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Use of Battery Storage to Increase Network Reliability under Faulted Conditions

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SUMMARY

The strategic use of electrical energy storage (EES) has been shown to have the potential to deliver increased power flow management capability and thus defer or remove the need for high-cost network reinforcement [1-6]. Often in such scenarios the network is assumed to be intact. EES can however provide increased network reliability under an (n-1) or (n-2) situation as well.

Under faulted conditions, one or more circuits in a power distribution network are not available to carry electrical energy to meet customer demand. This results in a new power flow equilibrium, in which one or more unfaulted circuits are required to carry more power than they would normally carry with the network intact. This increased power flow may exceed the rating limitations of one or more of the circuit components – transformer, switchgear, overhead line or underground cable. This may result in customers becoming disconnected from the network.

An alternative strategy would be available if EES, for example a battery bank, were installed and connected at an appropriate location in the network. By charging up the battery at non-peak times of day, and then discharging it throughout the peak period, overloading the limiting component can be avoided. Even if a reduced degree of overloading remains, it could be possible to remove this by performing a smaller number of network switching operations. This could allow disconnection of a smaller number of customers or avoid the need for disconnection altogether.

This approach is illustrated by a case study based on an actual suburban distribution network in the North of England. The paper describes this network in detail. It shows that, following the (n-2) loss of high voltage infeeds, reconfiguration at a lower voltage is required. Although such reconfiguration is adequate to meet all demand throughout the summer low demand period, there are 133 days during the winter period when it is insufficient to meet full demand. On such days, up to 17 MWh of energy cannot be supplied even when the limited amount of lower voltage interconnection is used to capacity.

EES can significantly reduce the energy not supplied, and therefore the number of customers not supplied, under such faulted conditions. Using actual demand data, predictions of the need to draw on EES can be made on a half-hourly basis. These predictions can be used in the control room to devise an equitable scheme of Rota Disconnection which will minimize, or even eliminate, the need for and extent of customer disconnection.

The present study is an initial approach to applying a combination of EES and network risk methodologies to a network under faulted conditions. There are a number of ways in which the study could be extended, and these are outlined in the conclusions section of the paper.

KEYWORDS

Smart Grids, Electrical Energy Storage, Network Risk, Reliability

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1. Introduction

The use of battery storage to enhance the performance of electricity distribution networks is well documented. Strategic deployment of electrical energy storage (EES) can allow the deferral and in some cases can negate the need for high-cost network reinforcement. Studies of this kind, which are reviewed in Section 2, generally assume that the network is intact with no planned outages or faults on the system.

However, EES can also bring benefits on occasions when the network is disrupted, in particular during prolonged outages where a single event such as a fire or flood may have disconnected one or more circuits. Under these circumstances, it may not be possible to reconnect and supply all customers simultaneously by alternative routes, and a schedule of Rota Disconnection may be necessary. The proportion of customers who can be re-supplied at any time, and especially at times of peak load, is likely to be limited by the thermal ratings, and consequent maximum capacity, of certain critical sections of the network. Increasing this proportion is at the very least an improvement in quality of service. Such improvements may be required and potentially rewarded by the national industry regulator. In certain circumstances, the requirement could involve costly capital expenditure, for example to re-conductor an overhead line or underground cable to a higher static thermal rating. Section 3 reviews previous work on measuring and mitigating such network risk.

However, if supplementary energy supplies are made available from EES, then the proportion of customers supplied during such an event can also be increased. This can be achieved by the smart deployment of a battery storage system. The composite methodology for combining EES technology with network risk assessment is outlined in Section 4.

This methodology is illustrated by a case-study which has been carried out as part of the Customer Led Network Revolution (CLNR) project to trial low-carbon technology on a distribution network in the North of England. Section 5 defines the test network, and calculates the supply shortfall that would be expected under faulted conditions. Section 6 describes how a battery storage system, to be installed in 2012, will be monitored to determine its input, storage and output characteristics, and therefore its potential effectiveness under circuit outage conditions.

The results that could be expected from such an application, in particular the effect of using EES on the number of days on which customers could be restored to supply, are presented in Section 7. Finally, Section 8 draws conclusions from the case study, in particular as regards the potentially wider use of EES technology and the associated methodology.

