Can integration of PV within UK electricity network be improved? A GIS based assessment of storage

Chiara Candelise\textsuperscript{a,b,⁎}, Paul Westacott\textsuperscript{c}

\textsuperscript{a} Centre for Environmental Policy, Imperial College London, United Kingdom
\textsuperscript{b} IEFE, Centre for Research on Energy, Environmental Economics and Policy, Bocconi University, Italy
\textsuperscript{c} Centre for Energy Policy and Technology, Imperial College London, United Kingdom

ARTICLE INFO

Keywords:
Photovoltaics
Electricity storage
Intermittency solutions
PV capacity credit
GIS

ABSTRACT

This paper analyses the potential of distributed storage to mitigate impacts of embedded PV generation on the distribution grid by improving local balance between generation and demand, thereby enabling higher levels of PV penetration. In particular it looks at the potential of storage to: 1. reduce impacts on power flows due to local supply and demand imbalances driven by PV deployment within the UK domestic and non-domestic markets; 2. of improving PV capacity credit, i.e. the contribution of installed PV to meeting electricity demand within the UK electricity system. Results highlight how, under current levels of deployment, PV generation does not create major problems for the local distribution network, but that storage might play a relevant role for higher levels of PV deployment across the UK. The paper contribute to academic debate in the field by providing a novel locally disaggregated framework for the analysis of embedded PV generation integration into the distribution grid. It also provides a useful tool for network operators, regulators and policy makers.

1. Introduction

Deployment of grid-connected photovoltaic (PV) systems in the United Kingdom (UK) has grown rapidly in the recent years. Cumulative PV installed capacity is now over 10GWp (Stoker, 2016) and PV contribution towards the UK's electricity generation has quickly grown from 0.1% in 2011 to 2.2% in 2015 (BEIS, 2016). Typically installed within the network much closer to the point of electricity consumption than conventional generation, PV deployment contributes to give to the UK energy system a more decentralised structure (BEIS and Ofgem, 2016; Snape, 2016). Decentralised energy systems provide new benefits, better locational matching of supply and demand, reducing losses and creating the possibility to avoid network upgrade work if local generation can meet some of the demand peak (for which networks are sized and upgraded). However PV is intermittent and generally considered a non-dispatchable electricity source as it generates electricity when there is available irradiation not when it is most needed by the electricity system. This means that whilst PV can generate electricity close to where there is demand, there is limited control over when it is generated. This may lead to significant changes on how power flows into the network (Westacott and Candelise, 2016a). Several contribution within the literature have highlighted how PV capacity might have an impact on power flow and network operational limits both at local and system (national level) scale. High PV penetration could lead to voltage rise, caused by a high local photovoltaic power feed-in, and overloading issues at low voltage (hereon referred as LV) distribution network level (Stetz et al., 2013; Navarro et al., 2013; Thomson and Infield, 2007). At higher system level it could also lead to upstream reverse power flow, where generation is greater than local demand causing power to flow back to higher voltage levels of the network and leading to challenges in terms of conventional power plant re-despatching and network congestion management (Stetz et al., 2014). Yet, increasing levels of PV deployment in the UK raise concerns over the amount of PV that can be hosted within the network, and more broadly how the value of PV to the electricity system can be maximised by better matching electricity supply and demand over time and spatially (Aurora Energy, 2016; BEIS and Ofgem, 2016; DNV GL - Energy, 2014).

Several technical solutions can be considered to mitigate impacts both at local and system level. These includes control voltage rise through reactive and active power control (which could be provided by the PV systems themselves generally through the inverter or by the Distribution System Operators - DSOs), curtailment as well as network reinforcement both at the regional and international level aimed at increasing balancing capabilities, flexibility, stability and security of supply (PV Grid, 2014; Stetz et al., 2014; IRENA, 2015). Reliable
alternatives are strategies to better match local PV generation and electricity demand throughout the day (Denholm and Margolis, 2016; Perez et al., 2016). In demand terms, this is achieved through demand-side management (DSM), where electricity usage is shifted to times when generation is high (Gruenewald, 2014; Hamidi et al., 2009). Generation can instead be shifted using storage technologies, which store electricity from the time of production to the time when it is required.

Storage technologies are increasingly deemed to be an effective solution to expand PV hosting capacity and minimise network impacts (PV Grid, 2014; Setz et al., 2014; Denholm and Margolis, 2016; Fazeli et al., 2014) as well as increasing UK electricity system flexibility and security (Sanders et al., 2016; BEIS and Ofgem, 2016; IRENA, 2015; Strbac et al., 2016). Indeed, a global momentum around storage technologies highlights an increasing consensus over their potential to provide vital grid services needed for the integration of PV and other intermitted renewables into the electricity systems (IRENA, 2017; World Energy Council, 2016). Storage systems can not only help in shifting load and balancing intermittency, but also provide other ancillary services to the network such as frequency response, voltage support and reserve capacity (Pierpoint, 2016; Setz et al., 2014). As such they can be implemented at distributed level (behind the meter and attached to PV systems and distributed generation), as well as standalone (bulk storage) within the transmission and distribution networks.

