



The addition of heat pump electricity load profiles to GB electricity demand: Evidence from a heat pump field trial



Jenny Love^{a,*}, Andrew Z.P. Smith^a, Stephen Watson^b, Eleni Oikonomou^a, Alex Summerfield^a, Colin Gleeson^c, Phillip Biddulph^a, Lai Fong Chiu^a, Jez Wingfield^a, Chris Martin^d, Andy Stone^a, Robert Lowe^a

^aUCL Energy Institute, University College London, Central House, 14 Upper Woburn Place, London WC1H 0NN, UK

^bSchool of Civil and Building Engineering, Loughborough University, Loughborough LE11 3TU, UK

^cUniversity of Westminster, 309 Regent Street, London W1B 2UW, UK

^dEnergy Monitoring Company, UK

HIGHLIGHTS

- An aggregated load profile is constructed using data from 696 heat pumps in GB.
- It contains a morning and evening peak, falling to 40% of its peak value overnight.
- After diversity maximum demand is calculated as 1.7 kWe per heat pump.
- A first order approximation of the impact of 20% uptake of heat pumps is presented.
- This is shown to lead to the GB national grid evening peak increasing by 14%.

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ABSTRACT

Previous studies on the effect of mass uptake of heat pumps on the capability of local or national electricity grids have relied on modelling or small datasets to create the aggregated heat pump load profile. This article uses the UK Renewable Heat Premium Payment dataset, which records the electricity consumption of nearly 700 domestic heat pump installations every 2 minutes, to create an aggregated load profile using an order of magnitude more sites than previously available. The aggregated profile is presented on cold and medium winter weekdays and weekends and is shown to contain two peaks per day, dropping overnight to around 40% of its peak. After Diversity Maximum Demand (ADMD) for the population of heat pumps is calculated as 1.7 kW per site; this occurs in the morning, whereas the peak national grid demand occurs in the evening. Analysis is carried out on how heat pump ADMD varies with number of heat pumps in the sample. A simple upscaling exercise is presented to give a first order approximation of the increase in GB peak electricity demand with mass deployment of heat pumps. It is found that peak grid demand increases by 7.5 GW (14%) with 20% of households using heat pumps. The effect of the same heat pump uptake on grid ramp rate is also discussed; this effect is found to be minor. Finally, a comparison of heat pump and gas boiler operation is given, discussing day and night time operation and mean and peak power at different external temperatures.

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1. Introduction

As the UK moves to a low fossil fuel future, heating of its 27 million dwellings needs to shift from the current predominance of CO₂-intensive, individual gas boilers [1]. One option is a significant increase of electrification of heating (coupled with the decarbonisation of electricity), of which the most energy efficient option is heat pumps [2,3] at either a dwelling or community scale. In most

Abbreviations: ADMD, After Diversity Maximum Demand; ASHP, Air Source Heat Pump; CLNR, Customer Led Network Revolution; DNO, Distribution Network Operator; EDRP, Energy Demand Research Project; GSHP, Ground Source Heat Pump; RHPP, Renewable Heat Premium Payment; SAP, Standard Assessment Procedure; TSO, Transmission System Operator.

* Corresponding author.

E-mail address: jenny.love@ucl.ac.uk (J. Love).

areas, heat demand density is not high enough to allow heat networks to be cost-effective [4] so individual heat pumps are likely to be a key technology [5].

During winter periods heating energy demand can reach around 5 times the magnitude of electricity demand in UK dwellings [1]. As such it is anticipated that a high uptake of individual heat pumps will have a significant effect on electric power demand and therefore the requirements of the local and national electricity grid at certain times of day and year [6].

Four potential grid problems arising from mass deployment of heat pumps arise, at either a national level (under the Transmission System Operator, or TSO) or substation level (under the Distribution Network Operator, or DNO).

The national scale problems are *peak demand increase* and *ramp rate increase*. Peak demand reflects the greatest demands on both the capacity of the transmission network and the generation infrastructure, in terms of both real and reactive power. Increases in peak demand are therefore likely to lead to investment in both new transmission capacity, and new generation capacity, if security of supply is to be maintained. Ramp rate reflects the need for electricity demand and supply to match on the grid, at a sub-minutely timescale. Currently the most rapid increase in demand over the day occurs between 06:00 and 07:00 in the morning, requiring supply to increase within this time too. If that morning ramp-up in demand were to coincide with heat pumps turning on, then further flexible plant would be required to provide the extra ramp up.

At the DNO scale, dwellings in areas that are connected to the gas network will generally have distribution network capacities designed for very little electric heating. The problems associated with connecting large number of heat pumps are excessive *voltage drop* beyond allowed limits [7] and insufficient *thermal capacity* of the Low Voltage feeder and transformer leading to overheating of these elements unless they are reinforced [8,9].

This article will focus primarily on the national level, due to the availability of data from the national grid. It will however refer to substation level studies and metrics where relevant. Furthermore, the scope of the article will be real power (Watts) only, as opposed to apparent power (var), again due to the nature of the data available.

The relevant metrics for the impact of heat pumps on the national grid are national half-hourly averaged peak electricity demand (GW) and maximum ramp rate (GW/half hour). The half hour timestep is used for averaging here since this is the trading period of the national grid. The relevant metric to use to construct an aggregated heat pump load profile is After Diversity Maximum Demand, which is now described.

It is known that for networks where demand is aggregated over a number of customers N , the magnitude of peak power demand is less than the simple addition of peak power per customer over all customers. This is due to the phenomenon of diversity: the notion that as the number of customers increases, the maximum time-coincident demand per customer falls [10]. The metric to be used to describe peak power is therefore known as the After Diversity Maximum Demand (ADMD) [11]. To calculate ADMD, demand per consumer is summed at each timestep, then the maximum of the resulting timeseries is found. This is shown in Eq. (1).

$$ADMD = \max_t \left(\sum_{n=1}^{n=N} demand_n(t) \right) \quad (1)$$

where t = time, n = customer, N = all customers

ADMD accounts for the coincident peak load a network is likely to experience over its lifetime [10]. This is typically defined for a local network. If households form all of the load on the network, then dividing ADMD by N customers gives an *ADMD per customer*.

Relating this specifically to heat pumps, *ADMD per heat pump* is taken to be the per-house ADMD of solely the aggregated heat pump demand, without the rest of the household electricity use. In this article, we define all ADMD using half hourly averaged data in accordance with Barteczko-Hibbert [10] and also to be consistent with the national metrics of grid peak demand and ramp rate given above, although it could underestimate effects on distribution networks [12].

Given these metrics, three questions can now be posed as follows. If large scale deployment of heat pumps occurs, what is the resulting peak demand of the national grid, what is the resulting ramp rate, and are either of these two outcomes then likely to be problematic? Answering these requires knowledge of not just the ADMD per heat pump, but the timing of the heat pumps' peak aggregated demand compared to the grid peak demand on a national scale.

2. Literature and previous datasets

We now describe the data and methods used in previous literature to construct aggregated heat pump load profiles and evaluate its potential effects on local or national electricity grids.