2. Background: Electrical Energy Storage

The benefits of energy storage systems in distribution networks, including reducing customer minutes lost, assisting in compliance with energy security standards, arbitrage and restoration, have been summarized in [1]. Several types of battery EES systems have been reviewed and the economic benefits of EES systems in distribution networks for load leveling, frequency regulation and end-user peak shaving have been evaluated in [2]. The conclusion suggested that the highest financial benefit for the owner of EES is power flow management. The multiple contributions of distributed EESs to the electricity value chain were studied in [3]. In this paper, the applications of distributed EES systems such as capacity support, contingency grid support and voltage control were discussed and a new method was proposed to combine the various benefits.

Several studies explored the potential of using storage systems for increasing network reliability. A Monte Carlo simulation based method was presented in [4] and the value of ESS for network reliability improvement was explored. The EES was located at the remote end of a 66kV feeder, where customers had already suffering from electricity interruptions. Historical load data was used to decide the peak load. Matlab simulations were carried out to find out the relationship between the storage system duration and the system reliability. Duration was defined as the time when a storage system fully discharged from 100% state-of-charge at its rated power. However, the analysis showed that the proposed system was not cost effective. In [5], the impacts and effectiveness of three control strategies using EES, namely standby backup control strategy, novel MPC-based control strategy and a hybrid control strategy have been assessed and compared. Standby backup control strategy aimed to improve system reliability while novel MPC-based control strategy was always employed to maximum economy within the distribution network. A hybrid control strategy was then proposed to maximise both the economy and the reliability of the distribution network using EES. Simulation results indicated that operation strategies of EES played an important role in the distribution network reliability and economy. The impacts of EES on enhancing system reliability with renewable sources were quantified in [6]. A hypothetical system was used to perform a case study. Simulation result showed that EES system can reduce loss of load expectation and loss of load energy expectation significantly and thus have a positive impact on system reliability.

As these studies show, the impacts of EES on intact network reliability enhancement have been proved and quantified. However the present study considers using EES systems under n-1 and n-2 conditions.

3. Background: Network Risk

The need to meet European low carbon targets by substantially increasing the proportionate use of electricity in both transport and domestic heating is well established [7, 8]. As electricity consumption increases during the period 2010-2030, distribution networks will also become more heavily loaded, particularly at peak times. The UK standard which details the maximum allowable level of network risk is P2/6, endorsed by the industry regulator OFGEM [9]. Specified for different load sizes are the maximum permissible customer disconnection times in the event of a first circuit outage (n-1), and for larger loads, in the additional event of a second circuit outage (n-2).

For loads between 12 MW and 60 MW, the n-1 requirement is to restore supplies to all customers within 3 hours. Since there is no guarantee that a fault can be repaired within that time, the network design must provide 100% redundancy, most typically in the form of a duplicate, parallel circuit. If there is no duplication at the supply voltage, then there must be the facility to reconfigure at a lower voltage to restore supplies to all customers.

If the peak network load increases to a level above the rating of a single transformer (or the OHL or UGC supplying it), then it would not be possible to supply all customers, and some may need to be disconnected for the whole or part duration of a network outage. This outage could potentially be longer than the 3 hour restoration requirement, particularly if the effective demand peak lasts for greater than 3 hours. If some customers can be transferred to alternative sources via the lower voltage network, then there is an increased potential for load growth. This potential is however, a finite resource. Eventually an n-1 scenario will occur, in which all customer transfer capability has been utilized, and the remaining load still remains above the plant rating for a period in excess of 3 hours. At that time, the network is no longer compliant with P2/6. This situation has been the subject of earlier research [10].

As well as complying with P2/6, the DNO is obliged to report failure to supply customers, and is rewarded or penalized by the regulator based on the frequency, duration and extent of such interruptions. The cost of this, as well as the cost to the DNO for unscheduled repairs and asset deterioration as a result of faults, have been combined in a single measure of Total Network Risk (TNR), measured as an expected cost in £k per year. This measure has been published [11, 12], and forms part of the background to the present paper.

