Power system benefits of simultaneous domestic transport and heating demand flexibility in Great Britain's energy transition

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Abstract

The electrification of heating and transport in Great Britain will allow households to provide more flexibility to the grid. Previous studies show how domestic demand flexibility enables more renewable generation to be usable and reduces the required capacity expansion of both network and dispatchable generation. However, it remains less clear how flexibility in transport and heat interact and how the achieved benefits are spatially distributed. This research addresses these questions using a novel linear optimisation model PyPSA-FES, designed to simulate optimistic and pessimistic transition pathways in National Grid ESO Future Energy Scenarios. PyPSA-FES models the future power system in Great Britain at high spatiotemporal resolution and integrates demand flexibility from both smart charging electric vehicles and thermal storage-coupled heat pumps. The model then optimises the trade-off between reinforcing the grid to align charging and heating profiles with renewable generation versus expanding dispatchable generation capacity. The results show that from 2030, under optimistic transition assumptions, domestic demand flexibility can enable an additional 20-30 TWh of renewable generation annually and reduce dispatchable generation and distribution network capacity by ∼20 GW each, resulting in a total cost reduction of around £5bn yearly. However, further experiments suggest that half of the total system cost reduction is already achieved by only 25% of electric vehicles alone, while the benefits of flexible heating are almost linear with rollout. Further, the cross-sectoral analysis shows that each sector's flexibility substantially affects the benefits achieved in the other. The findings indicate that once smart electric vehicle charging reaches a 25% penetration rate in households, minimal benefits are observed for implementing smart 12-hour thermal storages for heating flexibility at the national level. Additionally, smart heating benefits decrease by 90% across all metrics when only pre-heating (without thermal storages) is considered. Spatially, demand flexibility is often considered to alleviate the need for north-south transmission grid expansion. While neither confirmed nor opposed here, the results highlight a more nuanced dynamic where generation capacities are moved closer to demand centres, enhancing connectivity within UK sub-regions through ∼1000 GWkm of additional transmission grid capacity.

1 Introduction

The electricity system of Great Britain (GB) will rely increasingly on variable wind and solar generation. Paired with the phase-out of dispatchable generators, the challenge of their integration is compounded by the electrification of the transport and heating sectors, increasing annual consumer electricity demand by approximately 50% by 2035 (1). The measures to accommodate this decrease in flexibility include reinforcing the transmission grid (2) and the use of flexibility markets and services, such as a capacity market to provide backup for weather-dependent renewable generation sources (e.g. paying gas power plants to be on standby) (3; 4). Both of these incur substantial costs for consumers, underscoring the need for cost-effective sources of flexibility.

Consumer flexibility, mainly through the ongoing rollout of electric vehicles (EVs), heat pumps, and batteries, gives households the opportunity to contribute. In the case of EV charging, aligning times of charging with grid needs has been explored extensively (5; 6; 7; 8; 9), and is now widely regarded as a balancing tool for the future grid (10; 1). Similar expectations exist for electric heating, where various ways of delaying demand or pre-heating can also provide benefits for the system as a whole (11; 12; 13; 14). In outlooks on the Great British power system, flexible heating too, usually supported by heat batteries, is a standard component of the future flexibility mix (1).

Methods to integrate smart EV charging have been explored early in Teng et al. (5), indicating that consumer flexibility can reduce required backup generation, especially when Vehicle-to-grid (V2G) is included. The operational depth applied in (5) helped to show that realistic consumer behaviour and uncertainties in future demand do not prevent feasible integration of domestic flexibility. The utility of smart charging was further validated in Crozier et al. (6), highlighting the potential to flatten demand profiles to alleviate both distribution and transmission networks. Heuberger et al. (7) reaffirm this, noting that time-of-use tariffs can minimise network capacity expansion needs. The consensus on the value of EV flexibility is reflected in National Grid ESO's Future Energy Scenarios (FES) 2023 (1) and in the Climate Change Committee's (CCC) Sixth Carbon Budget (15). As of September 2023, EV charging participates in the GB Balancing Market (16).

Research on flexible heating has identified a similar potential. Early contributions have shown that heat pumps paired with heat batteries could enhance system efficiency, accommodating more renewable generation and reducing the need for capacity expansion (5; 17; 18). This is founded on an early finding that storing the energy as heat instead of electricity is cheaper by 60-90% (11; 19). Lizana et al. (11) estimates the whole-system benefits in the UK are maximised when heat pumps are coupled with residential thermal storage that allows demand shifting of about 12 hours, reducing additional power capacity by approximately 37%. Flexible heating is a standard feature in popular sector-coupled energy models such as PyPSA-Eur (20), and UK-specific outlooks such as bespoke FES (1) and the Sixth Carbon Budget (15).

Despite existing advances, the implications of domestic demand flexibility in the whole power system performance and planning are still unclear due to the following three research gaps/challenges.