Most studies investigate aggregation of heat pump load profiles using modelled (synthetic) electricity load profiles. These in turn are based on heat demand which is either measured from conventional heating systems [13,14] or modelled. Methods of modelling heat demand include use of static or dynamic building modelling (e.g. [15–17]), simple mathematical functions [18] or assumption of flat (continuous) heating [19].

For example, acknowledging the lack of real heat pump electricity data, Navarro-Espinosa et al. [13] start with monitored heat demand profiles from conventional heating systems and infer electricity consumption, taking into account variable heat pump efficiency (although from manufacturers' datasheets as opposed to in situ data) and assuming a use profile of auxiliary heating. In a study combining heat pumps and electric vehicles, Papadaskalopoulos et al. [20] take a sample of building types from the UK building stock in different regions, derive heat and electricity demand profiles from the dynamic simulation tool Energy Plus, and add a certain number of these together according to different heat pump uptake scenarios (10–30% penetration). This methodology of aggregate load profile creation is interesting in terms of combining different building types and regions but does not fully capture the phenomenon of diversity as introduced in Section 1.

An approach to creating an aggregated load profile which does recreate diversity to some extent is found in Pudijianto et al. [21], in which data from 21 monitored systems were aggregated to create assumed heat pump profiles. However the data were derived from boiler and micro-CHP systems, as opposed to heat pumps. Another method incorporating diversity is to use 'top down' modelling [22], starting with total UK gas used for heating and dividing it by an assumed average heat pump efficiency to derive hourly and seasonal electricity demand which would be required if heat pumps replaced conventional gas boilers.

However, the heat pump demand profiles in the above studies are all based on an assumption that heat pumps are run at the same times of day as conventional heating systems (or micro CHP in the case of [21]), and thus that data derived from heating systems other than heat pumps can be used to determine the timing characteristics of heat pumps. This assumption is not verified in the literature for the UK context. The timing characteristics of heat pump operation compared to the current dominant domestic heating system – gas boilers – then becomes an additional question to be investigated in this article.

In contrast to the above, an aggregation exercise by Veldman et al. [23] focussing on the Netherlands was based on measurements from a small number of heat pumps. A large number of heat

pumps were simulated from a small number of initial sites by creating a synthetic profile for each site and applying a mathematical function which randomises when the compressor is on, representing random customer behaviour [24]. This is an example of creating diversity synthetically but without empirical verification.

We now turn to available datasets on UK heat pump electricity use. The largest used in previously published research was gathered in the Customer Led Networks Revolution (CLNR) project [25]. This yielded good quality data for 89 heat pumps (out of an original 381 installations), and monthly load profiles were constructed from aggregation of this data across the sites at the half-hourly level. ADMD per customer of the heat pumps, dwellings, and heat pump-dwelling combinations was then calculated through a process of curve fitting and extrapolation [10]. The extrapolation went to 100 customers because this was judged to be a stable ADMD for the dwelling-only case.

For 100 customers, the ADMD per heat pump was around 1.3 kW; the ADMD of the dwelling without the heat pump was around 1.2 kW, and the ADMD of the dwelling-heat pump combination was around 2 kW. It is interesting that the total is less than the sum of the components; this indicates that the daily peak in heat pump use was not concurrent with the daily peak of the rest of the dwelling.

The above result highlights the importance of knowing the timing of daily peak demands, not just of the heat pumps but of the other electrical loads consuming power from the same cables. In this case the dwelling peak demand was indicated to occur at a different time from the heat pump peak demand, which mitigates the overall ADMD per customer.

A conclusion emerging from the literature is as follows. In attempting to aggregate and upscale heat pump electricity demand to a national level using a mass uptake scenario, it is extremely challenging to incorporate all of the following three aspects: timing characteristics of real heat pumps, diversity arising from large numbers of installations, and representativeness of a sample of heat pumps (real or modelled).

These three aspects are not all combined in this current study; however, the first two are attempted, addressing the well defined gap in the literature of studies which use real profiles of electricity demand from a population of heat pumps large enough to demonstrate that diversity effects have been captured. Incorporation of representativeness is the subject of further work.

3. Data

This current study utilises a newly available dataset of heat pump electricity consumption almost an order of magnitude larger than the CLNR dataset. The UK Government's Renewable Heat Premium Payment (RHPP) scheme included high frequency monitoring of electricity consumption, heat output and system temperature data for a subset of heat pump installations in the scheme, resulting in a dataset covering 696 sites. The dataset is introduced below.

3.1. Range of sites

The RHPP heat pump dataset was collected from a sample of 703 domestic heat pump installations from the wider population of installations in the RHPP scheme in Great Britain over the period December 2011–March 2015. Each site has a different metering start date within the overall trial period and around two years of data.

The sites included a range of dwelling types and ages. However, the majority of installations involved replacing an existing heating system with a new heat pump; as such most of the dwellings were not purpose-built to be heated by heat pumps. The RHPP gave

grants for heat pumps in homes not heated by mains gas, but with basic energy efficiency measures in place: 250 mm loft insulation and cavity wall insulation, where practical [26]. Two thirds of installations (473) were in social housing and the remainder in private housing.

3.2. Range of heat pump systems

The RHPP project monitored 120 different models of heat pumps produced by 24 manufacturers and covered at least 25 configurations of heat pump connected to ancillary equipment such as a domestic hot water (DHW) cylinder. A principal characteristic was the heat source: 530 installations were air source heat pumps (75%), and 173 sites were ground source heat pumps (25%).

Additional variations included whether the heat pump provided domestic hot water (DHW) or just space heating, and whether it incorporated one or more of a number of types of supplementary electric resistance heating.

The metering strategy was adapted for each heat pump configuration in order to capture as far as possible the same variables across the range of configurations. However, the heterogeneous nature of the population of heat pumps and ancillary equipment leads to challenges in ensuring consistency in monitoring. For example, some systems had internal boost heating which is within the heat pump electricity consumption, whereas others used boost heating supplementary to the heat pump's electricity consumption.

3.3. Representativeness of dataset compared to wider heat pump population

The mean capacities of heat pumps in the dataset, measured in kW (thermal) and for those sites where data is available, is 8.11 (ASHPs) and 8.21 (GSHPs). This is smaller than the mean of the population of sites in the RHPP scheme from which the sample was drawn (10.9 for ASHPs, 11.3 for GSHPs), and also smaller than the mean of other heat pumps installed over the same period but not part of the RHPP scheme (10.2 for ASHPs, 14.7 for GSHPs [27]). Furthermore, the predominance of social housing in the RHPP sample is not typical of GB heat pump installations of which the largest sector is owner-occupied [28]. The dataset is therefore not representative of current GB heat pump installations; in Section 4 the relevance of the dataset to future installations is discussed.

3.4. Contents of dataset

The RHPP dataset consists of timeseries data recorded at two-minute intervals for 696 sites; 7 of the original 703 did not provide data or metadata. These data include:

- Heat output and electricity consumption of the heat pump, integrated over each 2 min;
- Flow data from which the heat output was calculated;
- Four temperatures from the system: space heating flow temperature, domestic hot water flow temperature, temperature at the heat pump condenser, and temperature of the ground loop or evaporator;
- In some cases, separately metered heat to the DHW circuit and/or separately metered electrical boost. The latter can include DHW immersion heating, space-only boost or whole-system boost.

