high uptake of the economy seven tariff. The additional peak between 14:00 and 16:00 is the result of a Super Tariff in this area which gives a lower electricity price for six hours overnight and two hours in the afternoon.

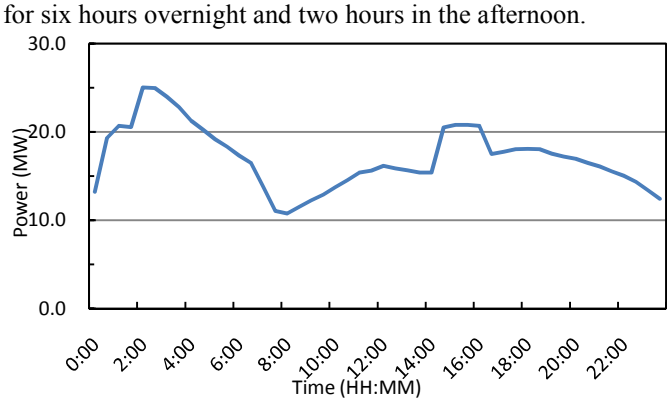

Fig. 6. Current load profile in the case-study network.

B. Modelling Methodology

A network model has been developed using IPSA2 (the model validation process is discussed in greater detail in section C). The LV section of the distribution network with EES2 is illustrated in Fig. 7. The model is based on detailed network data supplied by Northern Powergrid. The longest

branch of the longest LV feeder has been modelled in detail, due to the likelihood of voltage problems occurring. Loading on Branch 2 of this feeder and the remaining LV feeders are represented by lumped loads.

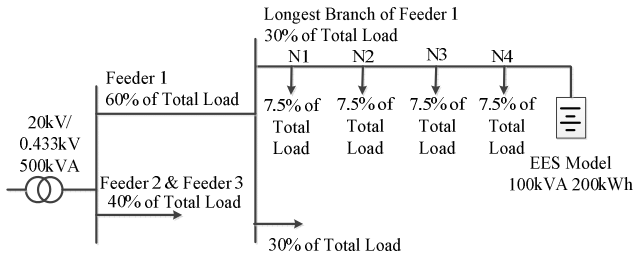

Fig. 7. Model of LV distribution network.

EES has been modelled in this system such that it can import/export real and/or reactive power in any combination within ratings. DSR is modelled as a controllable load. The EES model and DSR model capabilities are extended using Python 2.7, which has been adopted as a scripting language in IPSA2, to automate control of the network model and the load flow engine.

C. Model Validation

The network model has been validated against load flow results from an existing DINIS model within Northern Powergrid. The busbar voltages and feeder currents calculated in both models have been found in good agreement.

The network model has also been validated using measured data from both the HV/LV and primary substation sites. Real load data have been used in the IPSA2 network model. Load flow calculations have been carried out and the results were compared to the measured data. The model was found to be able to predict LV voltages to within 1% accuracy.

IV. Analysis of Increasing Penetration of EVs and HPs in Case Study Network

A. Electric Vehicle

Experiments have been carried out at Durham University to analyse the charging profile of an EV (Mitsubishi, i-MiEV) when charged from the University's smart grid laboratory. Results indicate that, during charging, the power consumed by the EV is initially constant, followed by a period where the charge current reduces as the EV reaches full charge. Profiles were derived from a range of initial states-of-charge. These results have been used within the EV modelling methodology in this paper.

Previous work has characterised EV users and analysed the daily usage patterns of vehicles [11]. According to this report, roughly 25% of trip purposes are for commuting. The blue trace detailed in Fig. 8 shows the probability of commuting vehicles being at home. It can be seen that from 21:00 until 06:00 the next day, the probability of commuting vehicles being at home is over 90%. During the hours from 09:00 until 16:00, the probability of commuting vehicles being at home is lower than 30%.

