Assessing local costs and impacts of distributed solar PV using high resolution data from across Great Britain

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Abstract

Highly spatially resolved data from across Great Britain (GB) are combined with a distribution network modelling tool to assess impacts of distributed photovoltaic (PV) deployment up to 2050 on local networks, the costs of avoiding these impacts, and how these depend upon context. Present-day deployment of distributed PV, meter density, and network infrastructure across GB are found to be highly dependent on rurality, and data on these are used to build up three representative contexts: cities, towns, and villages. For each context, distribution networks are simulated, and impacts on these networks associated with PV deployment and growth in peak load up to 2050 calculated. Present-day higher levels of PV deployment in rural areas are maintained in future scenarios, necessitating upgrades in ambitious PV scenarios in towns and villages from around 2040, but not before 2050 in cities. Impacts of load growth are more severe than those of PV deployment, potentially necessitating upgrades in cities, towns, and villages from 2030. These are most extensive in cities and towns, where long feeders connect more customers, making networks particularly susceptible to impacts. Storage and demand side response are effective in reducing upgrade costs, particularly in cities and towns.

Keywords: PV integration; solar power; electricity distribution network; energy storage; demand side response;

1 Introduction

Distributed solar photovoltaic (PV) provides cost-effective electricity with a low greenhouse gas impact close to demand centres. Deployment of small-scale PV (<50 kW) in Great Britain (GB) has increased rapidly over the past decade, rising from 930 MW in 2011 to 4.4 GW in 2016. Deployment has subsequently slowed, but is expected to accelerate in coming years, driven by the falling cost of PV installations and increasing price of electricity (1,2).
PV generates only when there is available irradiance. As such, high levels of PV deployment could lead to substantial changes to power flows in the electricity network (3). At the low voltage (LV) distribution network level, this could lead to capacity constraints (overloading of existing cables and transformers) and voltage rise (4–7). Increases in load associated with EV and heat pump deployment could counteract some of these impacts, or themselves lead to capacity constraints and falling voltage (1). Impacts are exacerbated in regions with longer feeders (the sections of cable connecting transformers to end users) and/or with feeders connecting higher numbers of end users with higher PV deployment. The longer the feeders and the higher the number of end-users connected, the higher the probability of voltage and capacity issues. Length and distribution of feeders varies with density and distribution of electricity consumers, each of which varies with rurality context. As such, an understanding of the local network infrastructure and balance of generation and demand is required to properly understand network requirements.

In a conventional network upgrade approach, these issues would be overcome by upgrading or laying parallel cables and replacing transformers with higher rated equivalents (8). Impacts could also be reduced or eliminated through deployment of distributed storage (9,10) and/or demand side response (DSR) (11–14), which could reduce local electricity consumption at times of peak load, and/or increase local electricity consumption during times of peak PV generation (10,15,16). Bayer et al. identify a range of alternative mechanisms which distribution network operators (DNOs) have used to overcome voltage constraints in Germany (such as tap changes on transformers and deployment of voltage regulators) (8), which could be a cost effective approach to increase PV hosting capacity in the UK (5) and internationally (17). How to choose which of these measures to deploy in a given situation is not straightforward.

A series of reports produced by UK DNOs examine grid impacts of distributed PV in different UK regions (18–21). These indicate few voltage issues, and no problems with reverse power flow at present, but anticipate more such problems as deployment of distributed PV increases. Several studies have modelled the impact of higher levels of PV deployment on local networks in GB (5–7). These studies use different methods and are applied to different networks, making direct comparison...
challenging. Thomson and Infield (6) and Bilton et al. (7) find voltage rise above acceptable levels when PV is deployed on 30% and 5% of households respectively in semi-urban contexts. Navarro-Espinosa and Ochoa compare impacts across feeders in a single urban network, finding that these begin to exhibit voltage rise at PV penetrations ranging between 30% and 100% of households (5).

These studies demonstrate the importance of local context in grid impact of distributed PV deployment. This finding is echoed in a review conducted by Aziz and Ketjoy on PV penetration limits in LV networks in an international context (22), who find limits of between 2.5% and 110% depending on load profiles, generation profiles and network configuration. Studies in Germany (8,23), Sweden (24), and the USA (25,26) further support this point, as do high level studies of renewables integration in GB (27–30) and across Europe (31,32). However, these studies offer no way of mapping between these individual contexts and the broader set of contexts within GB or internationally or understanding how these fit into the broader set of electricity system changes which are expected in coming decades. In a GB context, this is expected to include widespread deployment of EVs and heat pumps, bringing peak load in line with the 2005 historical maximum by around 2030 (1).