Electricity consumption from circulation pumps was not separately metered. Furthermore, contextual variables such as dwelling internal temperature were not monitored. A metadata file accompanying the data provides some contextual information (e.g.

dwelling tenure, heating emitter type) but lacks some important information to aid interpretation of the timeseries, e.g. which heat pumps have buffer tanks and how the controls were set up. Finally, since the measurement of electricity consumption consists of integration over two minutes, short term effects such as start-up currents are not observable in the data. Consideration of the real and reactive power demand implications of these effects are therefore outside the scope of this study.

The data used in this article are all available on the UK Data Archive [29]. A number of anomalies are known to be present in the published data [30]. However, the available data and metadata do not allow categorical statement of whether the anomalies are metering errors or genuine data points. The dataset with the most anomalies was found to be the heat data; therefore, this article focuses on analysis of the electricity data only, without comment on heat pump efficiency, heat demand or other uses of the heat data.

4. Methods

4.1. Construction of two-minutely aggregated load profile

Of the 696 heat pump installations for which data is available, Fig. 1 shows the number in the dataset at each two-minutely period. This varies, firstly because the start and end dates for each site were different, and secondly because sites with missing data for given time periods were excluded during those time periods (but the sites in question were not entirely discarded, unlike [25], meaning a large sample size could be maintained). The maximum number of sites with overlapping monitoring periods is 589.

From the period shown in Fig. 1, an interval of the period was taken from June 2013 to February 2015 as this time consistently had data from over 400 sites. Subsequent figures show data only for this interval of time.

The variable of focus is two-minutely heat pump electricity consumption, labelled as ‘Ehp’ in the published data on UKDA and given in Watt-hours per 2 min. Fig. 2 shows this transformed into kW(electrical) and averaged over all heat pumps, for each 2 min in the analysis period. (Please note that for the rest of this article, kW (electrical) is abbreviated to kW, kW(thermal) is abbreviated to kWth and kW gas is stated as it is. Also note that heat pump power in kW as given in Fig. 2 represents real power; single phase heat pumps are inductive loads and have power factors less than 1, but, as noted above, the electricity consumption data here only allows for consideration of the real part of the power). Superposed on this is daily mean external temperature from the Central England Temperature Series [31]. This of course will not be the corresponding external temperature with every site but gives an indication of the relationship between heat pump electricity consumption and external temperature across the country as a whole.

The five-minutely real power demand of the Great Britain (GB) electricity grid over the same period as the RHPP data was obtained from Elexon [32]. In Fig. 3 this is shown with the heat pump electricity consumption data; note these are again plotted using different y-axes.

The lighter series of Fig. 3 illustrates the increase in electricity demand on the GB grid occurring over the winter even with very few heat pumps connected to the grid, due to increased lighting energy consumption and electric space and water heating. Space heating causes the biggest absolute increase of these 3 electricity end uses. [33]

4.2. Calculation of half hourly ADMD per heat pump

The two-minutely heat pump electricity data shown above was aggregated half hourly and the maximum of this was then found to

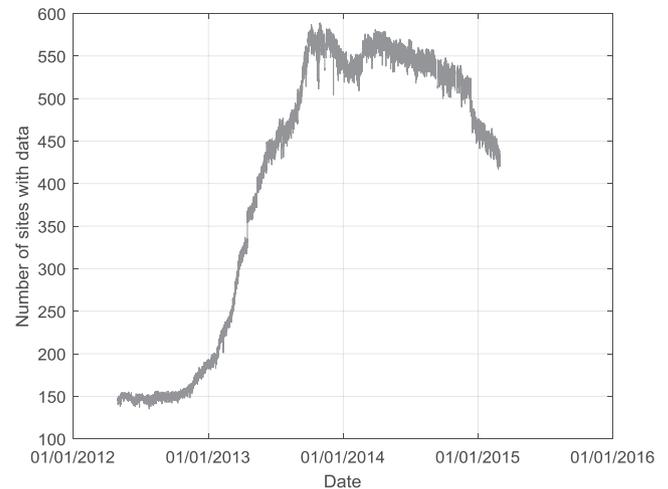


Fig. 1. Number of sites in the RHPP sample at any one time.

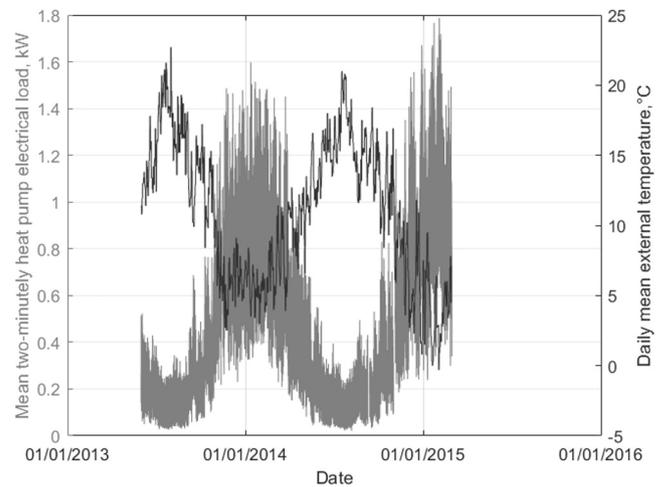


Fig. 2. Aggregated heat pump electricity consumption and external temperature timeseries.

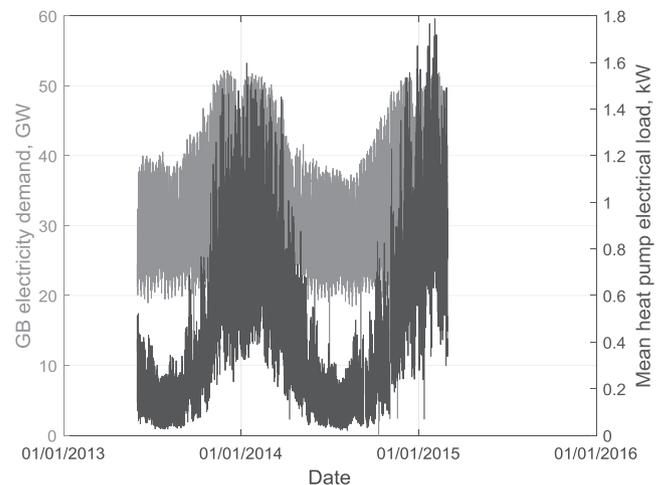


Fig. 3. E Aggregated heat pump electricity consumption and GB electricity demand.

produce the ‘ADMD per heat pump’ metric presented in the Introduction.

However, ADMD is not one single number, but changes with number of heat pumps considered. For example, for one heat pump

there is no diversity and ADMD is the peak half hourly consumption of that heat pump.

To the best of our knowledge, no previous analysis uses fully empirical data to determine how ADMD per heat pump varies with number of heat pumps, so this was carried out as follows:

The heat pumps in the RHPP population were sorted randomly into an order. The ADMD of the first was calculated. Then the first and second heat pumps were taken together and the ADMD of their combined consumption was calculated. One more heat pump was added each time until all heat pumps were included in the ADMD calculation. This results in a value of ADMD for each value of N heat pumps.