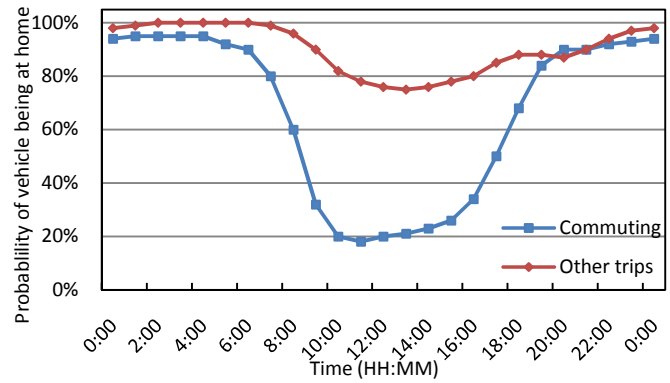

Fig. 8. Probability of vehicles being at home [11].

Similarly, for all other purposes, such as food shopping and business, the probability of vehicles being at home from 21:00 until 06:00 next day and from 09:00 until 16:00 are over 90% and below 80% respectively.

Under the tariffs described earlier, customers have a lower electricity price for six hours in the night and two hours in the afternoon. Considering the higher probability of vehicles being at home at night, it could be assumed that most EV users would tend to charge EVs during this period, instead of in the afternoon.

It is also reported that, without a fast charging infrastructure, most EVs have an initial state of charge of 60% to 70% prior to charging [11]. Due to the high cost of a fast charging infrastructure and the rurality of the area under consideration, it is reasonable to make the assumption that there would be minimal fast charging units available. Therefore, at the start of a charge, the EVs' SOC is assumed to be between 60% and 70%.

An aggregated charging curve based on the assumptions above; with a 15% penetration of EVs in the cluster is given in Fig. 9.

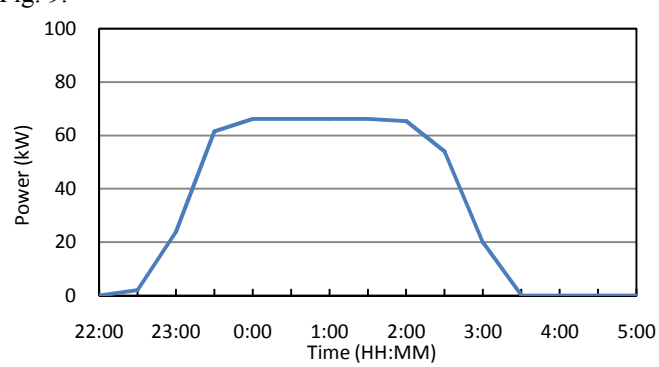

Fig. 9. Aggregated EV charging curve in the LCT cluster during night time.

B. Heat Pump

Work has been previously carried out in order to derive thermal profiles for typical UK building stock. Generic building data was used as an input to the models in combination with temperature data from a site in the UK.

Multiple occupancy scenarios for each considered building type (detached, semi-detached, flat, mid-terrace) are derived and aggregated in order to generate the final thermal profile

[12]. The results were found to agree favourably with UK national statistics.

In order to generate the electrical profile of the air-source heat pump (ASHP), the thermal profiles for the required building types have been scaled according to the methodology outlined in [13]. The methodology requires that the thermal profile be scaled down by the coefficient of performance (COP) of the ASHP. A value of 3 has been chosen for the ASHP system under consideration in line with previous work [13]. The derived electrical demand profiles of detached and semi-detached properties are given in Fig. 10.