Along with the increased recognition at the UK institutional and energy markets level of the potential important role of storage to support low-carbon energy transition and in the context of the solar power sector, the academic literature have begun to study its technical advantages as well as implementation conditions and implications for the UK electricity network (Wang and Mancarella, 2016; Zhou et al., 2015; Sanders et al., 2016; Waterson, 2017; Garvey et al., 2015; Taylor et al., 2013). Major UK techno-economic analyses on grid balancing challenges and the role of storage within the UK electricity system have looked at both standalone and distributed storage concluding that distributed storage offers higher value to the electricity system as it could reduce the need for distribution network reinforcement (Strbac et al., 2012c, 2012a). They also highlight how the magnitude of such value would depend on the characteristics of local generation and demand, despite it cannot be assessed within the given modelling framework. Indeed, a whole system modelling approach is used, where the distribution network is modelled on the basis of representative UK networks and data are not disaggregated at local level, in particular electricity demand data (Sanders et al., 2016; Strbac et al., 2012a, 2012c). These characteristics limit the model ability to assess and measure both local grid impacts of embedded PV generation and the potential contribution of distributed storage to mitigate them.

Yet, little work has to date specifically looked at how storage could optimise embedded PV generation output and minimise local impacts within the UK power system. This paper aims at addressing this gap in the literature by looking at how combining PV systems with distributed storage (hereon referred to as PVS) could improve local generation and demand balances and the integration of PV within the UK distribution network. In particular, it looks at PVS potential contribution from two perspectives:

1. Assessing how PVS could help in reducing impacts on power flows due to local supply and demand imbalances driven by PV deployment within the UK domestic and non-domestic PV market segments.

2. Assessing the potential of PVS of improving PV capacity credit, i.e. the contribution of installed PV to meeting electricity demand within the UK electricity system.

Few studies have looked specifically at the potential of distributed storage to mitigate embedded PV generation impacts on the UK distribution network. For example, Pholboon et al. explore the use of storage in a specific small energy community in Nottingham (UK) with grid-connected PV systems (Pholboon et al., 2015) showing that it can shave peak power demand and increase self-consumption, thus increasing grid stability and reducing distribution system losses. Wang et al. model storage associated with residential PV within a representative UK LV network case study showing its ability to relieve network congestion (Wang et al., 2015).

However, such type of analysis have to date been limited to specific case studies or small sections of the network, focused on UK PV domestic market segment only and based on demand load profiles simulations. This paper instead looks beyond specific case studies, encompassing wider geographical data and non-domestic PV market segment and is based on primary PV deployment and electricity demand data. As the potential benefits of PVS are expected to be strongly influenced by the local characteristics of PV generation and electricity demand, the analysis is based on the United Kingdom Photovoltaic Deployment (UKPVD) framework, a Geographical Information System (GIS) framework which maps current UK PV deployment and electricity demand disaggregated to sensitive spatial resolution and by market segment (Westacott and Candelise, 2016b, 2016a). While GIS approaches have been used to map generation potential of renewable energy sources such as PV or wind (Sinden, 2007; Süri et al., 2005, 2007) and optimisation of solar project siting (Brewer et al., 2015; Uyan, 2013), the UKPVD framework extend their use to the assessment of the local balance of PV generation and electricity demand, analysing impacts on power flows between LV and higher levels of the UK electricity network (Westacott and Candelise, 2016a). Moreover, the UKPVD framework is based on actual PV deployment figures and primary electricity demand data. Thus this study allows to have a realistic picture of where and how storage implementation could provide benefits in terms of increased PV hosting capacity in relation to the amount of local PV generation and electricity consumption across UK geographical areas.

The paper is structured as follows: Section 2 discusses the UKPVD GIS framework, the methodology and the data used. Section 3 presents the results of the analysis on how storage can contribute to improving PV hosting capacity within the UK electricity system. Section 4 concludes and provides some policy recommendations.

2. Methodology and data

The UKPVD is a geographical information system (GIS) based framework mapping current UK PV deployment and electricity consumption across PV market segments, i.e. domestic, non-domestic and ground mounted (Westacott and Candelise, 2016b, 2016a). It is based on the most detailed spatial disaggregation available, in order to capture as accurately as possible local variations in PV generation and electricity demand and consequent impact on high voltage/low voltage (hereon referred to as HV/LV) power flow. This paper focuses on a specific distribution region, the South-West England (SWE) licence area which serves around 1.5 million demand customers. This area has the highest level of PV deployment within the UK and as such is expected to experience greater impacts from PV generation than other network areas (Rowley et al., 2015). The area is disaggregated into 1888 Lower Layer Super Output Areas (LSOAs) which have been used as geographical units (Office of National Statistics, 2011). LSOAs are spatial areas containing on average 600 households, designed by the Office of National Statistics (ONS) to characterise the socio-economic characteristics of the UK. As population is relatively constant per LSOA they experience greater impacts from PV generation than other network areas (Westacott and Candelise, 2016b)). LSOA base maps are acquired from the ONS Geoportal (Office of National Statistics, 2014). For each LSOA complementary data-sets are developed for PV deployment and electricity demand (see Section 2.1). Fig 1 show spatial and statistical distribution of PV deployment across LSOA in the SWE distribution region,
calculating PV penetration (dividing total number of PV systems by the number of demand customers) for each LSOA. The map on the right shows significant variation in the amount of PV deployed per LSOA, with some local clustering characterized by higher PV penetration (darker areas). Such variation is also evident in the histogram on the left which shows distribution of LSOAs across different levels of PV penetration: a majority of LSOA have relatively low penetration, several clusters between 10% and 20% PV penetration and greater PV installation in rural areas.

2.1. Characterization of Summer and Winter Case Studies

The analysis is based on two case studies representing a summer and a winter scenario, chosen to depict two worst case scenarios (Table 1) in terms of local balance between PV generation and local electricity demand:

1. a summer time case when PV generation is at its peak and daytime demand is typically low;
2. a winter case characterized by low PV generation and high peak demand.