For multiple reasons, we expect the ADMD vs N relationship to differ if the order of heat pumps included changes: firstly, the heat pumps vary in size from one another; secondly, ADMD might occur at different times based on which sites are included; thirdly and related to the previous point, not all sites have data for each half hour. Therefore, the above process was carried out 50 times (as a satisfactory trade-off between comprehensiveness and computation time) using different randomised orders to produce a mean estimate of the relationship between ADMD and number of heat pumps, with standard deviation.

4.3. Simple upscaling method

A simple upscaling was carried out to investigate the effect of mass deployment of heat pumps on GB electricity demand. Mean half-hourly heat pump electricity consumption as described in Section 4.2 was added to mean half hourly national grid electricity demand, under four uptake scenarios: 5%, 10%, 15% and 20% of houses having heat pumps, as in [6]. The GB national housing stock was taken as 25.8 million households [34]. The effect on peak demand and ramp rate on each of the four days was calculated.

The limitations of this method are as follows. In Section 3 it was stated that RHPP sample is not representative of current GB heat pump installations. Furthermore, it is unknown to what extent the sample will be similar to future heat pump installations in a mass deployment scenario, since the population of heat pumps in question is one that does not exist yet and whose composition and characteristics are unknown. Heat pumps are likely to become more efficient in the next decades, the way in which heat pumps are installed and used could change as the technology becomes more familiar and integrated with storage and smart grids, and heat demand could decrease as the dwelling stock becomes more thermally efficient. In parallel, future electricity consumption is likely to change over time, for example with a widespread introduction of electric vehicles and other electro-thermal technologies such as micro CHP [35], or with an increase in efficiency in other uses of electricity.

Therefore the aim of this upscaling exercise is not to predict the exact profile of the resultant electricity demand after mass uptake of heat pumps, but to observe its approximate size in comparison to the rest of GBs electricity demand and to gain insights such as whether the heat pump aggregated peak occurs at the same time as that of the rest of the national electricity demand.

In future work, a more sophisticated upscaling method will be developed which aims to create a representative aggregate load profile and consider future changes to the characteristics of national electricity demand.

4.4. Comparing heat pump operation to gas boilers

This method concerns obtaining data on gas use in boilers in a similar format to the heat pump electricity data, and comparing how both change over the day and as external temperature decreases. The EDRP dataset (DOI:10.5255/UKDA-SN-7591-1) con-

tains half hourly gas use in 580 dwellings for space heating and is suitable for this task. However, much of the metadata about the RHPP and EDRP sites is not in the public domain so it is unclear whether the two samples are comparable in terms of their dwelling sizes and types.

For a given site in the heat pump dataset, each day of data was binned according to the external temperature that day. This was carried out by ascribing to it the closest integer value of mean daily external temperature according to the nearest weather station to the site.

Then for each bin of external temperature, the mean electricity consumption at each half hour (across all days of data in that external temperature bin) was calculated. This yielded one value of electricity consumption per half hour, per site and per external temperature bin.

Finally, the mean electricity consumption each half hour for each external temperature bin was calculated across all sites, to give a set of 24-hour profiles at different external temperatures. The process was then repeated for the gas consumption of all sites in the EDRP dataset.

The resulting electricity and gas consumption profiles were each then normalised to their daily peak, in order to compare the shapes of the profiles and specifically to observe the fraction of the peak at each time of day.

5. Results

5.1. Example aggregated heat pump load profiles

We begin by showing some example plots of the shape of daily load profiles on example days using a range of external conditions and day types. These are kept in two-minutely form to match the resolution of the heat pump electricity data. These days have been chosen because their external temperatures can be taken as representative of particular categories of typical day. By using a single day's observations in each case, we capture all the spatial diversity from the observed heat pumps, and do not introduce any inter-day smoothing which would misrepresent the issues that we are focussing on here: the particular potential strains on the electricity supply system caused by diurnal load profiles of heat pumps being added to existing electricity demand.

- Cold winter weekday/day of max ADMD per heat pump (Tuesday 03/02/2015, external temperature = -0.3 °C)
- Cold winter weekend day (Sunday 18/01/2015, external temperature = 1.4 °C)
- Medium winter weekday (Tuesday 03/03/2014, external temperature = 5 °C)
- Medium winter weekend day (Sunday 16/02/2014, external temperature = 5.2 °C)

The days to display were selected as follows. The analysis period, June 2013 to February 2015, contained atypically few very cold days in winter, so the winter months (December, January, February) from the entire RHPP monitoring period, December 2011 to March 2015, were used to determine a median winter temperature, 5.2 °C, used below as 'medium winter day'. The day on which the ADMD per heat pump of the whole dataset occurred was used for cold winter weekday. There was no very cold winter weekend day, so the coldest weekday in the analysis period was used, at 1.4 °C.

A number of observations can be made on the shape of the winter heat pump load profiles. Figs. 4-7 show that the mean heat pump daily load profile in winter has two peaks but does not fall to zero or near zero outside of the times of high demand. The first

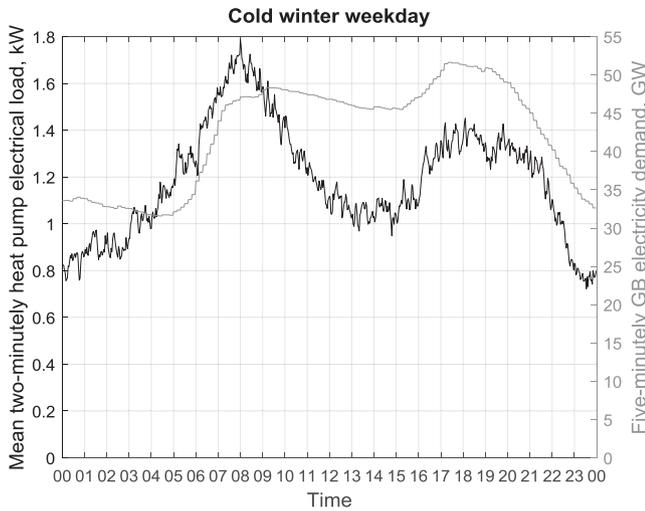


Fig. 4. Aggregated two-minute heat pump load profile for a cold winter weekday: 03/02/2015, external temperature = $-0.3\text{ }^{\circ}\text{C}$ (the day of highest aggregated HP demand).

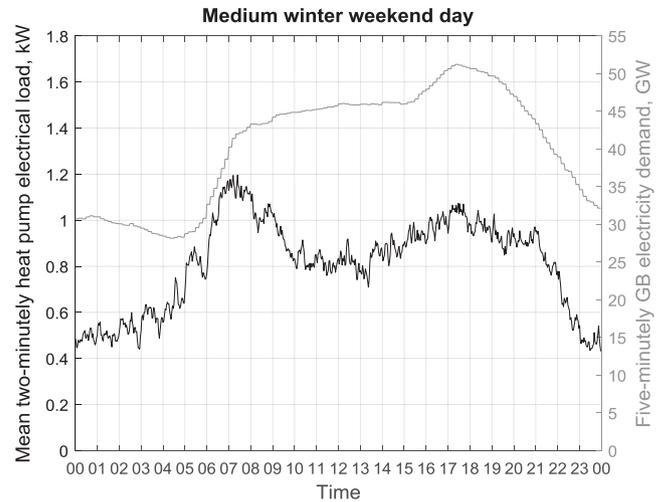


Fig. 7. Aggregated two-minute heat pump load profile for a medium winter weekend day: 16/02/2014, external temperature = $5.2\text{ }^{\circ}\text{C}$.