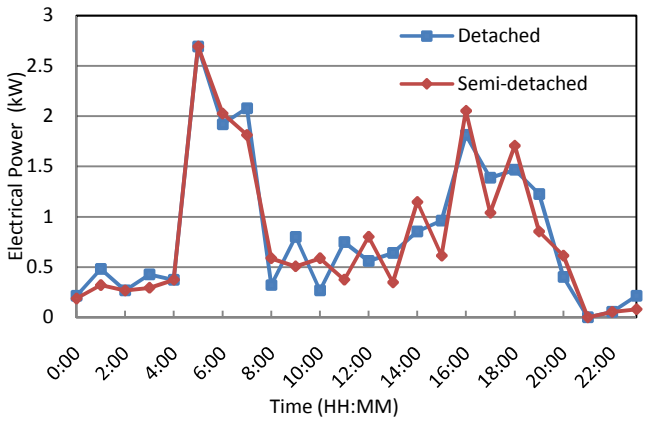

Fig. 10. Derived electrical demand for detached and semi-detached properties.

To derive the ASHP electrical demand profiles for this work, detached and semi-detached properties have been used, in a ratio of 9:1 respectively. This is in accordance with previous simulations of rural networks [13]. Fig. 11 shows the total demand curve due to the ASHP load, with an assumed penetration of 45%.

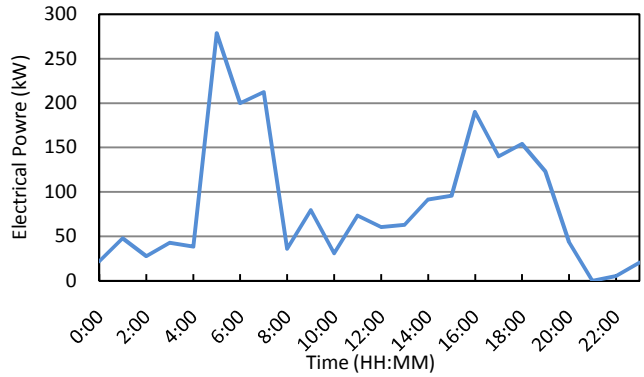

Fig. 11. Aggregated ASHP electrical demand curve in the LCT cluster.

C. Impacts of an Increased Penetration of EVs and HPs on Case Study Network

Using the model described in III. , a steady-state study was carried out to evaluate the impact of large penetrations of LCTs, specifically ASHPs and EVs on remote end LV voltages. The remote end of the longest LV feeder has been previously found to represent the worst case in terms of voltage variation in balanced and evenly distributed LV networks [14].

To enable this investigation, a number of load flow calculations were carried out with scenarios of increasing penetrations of ASHPs and EVs. According to Northern Powergrid data, there are over 7000 customers in this area. It is assumed that these customers take time-of-use price into consideration, which means they would tend to charge their EVs overnight. This study also assumed that in the LCT cluster, the penetration of customers owning an EV is 15% and 45% of customers have installed an ASHP. For all other customers in this area, the percentages of EV and HP owners are assumed to be 10% respectively.

Based on these assumptions and the aggregated models of EVs and ASHPs described earlier, the predicted load curves are illustrated in Fig. 12. The voltage profile under the predicted load is plotted in Fig. 13.