The *first challenge* relates to the limited scope of modelling. A realistic analysis of benefits necessitates an embedding within a comprehensive system model. The model should reflect the broad spectrum of operational and investment options accessible to the real system, which is crucial to capture cost trade-offs. For instance, models focusing solely on distribution-level costs might underestimate the value of enabling more renewable integration on the transmission level through distribution grid expansion. Equally problematic can be a lack of embedding within a larger European context. UK interconnectors in 2030 are estimated to have a cumulative capacity of 10-15 GW (2), which opens significant electricity trading opportunities. Finally, the model should be situated in a realistic macroeconomic context. This means scaling variables like carbon emissions and renewable rollout according to multi-year models, which draw conclusions from an (multi-)national economic perspective that exceeds the scope of operational studies. While FES (1) provides such a context, they are only featured in a subset of studies.

The *second challenge* concerns treating transport and heating flexibility in isolation, thereby neglecting their interaction. Studies typically either consider the benefits of heating *or* smart charging (6; 11; 7), or only consider the system with both in full operation (1; 10). This approach could overlook varying effects as flexibility is gradually added to the system, such as affecting assets' lifetime value, with implications for consumers and policymakers. For example, it could miss potential saturation points, where added flexibility only has a negligible benefit.

The *third challenge* concerns the exogenous definition of flexibility measures changing demand profiles. This approach is justified by time-of-use tariffs, which reward consumers for shifting electricity use to times of lower demand. Modelling the induced behavioural changes in consumers is beyond the models' scope, which justifies the exogenous insertion of profiles, as is done in (7) and (5). This is appropriate for today's consumer behaviour, and also a method explored for heat pumps (21). However, it is not able to simulate flexibility as it is expected to be operated in the future. Flexibility is expected to become increasingly *automated*, allowing consumers to set constraints on asset operation and then delegate charging control to the supplier, who has the appropriate resources to make optimal decisions. It is this setup that allowed the inclusion of EV charging into the Balancing Mechanism (16). Models that adapt charging times dynamically to renewable generation, recreate the real electricity market more faithfully. Meanwhile, the exogenous definition of profiles runs a risk of underestimating the true potential of flexible assets.

This research analyses how energy flexibility from domestic transport and heating affect investment and dispatch in the UK's future power system using the novel linear optimisation model PyPSA-FES. Blueprints of the future power system are provided by FES. Both the optimistic transition pathway *Leading the Way* and the pessimistic *Falling Short* are included.

The model features coarse approximations of neighbouring countries' power systems through the underlying European level energy system model PyPSA-Eur (20), capturing electricity trading opportunities via interconnectors. Central model parameters such as total emissions, demand and renewable generation capacities are set according to FES. Together, this approach provides a geographic and macroeconomic context missing in many similar studies (*addressing the first challenge*).

Electrified domestic heating and transport, and their respective opportunities for flexibility are included. While this is also the case in FES, additional depth is provided here through a set of experiments where rollout of each is gradually increased to capture cross-sectoral interactions (*addressing the second challenge*).

Further, the model is given the freedom to dynamically match charging/heating times to renewable generation. Thereby, the model endogenously determines cost-optimal demand profiles, aligning with how flexibility will increasingly be operated given its ongoing automation. It is this setup in which the model can realistically consider cost trade-offs between the maximisation of renewable integration, and cost savings through a minimisation of network expansion or dispatchable generation (*addressing the third challenge*).

The results are compared through a set of evaluation metrics that capture how the system's cost optimal configuration changes through the addition of flexibility: enabled renewable generation, prevented dispatchable generation capacity, reduced distribution grid capacity, total system cost and transmission grid capacity. In addition, changes in transmission grid reinforcement and the model's siting choices for renewable capacity are assessed.

The following research contributions are provided in this study to support cost-optimal power system planning:

- a novel energy system model PyPSA-FES, built to model Future Energy Scenarios *Leading the Way* and *Falling Short* with a focus on domestic demand flexibility (Contribution 1).
- a quantification of whole-system benefits achieved by domestic demand flexibility through heating and transport in future Great Britain's electricity system considering the Future Energy Scenarios *Leading the Way* and *Falling Short* (Contribution 2),
- a spatial analysis, showing how demand flexibility changes cost-optimal transmission capacity expansion and siting of renewable generation (Contribution 3),
- an analysis of cross-sectoral interactions during different rollout levels of transport and heat flexibility (Contribution 4),
- a comparison between heating and transport of how the temporal extent of flexibility affects the benefits achieved (Contribution 5).