During the summer, high daytime PV generation and low daytime demand could lead to local electricity supply and demand imbalances with resulting impacts on power flows and network operational limits. PV generation might cause back-feeding presenting challenges for the LV distribution network operation. PVS could reduce these effects by allowing surplus PV generation to be absorbed during the day and utilised locally later in the evening to meet demand. It can thus help in smoothing daily power flow, in minimizing the occurrence of power feed-in and in reducing the need for power flows management and network upgrade (Stetz et al., 2014). Moreover, at the higher electricity system level, reducing upstream reverse power flow would allow better management of UK electricity market balancing, better utilisation of other generation sources and reducing reliance on peaking plants to balance the system (Sanders et al., 2016). During winter instead PV generation is generally lower than local demand. In this context PVS has the potential to improve PV capacity credit by storing PV generation from the daytime and discharging during the hours of peak winter demand in the evening. It thus reduces the peak electricity imported into the LV distribution network from high voltage (HV) network, deferring or reducing reinforcement in transmission and distribution, as wires and transformers are typically sized and upgraded to meet winter peak (Sanders et al., 2016). This is particularly relevant in a context of expected increase in the UK electricity load, due to natural growth combined with expected progressive electrification of heat and transport (Baruah et al., 2014; House of Commons, 2016).

As summarized in Table 1, local electricity demand, PV generation and storage operation are considered and calculated out of the UKPVD dataset for each case study. Next sections present and discuss assumptions and data-sources used for electricity demand, PV generation and storage operation.

### Table 1
**Characterization of summer and winter case studies.**

| Case study | Demand                      | PV                      | Storage operation                              | Analytical metric                         |
|------------|------------------------------|-------------------------|------------------------------------------------|--------------------------------------------|
| Summer     | Lowest demand – summer Sunday| Single day of highest generation | Storage absorbs PV maximum generation and discharges during evening | 1. Quantify reduction in reverse power flow  |
| Winter     | Highest demand – winter weekday | Variation across all days (Nov–Febr) considered | Storage acts as “energy buffer” charging from PV when available and discharging fixed amount 4–7 p.m. everyday of winter | 1. Quantify reduction in winter peak demand |

Fig. 1. Distribution of PV penetration across the South-West England distribution region, map (left) and histogram (right). Sources: PV deployment data (DECC, 2014, Ofgem, 2014); number of demand customers (DECC, 2015).

C. Candelise, P. Westacott  
Energy Policy 109 (2017) 694–703
domestic customers developed by Elexon (Elexon, 2013). Such data have been used to derive half hourly electricity demand profiles for domestic and non-domestic market segments and for each LSOA of the distribution region considered (Westacott and Candelise, 2016a).

For the purpose of the case study analysis, in order to depict the two worst case scenarios, it was needed to identify within the dataset a summer day with lowest demand and a winter day with highest demand (see Table 1). However, the demand profiles differ across the market segments considered: consumption is higher in the non-domestic sector during weekdays, whereas in domestic sector it is higher at weekends (this broadly correlates with building occupancy, i.e. a greater proportion of people are at home during weekends and in workplaces during the week). The combination of the two consumption profiles has an impact on the net electricity consumption behaviour at LSOA level. Indeed, the maximum and minimum demand days are expected to vary with the proportion of domestic and non-domestic electricity consumption within each LSOA. Fig. 2 (top) presents the proportion of domestic electricity consumption as a percentage of total LSOA consumption (calculated by summing up domestic and non-domestic consumption), to investigate how this proportion varies across the LSOAs in the distribution region considered. The figure shows that in the majority of the LSOAs domestic consumption is significantly larger than non-domestic (e.g. the domestic proportion is over 50% of the total). The figure also reveals that it is most common for LSOAs to have around 80% domestic electricity consumption within them.

Therefore an LSOA with 80% of the total electricity consumption originating from the domestic sector is taken as representative within the target distribution region. In order to identify when daily maximum and minimum demand occur within it, its daily electricity consumption is plotted over a year (Fig. 2, bottom), disaggregated by domestic and non-domestic customers. Firstly the plot shows the expected seasonal trend of higher electricity consumption during winter. At shorter time-scales, significant patterns in daily demand can also be observed with demand typically peaking mid-week and reducing at weekends. This result highlights that even 20% of non-domestic energy consumption is enough to shift minimum demand to the weekend (whereas in the domestic only case this would occur on a weekday). Based on this evidence a summer Sunday has been chosen as the minimum demand day (namely, 29th July as the representative day) and a winter weekday as the maximum one (namely, 20th December as the peak demand day, Christmas day has been excluded from analysis as this is considered a “special day” (Staffell and Green, 2014)).

### 2.1.2. PV generation

Different PV generation data have been used for the summer and winter case studies.

#### 2.1.2.1. Summer case study

For the summer case study PV generation data are derived by combining data on PV deployment in domestic and non-domestic segments with PV generation profiles, i.e. how much electricity a given PV system is expected to generate and how generation is distributed across the day. Sources for PV deployment data are the central feed-in tariff register (Ofgem, 2014) administered by Ofgem as well as the renewable energy planning database (DECC, 2014) administered by the Department of Energy and Climate Change (DECC). Such PV deployment data have been combined with a PV generation profile derived from the Customer Led Network Revolution (CLNR) project (Sidebotham, 2015), resulting from the aggregation of monitored performance of 100 domestic PV systems with different tilts and orientation (in order to account for diversity in generation profiles). The average July generation profile has been used here. In addition, to account for the summer worst case scenario (i.e. highest PV generation, combined with low demand) empirical evidence presented by the Low Voltage Network Templates project (WPD, 2014) on
maximum coincident generation over a year of monitored PV systems located in the same spatial area has been used: the recorded maximum coincident generation was 81% of the aggregated PV capacity. Such a figure has been here assumed in calculating PV generation per LSOA. For example an LSOA with a total of 100 kWp of PV installed would have a PV generation profile that peaked at 81 kW (Westacott and Candelise, 2016a).