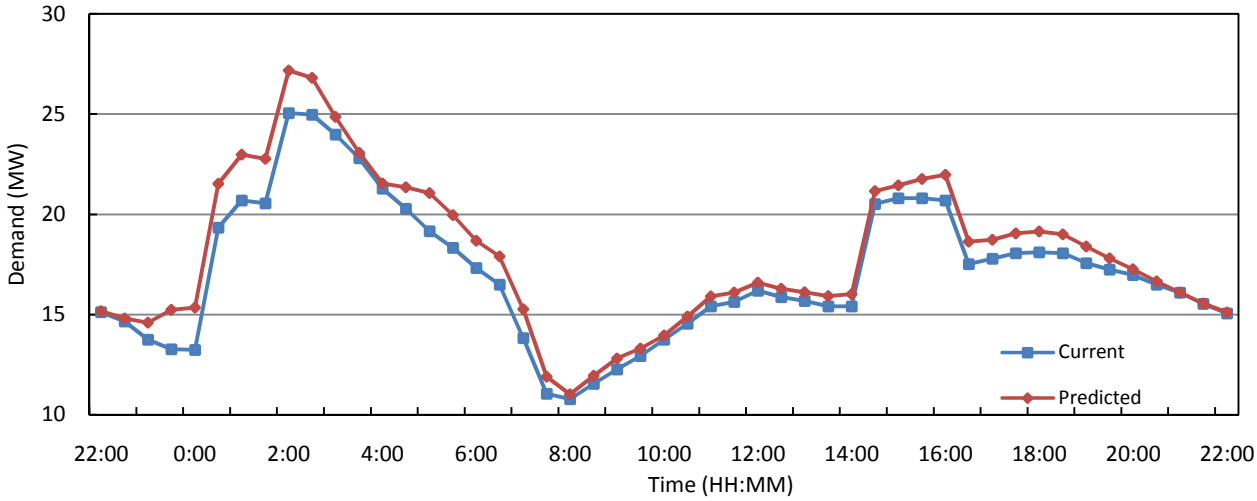

Fig. 12. Current and predicted demand profile.

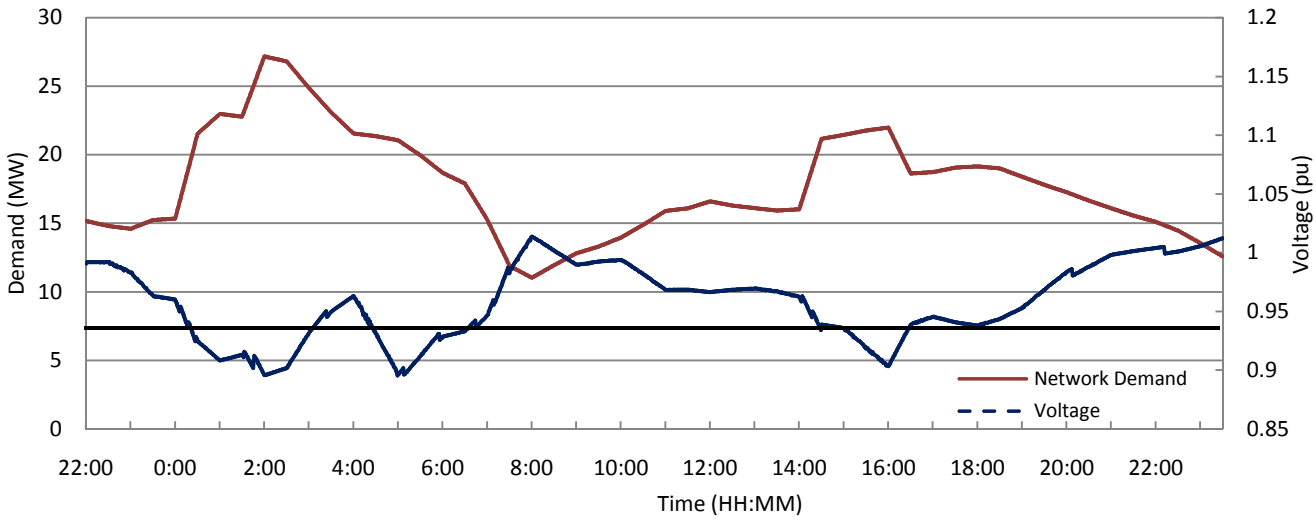

Fig. 13. Voltage profile in 24 hours

Simulation results indicate that, with the higher penetrations of LCTs, detailed earlier, in the modelled LV network, and a 10% penetration of both EVs and ASHPs across the whole network, the voltage at the remote end of the longest LV feeder will drop below the statutory limit (0.94pu in the UK). This will occur during the night-time peak period, early morning and afternoon peak time. The voltage is lower than 0.94pu from 00:00 to 03:00 due to charging of EVs. The large power consumption of ASHPs in the early morning will result in a voltage drop between 04:00 and 07:00. From 14:00 to 16:00, another peak can be observed due to the additional ASHP consumption in combination with the present network peak.