Pagani et al. (33) survey studies on power grids internationally, highlighting differences in network topology and the importance of using network models representative of the country context. Gan et al. (34) and Abeysinghe et al. (35) also note that most of these studies have focussed on high voltage transmission, rather than low voltage distribution grids. Studies which have focussed on the low voltage network have typically used idealised networks, or specific test cases, limiting applicability of their conclusions to other networks. Generation of statistically representative networks in order to draw more generally applicable conclusions is therefore highly desirable. Building on work in references (36–38), Gan et al. (34) make progress towards this goal, generating simulated networks using a fractal approach, parameterised based upon real GB networks (37). This modelling approach has been used in academic studies estimating distribution grid upgrade savings associated with smart use of heat pumps alongside EVs (39) and PV (40) in GB, and policy studies on grid impacts accelerated electrification in GB (41) and PV and microgeneration deployment across Europe (31,42). However, networks are simulated based on a subjective definition of rurality, which is not related back to the distribution of local contexts in GB. Present differences in level of PV deployment, network
infrastructure, and distribution of domestic and nondomestic meter density across GB rurality contexts are not taken into consideration.

Candelise and Westacott began work on understanding how local impacts of PV might differ between regional contexts through the development of the United Kingdom Photovoltaic Deployment (UKPVD) framework (3), a database that maps PV deployment, domestic and nondomestic demand, and grid assets across GB in a geographically disaggregated manner based upon real data. This framework has been used to assess the local balance of PV generation and electricity demand (43) and the potential of storage to mitigate local imbalances between PV generation and demand (10). The distribution and interaction of variables defining impacts vary across the country and rurality contexts, with higher levels of PV deployment in more rural areas (3), differing levels of reverse power flow depending on balance of supply and demand (10,43), and differences in grid assets between urban and rural contexts (44).

However, there remains a gap in connecting (a) the substantial body of data available on the distribution of quantities relevant to PV integration in local contexts across GB, with (b) the detailed modelling of local networks which allows an assessment of impacts of distributed PV deployment and cost-effective measures to avoid these impacts. This work seeks to bridge this gap, building on the work on Candelise and Westacott (3,10,43) for the former, and Gan et al. (34) for the latter part.

The distribution of key parameters relevant to integration of PV (current PV deployment, domestic and nondomestic meter density, and network infrastructure) across GB (3,10,43) are combined with classifications of rurality defined by the UK Government Statistical Service to arrive at a set of parameters representative of real cities, towns, and villages across the UK. These parameters are used as inputs to the network simulation tool developed by Gan et al. (34), allowing the simulation of networks which well represent of each of these contexts.

Scenarios for PV deployment, load growth, storage deployment, and demand side response are applied to these networks to estimate (i) dates at which grid impacts due to PV deployment and load growth might be expected to occur across contexts, (ii) costs associated with avoiding these impacts through conventional grid upgrades (cable and transformer replacement), (iii) the extent to which
these costs reduce when flexibility mechanisms (storage and DSR) are available. This approach thus accounts for distribution of current levels of PV deployment and local demand, local balance between supply and demand, and current conditions of grid assets (density and capacity of substations, length and capacity of feeders) in cities, towns, and villages across GB estimating impacts and relative integration costs of distributed PV on the LV network.

The remainder of this paper is organised as follows: Section 2 presents the methodology used in this study; Section 3 presents results broken down into impacts of load growth and PV deployment on the LV grid, costs of upgrading grid infrastructure to mitigate these impacts, cost savings associated with DSR and storage; Section 4 concludes and discusses policy implications. A list of key terms and abbreviations is included in an appendix.

2 Methodology

The methods and tools used in this study may be broken down into several steps. First, a representative set of local contexts are determined based upon high resolution real data on PV deployment, meter density, and network infrastructure contained in the UKPVD. Second, networks are simulated based upon median values of key parameters in each of these contexts. Third, scenarios are developed for peak load growth, PV deployment, storage, and DSR and applied to simulated networks. Finally, network impacts associated with these scenarios are assessed, alongside cost of upgrading networks to avoid these, and how these vary between contexts. These steps are described in turn in the following subsections.