Any mitigation measure which can reduce the level of network risk, or postpone the date at which the network becomes non-compliant, can enable high cost capital investment to be deferred or even avoided altogether. One such measure could be provided by EES, and the composite use of it to mitigate network risk is the subject of the present paper.

4. Composite Methodology

Under faulted conditions, one or more circuits in a power distribution network are unavailable to carry electrical energy to meet customer demand. In these circumstances, a new power flow equilibrium is established, in which one or more unfaulted circuits will be carrying more power than under normal, network intact operation. This increased power flow may exceed the capacity of one or more of the circuit components – transformer, switchgear, overhead line or underground cable.

In this event, typically an alarm will sound in the network control room, warning the network operator to offload the overloaded component. In certain configurations, this offloading may be carried out automatically. Where the degree of overloading is above a critical value, the circuit breakers protecting the component will be set to trip automatically. Following any or all of these responses, it may be possible to reconnect all customers by an alternative route, or there may be a proportion of customers disconnected for a length of time, until mitigating action can be taken, including possible repair of the original cause of the fault. The TNR methodology described in Section 3 can be used to evaluate the cost to the DNO of this outage. This will be a function of the number of customers disconnected, and of the duration of their disconnection.

Figure 1 illustrates a typical example, taken from the case study to be described in Section 5. The actual demand on 2 January 2011 reached a peak value of 10437 kW at a time around 1800 in the evening. If there had been an unplanned fault at that time, leading to a capacity restriction of 9400 kW in total by all alternative available routes, then the shortfall of 1037 kW would have required customer disconnection. If the fault had been of long duration, then the shortfall could have lasted for up to 3 hours, from 1700 until 2000, and the total amount of energy not supplied would have been at least 2141 kWh, as shown in Figure 1. In practice, the energy not supplied would probably have been greater, as a consequence of feeder granularity.

However, if a battery were installed on the customer side of the capacity restrictions, it could make up a proportion of this shortfall, depending on the output power flow rating and on the energy storage capacity of the battery. At the end of the evening peak demand period, the battery would be depleted to an extent, but could be

recharged during the night in preparation for the following day's peak, if the fault which required the use of the battery had not been repaired by that time.

This approach is illustrated by the case study which follows.