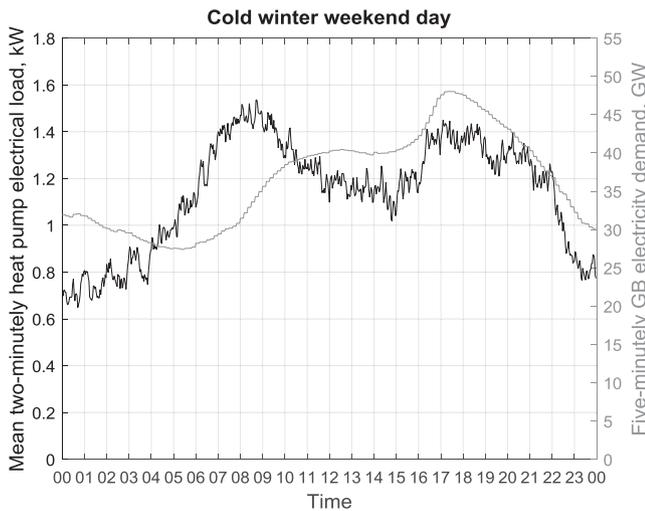


Fig. 5. Aggregated two-minute heat pump load profile for cold winter weekend day: 18/01/2015, external temperature = $1.4\text{ }^{\circ}\text{C}$.

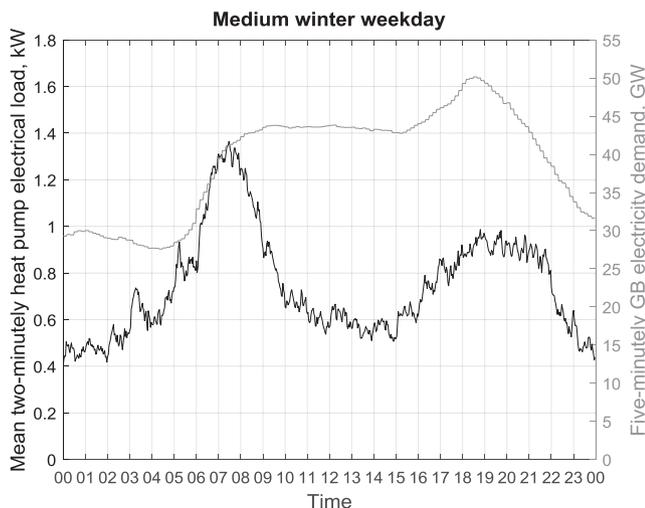


Fig. 6. Aggregated two-minute heat pump load profile for a medium weekday: 03/03/2014, external temperature = $5.0\text{ }^{\circ}\text{C}$.

peak is around 06:00–09:00 and the second is around 16:00–21:00; the morning peak is usually higher in power and shorter in duration than the evening peak. The morning peak being higher would imply that the main cooling down period of dwellings is overnight and thus the heat pumps have to provide their highest rate of output in the morning. There is evidence of at least some heat pumps being programmed to run throughout the night: but intermittent heating still dominates, and electricity consumption falls overnight to between one half and one quarter of its peak, in the examples shown above. This is returned to later.

We now comment on the shape of the heat pump load profiles compared to the second series on Figs. 5 to 8, the power load of the GB electricity grid.

The UK electricity grid daily load profile (2013–2015) typically has the following pattern [33]:

- Baseload overnight, of which the minimum occurs around 04:00–05:00; this represents always-on appliances such as fridges and freezers; 24-h industrial, institutional and commercial processes; and off-peak electric heating.
- Rise from 05:00 until 09:00 as households begin to turn on appliances and workplaces/non-domestic premises open;
- A plateau until 16:00;
- A peak from around 16:00 to 21:00 as lighting in streets and households comes on, as do other appliances
- A decrease through the evening, dropping to the overnight baseload by shortly after midnight.

The morning peak of the heat pump load profile is coincident with or begins just before the morning rise in load on the electricity grid, and the evening peak of the heat pump load profile is coincident with the evening peak in the electricity grid.

5.2. ADMD per heat pump

The two-minutely data were aggregated to half hourly as described in Section 3.2, and the ADMD per heat pump was calculated as 1.7 kW using all of the RHPP sites.

The trajectory from one heat pump to the above number, or the change in ADMD per heat pump as number of sites increased, was calculated and is shown in Fig. 8.

Note that as shown in Fig. 1, data is not available from all 696 sites for the whole period, and that the period in which ADMD occurred for most values of the number of heat pumps on the x axis

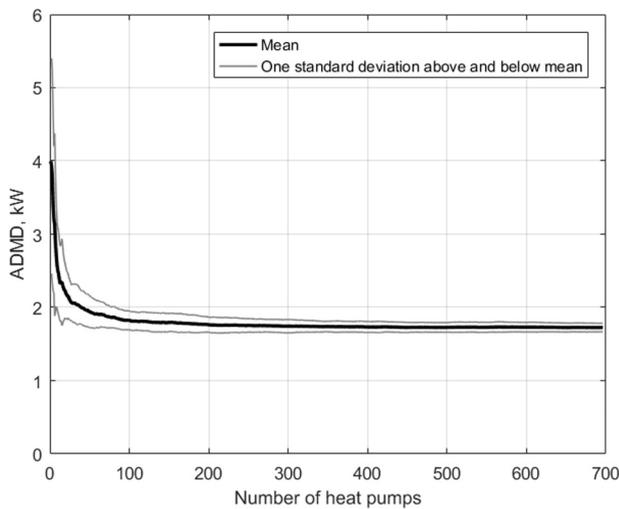


Fig. 8. ADMD per heat pump for increasing numbers of heat pumps in the RHPP population.

of Fig. 8 was early 2015, which Fig. 1 shows as containing 425–450 heat pumps.

Fig. 8 has a peak of 4.0 kW at 1 heat pump. After 40 customers ADMD falls to 2.0 kW (50% of its initial value), after 100 heat pumps it falls to 1.8 kW (45%) and at 275 heat pumps the ADMD reaches its final value (to 2 significant figures) of 1.7 kW (43%).

The standard deviation from the mean is also shown on Fig. 8 as a measure of the variation between samples [10]. As explained in Section 4.3, one reason for the variation is that heat pumps in the real world are different sizes and draw different power according to their needs (climate, building heat demand, etc) and for this reason one sample of a fixed number of heat pumps may give a different ADMD per heat pump than another sample drawn from the same population [16]. The standard deviation is 1.5 kW at the first heat pump and 0.1 kW at the 275th (the number at which ADMD reaches its final value to two significant figures). This reflects a fairly low uncertainty in ADMD per heat pump introduced by the subsampling method.