2.1 Determination of a representative set of rurality contexts

The UKPVD, developed in (3), contains real data on (i) domestic and nondomestic PV deployment produced by the GB energy regulator (45), (ii) domestic and nondomestic meter density produced by UK Government (46,47), and (iii) density and type of substations produced by Western Power Distribution (WPD), the DNO for the Southwest of England (SW England) (44). The data are organised at lower level super output area (LSOA) resolution, a geographical area containing approximately 600 households. With the exception of network infrastructure, these data are available across GB. We
choose to focus our analysis on the region of SW England for which data on network infrastructure is available, which contains 1.3 million domestic and 140,000 nondomestic electricity users. Local network impacts are expected to be highly dependent on PV deployment, meter density, and network infrastructure, each of which varies with rurality context. The UK Government Statistical Service classify each LSOA in GB into one of ten rurality categories based upon density and distribution of households (48,49). In SW England, 95% of LSOAs fall into three categories, “urban city and town” (66%), “rural town and fringe” (14%), and “rural village” (15%). Attention is restricted to these three ruralities for the remainder of the paper, which are referred to as “cities”, “towns”, and “villages” henceforth. Across GB, these three categories alongside “urban major conurbation”, account for 95% of LSOAs. Distribution of domestic and nondomestic meter density, PV capacity, and density of substations across each LSOA in SW England falling into the “cities”, “towns”, or “villages” rurality context are presented in Figure 1. These are broadly similar to those for GB as a whole, which are presented in supplementary material to this paper. The number of domestic meters per LSOA is broadly similar across ruralities, but these are much more densely packed in cities than towns and in towns than in villages (Figure 1a,b). Towns and villages have similar numbers of nondomestic customers per LSOA, around twice the number found in cities (Figure 1c). Domestic PV deployment is substantially higher in more rural contexts, with around twice and three times the quantity of domestic PV installed in villages and towns than cities, respectively (Figure 1d). Whilst absolute numbers are smaller, differences are even more striking in the nondomestic sector, where no PV is installed in the median case in cities, and deployment in villages is more than ten times higher than that in towns (Figure 1e). Combining nondomestic and domestic sectors, 2.5 and 4.3 times more PV are installed in the median case in towns and villages than cities. Since nondomestic load is concentrated in daytime hours, higher numbers of nondomestic customers could help to balance the higher PV deployment in towns and villages. There are substantial differences in network infrastructure between cities, towns, and villages, with the vast majority of substations being ground-mountedground-mounted transformers (GMT) in cities, pole-mounted transformers (PMT) in villages, and a combination of the two in towns (Figure 1f,g). The total
density of substations is substantially higher in more urban contexts, but each of these substations serves a larger number of customers (Figure 1h). This will tend to result in longer feeders with larger numbers of connected customers in more urban contexts, making feeders in cities and towns more susceptible to impacts associated with PV and load growth.

Figure 1 shows substantial differences in quantities relevant to PV integration between these cities, towns, and village, indicating that they represent a sensible range of contexts on which to model impacts. There is, however, substantial variation in these quantities within each context, indicating that individual LSOAs may be subject to greater or lesser impacts than can be captured with a single set of parameters per rurality.
Figure 1: Box and whisker plots showing median, standard distribution, and extreme values of key parameters across LSOAs representing cities, towns, and villages in SW England: (a) number and (b) density of domestic meters, (c) number of nondomestic meters, (d) domestic and (e) nondomestic PV capacity, density of (f) ground-mounted and (g) pole-mounted transformers (GMT and PMT, respectively), and (h) number of domestic meters per substation.

2.2 Simulation of networks to represent each rurality context

For each rurality context (cities, towns, and villages), fifteen LV distribution networks are simulated based upon median values of domestic and nondomestic meter density, PV capacity, and type and density of substations associated with LSOAs of that rurality (Figure 1).

This study uses the statistical network design and investment methodology developed by Gan et al. (34), which is selected owing to three unique capabilities of this methodology: (1) its ability to reproduce realistic network topologies and lengths, as calibrated against real GB distribution networks, using data available in the UKPVD across GB as inputs, (2) its ability to calculate impacts of increased load and deployment of low carbon technologies on these networks, and (3) its ability to calculate
infrastructure upgrade requirements to keep impacts to acceptable levels, and costs associated with these. Methodology is described in detail in references (34) and (40).

An example of a simulated network of each rurality category is shown in Figure 2, alongside mean values of key network parameters arising from simulated networks of this rurality. Total cable length is lower in more urban contexts where households are more densely packed. However, there are also substantially fewer substations per customer in urban than rural contexts, resulting in longer feeders serving higher numbers of households.

