Assessing the impacts of photovoltaic penetration across an entire low-voltage distribution network containing 1.5 million customers

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Abstract: Deployment of grid-connected photovoltaics (PV) in the UK has increased rapidly. By 2014 there were over 650,000 installations (over 5 GWp), spread over different market segments (on site of existing domestic and non-domestic electricity demand customers, or connected directly to the network, e.g. solar farms). This rapid deployment and diverse market segmentation raises questions about impacts upon the electricity network. Here the authors present a novel geographical information system framework which maps current PV deployment and electricity demand to sensitive spatial resolution and by market segment. This is used to understand how current PV deployment affects power flows between the high-voltage (HV) and low-voltage (LV) network. The analysis reveals that overall, current LV PV generation is significantly below summer daytime LV demand – with over half of the areas investigated showing electricity demand five times greater than peak PV generation. Interestingly a small number of areas exhibit peak PV generation greater than demand, where reverse power flow from LV to HV may occur. The framework is hence capable of identifying the areas where network impacts are likely to occur and will also be useful to consider how integration strategies, such as energy storage and demand response could facilitate further PV deployment.

1 Introduction

Over the past 5 years there has been a vast increase in the amount of grid-connected photovoltaics (PV) within the UK. PV installed capacity has grown from around 30 MWp in 2009 to over 5 GWp (totalling over 650,000 installations) by the end of 2014 [1]. This rapid increase has raised concerns about the impacts on electricity networks, as these PV installations generate electricity within networks that were originally designed (and have historically operated) with only demand customers connected [2]. It is therefore expected that this embedded generation may significantly change how power flows through the network [2–4]. The extent to which power flows will change is dependent upon the local balance of PV generation and electricity demand, which are in turn influenced by: the amount of PV installed; the number and type of electricity consumers (e.g. households, commercial premises etc.); their relative demand profiles; and the time of day/year (as a consequence of PV generation and demand variation over time).

Increasing the amount of PV within a given section of the network may significantly alter the networks’ power flows thus possibly leading to: voltage rise (increasing voltage above statutory limits) [5]; thermal overload (where the current in a circuit surpasses the maximum operational limit) [6]; and upstream reverse power flows (where PV generation is greater than demand, causing power to flow back to higher voltage levels in the network, which can make operating the network more challenging) [4]. Hence the maximum amount of PV that can be hosted within the network could be limited by these potential impacts [7, 8] or require the implementation of impact mitigation strategies – such as energy storage [9] or demand-side response [10, 11] – to increase the amount of PV that could be hosted. As such developing an understanding of how PV generation compares to end users demand is important to:

- determine how much PV can be hosted within the network without incurring the above effects;
- anticipate areas that may reach these hosting limits first [4];
- identify the potential of integration strategies to mitigate impacts.

A number of studies within the literature have considered how installing different amounts of PV within low-voltage (LV) UK distribution networks will impact upon power flow and the network’s operational limits. For example, Thomson and Infield [5] conducted detailed unbalanced load-flow analysis of a domestic UK urban network under different levels of PV penetration, revealing that up to 30% penetration could be incorporated into the grid. Along similar lines Navarro et al. [6] modelled a number of local sections of domestic urban network in the North of England revealing broadly similar conclusions and highlighting how the amount of PV that could be installed without causing network constraints depends on local demand characteristics. These studies have provided a good understanding of PV network integration in specific domestic urban networks, however computational complexity and limited network data availability has meant that to date such type of analysis has been limited to small sections of the network.