However, ADMD per heat pump is not an especially useful metric for national grid considerations. More important is the effect on peak grid demand – the maximum of which may not occur at the same time as the ADMD of heat pumps alone. This is considered next.

5.3. Effect of mass deployment of heat pumps on the GB electricity system

We now answer two of the questions posed in the Introduction: what would be the resulting peak demand of the national grid if various mass deployment scenarios of heat pumps occurred, and what would the corresponding ramp rate increase be?

Applying the upscaling method described in Section 4.3 led to a timeseries of resultant grid demand for each heat pump uptake scenario. The maximum of each timeseries is then the grid peak

demand for each scenario and is given in Table 1. Notably, the day and time at which ADMD per heat pump occurred (03/02/2015, morning) is not the same as the day and time of grid peak demand before addition of heat pump load (19/01/2015, evening). Furthermore, the results of the upscaling showed that the day and time of the grid ADMD after addition of heat pump load (02/02/2015, evening) is different again.

Fig. 9 below shows the day of the new overall grid peak in the 20% heat pump deployment scenario, before and after deployment. This is shown to illustrate the effect of the heat pump load on the previous grid load that day. It can be seen that the shape of the grid load is not changed a great deal, and that the peak is still in the evening. The heat pump load has added most to the morning, and is beginning to create a morning peak in the grid load where there was not one before. However, at 20% deployment of heat pumps this effect is not very strong. Thus, the main effect is not a change in shape of the daily grid load but the addition of a slowly varying extra load throughout the day and night.

Next, the effect of the same heat pump uptake scenarios on grid ramp rate was calculated. The day and time of maximum ramp rate prior to heat pump deployment was the morning ramp-up of 24/10/2013. This is not the middle of winter but a swing season. The day and time of maximum ramp rate after heat pump deployment was 19/01/2015.

The effect of heat pump deployment on maximum ramp rate is presented in Table 2.

Thus, the worst case scenario is an increase of 0.3 GW/half hour on current levels.

The effect on ramp rate caused by mass heat pump uptake is shown in Fig. 10. It can be seen that the effect is small.

We now move on from comparison with the electricity grid to comparison of heat pump operation with the current dominant heating system – gas boilers.

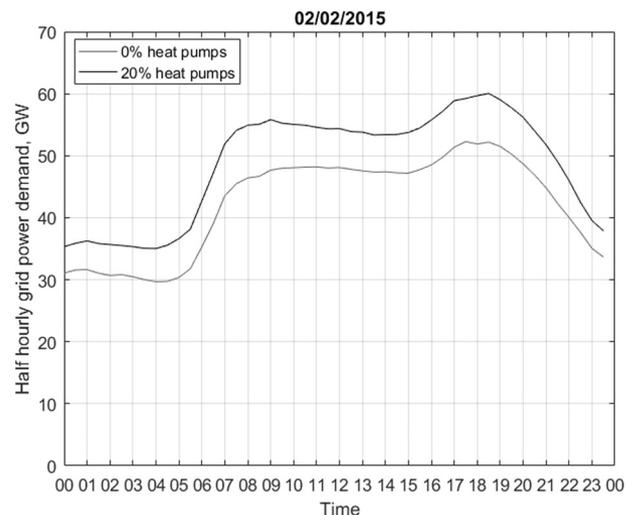


Fig. 9. Predicted national grid power demand on the day of new maximum demand under the 0% and 20% heat pump deployment scenarios.

Table 1

	Heat pump penetration				
	0%	5%	10%	15%	20%
Max demand (GW)	52.5	54.4	56.2	58.1	60.0
Increase from 0% scenario		+3.5%	+7.1%	+10.6%	+14.3%
Date of grid peak demand under this scenario	19/01/2015	19/01/2015	19/01/2015	19/01/2015	02/02/2015

Table 2
Maximum half hourly ramp rate under different heat pump uptake scenarios.

	Heat pump penetration				
	0%	5%	10%	15%	20%
Maximum ramp rate (GW/half hour)	4.7	4.7	4.8	4.9	5.0
Increase on 0% scenario		+0.6%	+2.0%	+4.1%	+6.1%
Date	24/10/2013	24/10/2013	20/01/2014	20/01/2014	20/01/2014

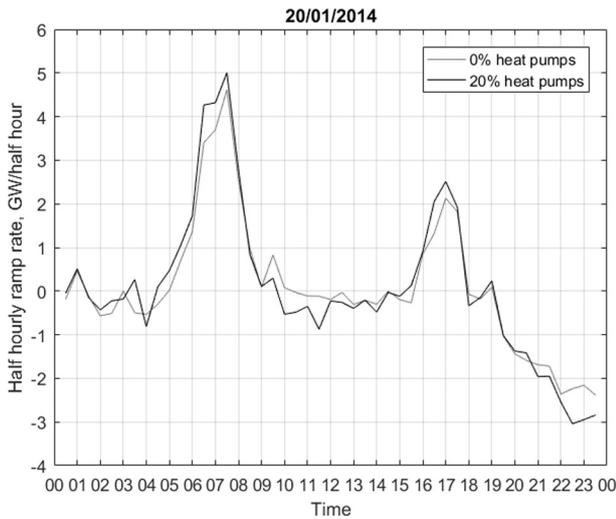


Fig. 10. Ramp rate under different heat pump uptake scenarios.

5.4. Heat pumps and boilers

The final question posed in the introduction was: what are the timing characteristics of heat pumps compared to conventional boilers?

This is firstly shown in timeseries form over 24 h. Using the method described in Section 4.4, gas use for boilers and electricity use for heat pumps were collated for days of similar mean external temperature. Gas boilers and heat pumps can then be compared in terms of the shape of their daily profile of gas/electricity consumption at certain external temperatures. Fig. 11 and Fig. 12 show the average gas use from boilers and electricity use from heat pumps on days on which the external temperature was 0 °C and 5 °C.

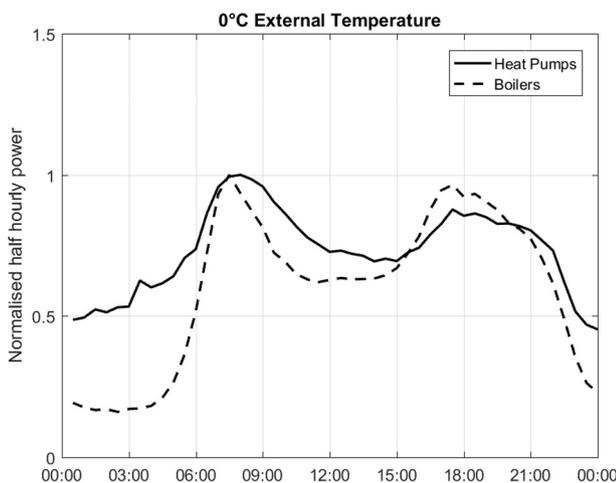


Fig. 11. Comparison of heat pump and boiler daily load profiles at 0 °C external temperature.