Cables and transformers are assumed to be sized to handle the historical peak in load (in 2005), but not oversized for the potential of higher loads. Transformers are assumed to be symmetric (capable of handling similar levels of power flow in forward and reverse directions). This is typically the case for distribution transformers operating at the low voltage level considered in this study (50). However, transformers operating at higher voltage levels are typically somewhat asymmetric, with a lower capacity in the reverse direction (values of between 30% and 66% of forward capacity are reported in the GB network in ref (50)), and high levels of reverse power flow could cause issues in parts of the network not considered here. A figure is included in supplementary materials showing the proportion of transformers experiencing some level of reverse power flow in considered PV deployment scenarios.
Figure 2 Example of a simulated network in each rurality context. Dots, stars and lines represent demand meters, substations and feeders, respectively. Average cable length per LSOA, number of feeders per meter, demand nodes per feeder and feeder length (with standard deviation, \( \sigma \)) across the fifteen simulated networks for each rurality context are also indicated.

2.3 Design of distributed PV, load growth, and flexibility scenarios and application to simulated networks

To each simulated network, load growth, PV growth, storage and DSR scenarios are applied, and local network impacts associated with these calculated PV, load growth, and storage deployment scenarios to 2050 are based upon the GB electricity system operator, National Grid’s, future energy scenarios(1). Whilst there is no guarantee these scenarios will be realised in practice, they represent of the range of scenarios the system operator is planning for, and have come to be used as benchmarks for a range of studies planning for the future GB electricity system (28,51–54).

Of National Grid’s four future energy scenarios, the two with highest deployment of solar PV are considered here: “Two Degrees” and “Community Renewables” (referred to as “Mid-PV” and “Hi-PV” henceforth). The second of these is highly ambitious in terms of distributed PV deployment, with a growth factor of 4.2 by 2030 and 16.4 by 2050 relative to 2017, making it particularly relevant for assessing the impact of high penetrations of distributed PV. Since the other two scenarios involve a lower deployment of PV, grid impacts may be expected to be smaller in these scenarios. These
scenarios are also associated with growth in peak load (Figure 3a), which is assumed to occur with a similar growth factor across electricity users in domestic and nondomestic sectors.

Whilst National Grid scenarios specify growth factors by year for distributed PV, they do not specify how this growth will be distributed across sectors or regions. In scenarios considered in this study, PV growth factors in “Mid-PV” and “Hi-PV” scenarios are applied to LSOAs of each rurality such that the size of PV installations on modelled domestic and nondomestic meters remains at median 2017 values obtained from the UKPVD (3.1 kW, 3.5 kW and 3.7 kW for domestic PV installations and 9.9 kW, 8.0 kW and 12.0 kW for nondomestic PV installations in cities, towns, and villages respectively), but the proportion of meters with PV installed grows over time in line with National Grid scenarios. The ratio of quantities of deployed PV across ruralities thus remains at present day levels up to 2050, with 2.5 and 4.3 times more PV installed in towns and villages than cities, respectively (as per Figure 1).

The only exception to this rule occurs in villages in the Hi-PV scenario after 2045, when deployment reaches 100% of rooftops. Resulting PV deployment across scenarios and ruralities is shown in Figure 3b.

Whilst National Grid scenarios specify the total quantity non-transmission connected storage, they do not indicate the size of individual storage devices or the voltage level at which they are deployed. In analysis presented here, three scenarios of storage deployment (S10, S25 and S50) are developed in order to explore the implications of 10 – 50% of GB non-transmission connected storage being deployed at a local level to balance distributed PV generation.

Storage capacity (kW) per kW of PV is obtained from National Grid scenarios using the following formula:

$$\text{S}_\text{p,}\text{ deployment scenario} = C_s \times \frac{S_{\text{p,GB}}(y)}{PV_{\text{p,GB}}(y)}$$

Where $$\text{S}_\text{p, deployment scenario}$$ represents the quantity of distributed storage deployed per unit of distributed PV in deployment scenario $$\text{p}$$ (Mid-PV or Hi-PV) and storage scenario $$\text{s}$$ (S10, S25, or S50) in year $$y$$; $$C_s$$ is a parameter to distinguish the three storage scenarios ($$C_{S10} = 10\%$$, $$C_{S25} = 25\%$$ and $$C_{S50} = 50\%$$); and $$S_{\text{p,GB}}(y)$$ and $$PV_{\text{p,GB}}(y)$$ represent the GB-wide deployment of non-transmission connected...
storage and distributed PV in corresponding National Grid scenarios in year $\bar{y}$. This approach results in higher levels of deployed storage in more rural contexts where levels of PV deployment are higher and by the same ratios (2.5 and 4.3 times more PV installed in the towns and villages than cities, respectively). Resulting storage deployment in S50 scenarios is shown in Figure 3c. Storage is modelled with a two hour capacity when operating at full power (i.e. capacity in kWh is twice the kW rating) in line with typical values for residential lithium-ion batteries (55).