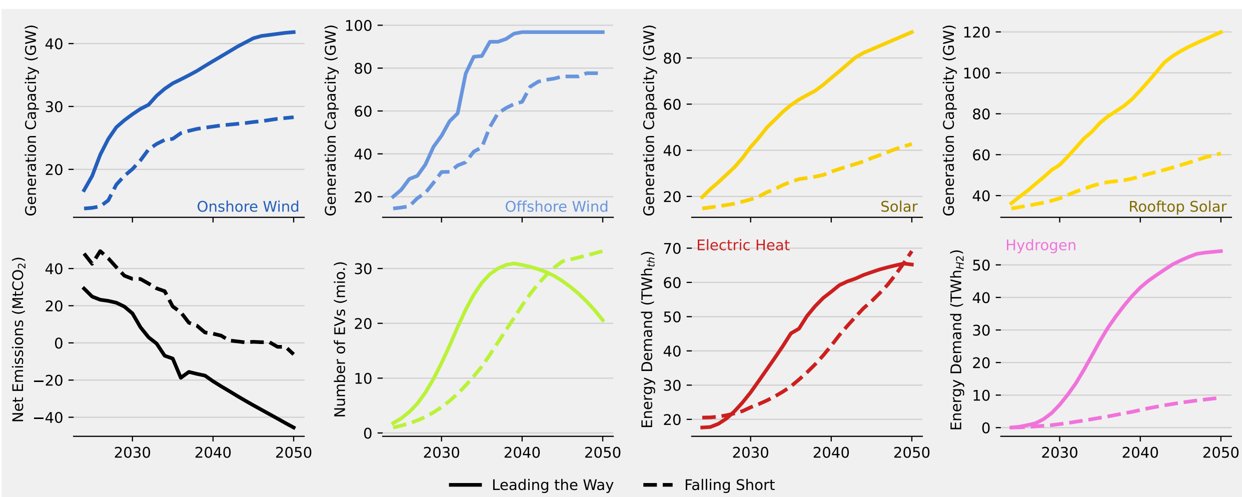

Figure 1: Overview of central model parameters taken from Future Energy Scenarios.

The following text first introduces the modelling methods, data inputs and performance metrics in Section 2, and then present the results in Section 3. Note the discussion for each result is contained in the respective subsection. An overview of the study's limitations is provided in Subsection 3.5 and the study concludes in Section 4.

2 Methods

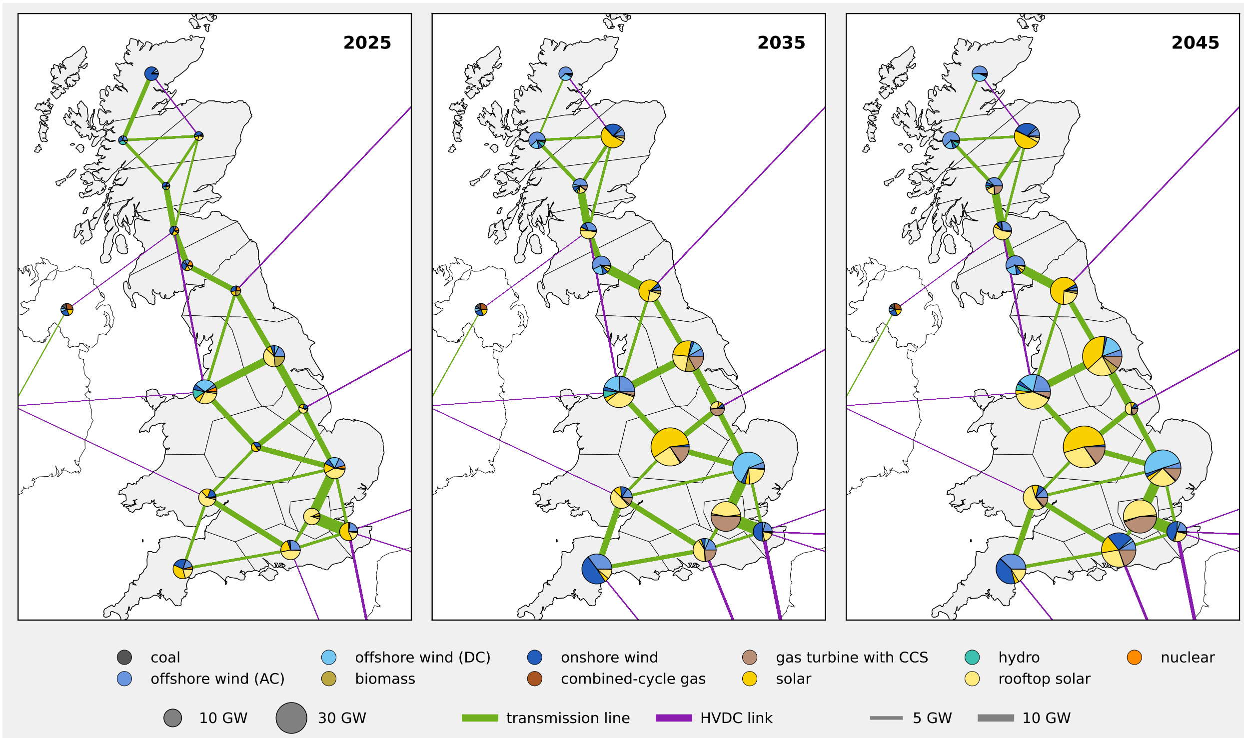

Figure 2: Mapped outlook of generation capacities in *Leading the Way* for 2025, 2035 and 2045.