2.1.2.2. Winter case study. The aim of the winter case study is to explore the potential of PVS to improve the contribution of PV systems to meeting electricity demand within UK electricity system, i.e. to increase PV Firm Capacity Credit (FCC). FCC is here defined as the minimum power that can be dispatched daily at peak demand (as a percentage of installed PV capacity). The FCC which PV systems could provide is strongly dependent upon the variation in daily PV generation (see also storage operation in Section 2.1.3). Therefore data on monitored PV system operation over a year has been used to investigate how PV generation varies across an entire winter (here defined as the period between November and February), as shown in Fig. 3. It is noted that, due to data availability, generation data comes from the monitored performance of a solar farm in South-West of England (Primrose Solar, 2015). While data from monitored domestic rooftop systems would ideally be used, what is here relevant to capture is the longer run trends in daily variability (e.g. the occurrence of sunny or darker days) which is equally captured by solar farms performance.

2.1.3. Storage operation

Optimum operation for energy storage is here defined in order to meet the objectives of each case study, i.e. absorbing peak PV generation in the summer months and providing firm-capacity to meet peak demand during winter. Storage is assumed to be deployed at a ratio of 1 kWh per kWp of PV installed, with assumed round-trip efficiency (RTE) of 80%. Storage penetration (e.g. the percentage of PV systems with deployed storage) varies under the different scenarios outlined in the following section.

2.1.3.1. Summer case study. In the summer storage is assumed to absorb as much of the peak PV generation as possible during the day and to release electricity later in the evening. This operation has the net effect of smoothing the power flow through the day and helps in minimizing impact of reverse power flow when it occurs. The shapes presented in Fig. 4 compare PV generation profile without and with storage, i.e. replacing a PV only profile with PVS. The level of peak shaving (i.e. the plateau at −0.59 kW in PV generation profile, Fig. 4) is optimised to maximise peak shaving without surpassing storage maximum state-of-charge (SOC). The absorbed electricity is then discharged as the sun begins to set, starting at around 6 p.m. The discharge is assumed to continue until the storage is at 20% SOC, i.e. discharge stops after 80%, reflecting the assumed RTE of 80%.

2.1.3.2. Winter case study. In the winter storage is assumed to operate as a “buffer” to move energy between sunny and darker days, in order to increase FCC, i.e. the minimum power that can be dispatched daily at peak demand (as a percentage of installed PV capacity). This has been modelled using Eq. (1):

$$SOC_d = SOC_{d-1} - DD + PV_d; DD \leq SOC_d \leq SS$$

where $SOC_d$ denotes the state-of-charge at sunset (e.g. when PV generation for the day is complete and prior to evening discharge). $DD$ is the daily discharge required every day and $PV_d$ is the daily PV generation. Subscript $d$ refers to the current day, and $d-1$ to the previous day. The equation is subject to the constraint that the SOC is greater or equal to $DD$ and does not exceed the storage size (SS). The equation is then optimised to maximise the DD, based on the variation in $PV_d$. Results of this optimisation are shown in Fig. 5: a DD of 0.29 kWh/kWp.

2.2. PVS deployment scenarios

For each of the two case studies a range of deployment scenarios combining PV and storage (PVS) are investigated beginning with a baseline level of electricity demand and PV generation and extending to hypothetical increased levels of PV ad storage deployment. Four different scenarios are considered (Table 2):

- a base case, based on current levels of PV deployment and without implementation of storage;
- a 50% storage scenario in which it is assumed that one in two PV systems currently deployed in the target distribution region (domestic and non-domestic) have 1 kWh of storage installed per kWp of PV;
- a 100% storage scenario where all PV systems are assumed to have storage attached to them.

Fig. 5. model used to calculate the maximum daily discharge for a PVS system. The example depicts a 1 kWp PV array with 1 kWh of storage. PV daily generation (kWh) is shown (blue bars) in conjunction with the storage state-of-charge (SOC) prior to evening peak (red). The daily discharge (DD) is also shown (purple). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)
Table 2

Scenarios considered.

| Scenarios          | Demand   | PV            | Storage deployment |
|--------------------|----------|---------------|-------------------|
| Base case          | Current  | Current       | None              |
| 50% storage        | Current  | Current       | 50% of PV installations have 1 kWh/kWp installed |
| 100% storage       | Current  | Current       | 100% of PV installations have 1 kWh/kWp installed |
| 200% PV            | Current  | Double        | None              |
| 200% storage       | Current  | Double        | 100% of PV installations have 1 kWh/kWp installed |

To explore the potential of storage to allow higher penetration of PV within the UK electricity network in the future, two scenarios with higher levels of PV deployment are assumed:

- in the 200% PV scenario PV capacity within each LSOA is doubled across the entire distribution region, whilst maintaining the current proportion of domestic versus non–domestic deployment (Westacott and Candelise, 2016b, 2016a),
- the 200% storage scenario assumes a deployment of a 1 kW of storage per kWp of PV deployed as under 200% PV scenario.

3. Results

The analysis characterises how storage changes the local balance of electricity supply and demand during the summer and winter worst case scenarios discussed above. This approach allows to quantify at a geographically disaggregated level (i.e. at LSOA level) how the introduction of storage can help in smoothing power flow and reducing peak PV export during the summer, on one hand, and in improving PV contribution to winter peak demand on the other.