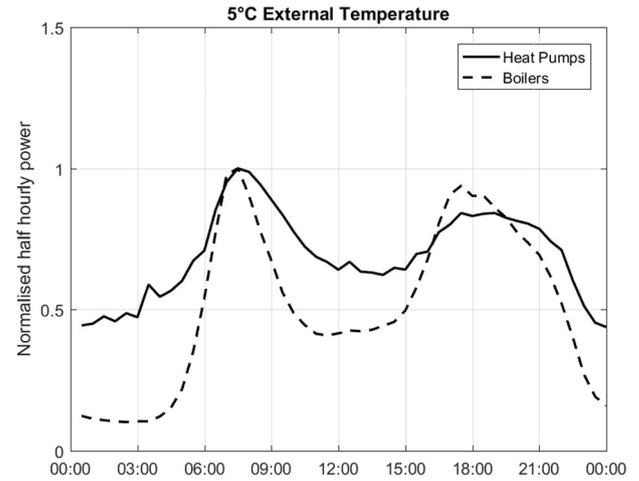


Fig. 12. Comparison of heat pump and boiler daily load profiles at 5 °C external temperature.

The two series on each plot are normalised to their respective peaks to allow easier comparison of their shapes.

A number of observations can be made from Fig. 11 and Fig. 12.

Firstly, boiler load profiles and heat pump load profiles both contain two peaks. The morning peak and evening peaks are reached at approximately the same time for both types of system, but the ramp up and down is faster for boilers (Fig. 11 and Fig. 12).

Secondly, the boiler profile varies more over the day than the heat pump profile – that is, it is more ‘peaky’. Although it is not appropriate to compare the absolute size of the boiler daily peak to the heat pump daily peak (as was previously explained, the mixes of property types and heat demands served are different), the ratio of the peak to the mean of each type of heating system can be compared. At 0 °C external temperature, the peak:mean ratio for boilers is 1.67 and for heat pumps is 1.37. Similarly, the peak:trough ratio can be calculated, showing that boilers fall to 16% of their peak output at night on cold days, whereas heat pumps fall to 41%.

It could be the case that for each type of heating system the size of the morning peak is inversely related to the amount of night time delivered power. Assuming that the morning peak is serving some proportion of space heating, as opposed to domestic hot water, the consequence of significant heating overnight would then be that the dwellings with heat pumps do not cool so much in the night and therefore require less heating in the morning.

We now move on to another way of displaying the data, delivered power plotted against external temperature, elsewhere termed the ‘Power-Temperature Gradient’ [36]. The range of external temperature used for heat pumps is -1 to 20 °C and for boilers is -2 to 24 °C, because over these ranges at least 400 sites of each heating system type have at least one day of data.

Fig. 13 shows daily delivered power versus daily external temperature for dwellings with heat pumps and boilers. Fig. 13 was created using a similar method to Fig. 11 and Fig. 12, by taking, at each degree band of external temperature, the mean power per site on days falling into this temperature band, and then taking

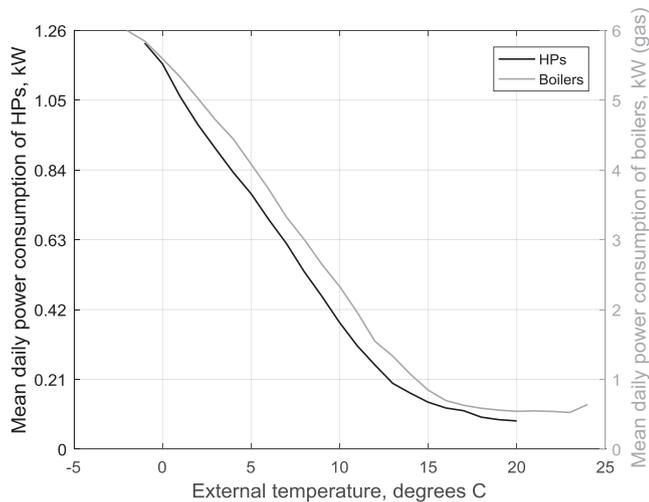


Fig. 13. Power Temperature Gradient for heat pumps and boilers using mean power consumption.

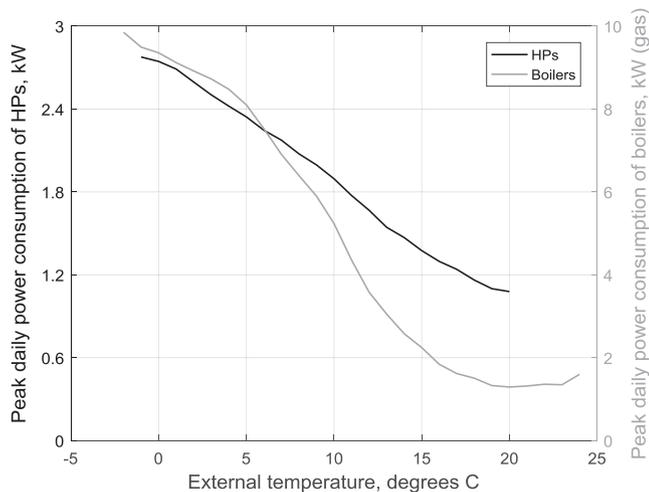


Fig. 14. Power Temperature Gradient for heat pumps and boilers using peak power consumption (at half hourly resolution).

the mean over all sites. This method was chosen to match that used in previous work on the Power Temperature Gradient [36]. In Fig. 13 heat pumps and boilers are plotted on separate y axes so that their shapes can be easily compared.

The two series on Fig. 13 are similar in shape: they are both approximately linear at external temperatures below 12–13 °C. It may have been expected that, due to a sample of heat pumps dominated by air source models which become less thermodynamically efficient as external temperature drops, the heat pump power-temperature relationship would have steepened at low external temperatures. This cannot be seen in the RHPP dataset. Further analysis is needed to uncover the factors causing the heat pump power-temperature relationship of heat pumps to result in a linear shape. In particular, more data is needed from cold days (where external temperature is below 0 °C) to observe whether the relationship is still linear.

Finally, we return to the topic of daily peak power consumption. In Fig. 14, daily peak power averaged over all sites is plotted against daily mean external temperature, for each type of heating system. Peak power was calculated as follows: for a given external temperature, all the days in the dataset from a site were selected, and the peak electricity (or gas for boilers) consumption per day

averaged to obtain one value per site. These were then averaged over all sites to obtain a peak electricity (or gas) consumption for each external temperature.

The difference between the shapes of the heat pump and boiler series on Fig. 14 is notable. Boilers produce a shape resembling a logit curve. As external temperature decreases from right to left, the rate of increase in the peak power rises, then decreases at low external temperatures. The latter could be as a result of boilers reaching their maximum heat output.

Heat pumps do not produce the same shape. Below about 15 °C externally, their peak power rises fairly constantly until 0 °C where it may start to flatten, although there are not enough data points to confirm this. There are a number of possible explanations for this, each of which deserves investigation in further work. For example, it could be that the heating in gas boiler heated dwellings is used for more of the night on colder days, reducing the anticipated increase in peak (morning) load as external temperature drops, whereas heat pumps are already used more commonly in the night and this use does not increase on colder days. Alternatively, the internal boost (resistance heater) present in some models of heat pump could be coming into operation at the lowest external temperatures.