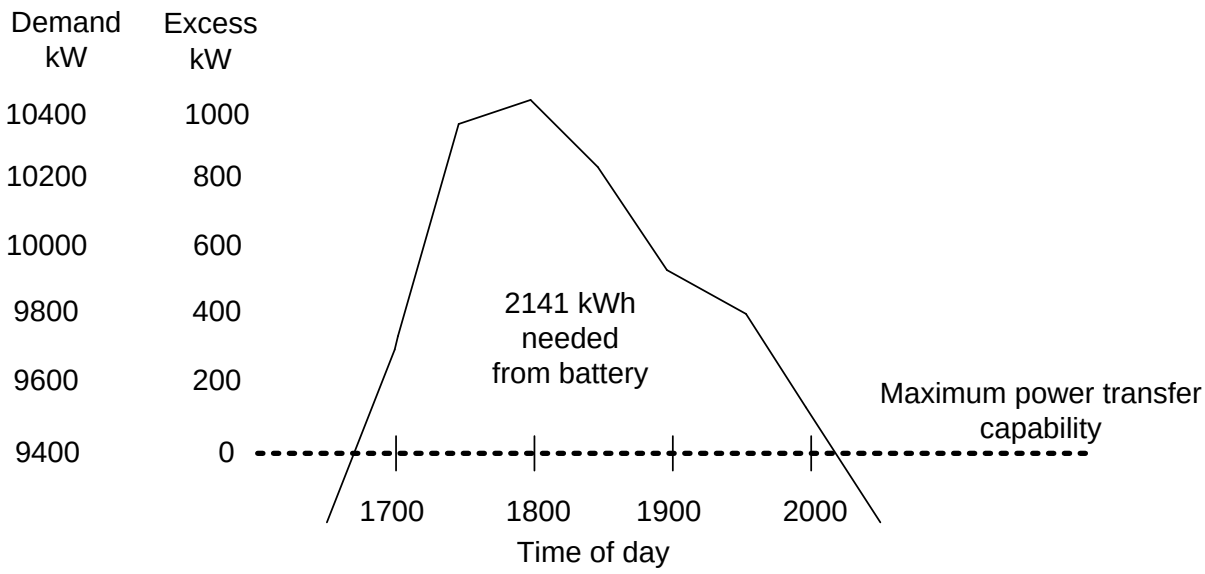

Figure 1 – Excess demand at case study location on 2 January 2011

5. Case Study: Suburban UK Network

The Customer led Network Revolution (CLNR) is an initiative funded by the UK government, which is being carried out by a consortium of a UKDNO, an electrical energy supply company, a university, and an independent consultancy. CLNR seeks to answer a number of seminal questions about the use of smart grid technology, in particular determining to what extent the existing network is flexible, and what the is the cost of that flexibility.

The CLNR project is centered at a number of locations, one of which is a compact suburban network in the North of England supplying around 16 000 customers. In the CLNR project, six battery energy storage systems will be installed at various of voltage levels and a series of locations including the low voltage side of a primary transformer, substations and low voltage feeders in three trial networks. At the same time, demand side response, real time thermal rating (RTTR), on-load tap changer transformer (OLTC) and in line regulators will be also employed. This deployment will enable the study of collaborative control and operation of the wide range of smart grid techniques and technologies. Figure 2 shows a schematic of this network. It is operated at 6.6 kV, with no interconnection to the surrounding network which operates at 11 kV. The network is supplied through two primary substations, each with two independent transformers. In the event of a double circuit fault at Primary 'A', it would be necessary to supply all the customers in the network through Primary 'B', and it is this event which the present case study considers.

The capacity restrictions occur at four normally open points (NOPs) between the Primary 'A' and Primary 'B' subsystems. The capacity of each is shown in Figure 2, and is derived from the thermal limits of the most restrictive component (generally underground cable), and in the case of NOPs 'W' and 'X', the expected peak demand of customers between Primary 'B' and the NOP. The total of the four restrictions comes to 9.9 MVA, equivalent to 9900 kW as the power factor at this location is close to 1.00. In practice, however, the restriction is reduced to 9400 kW to take account of feeder granularity.

Analysis of demand data for the whole year 2011 shows that the peak load at Primary 'A' was 12400 kW, giving a peak power shortfall of 3000 kW. On the day of greatest demand (7 January), the shortfall period lasted from 0900 until 2130, with a total shortfall of 17300 kWh. Shortfalls continued throughout January, February and 19 days in March. There was no shortfall between April and September, 2 days in October, and most of November and December. In total, 133 days during the winter period could expect to see customer disconnections in the event of a loss of supply to both transformers at Primary 'A'. The extent to which the planned battery installation could mitigate this situation is analyzed in the following sections.