Since there has been little deployment of DSR measures in households to date, developing robust scenarios for future deployment is challenging. In order to consider the possible role DSR could play in reducing grid impact of PV at a local level, two hypothetical DSR scenarios are considered based upon between 50% (DSR50) and 100% (DSR100) of households participating in DSR measures (smart dishwasher, washing machine, and tumble drier) by 2030 (Figure 3d). A recent nationwide survey indicates that around 50% of the UK population would be willing to shift times of dishwashing and laundry, indicating that the first of these scenarios could be achievable without substantial changes in attitudes (56). Modelled impacts of these measures on power demand are as described in references (57,58).
2.4 Assessment of local grid impact and associated network upgrade cost

Load growth, PV, storage, and DSR scenarios (Figure 3) are applied to each of the fifteen networks simulated for each rurality (Figure 2) by year. Resultant power flows across the network during a winter evening (peak load alongside minimum distributed generation) and summer midday (peak distributed generation alongside low load) are calculated. Impacts on the network associated with these power flows are calculated in terms of voltage rise (associated with PV generation), voltage fall (associated with increased load), and capacity constraints (cables and transformers in which power flows exceed operational limits). Voltage rise and fall are quantified in terms of maximum over- and undervoltage on networks, and length of cable requiring replacement to keep within statutory limits of...
+10%-6% of nominal voltage (59). Capacity constraints are quantified in terms of proportion of transformers overloaded, and length of cable requiring replacement to overcome these issues. Alternative upgrade approaches may be taken to overcome voltage issues in practice (5,8,17).

Capital costs associated with network upgrades are calculated as follows:

$$\text{Cost}_{r,i}(t) = N_{r,i}(t)C_{r,x} + (L_{y,i}(t) + L_{l,i}(t))C_{c,r}$$

Where $\text{Cost}_{r,i}(x)$ represents the capital cost associated with upgrading simulated network $r$ (1 to 15) representing rurality $r$ (cities, towns, or villages) to handle network impacts in year $t$. $N_{r,i}(t)$ represents the number of transformers requiring replacement in network $r$ of rurality $r$ in year $t$, and $C_{r,x}$ represents the cost of replacing a transformer in rurality $r$. $L_{y,i}$ and $L_{l,i}$ represent the length of cable requiring replacement in network $r$ and $C_{c,r}$ represents the cost per length of cable replaced in rurality $r$. Infrastructure costs $C_{r,x}$ and $C_{c,r}$ are as specified in (60). Upgrade costs per unit replacement are substantially higher in cities and towns where cables are assumed to run underground rather than overhead, and transformers are assumed to be ground-mounted rather than pole-mounted. Mean costs across simulated networks of each rurality, $\overline{\text{Cost}}_{r}(x)$, are calculated as:

$$\overline{\text{Cost}}_{r}(x) = \frac{\sum_{i=1}^{15} \text{Cost}_{r,i}(x)}{15}$$

Capital cost required to upgrade networks to accommodate demands expected in a given year are presented per LSOA. This metric as this serves as a proxy for severity of network impacts and effort required to overcome them. Where upgrade costs are zero, this implies that these flexibility mechanisms are sufficient to avoid network upgrades. Where costs are close to zero, minimal upgrades, or small amounts of additional flexibility may be required to avoid problematic network impacts.

The above procedure is initially carried out for growth in peak load alone (Figure 3a). PV deployment scenarios (Figure 3b) are then applied in conjunction with load growth, such that the additional impact and capital cost associated with grid upgrades to accommodate distributed PV over and above load growth may be calculated. Storage (Figure 3c) and DSR (Figure 3d) scenarios, both together and
separately, are then applied alongside load growth and PV. Savings in network upgrade cost associated with these flexibility measures are calculated by subtracting upgrade costs in scenarios in which these measures are included from those in which they are excluded.

3 Results and Discussion

3.1 Low Voltage Network Impacts to 2050

This section presents impacts associated with application of load growth and PV deployment scenarios to simulated networks. In each case, these are presented as mean values across the fifteen simulated representing each rurality context (cities, towns, villages).

The maximum undervoltage associated with load growth is shown in Figure 4a. Increasing peak load causes undervoltage in later years in each cities, towns, and villages. Undervoltage reaches levels outside of statutory limits (+10/-6% of nominal voltage (59)) in towns and cities from around 2030 in both Mid-PV and Hi-PV scenarios, coinciding with peak load exceeding the 2005 historical maximum (1). Voltage issues are exacerbated by long feeders serving high numbers of customers, and shorter feeders serving few customers in villages than in towns and cities keep voltage within statutory limits here (see Figure 2).