To date the literature has mainly focused on the UK domestic market segment. However, both demand and PV deployment have different characteristics across market segments. For instance non-domestic PV systems tend to be larger in size and also more geographically dispersed than domestic ones [12]. Similarly, demand profiles differ across customers: for example, a large office (non-domestic customer) may use much more energy than a domestic customer on an annual basis, as well as a greater proportion during the daytime (when building occupancy is the highest), whereas a domestic customer would be expected to use more electricity during the evening.
To provide an example of how net power flow, as a result of PV generation can differ across market segments Fig. 1 compares typical PV generation and load profile for: domestic, non-domestic and ground mounted PV systems. The top part of the figure displays the half-hourly PV generation and electricity consumption for an average day in July. July was selected as demand is typically the lowest and generation the highest (see bottom panel) resulting in the largest expected impacts upon power flow from installed PV. The bottom panel presents monthly variations in electricity import/export balance. The data presented here use Elexon monthly demand profile shapes [13] for domestic (profile class 1), non-domestic (profile class 3) and ground-mount (no demand) customers. These are then combined with a monthly PV generation profile obtained from the Customer Led Network Revolution (CLNR), an industrial innovation project focused on understanding the impacts of low-carbon technologies in distribution networks [14]. The project was led by Northern Powergrid, a UK distribution network operator (DNO). The figure presents the balance of PV generation and demand for each market segment and at different times of year and the relative different impacts on power flows. Both figures highlight very different power flow impacts across market segments. For example, in the domestic market, more energy is used during the evening, meaning a lower matching of generation and demand. This results in a larger fraction of generated electricity contributing to reverse power flow in the domestic example. Conversely, in the non-domestic sector the higher self-consumption results in lower PV export in the non-domestic sector, due to a greater portion of demand occurring during day-light hours.

Hence this paper aims at improving the understanding of PV deployment impacts on power flows and network operation by developing an analysis which looks beyond a specific section of the network (considering wider geographical area), includes the non-domestic market segment and uses real PV deployment and electricity consumption data. Indeed, the study uses a geographical information system (GIS)-based framework to map current UK PV deployment [12] and electricity consumption across market segments for an entire distribution network region (South–West England (SWE), serving around 1.5 million demand customers). While GIS approaches have been used to map the generation potential of renewable energy resources, including solar PV [15, 16] and wind [17, 18], this study focuses on the local balance of generation and demand, by analysing how PV generation impacts on the amount of power flowing between the high-voltage (HV) and LV levels of the network.

The analysis takes a worst-case scenario approach focusing on the month of July, when PV generation is highest and electricity demand lowest thereby allowing the most pronounced impact of PV upon power flow to be captured. The methodology developed also highlights in which areas local generation exceeds demand, thus leading to upstream reverse power flows. Such information is valuable for DNOs to identify areas where monitoring equipment could be deployed to assess the actual network condition or to consider the benefits of implementing various integration strategies (such as network reinforcement, energy storage and demand-side management) to mitigate power flow impacts.

The remainder of this paper is arranged as follows: Section 2 discusses the GIS framework, the methodology and the data sources. Section 3 presents results for PV deployment in the targeted distribution region and the relative impact upon power flows. Section 4 concludes and discusses the future direction of research.

2 Methodology

To assess how PV deployment within the LV network would impact upon the HV/LV power flow, this study analyses how much of the local electricity demand is met by local PV generation: if PV generation meets only a small amount of local demand then the majority of power will still flow from higher voltage levels to meet demand, meaning a relatively small change in HV/LV power flow compared with the case where no PV was installed. If PV meets a large amount of the local demand then this will result in a larger reduction in power flowing from higher voltage levels. Similarly if local PV generation exceeds local demand then it is expected that these areas will experience reverse power flow between HV/LV.

To assess such impacts at a geographically disaggregated level a previously developed GIS-based framework, the United Kingdom Photovoltaics Database (UKPVD), is used. The UKPVD draws together and maps to high spatial resolution PV deployment data for over half a million installations within the UK including all market segments [12]. The framework is here extended to include domestic and non-domestic electricity demand profiles in order to analyse at a high spatial resolution impacts of PV generation on power flows. The following subsections describe how PV generation and electricity demand have been characterised within the framework and the relative data sources.