This study is based on the novel linear optimisation model PyPSA-FES, described here. This section first outlines the model's general philosophy, followed by details on its features, modelling methods, and data assumptions.

The model is the first fork of the PyPSA-Eur dataset (20) that is specifically tailored here to simulate any year of Great Britain's Future Energy Scenarios (FES), including the optimistic *Leading the Way* and pessimistic *Falling Short* versions (1). By aligning parameters with FES, the model operates within a plausible context: the relative magnitude of system parameters and constraints such as emission targets, interconnection balances, hydrogen demand, and transmission level battery capacity are realistic, as they are the result of nuanced economic modelling outside the scope of operational models like PyPSA-Eur. Some of the projections used are shown in Fig 1, and visualise the model's layout in Fig 2.

Fundamentally, the model processes regional load profiles over a year and optimises investment and operation to meet the load at minimal cost. These loads include all electricity-based demands, e.g. heating is only considered if generated by heat pumps or resistive heaters. To analyse domestic demand flexibility, the model splits the demand vectors *electrified heat*, *transport*, *current demand*, and *electrolysis* to isolate their interactions with their respective flexibility sources (Fig 3).

The model splits the UK into 17 zones (see Fig 2) based on a layout by National Grid ESO capturing transmission network bottlenecks, featured for instance in Pfenninger and Staffell (22). It performs linear optimisation of dispatch and capacity expansion over a full year with hourly reso-

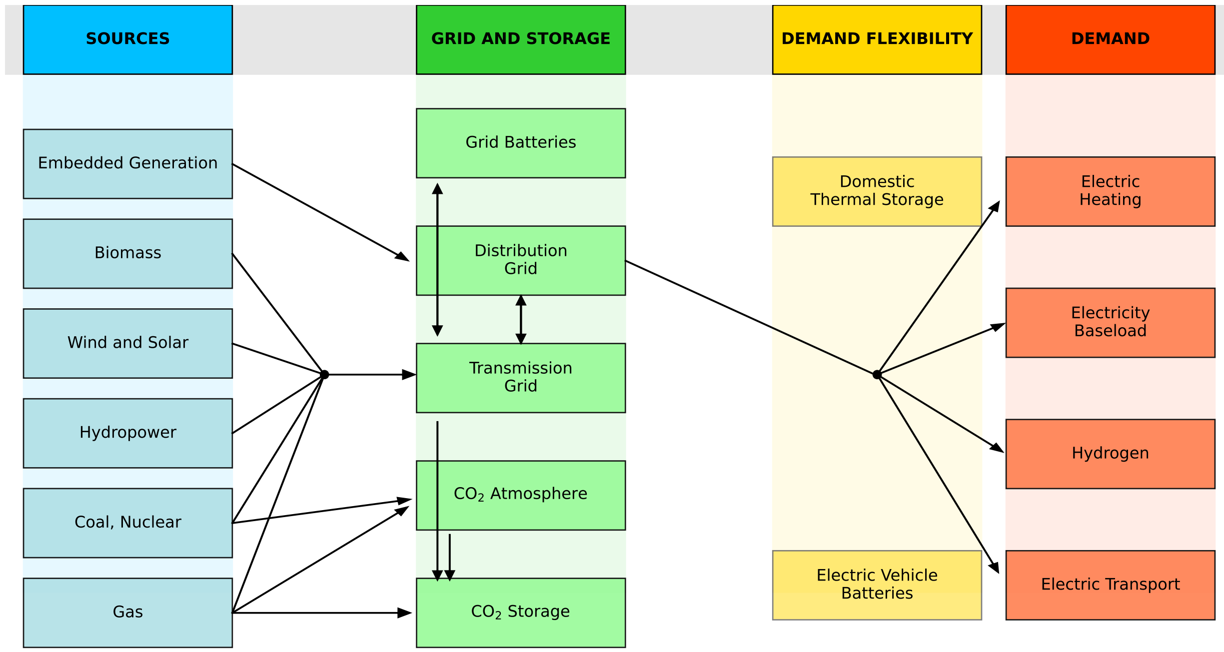

Figure 3: Overview of the energy vectors included in PyPSA-FES.

lution. The model also includes all countries that are connected to the UK via interconnection as single nodes, making use of the underlying European model. This choice strikes a balance between computational effort and capturing electricity trading opportunities between countries.