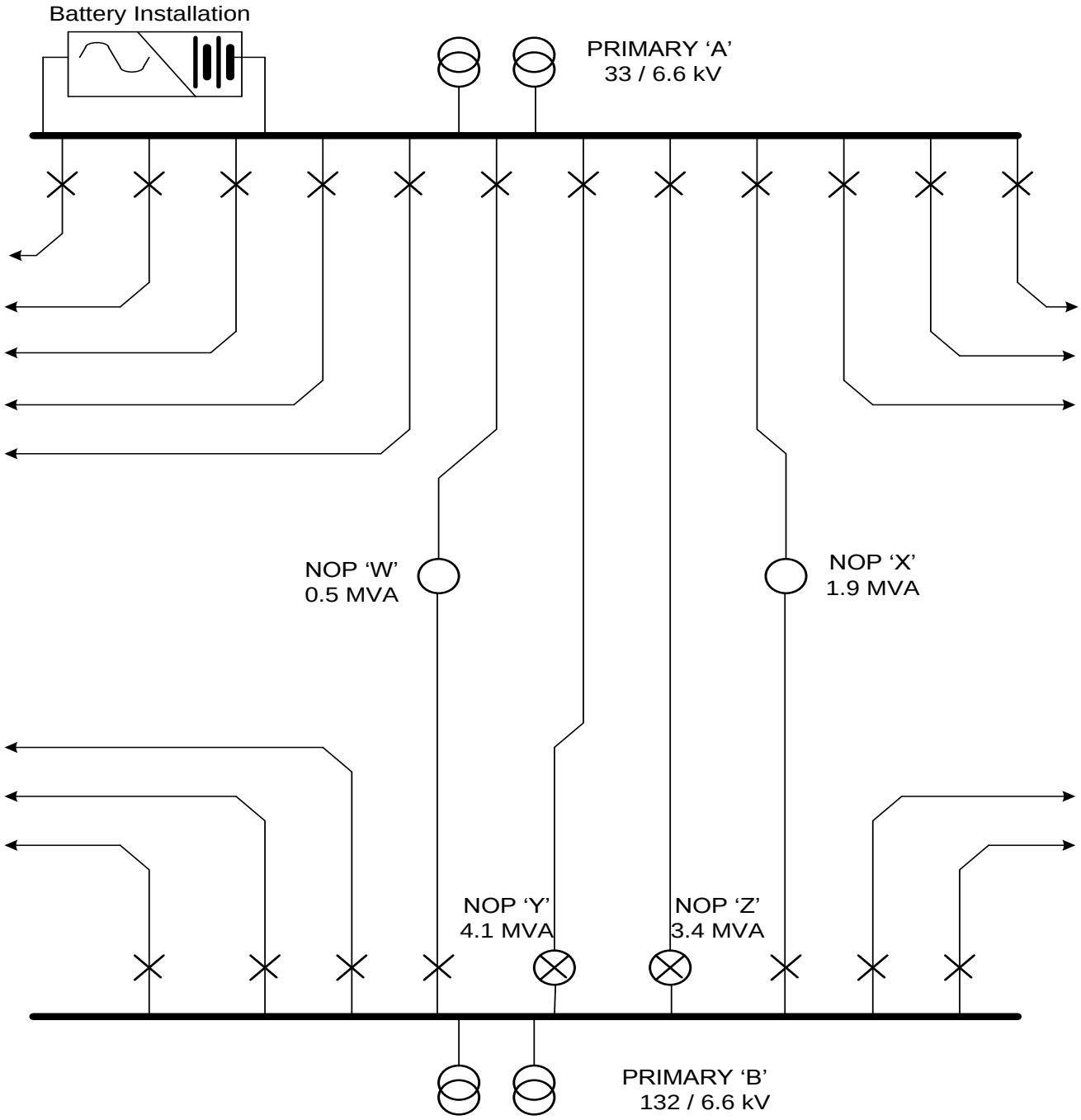

Figure 2 – Case study network

6. Battery Capability

As part of the CLNR project, an EES system, which has the apparent power and capacity rating of 2.5MVA and 5MWh respectively, will be located at the LV side of the transformer at the 33/6.6 kV primary A. The EES systems in the CLNR project have the four-quadrant operating capability, which means they are able to input and/or output real and/or reactive power simultaneously in any combination. The ESS systems feature the lithium ion iron nano-phosphate technology. The manufacturers specify that the ESS systems will have deep depth of charge of 100%, high round-trip efficiency of over 90%, and fast ramp rate, within 20ms from 0 to maximum power output [13]. The EES systems will be used for power flow management, voltage control and increasing network reliability. Following installation, planned for the end of 2012, trials will be carried out to determine the extent to which these design specifications can be realized in practice. Until then, for the purposes of the present case study, it will be assumed that the design specifications can indeed be achieved in practice.

This has particular significance on days when peak demand (in excess of 9400 kW) lasts for over 12 hours, and there might not be time to recharge the battery fully between daily peaks. However, analysis of demand data shows that, even on the worst days, there is a 7 hour period (0000 to 0700) throughout which demand is

consistently below 6900 kW, which allows 2500 kW surplus (below the 9400 kW capacity limitation) for recharging. During this period, the battery could be recharged at maximum power, going from minimum state-of-charge (assumed to be zero) to maximum state-of-charge (assumed to be 100% or 5000 kWh) in just 2 hours.