2.1 Characteristics of spatial analysis

As the impact of PV on HV/LV power flow is intimately linked to the local balance of PV generation and demand [4], the UKPVD framework 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. Lower layer super output areas (LSOAs) (spatial areas containing on average 600 households) have been used as a geographical unit [19]. LSOAs were designed by the Office of National Statistics (ONS)
2.1.2 Market segmentation: Market segmentation analysis has shown that higher numbers of PV systems are located in rural areas, which are characterised by quite different levels of PV deployment, higher in rural than urban areas (as previous analysis has shown [12]). Moreover, the characteristics of electricity networks in urban and rural areas tend to differ in terms of:

- feeder lengths,
- customer numbers and
- market segmentation [22].

As such, distinguishing trends in these geographies is expected to provide a useful additional level of detail for analysis. Rural/urban LSOA are characterised within the UKPVD framework using ONS standard classifications of urban and rural geographies [23].

2.2 PV generation

To assess the impact of PV generation within a given LSOA the UKPVD framework accounts for the amount of PV deployed within the area, how much electricity this is expected to generate and when this generation will occur throughout the day. Current PV deployment data for each LSOA are combined with results of DNO-led Low Carbon Network Fund studies which monitored half-hourly performance of PV systems across the UK, to investigate the real performance and impacts of PV in UK LV networks [14, 24].

2.2.1 PV deployment: Data was collected from the central feed-in tariff register [25] administered by Ofgem as well as the renewable energy planning database [26] administered by the Department of Energy and Climate Change (DECC). Extracts were taken in June 2015 and filtered to ensure only installations commissioned up to 2014 were included. Installation to the end of 2014 was chosen, to reduce the effect of installations being reported at different times after commissioning. Thus achieving a more complete snapshot of PV capacity at a given moment in time. The installations were then grouped by LSOA. For the purpose of this analysis, it has been assumed that all domestic and non-domestic PV systems below 250 kWp are connected to the LV network.

2.2.2 PV penetration: PV penetration is calculated by dividing the total number of PV systems within an LSOA by the total number of demand customers.

2.2.3 PV generation profile: As buildings within an LSOA are likely to vary in orientation and roof tilt, it is expected that PV systems that are located upon these may generate electricity at different times. For example an east-facing system would generate more during the morning and a west-facing system during the afternoon. To account for some of this diversity a ‘diversified’ generation profile shape created by the CLNR [14] has been used. This generation profile results from the aggregation of the monitored performance of 100 UK domestic PV systems with differing tilts and orientations, and hence accounts for some of the expected diversity. In the analysis presented here, we utilised the average July profile shape.

To ensure a worst-case scenario (here referring to high PV generation and low demand) was analysed, empirical evidence presented by Western Power Distribution, a UK DNO, through the Low Voltage Network Templates project [24] has been used. This study analysed the maximum simultaneous generation from PV systems located close together. The spatial areas investigated were of comparable size (e.g. km²) to LSOAs and were carried out in South Wales over the whole of 2013. Over the year the maximum coincident PV generation recorded in any area was 81% of the aggregate PV capacity. In light of this finding, the maximum generation of PV in an LSOA was assumed to be 81% of the aggregate PV capacity installed. For example an LSOA with a total of 100 kWp of PV installed would have a PV generation profile that peaked at 81 kW.

2.3 Electricity demand

To characterise electricity demand within the UKPVD framework the number of different types of demand customer per LSOA (e.g. domestic against non-domestic), their total electricity consumption and time of use are considered. To this end data on domestic and non-domestic customers’ annual electricity consumption within each LSOA are combined with half-hourly demand profiles for
each customer type to construct a half-hourly representation of demand within each LSOA (see Fig. 3).

2.3.1 Number and type of demand customers per LSOA:
For the purpose of this analysis, all domestic customers and all non-half-hourly metered non-domestic customers are considered to be connected to the LV network. In reality, it is also possible for smaller half-hourly metered non-domestic customers to be connected to the LV network, but due to the low number of these across UK and the limited data resolution for them, they have been excluded from this analysis. The characteristics of demand customers were acquired from sub-national electricity consumption data administered by DECC [27], which provides data for the domestic market aggregated to LSOA level: in particular the number of electricity customers (both unrestricted and economy 7) and their annual electricity consumption [megawatt-hour (MWh)]. For non-domestic electricity customers, the same data is available aggregated to groups of around five LSOAs. In order to get a representation of this data at LSOA level the aggregate total is divided by the number of LSOAs, (e.g. if 10 MWh of non-domestic electricity use were aggregated across five LSOAs, it was assumed each LSOA has 2 MWh of non-domestic electricity use). The authors acknowledge that future work would benefit from the use of a more spatially accurate data-set for non-domestic demand, but are not aware of one at present.