There is an apparent conflict between the model's ability to optimise capacity expansion, and these quantities being given by FES. To address this, the network components are categorised into two groups. The first group features components that are generally considered conducive to the energy transition. This includes renewable generation capacities, infrastructure for electrification, interconnection trade balances, and emission reduction targets. These quantities are fixed as constraints; the model only chooses cost-optimal operation. In the case of renewable generation capacities, the model also optimises the zones in which assets are built but is forced to install the total capacity set by FES. The second group consists of (mostly generation) assets that offer flexibility, where generally, less is better in terms of cost and/or emissions. These include dispatchable generation capacities such as Gas Turbines with Carbon Capture and Storage and distribution grid capacity. For these, capacities anticipated by FES are not enforced. This grouping allows us to measure whole system benefits in terms of the above metrics. An overview of how different system components and technologies are included is shown in Table 1.

Table 1: Overview of system parameters, and the method chosen to set their capacity. Note that, except for demand, all hourly dispatch decisions are endogenous.
Key: **EX**: Exogenous, **EN**: Endogenous, **SD**: Spatial distribution

Component	Technology	Implementation	Source
Demand	Electric Transport	**EX**	(1; 20)
	Electric Heating	**EX**	(1; 20)
	Electric Baseload	**EX**	(1; 20)
	Hydrogen Production	Total Demand **EX**, Profile **EN**	(1)
Generation	Onshore Wind	Total Capacity **EX**, **SP EN**	(1)
	Offshore Wind	Total Capacity **EX**, **SD EN**	(1)
	Transmission Level Solar	Total Capacity **EX**, **SD EN**	(1)
	Rooftop Solar	Total Capacity **EX**, **SD EN**	(1)
	Nuclear	Total Capacity **EX**, **SD EN**	(1; 20)
	Biomass	Total Capacity **EX**, **SD EN**	(1; 20)
	Coal	Total Capacity **EX**, **SD EN**	(1; 20)
	Hydro	Total Capacity **EX**, **SD EN**	(1; 20)
	Combined-Cycle Gas Turbine	**EN**	(23; 20)
	Open-Cycle Gas Turbine	**EN**	(23; 20)
	Gas Turbine with CCS	**EN**	(23; 20)
Network	Transmission	Existing Network **EX**, Expansion **EN**	(20; 23)
	Distribution	**EN**	(23)
	Interconnection	**EX**	(20; 2)
Storage	Transmission Level Batteries	Total Capacity **EX** (FES), **SD EN**	(1)
	Thermal Storage	**EX**	(1; 20)
	Building's Thermal Inertia	**EX**	(11; 21)
	EV batteries	**EX**	(1; 20)
Constraints	Net Emissions	**EX**	(1)
	Interconnection Trade Balance	**EX**	(1)
Conversion	Direct Air Capture	**EN**	(20)
	Biogas Upgrading	**EN**	(20)
	Electrolysis	Total Capacity **EX**, **SD EN**	(1; 20)

2.1 Mathematical Formulation

The model uses Python for Power System Analysis (PyPSA) (24) to find the cost-optimal configuration of investment and dispatch.

The model defines a network as pairs of nodes and time steps. At each pair the in- and outflow of energy must exactly cancel each other out. The primal outflow is the load, given as an input to the model at each pair. The only energy flowing into the model comes from generators, assigned to the network nodes and able to generate at each time step in accordance with their capacity. To mediate, there are lines and links to shift energy between connected nodes and storages to shift energy between different time steps. Here, the behaviour of lines is dictated by Kirchhoff voltage law, while links simply transport energy and used to represent interconnections and conversion between different energy carriers, such as heat pumps. For generators, lines, links and storages, both operation and capacity can be costed as marginal and capital cost, respectively. The model finds the configuration of these components that minimises overall cost. Finally, constraints simulate physical realities. For instance, they can upper bound generation of a wind turbine to reflect local weather, limit the volume of carbon the system is allowed to emit, or can be used to prevent nuclear power plants from generating in unrealistically erratic patterns. For a more explicit discussion of the underlying equations, the reader is referred to (24).

2.2 Demand

As indicated by Fig 3, electricity demand is split by end-use, in particular baseload electricity demand, representing today's demand, transport demand through electric vehicles, heat demand through heat pumps and resistive heating, and finally, **hydrogen** demand through electrolysis. The split has multiple benefits. First, it allows the scaling of different demand types independently of one another, capturing changes to the overall demand *profile* that result from different mixes of e.g. transport and heating demand. Second, it ensures a realistic operation of flexible assets, providing a natural method to constrain a flexibility-providing asset to its respective sector. Otherwise, for instance, a heat battery could charge and discharge to, in effect, smooth EV charging profiles. Only demand met through electricity is considered. For many of the discussed types of demand, a more elaborate discussion can be found in the supplemental material of Neumann et al. (20), but a summary is provided here.