Another situation which is sensitive to actual battery capability is a day with bimodal excess demand, an example of which is shown in Figure 3. The morning shortfall of 660 kWh could easily be met from a full battery which had been recharged overnight. There would in theory just be sufficient time and spare transfer capacity before the evening peak to recharge the battery fully, so as to be able to satisfy around 78% of the evening shortfall of 6445 kWh. However, for such frequent switching between charging and discharging cycles, the round trip efficiency of the battery becomes significant. The manufacturers claim that this should be in excess of 90%. Field trials during 2013 should help to establish whether or not these performance parameters can be consistently maintained.

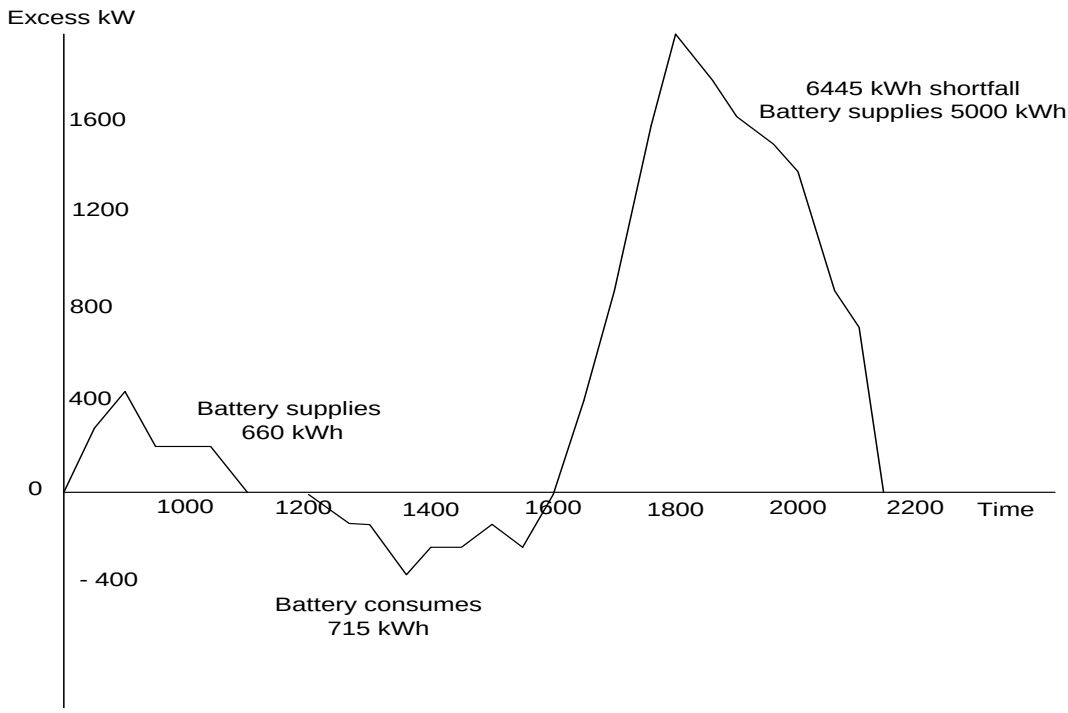

Figure 3 – Bimodal day discharge, recharge, discharge cycle

7. Case Study Resultss

Figure 4 indicates that, of the 133 days of 2011 in which there would be an energy shortfall at Primary 'A' in the event of a double fault, 105 days have a shortfall of less than 5000 kWh. On these days, the use of a battery connected to the 6.6 kV busbar at Primary 'A' would enable customer disconnection to be avoided completely.

On the other 28 days, the energy shortfall would be greater than 5000 kWh. Use of the battery would reduce the extent of this shortfall by up to 5000 kWh, but could not eliminate it completely. On 18 of the 28 days, over half the shortfall could be supplied by the battery, while on the worst of the other 10 days only 30% could be supplied. A Rota Disconnection scheme would need to be implemented, with some customers being disconnected for up to 4 hours. The amount of disconnection actually required would be subject to a degree of uncertainty as a consequence of three factors: feeder granularity, actual battery capability, and customer demand profile (how much of the curtailed demand is recovered in the subsequent period). It is intended to investigate these factors in more detail in 2013.