2.3.2 Demand profiles:
Half-hourly profile shapes for domestic and non-domestic customers developed by Exelon [13] have been used. Exelon profile classes cover domestic (unrestricted and economy 7, Profile Classes 1 and 2, respectively) and non-domestic (Profile Classes 3–8) customers.

2.3.3 Constructing LSOA level demand profiles:
To construct the half-hourly demand profile for the entire LSOA the demand profile for each customer type has been scaled up by the annual electricity consumption for that profile class within the LSOA (as derived from [27]). This process has been repeated for all customer types and the LSOA aggregate load demand profile has been derived by summing up the load profile of each customer group. A summary of this process is presented in Fig. 3.

2.4 Assessing impact of PV on power flow
To assess the impact of PV deployment upon the HV/LV power flow for each LSOA, the analysis is run for the worst-case scenario, i.e. the time of year when PV generation is expected to be largest relative to demand, to ensure that the maximum effects upon power flow are observed and any areas where upstream reverse power flow (e.g. where generation is greater than demand) can be identified. To this end a typical July day is investigated, which, as
also shown in Fig. 1, exhibits the largest PV generation and lowest demand in both domestic and non-domestic customers.

To assess the impact of PV generation upon the HV/LV power flow the peak PV generation (usually occurring around 2 pm) for each LSOA has been divided by the aggregated LSOA load demand occurring simultaneously (a graphical representation of this analysis is presented in the results section (Fig. 5 – left)). The resulting value represents the LV load met by PV generation within each LSOA, or in other words the percentage of electricity demand met by peak PV generation. If the value is close to zero it means that peak PV generation meets a relatively small amount of demand, and hence is not expected to change the amount of power flowing from HV to LV significantly. As the value approaches unity, peak PV generation becomes comparable in size to the simultaneous demand, indicating a larger reduction in power flowing from HV/LV. Moreover, a value greater than unity indicates that PV generation exceeds local demand, and that the LSOA is expected to experience reverse power flow from LV to HV. The calculation is repeated for each of the 1888 LSOAs within the SWE distribution area to provide a comprehensive picture of how PV is changing the power flow across the whole region.

3 Results

Fig. 4 displays the spatial and statistical distribution of PV penetration across all LSOAs in SWE distribution region. A large variation in the amount of PV deployed per LSOA is highlighted, with some LSOAs displaying close to zero PV penetration. In other areas, PV penetration reaches 20% (in an LSOA of 600 electricity customers this would mean that 120 of these customers had PV installed). The map in Fig. 4 presents the spatial distribution of PV, showing significant localised clustering with some LSOAs characterised by high penetrations of PV (thus appearing darker on the map) whereas adjacent ones have relatively little installed.

The histogram in Fig. 4 (right) shows that the majority of LSOAs have relatively low PV penetration, with over half (1043 of 1888) LSOAs below 4% PV penetration. The number of LSOAs diminishes as PV penetration increases. When disaggregating between urban and rural areas (different colours in the histogram) it is clear that the underlying trends are remarkably different. For example rural areas generally have significantly higher penetration compared with urban ones, implying a greater propensity for rural electricity customers to install PV than their urban counterparts. Indeed, the most common (modal) penetrations for the rural and urban LSOAs (4–6% and 0–2%, respectively) reveal that in the rural case over twice as many electricity customers have PV installed compared with the urban. In addition to these overall trends, it is important to note that both the urban and rural case exhibit a small number of LSOAs with PV penetrations above 14%.