3.1. Summer scenario: smoothing and reducing reverse power flow

To interpret the results of the summer case study, i.e. the potential of storage of reducing impact on power flows, it is relevant to present results of a recent work (Westacott and Candelise, 2016a) which has investigated the impact of PV generation on power flow by comparing PV generation and electricity demand throughout the day within each LSOA of the South-West England, the same region here targeted. The study is also based on the UKPVD framework and the same datasets for electricity demand and PV generation used in this paper. It analyses how much PV generation is contributing to local demand, by calculating the maximum proportion of demand load met by peak PV generation for each LSOA (usually at around 2 p.m.) (Fig. 6, left). The study assumes that all the electricity is consumed within the LV network and, therefore, that such LV load met by equates to a reduction in the power flow from high voltage (HV) to LV network. In other words, in this context the lower is the percentage of LV load met by PV the lower is the impact on HV/LV power flow. Moreover, the study shows how different amounts of PV deployed and electricity consumption lead to different impacts on power flow across LSOAs. In particular, it shows how in most of the LSOAs current PV generation meets less than 20% of the daytime load, meaning a very limited impact. PV generation is higher than demand only in a very small number of LSOAs (i.e. where PV meets more than 100% of the LV load) and these areas are expected to experience power feed-in and reverse power flow (Fig. 6, right).

According to this previous analysis, results for the summer case study are presented for two different LSOAs, in particular:

- an ‘average’ LSOA, where PV generation meets 20% of the LV load;
- a ‘maximum’ LSOA, where PV meets more than 100% of LV load and reverse power flow (RPF) is experienced.

Summer case study results are shown for the minimum demand day chosen (i.e. 29th July, see Section 2.1.1).

Fig. 7 presents results for an ‘average’ LSOA. The figure presents the aggregate load demand (sum of domestic and non–domestic demand within the LSOA) (blue) and the residual load demand, i.e. demand net of PV generation (green on the left dark orange on the right). Fig. 7 (left) depicts the base case scenario (dark green), based on current level of PV deployment, and the introduction of 50% and 100% storage scenarios (lighter green). Under the base case scenario PV generation has an impact on power flow, with a significant reduction around midday, followed by a ramping of required power (from HV to LV network) as the sun begins to go down (at ~6 p.m.). The addition of storage to 50% of the installed PV systems has the effect of smoothing the overall power flow, by absorbing PV generation around midday and discharging later in the evening. Increasing storage deployment to 100% further smooths the power flow. When PV deployment is doubled (Fig. 7 (right)) these effects are more pronounced: PV generation has a stronger impact on power flow, with daytime demand dropping below night time levels. The introduction of storage (at 100%) helps considerably in smoothing the power flow. Fig. 8 shows results for a ‘maximum’ LSOA, where PV generation has a stronger impact on residual load demand (dark green), leading to RPF (moving into the darker area below zero). In the base case (left) the reported RPF is of around 350 kW, which is reduced under 50% and 100% storage scenario by respectively ~140 kW (to ~210 kW) and ~100 kW (to ~110 kW). When PV penetration is higher the impact on daytime demand is stronger (~1300 kW) and the introduction of storage helps in reducing RPF by ~500 kW.

Analysis up to now has focused on single LSOAs, but it is interesting to look at how representative they are of the total distribution region considered. Fig. 9 presents the distribution across LSOAs of the percentage of daytime load met by PV. The dark green line depicts the base case situation, i.e. based on current PV deployment and demand (it is the continuum approximation of distribution in Fig. 6 right). As also noted above, for around 1/3 of the LSOAs PV meets less than 10% of load and for a progressively smaller number of LSOAs higher amounts of load are met by PV. The addition of storage (50% and 100% scenarios in lighter green) has two effects. The overall smoothing effect resulting from the storage operation, observed here as a reduction in daytime load met by PV (and therefore a reduction in the HV/LV power flow), pushes LSOA’s distribution towards zero. The RPF reduction effect of storage instead (magnified on the inset) reduces the number of LSOAs experiencing it. Under 100% storage scenario the smoothing effect is more pronounced, implying a greater number of LSOAs with low percentage of demand met by PV, i.e. low power flow impact. The number of LSOA experiencing RPF is halved (reduced from 4 to 2), highlighting how storage could be successfully deployed to mitigate RPF in the target distribution region.

When PV deployment is doubled (200% PV scenario) impact on power flow are more pronounced, as the number of LSOAs where high levels of LV load are met by PV increases dramatically (dark red line in Fig. 10). Furthermore, RPF occurs in 121 LSOAs, 3 time more than the base case scenario. This is significant as it shows that if PV deployment trends continue as they have historically, the occurrence of RPF is due to increase considerably. Installing storage on all of the PV systems however has a substantial effect. Firstly it smooths power flow, as shown by the decline in LV load met by PV across LSOAs (orange and green lines in Fig. 10). Secondly it reduces the number of LSOAs where RPF occurs from 121 to 33 (75% reduction). This highlights the benefits of installing storage in areas characterized by increasing levels of PV penetration.