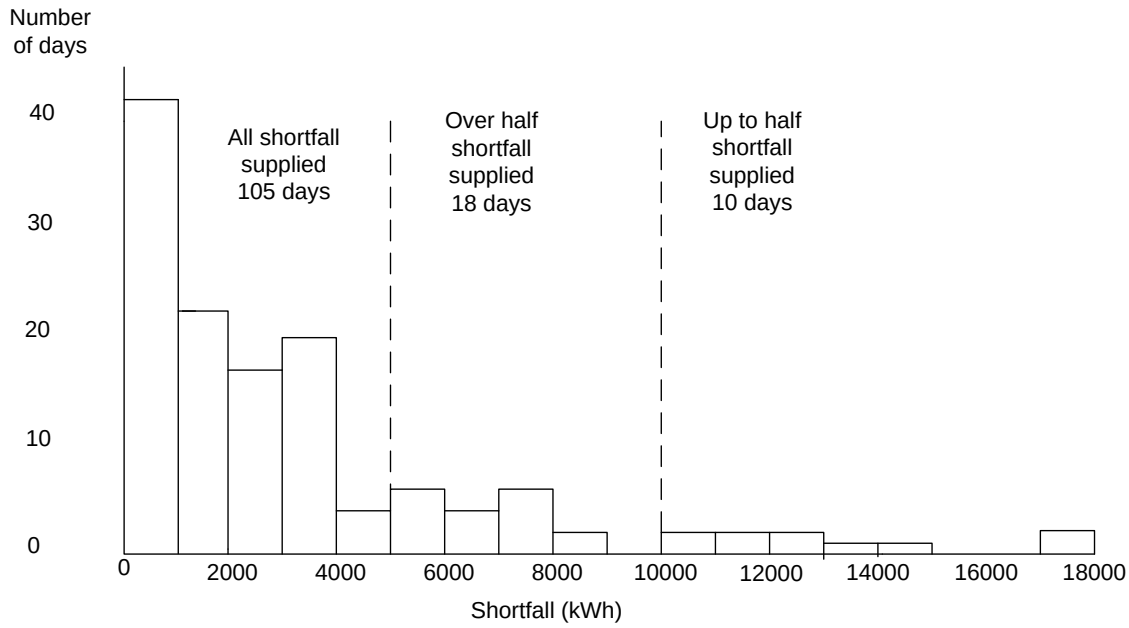

Figure 4 – Analysis of battery supplied shortfall for 133 days in 2011

8. Conclusions

This paper shows that there are potential synergies between EES technologies and network risk evaluation and mitigation methodologies. Analysis of an actual case study, based on 2011 demand data, suggests that under fault conditions lower voltage interconnection would be sufficient throughout the summer period, but would be insufficient to meet demand and avoid customer interruptions for 133 days during the winter period. With a 5000 kWh, 2500 kW battery connected to the primary substation low voltage busbars, however, the full customer demand could be met on 105 of those 133 days, and the demand shortfall could be significantly reduced on the other 28 days.

There are potential financial implications of this reduction in customers not supplied, not only for the customers themselves (which are hard to quantify), but also for the distribution network operator. Based on the rewards and penalties presently imposed by the UK industry regulator, the improvement as a consequence of implementing EES could be expected to reduce the cost of a single day peak time outage by around € 60 000. While this scenario would probably not itself justify the implementation of EES, since the probability of such a double fault event is low, it does contribute to an economic case based on other justifications.

This initial study demonstrates that there could be potential value in using EES schemes to mitigate network risk. However, in order to enhance these conclusions, a significant amount of further work needs to be done. It is hoped to carry out this work over the next 18 months, and to report it in subsequent papers. As regards improving the accuracy and applicability to the present case study, in particular, it will be useful to carry out field trials on the battery once it is installed, in order to gain a more accurate estimate of actual battery capability.

Generalizing from the case study could also be carried out, both for generic or representative networks, and also for other actual locations where loss of infeed has a higher probability. In particular there are locations on the network where the implementation of EES could mitigate single (n-1) as well as double (n-2) faults, and therefore have greater benefits. It is also intended to investigate possible symbiosis with other low carbon technologies, including real time thermal ratings, strategic use of generation, and demand side reduction.

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