The profile for **baseload electricity demand** is taken from the Elexon Sum Plus Embedded Net Imports (ESPENI) dataset (25). This dataset enhances the commonly used national demand dataset provided by National Grid ESO (26), which uses total generation as a proxy for loss-adjusted demand. However, ESO's generation mix does not include embedded generation and electricity imports via interconnection. The ESPENI dataset rectifies this through additional data injections and provides an account of total generation suitable for use as demand. In terms of aggregate demand, the model scales the ESPENI profile to the numbers provided by FES which project developments of demand for the residential, commercial and industrial sectors. The model distributes country-level demand to regions based on their population and income level. We chose the year 2019 for the demand profiles.

In terms of **heating demand**, the model uses the built-in methods provided by PyPSA-Eur (27), and recently enhanced by Halloran et al. (28). These methods generate profiles that are then scaled to conform to FES projections for accumulated electric heating demand. The pipeline to estimate space heating demand uses *atlite* (29) to compute the linear distance between the local temperature profile and the threshold temperatures that necessitate heating. The daily heating demand resulting from this computation is then disaggregated to an hourly profile based on the *demandlib* repository by *oemof* (30; 20). One issue of this approach is that (30) uses gas boiler operation as a proxy for heating demand. However, gas boilers' operation is typically more "spiky" than heat pumps', leading to an overestimation of peaks if the model is meant to simulate heat pumps. This problem was solved by Halloran et al. (28), replacing the underlying hourly demand profile with a profile of actual heat pump operation. It is this method that is employed in PyPSA-FES. As a final step, a division by hourly and location-specific heat pump coefficients of performance gives electric heating demand.

The underlying **transport demand** time series aims to capture the actual energy usage on the road. To that end, it uses a weekly traffic profile reported by the German Federal Highway Research Institute (BASt) (31; 20). From this profile, the model computes charging demand and, in the case of flexible operation, the availability for temporally shifted charging and V2G. The model is subject to a constraint forcing all EVs to be filled to 75% at 7 am every morning, representing typical consumer preferences. Additional electricity demand of EVs is added by heating and cooling when required by weather conditions, which entails additional 0.98 %/°C demand for ambient temperatures below 15°C, and 0.63 %/°C above 20°C (20). The resulting profiles are again disaggregated to regions based on population data, and then scaled according to FES.

Finally, **hydrogen** demand is based on estimations made in FES. From these, the model reads the total volume of expected hydrogen production of a given year and scenario along with the projected electrolysis capacity. The model optimises the spatial distribution of electrolysis capacity, and the efficiencies of hydrogen synthesis are taken from PyPSA-Eur (20). Over the course of the year, the model is constrained to generate the desired volume of hydrogen. This is a simplified representation, as it neglects considerations of hydrogen storage capacity and constraints imposed by the GB gas/hydrogen network, which seems, however, appropriate given the secondary role of hydrogen in the present work.

Electricity demand in other European countries is left to their default in PyPSA-Eur (20), which stems from country-level hourly demand data published since 2013 by ENTSO-E.

2.3 Generation

The underlying dataset of existing generation capacity in Great Britain is discussed first, followed by a description of the assumptions made by FES projections concerning generation fleet, split into renewable and dispatchable technologies.

As inherited from PyPSA-Eur, current-day generation capacities are estimated by the Python library *powerplantmatching* (32). *Powerplantmatching* harmonises different databases, and adds gas turbines, coal and nuclear power plants along with hydropower, and their respective capacities and geolocations to the model. In the case of hydropower, the data is complemented by atlite (29), which estimates runoff and, thereby, generation potential based on local topography. Renewable generation capacities are also taken from *powerplantmatching*. Here too, *atlite* is used to compute hourly capacity factors based on spatiotemporal data provided by ERA5 reanalysis historical weather (33). The weather year chosen is 2019.

2.4 Storage

The model considers opportunities to shift demand and generation in time using grid-level batteries. For Pumped-Hydro Storage, the spatial distribution is taken from PyPSA-Eur (20) and then scaled according to FES. In addition, FES expects a mix of Liquid and Compressed Air Energy Storage to complement consumer-level flexibility. The majority of the rollout of these technologies is expected towards 2050 in *Leading the Way*, and remains at lower levels outside these cases. The spatial distribution of these batteries is matched to the distribution of demand. Charging and discharging efficiencies of 97% are assumed (23).

2.5 Network

The model uses an adapted version of the network processing pipeline provided by PyPSA-Eur. This pipeline starts with all European power lines of a voltage of at least 220 kV as made available through the ENTSO-E Interactive Map (34). Then, Voronoi cells are used to assign regions to the respective substations. PyPSA-Eur runs k-means clustering to group these zones into a flexible number of regions to accommodate different levels of computational resources. In PyPSA-FES, the model's layout and number of regions are fixed, and assign each substation to a map of zones provided in National Grid ESO's Electricity Ten Year Statement (ETYS) (35). This layout, splitting Great Britain into 17 zones, captures bottlenecks in the transmission grid. It is therefore suitable to provide an accurate assessment of limitations to electricity transport while also allowing laptop-scale computational resources to execute the model. PyPSA-Eur also provides data on existing interconnections (HVDC) between Great Britain and mainland Europe, which are manually enhanced, following the OFGEM's data table of existing and future UK interconnection projects (2). All HVDC links that are expected to be completed before the modelled year, are included in the model, see Fig 2.