The maximum overvoltage associated with PV deployment is shown in Figure 4b, which steadily rises up to 2050 across rurality contexts. In towns, PV deployment is substantially higher than in cities and feeder lengths are substantially above those in villages. The combination of these factors causes voltage rise above statutory limits in towns after 2040 in the Hi-PV scenario, whilst staying within statutory limits in cities and villages throughout the time horizon. Voltage does not rise above statutory limits in any rurality in the mid-PV scenario.

The proportion of cables which must be replaced to bring undervoltage associated with load growth within statutory limits is indicated in Figure 4c. This rises steadily from 2030 in cities and towns, with 13% of cables requiring replacement in cities by 2050 in the Hi-PV scenario, and 11% in the Mid-PV scenario. In towns, where feeders are somewhat shorter, impacts are less widespread, and these
quantities reach only 8% and 6%. The additional proportion of cables which must be replaced to bring overvoltage associated with PV deployment within statutory limits is indicated in Figure 4d. This value is nonzero only in towns in the Hi-PV scenario in later years, where it reaches 4% of cables by 2050, representing around half of the replacement length required to overcome undervoltage due peak load growth.

Load growth and PV also cause power flows higher than cable ratings, necessitating capacity driven upgrades. Figure 4(e,f) quantify the proportion of cable requiring replacement to accommodate these higher power flows, which represents around a quarter of that required to overcome voltage issues in each rurality (Figure 4(c,d)).

Figure 4g indicates the proportion of transformers overloaded due to peak load growth. This occurs across rurality contexts from 2030, but is most widespread in cities, where almost 50% of transformers require replacement by 2050 in the Hi-PV scenario (35% in the Mid-PV scenario). By contrast, in villages these values reach only 28% and 21%. Since data on transformer capacity is not available, these numbers are subject to assumptions taken in network simulation. However, the higher number of customers which each transformer serves in more urban contexts is likely to result in their operating closer to their capacity limits, leaving less space to accommodate growth in load.

Figure 4h indicates the additional proportion of transformers overloaded due to high power flows associated with PV deployment. This is widespread only in villages in the Hi-PV scenario, where the it steadily grows from 2030 to reach 30% of transformers by 2045. (The slight reduction between 2045 and 2050 is due to PV deployment in villages reaching 100% in 2045, but load growth continuing to 2050, meaning that more transformers are overloaded due to load growth in 2050, no longer counting as additional transformers overloaded by PV.) This is primarily a result of higher levels of PV deployment in more rural contexts, whose generation more than counteracts higher daytime load associated with greater numbers of nondomestic meters (see Figure 1). A figure in supplementary materials shows that a substantial portion of transformers experience some level of reverse power flow across ruralities from mid 2020s, particularly in the Hi-PV scenario. The aggregate impact of these
could become problematic for primary transformers at higher voltage levels (as noted in Section 2.2).

However, these fall outside of the scope of our current study.
Figure 4 Average impact of load growth and PV deployment on networks prior to infrastructure upgrades in Hi-PV and Mid-PV scenarios across simulated cities, towns, and villages. Average maximum (a) undervoltage due to load growth and (b) overvoltage due to PV deployment (as a proportion of the nominal 230V) alongside statutory voltage limits, (c,d) length of line requiring under- and over-voltage driven upgrade, (e,f) length of line requiring capacity driven upgrade, (g,h) proportion of transformers overloaded due to load growth and PV deployment.
3.2 Network Upgrade Costs to 2050

This section presents the cost of avoiding LV network impacts described in the previous section through conventional methods: upgrading cables to keep voltage at acceptable levels and accommodate higher power flows, and replacing overloaded transformers. These costs are shown across contexts and scenarios in Figure 5.

Capital costs associated with accommodating peak load are very similar in cities and towns, reaching £185,000 – 230,000 per LSOA to meet 2050 requirements (equivalent to one-off costs of around £230 - 330 per meter). Costs in villages are substantially lower, at £73,000 – 95,000 per LSOA (around £90 - 120 per meter). This is predominantly due to undervoltage issues associated with longer feeders in cities and towns (see Figure 4a), which are not realised in villages. However, lower unit costs associated with replacing overhead cables and pole-mounted transformers in rural contexts than underground cables and ground-mounted transformers in more urban contexts also contribute to this difference.