V. Collaborative Voltage Control Scheme

In order to mitigate the violation of steady-state voltage limits caused by the increased penetration of LCTs, the collaborative control system will instruct the EES to operate first and export real power into the LV network to increase the voltage at the remote end. There is no reactive power output from EES because this network has a low X/R ratio and the impact of reactive power on voltage control is limited. The collaborative voltage control scheme will simultaneously call DSR.

Since the EES has a limited resource, a possible scenario arises such that if the voltage problem cannot be solved with the available capacity of the EES, the under voltage problem would remain. If DSR is available at the occurrence of the under voltage, the collaborative control scheme will therefore call this response in order to provide security to the operation of the EES. When operation of the DSR is confirmed and the steady-state voltage is within limits, the collaborative voltage control system will instruct the EES to reduce real power export and thus conserve its limited resource.

Due to the previously explained penetrations of EVs and ASHPs three separate under voltage incidents occur on the network under study.

A. Under Voltage Due to Night Peak

In this case, collaborative voltage control is carried out using EES and DSR customer B. Customer B is called due to its 24 hour operation.

The simulation results illustrating the operation of the EES and DSR customer B to control voltage during the mid-night peak period are shown below in Fig. 14 and Fig. 15. In Fig. 14, the voltage profile between 23:30 to 04:00 is plotted. It can be seen that the voltage dropped below the 0.94pu limit, at approximately 00:15 in the morning. The EES then injected 10kW of real power into the grid to bring the voltage back above the limit and, at the same time, the DSR command was issued. After 20 minutes, the consumption of DSR customer B started to reduce but did not reach a stable level until 01:00. At this time, installed monitoring equipment showed that the voltage of the network was close to the statutory limit therefore the collaborative voltage control scheme decided to maintain the output of the EES, in order to prevent a further voltage problem. However, around 45 minutes later, when the voltage again went below the limit, the EES started to inject more power into the network to maintain the voltage above limit.

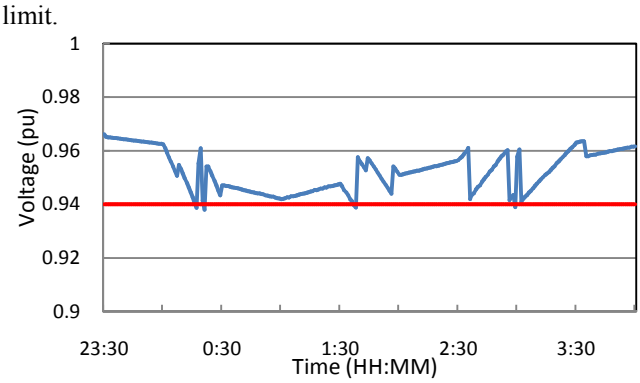

Fig. 14. Voltage profile with DSR customer B and EES during the night peak period.

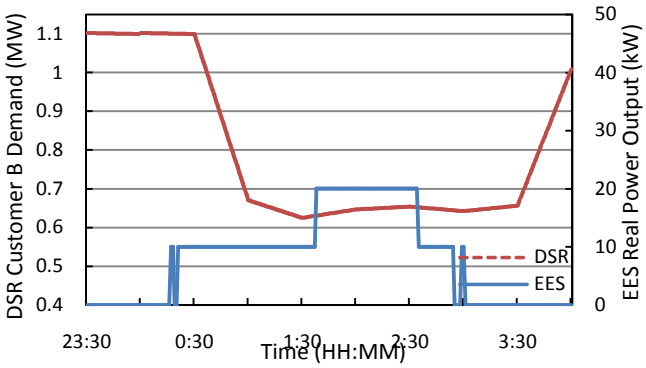

Fig. 15. DSR customer B demand and real power output of EES.