In terms of grid expansion, two scenarios for transmission grid reinforcement are included. The first is the Holistic Network Design (HND) proposed by ESO to support offshore wind deployment towards 2030. This plan expects transmission network investment ramps, starting 2023 and reaching approximately £10bn yearly in 2026 and holding/increasing at that level in the years after. In contrast, over the past decade, yearly investment into the grid has averaged approximately £1bn. PyPSA-FES includes one scenario "HND" which simulates a realisation of ESO's demand. In this case, the model is constrained in terms of transmission capacity expansion in, say, 2040 by the investment accumulated between now and 2040. The other scenario is "historic", and simulates ESO being unable to convince stakeholders to increase their investment resulting in a continuation on historic levels, i.e. £1bn per year. If not stated otherwise, *Leading the Way* uses the "HND" scenario, and *Falling Short* uses the "historic" one. However, in the former case, the model does not saturate the constraint.

2.6 Flexibility

We consider flexibility in two sectors, domestic heating and transport. In all experiments, the demand is left unchanged, but upon activating flexibility allow the model additional freedom in drawing electricity from the transmission grid. Implicitly, this assumes a certain level of automation of flexible assets, as for consumers it is not feasible to track the electricity price in real time to make optimal decisions, even when motivated by time-of-use tariffs.

- **EV charging:** When flexibility is activated, the model receives full control of EV charging. Constraints are imposed to reflect availability for charging based on time of use profiles. Additionally, EVs need to be charged to at least 75% each morning at 6 am, which is a typical consumer preference. Here, it is assumed that each car has a battery capacity of 50kWh to a rate of charge of 11kW and 90% charging efficiency (20).
- **Heating:** As projected by FES, a subset of consumers will have access to heat storage (1). In Lizana et al. (11) it was estimated that heat demand shifting of around 12 hours maximises whole system benefits. Following this, heating demand in PyPSA-FES is enhanced by energy storage that can shift demand by around 12 hours with an hourly heat loss of 2% which is a typical value for small scale thermal batteries (23). In this study, the additional costs incurred from the installation of thermal storages is not considered.

The *activation of flexibility* gives the model operational freedom in accordance with these points. Without this activation, it is assumed that EVs are charged as soon as they are plugged in, and heat pumps follow the heating demand profiles.

Further, two additional types of flexibility that are *only used in Subsection 3.4* are defined. These are referred to as *constrained* since they limit the operational freedom the model is given. They aim to reflect approaches suppliers have chosen to implement flexibility over recent years. The goal of their inclusion is to determine the share of benefits that are already available through current tariff arrangements.

- **Constrained EV charging** allows automation of charging but only during 4 hours: between 12 am and 4 am. Additionally, the model assumes that each day 12% of consumers opt out of flexible charging and require their vehicle to be charged on the spot.
- **Constrained Heating:** This constraint removes the heat battery and thereby assumes the only shift in heating is available through pre-heating. The temporal extent available to the model is before morning and afternoon peaks, loosely following tariff arrangements explored by suppliers. These typically assume consumers can utilise a cheap electricity window of 2-3 hours (21).

2.7 Evaluation Metrics

The following metrics are used to quantify the effect of flexibility on the system

- **Enabled renewable generation:** This metric estimates the annual volume of renewable generation made available to the system by using flexibility to match times of charging/heating to times of high generation. Note that whenever the metric is used, the overall generation *capacity* remains unchanged.
- **Prevented dispatchable generation capacity:** This metric tracks changes in the firm generation fleet required to balance the system. Depending on the emission targets for a particular year, the displaced capacity consists of biomass, Combined-Cycle Gas Turbines or Gas Turbines with Carbon Capture and Storage. Reductions of peak demand, achieved through flexibility, are expected to be main contributor to changes in this metric.
- **Reduced distribution grid capacity**: Distribution grid capacity has to match peak demand, and therefore is expected to see reductions in its required capacity once demand flexibility can be used to shave winter peaks. Note that the distribution network complexity far exceeds the level of detail captured by national level modelling, as done here, therefore the provided figures should be interpreted as a rough estimate.
- **Total system cost**: The aggregate of these metrics results in the overall yearly system cost, which the model minimises. Due to the inclusion of neighbouring countries in the model, the majority of cost is incurred outside the UK, complicating an estimate of exactly which costs are associated with which region. As such, this metric only shows the *cost difference* between runs where flexibility is not activated versus when it is activated. This is justified by the neighbouring countries' supply and demand remaining unchanged in both cases, such that all changes in cost should be incurred within the UK. Cost figures are given in their 2024 value.
- **Transmission grid capacity**: Transmission capacity built by the model is a marker of geospatial shifts in electricity generation and consumption. In the spatial part of the results, the analysis tracks where the model decides to reinforce or reduce grid capacity. In case of the transmission grid, results are never presented outside a geospatial context, as it is the only metric where a single number always oversimplifies a more nuanced story of reallocation of transmission assets.