6. Discussion

This article set out to estimate two unknowns: the load profiles of a large sample of heat pumps and their timing characteristics compared to conventional boilers, and (to first order) the increase in peak half hourly demand and change in maximum ramp rate of the national grid with mass uptake of heat pumps.

6.1. Shape of aggregated load profiles

It is assumed in some previous studies that heat pump load profiles are flat, implying continuous operation [19], and in other literature that they are run at times of assumed space heating demand [13–15], giving a bimodal profile with two strong peaks similar to the load profile of gas boilers. The evidence given by recent field trials shows that the answer is somewhere in between. In the aggregated load profiles from both the RHPP data described here (containing 400–589 sites at a time) and the largest previous study (CLNR, containing 89 sites), the aggregated heat pump load profiles have two daily peaks, at 06:00–09:00 and 16:00–20:00. The CLNR sites showed a third peak at 3 a.m. which was not visible in the RHPP data. The electricity consumption in the RHPP dataset fell overnight to around 40% of its peak. The implications of this operation are discussed below.

6.2. Implications for the national grid

The current daily national grid peak occurs in the evening around 17:00–18:00. This is not the same time as the daily peak of the aggregated heat pump load profile, which occurs in the morning around 07:00–08:00.

Although as described in Section 4.3 the shape and magnitude of both aggregated heat pump demand and national grid demand in the coming decades are not likely to be exactly represented by those observed now, some general insights can be gained from the upscaling exercise carried out in this article which combined a 20% heat pump deployment scenario with current national grid demand. These insights are as follows:

1. The shape of the national grid profile is approximately preserved; heat pumps at 20% penetration do not have a large enough effect to significantly alter it – though, this may change in significantly colder weather.

2. However, 20% heat pump penetration begins to create a morning peak; higher heat pump deployment scenarios would enhance this.
3. The peak power demand (real power only) of the grid increases by 7.5 GW (14%), occurring during the evening peak.
4. The day of maximum grid demand is neither the day in which previous maximum grid demand occurred nor the day on which ADMD per heat pump occurred.

Despite both the daily maximum heat pump load and the daily national grid ramp rate being at their highest values in the morning, the 20% heat pump deployment scenario only increased maximum ramp rate by 0.3 GW/half hour (6%).

These increases in national peak demand could be mitigated by implementing heat pump control strategies that diversify the heat pump load profile, and make use of periods of lower national electricity demand (such as overnight 22.00–06.00); such strategies should also be designed to mitigate, rather than to exacerbate, the morning ramp-up of national demand. The RHPP dataset suggests that this is being carried out already to some extent. Comparison of the operation of heat pumps and boilers shows that there is more overnight operation of heat pumps than boilers; this is likely to result in the morning peak being reduced from what it would have been in the absence of night operation. However, the clear existence of peaks at the same time as those occurring in boiler-heated dwellings show that heat pumps are to an extent being used in the same manner as boilers.

As for why this might be, it is possible that this comes about as a result of some of the heat pumps in the sample being retrofitted into homes with timed heating systems (such as oil boilers) without changing the timing set up on the heating controls. However, the data and metadata from the RHPP trial are not sufficient to determine the heat pump control strategy implemented at each site; furthermore, it is not known how many sites already have and use heat storage via buffer tanks. Therefore, the technical potential for demand shifting in time cannot be determined from the current dataset.

6.3. Implications for models incorporating heat pumps

The RHPP dataset can help inform how heat pump operation is modelled. Heat pumps are represented in the UK's Standard Assessment Procedure (SAP) building energy model through a Seasonal Performance Factor and an adjustment to mean internal temperature. The latter is on the premise that heat pump operation is continuous, so dwelling mean internal temperature is higher than if a dwelling is heated using a conventional boiler and one or two heating periods a day (weekends and weekdays respectively). The Seasonal Performance Factor is also based on continuous operating conditions; these conditions allow for lowest possible supply temperatures and therefore as efficient performance as possible [30].¹ The shape of the empirical daily load profiles contrasts with this assumption of continuous operation as there exist peak times of operation. The consequence may be that the heat pumps are not operating as efficiently as possible nor as efficiently as assumed in the SAP model.

Heat pumps are also modelled in electricity system models, at both local and national levels. The results in this study showing ADMD per heat pump change with number of heat pumps are interesting for these applications. The ADMD was shown to fall to half of its initial value after 40 sites, which is similar behaviour to a previous study combining data and modelling [10]. ADMD

continued to fall after 100 sites, the maximum number used in the previous study, and reached its final value to one significant figure after 275 sites. This is perhaps not important for local level considerations since substations generally do not have this many domestic connections (for example, the UK DNO Western Power Distribution report 120 customers per urban substation [37]). However, the finding is relevant at a national level. The ADMD curve for heat pumps has not previously been demonstrated fully empirically.

The bimodal shape of the aggregated load profile may not be observed in countries other than Great Britain. However, the findings presented here of the ADMD of a heterogeneous population of heat pumps reaching approximately its final value after 275 sites and the observed advantages of using real data not synthetic profiles at assumed times of heat demand may be useful results for countries seeking to carry out research into the effect of an aggregate heat pump load profile on local and national grids.

7. Conclusion and next steps

This paper utilises the largest dataset of heat pump data electricity use available in the UK for retrofitted heat pumps to existing dwellings and systems, and focusses on the electricity consumption. The aggregate winter profile shows two peak heating periods at the same time as those found in homes heated by boilers, but with lower peaks and more night time operation. The ADMD per heat pump was 1.7 kW, occurring in the morning and not concurrent with the national daily peak demand. A simple upscaling method to add heat pump electrical load to the existing national grid indicated a peak demand increase of 7.5 GW and maximum ramp rate increase of 0.3 GW/half hour.

The next steps in this exploration might be:

- To improve existing modelling of forecast load curves, combining the new results presented here with other results on load-curves for other new loads such as electric vehicles;
- A more thorough consideration of social factors and house type to give more representative and detailed estimates of national electricity demand under various heat pump uptake scenarios.

However, the results here indicate a need – and an opportunity – to implement ways to spread out the load to reduce the extra capacity required on the grid:

- Work to understand the behaviour of a fleet of heat pumps at much lower external heat pumps (as noted, the RHPP dataset included little data below 0 °C);
- An exploration of the differences between ground and air source heat pumps
- Exploring clusters of sites with different operation modes;
- Exploring space heating behaviour and DHW heating behaviour and investigating whether the bimodal daily load profile observed in winter is also apparent on a site-by-site basis or a result of some heat pumps switching off in the middle of the day and some remaining on;
- Further empirical and simulation work to understand the shape of the power-temperature curve.

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¹ SAP is also provides an option not to use this assumption, in which case a default (lower) SPF and bi-modal heating at the same times as a boiler are assumed.

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Declaration of interest

To the authors' knowledge there are no actual or potential conflicts of interest including any financial, personal or other relationships with other people or organisations within three years of beginning the submitted work that could inappropriately influence, or be perceived to influence, this work.

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