B. *Under Voltage Due to Morning Peak*

During the early morning peak period, a voltage problem was fixed purely by the EES. A DSR operation was not called in consideration from Customer B as the number of DSR operations available in a day is limited for this customer. Customer A was unavailable as the voltage problem occurred in the early morning. This customer is assumed to operate a typical 09:00 to 17:00 working day and is not preferred to provide a DSR outside these hours. This case also helps to illustrate the potential unavailability of DSR as well as customer flexibility (the non-calling of customer A).

The voltage profile between 04:00 and 07:00 is plotted in Fig. 16. Real power output of the EES will increase in steps when an under voltage problem occurs and will decrease in steps when the voltage goes up to 0.96pu to reserve available capacity.

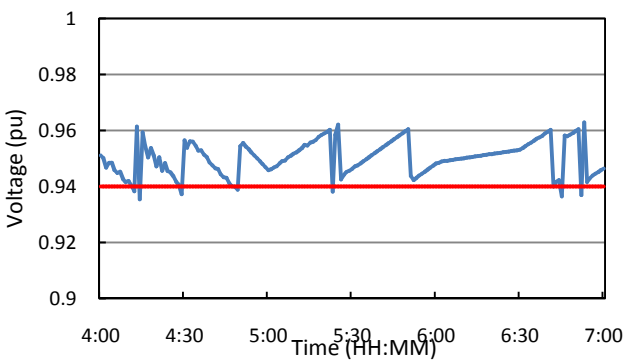

Fig. 16. Voltage profile at the end of the feeder with EES control only during the morning peak period.

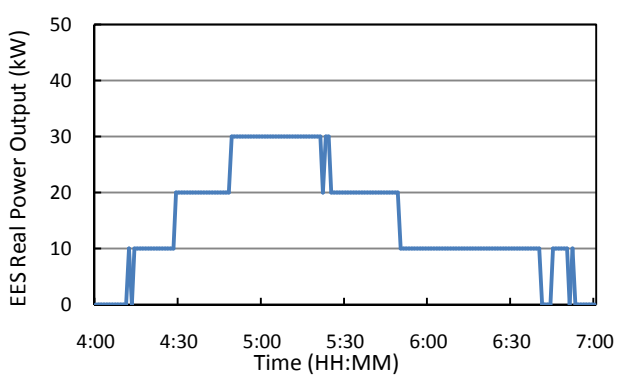

Fig. 17. EES real power output during the morning peak period.

C. *Under Voltage Due to Afternoon Peak*

A similar simulation was carried out to investigate the collaborative operation of EES and DSR customer A, as illustrated in Fig. 18 and Fig. 19. In order to cope with the voltage problem during the afternoon peak, at approximately 14:25, voltage dropped below 0.94pu and continued to decrease. EES reacted first to bring the voltage back to 0.96pu. A DSR command was issued at the same time to customer A. After 20 minutes, at 14:45, the demand of customer A decreased to 0 in a very short period of time. Despite the magnitude of customer A's DSR, at 15:30, the voltage violated the limit again due to the increasing load. As a result, the EES started to inject real power into the network again.

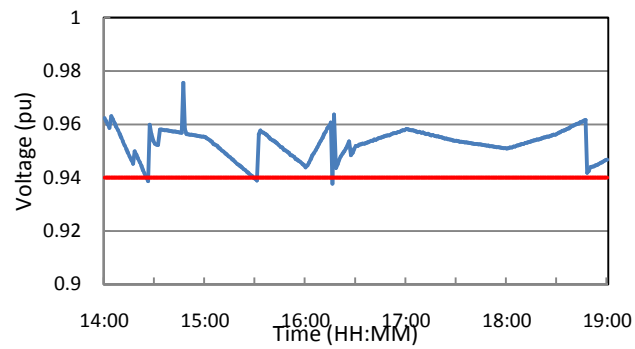

Fig. 18. Voltage profile with EES and DSR customer A during the afternoon peak period.