To consider how this PV penetration impacts upon HV/LV power flow in different LSOAs a high PV penetration LSOA is taken as exemplary case. Fig. 5 (left) depicts the power flow characteristics of an LSOA with 17% PV penetration. It displays the aggregate load demand (sum of the demand from all domestic and non-domestic customers) (blue), the total PV generation (yellow) and the residual load demand (e.g. demand net of PV) (red). The figure shows how throughout the day PV generation in the LSOA compares with demand. At around 2 pm the installed PV generates around 500 kW of electricity, which is equivalent to 55% of the simultaneous electricity demand. Assuming all of this electricity is consumed within the LV network of the LSOA it will mean that the installed PV is able to meet 55% of the LV demand, resulting in a 55% reduction in the HV/LV power flow, compared with the case when no PV is installed. It is noted here that the spatial resolution of this analysis means that it is not possible to capture dynamics accruing at finer spatial resolution than the aggregate LSOA level. For example, if a large portion of the PV systems were clustered within a small area of the LSOA which also had low demand this may cause localised impacts on HV/LV power flow larger than that observed for the whole LSOA. This is an inherent limitation of the present analysis and is an area for further investigation.

The example in Fig. 5 – left demonstrates the impact of PV on daytime load in a high penetration LSOA. The LSOAs within SWE distribution area are characterised by different amounts of PV deployed and mixes of demand customers consuming different amounts of electricity. As a result the impact of PV deployed on HV/LV power flow is expected to vary significantly across the region. To capture these variations the maximum percentage of daytime demand load that is met by peak PV generation is calculated for each LSOA (for example in Fig. 5 – left, this equates to 55%). Fig. 5 – right displays the maximum proportion of demand load met by peak PV generation against the number of LSOAs in which it occurs. The first thing to note here is that in the majority of the LSOAs the reduction in HV/LV power flow appears relatively low. For example in over half of the LSOAs (1043 out of 1888) the deployed PV reduces HV/LV power flow by <20%. Similarly there are only a small number of instances (<10%) where PV generation results in >50% reduction in the HV/LV power flow. It is notable that currently only six LSOAs exhibit PV generation which is above 100% of demand. In these areas, it is expected that the LSOA will become a net exporter, resulting in upstream reverse power flow (e.g. from LV to HV) at some points during the year.

Comparing results for urban and rural penetration impact on HV/LV power flow highlights significant differences. In rural areas, PV most commonly meets 20–30% of electricity demand, whereas in the urban case, this figure is <10% of demand. This result highlights how the different tendencies for urban and rural demand customers to install PV significantly affect the HV/LV power flow.
flows and enable consideration of the appropriate integration strategies. For example, if the tendency to deploy more PV in rural areas continues, it is likely that a strategy to manage a large number of rural areas with reverse power flow would be required. For example the strategy that is most appropriate to integrate PV in a single high penetration urban area may differ significantly from the one that covers a large number of rural areas.

The framework will be used as a basis to consider the potential integration strategies to host higher levels of PV within the distribution networks. For example, assessment of the impacts of energy storage within the power-flow analysis is currently underway. Furthermore, the framework could be used to determine how PV could be optimally deployed across the network to provide the best match between generation and demand. This could minimise the impacts upon the network by reducing upstream power flow and hence reduce the overall costs of integrating PV into the energy system.

Another future work is to incorporate in the UKPVD framework and analysis of PV systems deployed at higher voltage levels, such as large (>250 kWp) non-domestic industrial rooftop PV and ground-mounted solar farms. This would complete the picture of the assessment of PV generation impact upon the UK electricity network. For example it would be possible to extend analysis from the LV level presented here up through the different voltage levels of the network to the distribution/transmission network interface. This analysis would be valuable to understand how installing PV in different market segments (e.g. domestic, non-domestic and ground-mount) impact upon the network. It would also provide valuable insight for the transmission network operator who would benefit from a better understanding of how embedded generation is likely to impact on the amount of power flowing off of the transmission system into the distribution networks.

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