3.2. Winter case study: Reducing peak demand

Considering that the aim of the winter case study is the potential of PVS to improve PV generation contribution to evening peak demand,
results are here presented for the maximum demand day chosen (i.e. 20th December, see Section 2.1.1) and for an LSOA with maximum PV installed relative to load. As in the summer case study, Fig. 11 presents aggregated daily load demand (sum of domestic and non-domestic demand within the LSOA) (light blue). In absence of storage PV generation does not contribute to evening peak demand. The addition of storage instead enables a 5% contribution of PV generation to the evening peak demand of the given LSOA. Such contribution is greater under 100% storage deployment scenario (~10%). Results are similar under the 200% PV scenario (Fig. 12): in absence of storage PV generation does not contribute to evening peak demand, but its introduction allows a contribution of about 20%, hence greater than in the base case PV scenario (Fig. 11). Thus, higher deployment of PV, if coupled with storage, can substantially increase PV Firm Capacity Credit (FCC).

Fig. 13 expands the analysis across all LSOAs of the distribution region. In absence of storage PV contribution to evening peak demand is below 0.1% in all LSOAs (green bar). Under 50% storage scenario PV contribution increases, with evening peak demand reducing across LSOAs (green line in Fig. 13). Increasing storage to 100% leads to
deployment scenario as well PV alone does not provide any contribution to evening peak (dark red bar in Fig. 14). Similarly to the base case scenario the introduction of storage improves the situation. However, in this case PV generation contribution is larger: about 75% of LSOAs show a peak reduction above 1%, with maximum recorded reduction of 20%. These results show how storage could allow newly deployed PV capacity to increasingly contribute to meeting UK peak evening demand and hence benefit the wider UK electricity system.

4. Conclusions and policy recommendations

This study provides evidence of increasing importance of storage technologies within the UK electricity system, quickly progressing toward higher deployment levels of renewable and intermittent generation including distributed PV. It tells where and how distributed storage could provide benefits in terms of increased PV hosting capacity in relation to the actual amount of local PV generation and electricity consumption across different geographical areas. In this context the evidence provided is twofold. Firstly, the potential of distributed storage to reduce power flow impacts (by charging when PV generation is high during the daytime and discharging during peak evening electricity demand) is assessed across South West England. The net effect is a smoother power flow from higher voltage levels, due to the better matched local supply and demand, reducing the need of local power flow management and network upgrade. Results show that, under current levels of PV deployment, in the majority of the areas analysed (i.e. LSOAs) PV generation does not exceed local demand and sums up to a relatively small fraction of the total peak demand. In other words, few are currently the areas in the South West England where distributed storage might be needed. However, results change for higher levels of PV deployment where the number of areas where distributed storage could help in minimizing power feed in and smoothing power flow increase.

Secondly, the analysis indicates how storage can help in increasing PV firm capacity credit (FCC), i.e. PV generation contribution to evening daily peak electricity demand. This could provide benefits to the network operator, reducing or deferring reinforcement in transmission and distribution network (as wires and transformers are typically sized and upgraded to meet peak demand), allowing a better utilisation of other generation sources and reducing reliance on peaking plants to balance the system. In other words, the analysis shows that the implementation of storage can not only optimise solar output by offering a firmer power delivery into the network at a local level, but can also increase PV generation contribution at wider system level. As above, results show that, under current levels of PV deployment, contribution of PV generation to peak demand achieved with the introduction of storage is overall relatively small across the area considered, but it would increase in presence of larger PV penetration.

These results are particularly relevant in a context of expected increase in UK electricity load (due to natural growth combined with expected progressive electrification of heat and transport (Baruah et al., 2014; House of Commons, 2016)) and the need of the UK electricity network to progressively upgrade to increase its flexibility to allow the transition toward a secure, low carbon energy system (Sanders et al., 2016).

This paper adds to the academic and modelling efforts surrounding PV deployment integration into the UK electricity grid, by providing a novel locally disaggregated framework for the analysis of embedded generation integration into the distribution grid. By being disaggregated to sensitive spatial resolution and based on actual PV deployment figures and primary electricity demand data, it provides a useful tool to consider which areas would most likely incur in power flow imbalances and potentially benefit from storage deployment (or other flexibility solutions) along with progressive deployment of PV across UK territory. Therefore it could be used as a basis to consider and evaluate potential strategies for better integration of PV within UK
It is recognised that the framework and the analysis presented have some limitations and further work is envisaged to improve them. Both the spatial and temporal resolution can be improved, despite heavily relying on the availability of data. Integrating finer temporal details across an entire year would allow to extend the analysis beyond the worst case scenario, e.g. assessing how frequently it actually occurs. Finer spatial analysis within a given LSOA could allow to capture more localised power flows variations, e.g. impacts of clusters of PV deployment or the potential of balancing across different end users demand profiles. Moreover, the UKPVD framework will be extended to include distribution network asset data in order to more inclusively assess PV generation local network impacts (e.g. including voltage rise) disaggregated to a spatially sensitive scale, which would also allow to evaluate the potential of storage not just in terms of power flow management and peak shaving but also to provide other ancillary services such as voltage control or local power outages management (REA, 2016; Hoff et al., 2007). Finally an economic layer of analysis will be added in order to estimate cost implications of local network upgrade caused by PV deployment, and build up scenarios to assess the economics of storage deployment versus local network upgrade or the relative cost effectiveness of distributed versus standalone storage. These assessments will be across different UK areas and accounting for a set of potential storage benefits, including peak shaving and other ancillary services. For example, local network upgrades needed to integrate a given level of additional PV capacity and their relative costs are likely to be different in rural areas when compared to urban ones, thus also changing the economic case for storage implementation in the different areas.

This study, and the framework developed, could potentially be used by network operators and regulators to have a realistic picture of where and how embedded PV generation might impact local network, and how and where storage implementation could provide benefits in terms of increased PV hosting capacity. This would allow to fine tune grid network management, PV and storage deployment across the country by accounting for local variations in PV generation and electricity demand balance. For example it could be used by DNOs to identify potential critical areas, where e.g. storage installation could constitute a more timely intervention to accommodate increasing levels of PV deployment while planning longer term network upgrade.