Upgrade costs are broken down into cable replacements associated with voltage and capacity constraints, and transformer replacements associated with capacity constraints in Figure 4c. Across scenarios and years, approximately two-thirds of costs in cities are associated with cable replacement, with the remaining third attributable to replacement of distribution transformers. In towns, this balance is approximately half and half, whilst in villages upgrade costs are almost entirely attributable to transformer replacement. Since the majority of cable replacements are due to voltage, rather than capacity constraints, a substantial portion of upgrade costs in cities and towns could potentially be avoided using voltage regulators, and/or seasonal tap changes to transformers, where voltage issues manifest themselves. Based upon experience of German DNOs, upgrade requirements associated with capacity constraints will be harder to avoid (8).

In the Hi-PV scenario, PV integration costs become substantial in villages and towns. When ambitious PV growth is included alongside load growth, cost to accommodate 2050 requirements increases by £80,000 per LSOA in villages and £90,000 per LSOA in towns (45% and 30% of total upgrade cost in 2050). Again, these are divided between cable and transformer replacement in towns, and solely...
attributable to transformer replacement in villages. In the Mid-PV scenario, PV integration costs are a small component of total upgrade costs in villages and no LV grid upgrades above those for load growth are required to accommodate PV in towns (in line with minimal grid impacts in Figure 4). There are no network upgrades required to accommodate PV in cities throughout the time horizon in either considered scenario.

Figure 5 Capital cost (1000s of 2016GBP) associated with upgrading networks to accommodate load growth and PV deployment by year in (a) Mid-PV and (b) Hi-PV scenarios. Where PV deployment adds costs over those associated with load growth, costs with load growth alone are presented with a dashed line. 2050 costs are broken down into constituent cost categories in (c).

3.3 Cost Savings associated with Storage and Demand side response

This section presents savings in network upgrade cost when storage and DSR are installed alongside load growth PV. Capital cost to upgrade networks to accommodate load and PV growth in the Hi-PV scenario, alongside costs when storage and DSR are also included are presented in Figure 6, with savings associated with these measures indicated.
In considered scenarios, storage is deployed in proportion with PV in each rurality, so more storage is deployed in villages where PV deployment is highest (Figure 3b,c). However, cost savings associated with storage are higher in towns and cities (Figure 6a,b) than villages (Figure 6c). This is primarily due to the larger extent of, and combination of multiple sources of, network upgrade requirement in cities and towns (cable and transformer upgrades), compared to the single source in villages (transformer upgrades alone) and the higher unit cost of replacements in towns and cities.

DSR also has a larger impact in cities and towns (Figure 6d,e) than villages (Figure 6f) for similar reasons. Absolute cost differences are somewhat higher for DSR, as they are not mitigated by larger quantities of storage deployment in villages. At deployment levels considered in our scenarios, storage and DSR together are able to eliminate upgrade requirements in towns and cities until after 2040 and 2050, respectively (Figure 6g,h). Modelled quantities of storage and DSR reduce the cost of upgrade in villages, but do not eliminate the need for grid upgrades (Figure 6i).

Whether storage and DSR complement or compete with one another depends upon context. In some cases where small quantities of both are deployed and neither flexibility measure alone sufficiently reduces strain on network assets to avoid network upgrades, the two flexibility measures in tandem can do so. In such cases, the measures are complementary, and the value of storage is increased by the availability of DSR. In other cases, typically when large quantities of storage or DSR is deployed, one measure is sufficient to avoid upgrades, and the added value of a second measure decreased by its presence. Hence a large impact of DSR over storage alone in S10 scenarios in cities where minimal storage is installed, but a smaller impact of DSR when applied alongside S50 scenarios in villages where larger quantities of storage are installed.
Figure 6: Network upgrade cost associated with load growth (LG) & PV deployment in the Hi-PV scenario and savings (1000s of 2016GBP) associated with (a,b,c) storage, (d,e,f) demand side response, and (g,h,i) storage and demand side response together in (a,d,g) cities, (b,e,h) towns, and (c,f,i) villages. Scenarios with differing quantities of installed storage (S10,S25,S50) and levels of DSR participation (DSR50, DSR100) are included.

4 Discussion and Conclusions

This work has used high-resolution data from across Great Britain to assess future impact of PV deployment and expected load, based upon National Grid's future energy scenarios (1), across rurality contexts, i.e. in cities, towns, and villages. The costs associated with avoiding these impacts through conventional network upgrades are calculated, as well as the extent to which these costs reduce when storage and DSM are deployed.
Two scenarios of intermediate and high PV deployment are considered alongside load growth. In these scenarios, PV deployment is much higher in villages and towns than cities, in line with current levels of deployment, and resulting impacts are more severe. In the more ambitious deployment scenario, PV could necessitate replacement of 30% of transformers in villages by 2045, and of 10% of transformers alongside 5% of cables in towns by 2050. No adverse impacts are expected in cities, where PV deployment is expected to be much lower. This is despite larger numbers of nondomestic customers in villages and towns than cities, whose higher levels of daytime load might be expected to reduce network stresses associated with PV deployment. In the intermediate PV scenario, impacts are minimal across cities, towns, and villages.