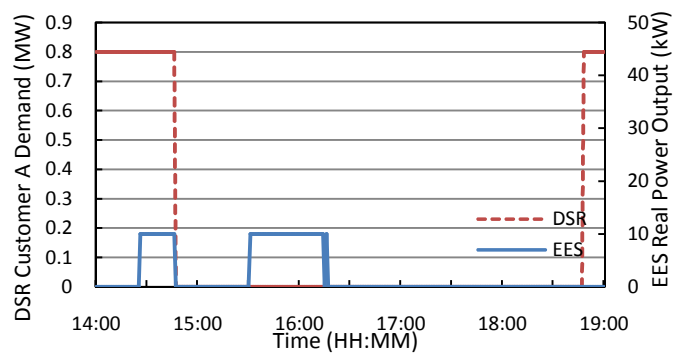

Fig. 19. DRS customer a consumption and EES real power output during the afternoon peak period.

The energy output of EES in the simulation are 35.8 kWh, 45.1 kWh and 11.0 kWh, respectively. It is estimated that this presents percentage change of SOC of 17.9%, 22.6% and 5.5% based on the 200kWh capacity EES.

Due to these percentage changes in SOC provided that the initial state of charge of the EES is greater than 46% (and the Lithium-Ion battery is capable of a maximum depth-of-discharge (DOD) of 100%) the EES will not require re-charging during one day.

Simulations additionally showed that if the battery bank of the EES were to have been optimally re-charged throughout the day using a methodology not considered as part of this scheme, the EES would have not be required to achieve a deep discharge which could potentially damage the battery.

VI. Conclusion

Simulation results have demonstrated the impacts of EVs and ASHPs in LV networks. With a 15% penetration of EVs and a 45% penetration of ASHPs in a localised LCT cluster, the voltage at the end of the longest feeder is found to drop below the statutory limit on three significant occasions in the course of a day. In response to this, a collaborative voltage control strategy incorporating EES and DSR was developed to mitigate the voltage drop. The simulation results demonstrate that EES and DSR can be operated collaboratively to mitigate the voltage drop problem successfully.

Furthermore it can be seen that the use of the two techniques in collaboration offers benefits beyond the use of a single technique: firstly the use of DSR would result in a sustained voltage problem for approximately 20 minutes, which is avoided due to the fast response of the EES. Secondly the capacity of the EES required is reduced because the DSR system can remove or reduce the need for storage intervention after 20 minutes. Given that EES technology is currently expensive and the cost of DSR is lower than the cost of EES, this is a valuable contribution.

VII. Acknowledgment

The authors would like to thank David Miller, Ian Lloyd and Andrew Webster from Northern Powergrid for their help in accessing data regarding the case study network.

VIII. References

[1] Department of Energy and Climate Change. Climate change act 2009 impact assessment; March 2009

[2] N.S. Wade, P. C. Taylor, P. D. Lang, P. R. Jones, "Evaluating the benefits of an electrical energy storage system in a future smart grid." *Energy Policy*, 38(11): pp. 7180-7188, 2010..

[3] P. F. Lyons, P. Trichakis, P. C. Taylor, G. Coates, "A practical implementation of a distributed control approach for microgrids." in *Proc. 2009 Intelligent Automation and Soft Computing, An International Journal,*. pp. 319-334.

[4] C. M. Campbell, C.K.V., "A123's Advanced Grid Storage, Extending Our Experience to Distributed Resource Applications and Microgrids," in MicronGen 11: Glasgow. 2011

[5] Strbac, G., "Demand side management: Benefits and challenges." *Energy Policy*, 36(12): pp. 4419-4426, 2008.

[6] Seng, L.Y. and P. Taylor. "Innovative Application of Demand Side Management to Power Systems," in Industrial and Information Systems, First International Conference on, 2006.