While storage is increasingly acknowledged by UK government and regulators as an essential part of the future UK energy mix (BEIS and Ofgem, 2016; NIC, 2016) and storage installations have been slowly increasing (REA, 2016), private and public investments in all possible storage applications are still limited. This in particular in the distributed storage segment, characterized to date only by few pilot programmes (REA, 2016). Significant regulatory barriers need to be removed. This includes the lack of storage specific UK regulatory framework (such as clear network fees associated with storage services and better regulation of storage access to capacity market) which would allow creating a level playing field for storage to participate in the provision of electricity market services. Along with possible regulatory framework interventions, policy makers have also control over several policy tools. For example, demand pull policies could be implemented, including direct financial support to storage implementation which would speed up market uptake and allow progress of storage technologies along the innovation chain, while also improving their economics. Supply push policies providing continuous funding to storage technologies research, development and demonstration project are also needed to guarantee progressive technological development and scaling up. The framework here developed, in particular when integrated with the economic layer of analysis, could also be used to provide evidence to support policy makers in potential regulatory and policy decisions in the field. For example while identifying best location and deployment level of storage, it can also be used to help the decision maker in understanding the appropriateness and cost effectiveness of different

distribution network. For example, it can be used to determine how PV could optimally be deployed across the network to provide the best match between local generation and demand. It can also be used to identify areas where expected high PV penetration would be combined with peak demand close to equipment limits and which have potentially the most to gain from deploying storage, which would both help to integrate PV into the network smoothly and also reduce the need for upgrading equipment.
storage options, compare them with other flexibility solutions as well as assess the overall cost of storage implementation and, potentially, the relative cost of policy support across the UK.

Acknowledgements
This work was conducted as part of the research project ‘PV2025 – Potential Costs and Benefits of Photovoltaic for UK Infrastructure and Society’ funded by the RCUK’s Energy Programme (Contract no: EP/ K02227X/1).

References
Aurora Energy. 2016. Intermittency and the cost of integrating solar in the GB power market. Report commissioned by the Solar Trade Association. September 2016. Available at: https://www.solar-trade.org.uk/wp-content/uploads/2016/10/Intermittency-and-the-cost-of-integrating-solar-Aurora-Energy-Research-September-2016.pdf (Accessed 17 January 2016).

Barah, P.J., Eyre, N., Qadrdan, M., Chaudry, M., Blaineay, S., Hall, J.W., Jenkins, N., Tran, M., 2014. Energy system impacts from heat and transport electrification. Energy 167 (Issue), 139–151.

BEIS, 2016. Renewable sources of energy: Chapter 6. Digest of UK Energy Statistics (DUKES). Available at: https://www.gov.uk/government/collections/digest-of-uk-energy-statistics-dukes (Acessed 17 January 2017).

BEIS, Ofgem. 2016. A smart, flexible energy system. A call for evidence. Department for Business, Energy & Industrial Strategy (BEIS) and Ofgem Consultation Document. Available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/576367/Smart_Flexibility_Energy_Call_for_Evidence1.pdf (Accessed 16 January 2017).

Brewer, N., Ames, D.P., Lee, R., Carlisle, J., 2015. Using GIS analytics and social preference data to evaluate utility-scale solar power site suitability. Renew. Energy 81, 825–836.

DECC. 2014. Renewable Energy Planning Database. Department of Energy and Climate Change. Available at: https://www.gov.uk/government/publications/renewable-energy-planning-database-monthly-update (Accessed June 2015).

DECC. 2015. Sub-national electricity consumption data. Department of Energy and Climate Change. Available at: https://www.gov.uk/government/publications/sub-national-electricity-consumption-data ([Accessed June 2015]).

Denholm, P., Margolis, R., 2016. Energy storage requirements for achieving 50% solar photovoltaic generation in California. NREL (Technical Report). NREL/TP-6A20-66595. August 2016.

DNV GL - Energy. 2014. Integration of renewable energy in Europe. Final report. Report commissioned by European Commission. In collaboration with Imperial College London and NERA. Project number: ENER/C1/427-2010. June 2014. Available at: (https://ec.europa.eu/energy/sites/ener/files/documents/201406_report_renewables_integration_europe_en.pdf) (Accessed 18 January 2017).

ELEXON. 2013. RE Load Profiles and their use in Electricity Settlement. Fazeli, A., Sumner, M., Christopher, E., Johnson, M., 2014. Power NIC, 2016. Smart power.

Fazeli, A., Sumner, M., Christopher, E., Johnson, M., 2014. Power NIC. 2016. Smart power.

Garve, S.D., Eames, P.C., Wang, J.H., Pimm, A., Waterston, M., Mackay, R.S., Giulietti, M., Flatley, L.C., Thomson, M., Barton, J., Evans, D.J., Busby, J., Garvey, J.E., 2015. Energy generation integrated energy storage. Energy Policy 86, 544–551.

Gruenevald, P., 2014. Any response? How Demand Response Could be Enhanced Based on Early UK Experience. Hamdii, V., Li, F., Robinson, F., 2009. Demand response in the UK’s domestic sector. EHP, 1722–1726.

Hoff, T.E., Perez, R., Margolis, R.M., 2007. Maximizing the value of customer-sited PV systems using storage and controls. Sol. Energy 81, 940–945.

House of Commons, 2016. 2020 renewable heat and transport targets. Second Report of Session 2016–17. Energy and Climate Change Committee Report. 9th September 2016.