Load growth alone could necessitate local network upgrades across rurality contexts from 2030. Impacts are most severe in cities and towns, where transformers each serve larger numbers of households through longer feeders. By 2050, load growth necessitates replacement of 30 - 50% of transformers and 13 – 16% of cables in cities, of 20 – 30% of transformers and 7 – 9% of cables in towns, and of 20 – 30% of transformers but no cables in villages. Note that this is based upon the conservative assumption that networks are designed to handle loads at the level of the historical peak in GB electricity demand. These dates and impacts should as such be considered worst-case scenarios.

Deployment of storage and DSR allow for delayed and reduced network upgrades. These are most effective in cities and towns, where grid impacts of load growth are more extensive, and split across different upgrade cost categories (cable and transformer upgrades). Quantities of storage in considered scenarios eliminate grid upgrade requirements until after 2035 in cities and towns, and after 2040 if deployed alongside DSR.

Approximately half of network upgrade costs in towns and cities are attributable to cable replacements to overcome voltage issues, rather than constraints associated with power capacity of cable and transformers. In such cases, it could be more cost effective to use voltage regulators, and/or seasonal tap changes to transformers, as have been used to overcome voltage issues in Germany (8) and have been proposed in the UK (5) and internationally (17). Questions remain around the extent to which
such measures eliminate, or merely delay, upgrade requirements (8).

This work makes substantial progress in connecting the local to the national context in planning for distributed PV integration. However, it remains limited in that only median values for domestic and nondomestic meter density, PV deployment, and substation density are directly used in defining each rurality context. More extreme LSOAs within the distribution (e.g. those with higher PV deployment and a lower density of substations) will be subject to more or less severe impacts. Subsequent work will seek to build upon this analysis by developing a framework to assess the impacts of load growth and PV deployment in each of these individual contexts to further inform planning decisions for accommodating a transition to a low carbon electricity system.

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### Appendix: List of Key Terms and Abbreviations

#### Table A1: List of key terms and abbreviations used in this paper

<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
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<tbody>
<tr>
<td>Cities</td>
<td>Rurality context based upon the UK Office for National Statistics’ “urban city and town” classification.</td>
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<tr>
<td>DSR</td>
<td>Demand side response</td>
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<tr>
<td>DSR50, DSR100</td>
<td>Scenarios in which 50 and 100% of households participate in demand side response by 2030</td>
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<tr>
<td>EV</td>
<td>Electric vehicle</td>
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<tr>
<td>Feeder</td>
<td>The section of cable at a lower voltage level attached to a given transformer. In the case of distribution feeders, the section of able transferring power from a distribution transformer to individual customers.</td>
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<tr>
<td>GB</td>
<td>Great Britain</td>
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<tr>
<td>GMT</td>
<td>Ground Mounted Transformer</td>
</tr>
<tr>
<td>Hi-PV</td>
<td>A scenario with mid-level PV deployment based on National Grid’s “Community Renewables” scenario</td>
</tr>
<tr>
<td>LCNF</td>
<td>Low Carbon Network Fund</td>
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<tr>
<td>LG</td>
<td>Load Growth</td>
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<tr>
<td>LSOA</td>
<td>Lower Layer Super Output Area</td>
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<tr>
<td>LV</td>
<td>Low Voltage</td>
</tr>
<tr>
<td>Mid-PV</td>
<td>A scenario with mid-level PV deployment based on National Grid’s “Two Degrees” scenario</td>
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<tr>
<td>PMT</td>
<td>Pole Mounted Transformer</td>
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<tr>
<td>PV</td>
<td>Photovoltaic</td>
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<tr>
<td>RPF</td>
<td>Reverse Power Flow</td>
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<tr>
<td>S10,S25,S50</td>
<td>Scenarios in which 10%, 25%, and 50% of distributed storage per PV capacity specified in National Grid scenarios is installed on simulated networks.</td>
</tr>
<tr>
<td>Towns</td>
<td>Rurality context based upon the UK Office for National Statistics’ “rural town and fringe” classification</td>
</tr>
<tr>
<td>Villages</td>
<td>Rurality context based upon the UK Office for National Statistics’ “rural village” classification</td>
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