[7] Zhang, J. and L. Ji. "An effective hybrid energy storage system based on battery-EDLC for distributed generation systems," in Industrial Electronics and Applications (ICIEA) 2010 the 5th IEEE Conference on. 2010.

[8] J. Chunlian, N. Lu, S. Lu, Y. Makarov and R. A. Dougal, "Coordinated control algorithm for hybrid energy storage systems,2 in Power and Energy Society General Meeting, 2011 IEEE.

[9] V. Stanojevic, , V. Silba, D. Pudjianto, G. Strbac., P. Lang and D. Macleman. "Application of storage and Demand Side Management to optimise existing network capacity". in CIRED 2009

[10] S. Andreas, "Modeling storage and demand management in power distribution grids," *Applied Energy*, 2011. 88(12): p. 4700-4712.

[11] Element Energy Limited, "Strategies for the uptake of electric vehicles and associated infrastructure implications," 2009.

[12] Abu-Sharkh, S., et al., Can microgrids make a major contribution to UK energy supply? Renewable and Sustainable Energy Reviews, 2006. 10(2): p. 78-127.

[13] Mancarella, P., G. Chin Kim, and G. Strbac. "Evaluation of the impact of electric heat pumps and distributed CHP on LV networks," in PowerTech, 2011 IEEE Trondheim. 2011.

[14] P. F. Lyons, P. C. Taylor, L. M. Cipcigan, P. Trichakis and A. Wilson "Small Scale Energy Zones and the Impacts of High Concentrations of Small Scale Embedded Generators." in *Proc. UPEC 2006*.

IX. Biographies

Jialiang Yi received MSc degree from Southampton University, UK in 2011.He is currently pursuing a PhD at Durham University in the field of power system engineering. His research interests include electrical energy storage systems and demand side response in distribution networks.

Pengfei Wang is a PhD student in the field of power system engineering at Durham University. Before joined Durham University, he was working in Alstom Grid, Stafford, UK as a BOND Engineer. He received a M.Sc. degree in Electrical Power Engineering from TU Darmstadt, Darmstadt, Germany in 2010. His major research interests are in the area of power system coordinated voltage control and micro-generation integration.

Philip Taylor is a professor at Durham University. He carries out research which focuses on the challenges associated with the widespread integration and control of distributed/renewable generation in electrical distribution networks He currently holds the DONG Energy Chair in Renewable Energy. He is the Deputy Director of the Durham Energy Institute and the Director of the Multi-disciplinary Centre for Doctoral Training in Energy.

Peter Davison received BEng and MSc degrees from Durham University in '10 and '11 respectively. He is currently studying for a PhD in smart grids. His research interests include real time thermal ratings and domestic load modelling.

Pádraig Lyons is the lead researcher on the Customer Led Network Revolution at Durham University. Dr Lyons' research interests include active network management (ANM), smart grids and experimental design and analysis for smart grids. His doctoral research, at Durham University, was an investigation into ANM techniques to enable the integration of small-scale renewables in distribution networks. He has BE in Electrical and Electronic Engineering and a MEngSc in the area of series hybrid electric vehicles both from University College Cork. He also has industrial experience at ESBI, Ireland and at TNEI Services Ltd., UK. He is a chartered engineer.

Daniel Liang (PhD, 2008; M. Eng, 2003; B. Eng, 2000) is currently working in Durham University, UK as a post-doctoral researcher. His research interests include demand side management, power flow management and voltage regulation in smart grid.

S. Brown works for Northern Powergrid, UK, a distribution company in the north of England. He is currently involved in a number of low carbon network projects with particular emphasis on innovative commercial arrangements.

D. Roberts manages the Smart Grid Delivery Team at EA Technology Consulting in the UK. David is an electrical engineer and project manager who has spent many years working in the field of distribution network engineering both for a network operator and network equipment manufacturers. He utilises his broad range of knowledge and experience to assist customers in tackling the increasing challenges they are facing in operating their distribution networks.