IRENA. 2015. Renewable Energy Integration in Power Grids Technology Brief. IIEA-ETSAP and IRENA® Technology Brief E15 – April 2015. Available at: (https://www.iea.org/Pages/Paper/12014New.aspx?Mnu=cat&PriMenuID=36&CatID=141&Statistics.duels (Accessed December 2014).

IRENA. 2017. Rethinking Energy 2017: Accelerating the global energy transformation. International Renewable Energy Agency, Abu Dhabi. 2017. ISBN 9789295111059 (print) | ISBN 9789295111066 (PDF).

Navarro, A., Ochoa, L.F., Randles, D., 2013. Monte Carlo-based assessment of PV impacts on real UK distribution networks. IEEE Power Engineering Review (PER 2013), 24–25 September 2013.

NIC, 2016. Smart power. National Infrastructure Commission Report. March 2016. Available at: https://www.gov.uk/government/publications/smart-power-a-national-infrastructure-commission-report (Accessed 28 June 2017).

Rowley, P., Leicester, P., Palmer, D., Westacott, P., Candelise, C., Betts, T., Gottschalg, R., 2013. Multi-domain analysis of photovoltaic impacts via integrated spatial and probabilistic modelling. IET Generation, Transmission Distribution 67.

Stetz, S., Merten, F., Braun, M., 2013. Improved low voltage grid-integration of photovoltaics in systems in Germany: Lessons from practice. IET Generation, Transmission Distribution 7.

Stetz, T., Reckinger, M., Theologis, I., 2014. Transition from unidirectional to Bi-directional distribution grids: management summary of IEA Task 14 Subtask 2 – Experience. IEA Task 14 Project, 2014.

Stoker, L., 2016. Exclusive: UK solar industry hits 10GW cumulative PV capacity. The Solar Power Portal. 16th February 2016. Available at: http://www.solarpowerportal.co.uk/news/exclusive-uk-solar-industry-hits_10gw_cumulative_pv_capacity_3728 (Accessed 17 January 2017).

Strbac, G., Auneddi, M., Pujdijano, D., Djicic, P., 2012a. Understanding the balancing challenge. Imperial College London and NERA Consulting Report. Commissioned by Department of Energy and Climate Change. August 2012. Available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48553/5767-understanding-the-balancing-challenge.pdf (Accessed 27 June 2017).

Strbac, G., Auneddi, M., Pujdijano, D., Djicic, P., Feng, S., Sturt, A., Jackravat, D., Saxsom, R., Yutf, V., Brandon, N., 2012c. Strategic assessment of the role and value of energy storage systems in the UK low carbon energy future. Energy Futures Lab and Imperial College Report, commissioned by Carbon Trust. June 2012. Available at: https://www.carbontrust.com/media/307965/storage-systems-roles-value-strategic-assessment.pdf (Accessed 27 June 2017).

Strbac, G., Konstantelos, I., Djicic, P., 2016. Analysis of Integrated Energy Storage Contribution to Security of Supply. Power Network and Imperial College, University of London. Report commissioned by the Solar Trade Association. June 2016. Available at: http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Smarter-Network-Storage/SNS/ (Accessed 18 January 2017).

Stærk, M., Huld, T.A., Dunlop, E.D., 2005. GIS: a web-based solar radiation database for the calculation of PV potential in Europe. Int. J. Sustain. Energy 24, 55–67.

Stærk, M., Huld, T.A., Dunlop, E.D., Osenbrink, H.A., 2007. Potential of solar electricity generation in the European Union member states and candidate countries. Sol. Energy 81, 1295–1305.

Taylor, P.G., Bolton, R., Stone, D., Upham, P., 2013. Developing pathways for energy storage in the UK using a coevolutionary framework. Energy Policy 63, 230–243.

Thompson, M., Infeld, D.G., 2007. Impact of widespread photovoltaics generation on residential distribution grids: management summary of IEA Task 14 Subtask 2 – Residential distribution systems. IET Renew. Power Gen. 1, 33–40.

Uyan, M., 2013. GIS-based solar farms site selection using analytic hierarchy process (AHP) in Karapinar region, Konya/Turkey. Renewable. Sustain. Energy Rev. 28, 11–17.

Wang, H., Mancarella, P., 2016. Towards sustainable urban energy systems: High resolution modelling of electricity and heat demand profiles. 2016 IEEE International Conference on Power System Technology (POWERCON), Sep. 26-Oct. 1 2016 1, pp. 1–6.

Wang, Z., Lihan, Q., Gu, C., Li, F., 2015. Distributed storage capacity reservations for residential PV generation utilization and LV network operation. 2015 IEEE Power and Energy Soc. Meet. 26–30 (2015), 1–5.

Waterson, M., 2017. The characteristics of electricity storage, renewables and markets. Energy Policy.

Waterson, M., Candelise, C., 2016a. Assessing the impacts of photovoltaic penetration across an entire low-voltage distribution network containing 1.5 million customers. IET Renew. Power Gen. [Online] 10. (Available). [http://digital-library.theiet.org/content/journals/10.1049/iet-rpg.2014.0374].

Waterson, M., Candelise, C., 2016b. Framework to characterize photovoltaic deployment in the UK: Initial Evidence. Energies 9.

World Energy Council, 2016. World Energy Resources. E-storage: Shifting from cost to value and solar applications. World Energy Council Report. London. 2016.

WP4. 2014. Low VoltageNetworkTemplates Summary Report. In: 2015. W. P. D. R. A. H. W. W. C. U. D.-L. W.-I.-R. E. A. J. (ed.).