3 Results

The results are shown and discussed in the following subsections:

- Subsection 3.1 explores the total system benefits achieved over the course of the energy transition when both flexible EV charging and heating are activated simultaneously (Contribution 2).
- Subsection 3.2 estimates the spatial implications of demand flexibility (Contribution 3).
- In Subsection 3.3, the incremental benefits of EV and heating flexibility are assessed (Contribution 4).
- Subsection 3.4 examines the role played by the temporal extent of flexibility (Contribution 5).

3.1 Whole-system benefits of simultaneous domestic transport and heating flexibility

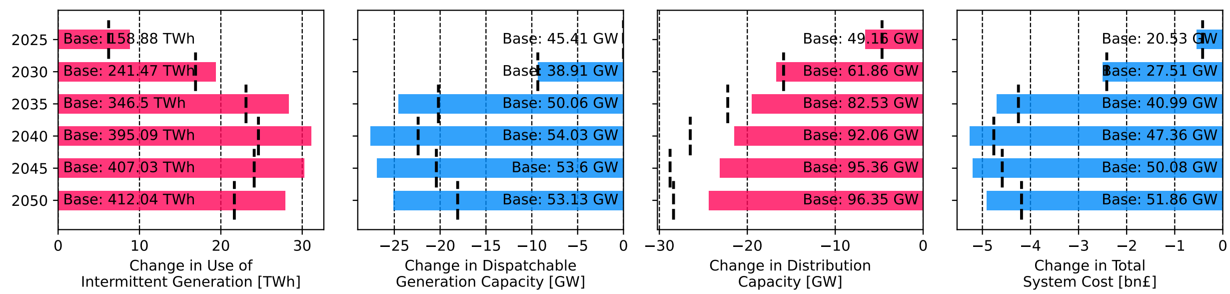

Figure 4: Total system changes in different years assuming FES scenario *Leading the Way*.

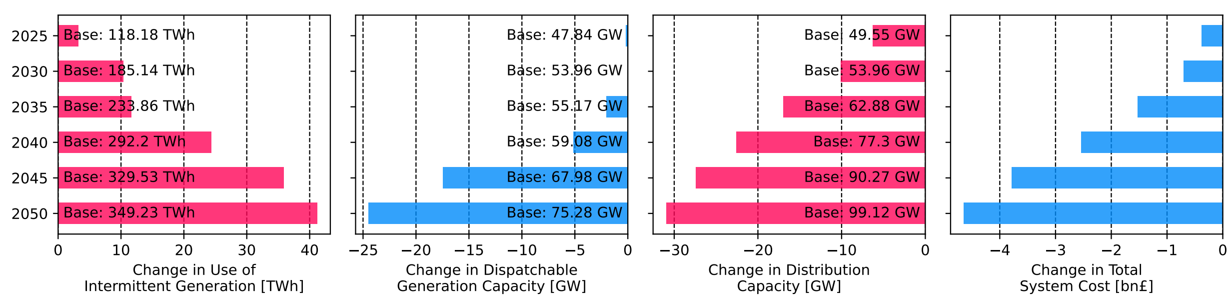

Figure 5: Total system changes in different years assuming FES scenario *Falling Short*.

This section compares power system performance for different years with both types of domestic flexibility either switched on or off under the two FES scenarios (*Leading the Way* and *Falling Short*). The results are based on a 100% rollout of smart EVs with charging times aligned with renewable generation and smart heat pumps coupled with 12-hour thermal storages. However, given the higher cost of thermal storage to support heating electrification, a more modest rollout of 25% is also explored in the flexible heating case.

Fig 4 shows the results for the *Leading the Way* scenario. Horizontal bars show the changes between the baseline scenario (without flexibility) and with simultaneous domestic transport and heating flexibility. The *Base* shows the respective quantity with all domestic demand flexibility switched off. To quantify induced changes the first four metrics lined out above in Subsection 2.7 are used; the transmission grid capacity metric will be used in Section 3.2. For total system cost, the *Base* case is not shown due to the difficulty of identifying all costs that relate to Great Britain in a multi-country model. The benefits achieved when only 25% of heating demand has access to a thermal storage is indicated by the vertical dashed line.

All four metrics reach their peak around 2035, then plateau or decrease in subsequent years. Distribution capacity is an exception, with benefits continuing to increase after 2035. The variable generation made usable (*left* in Fig 4) averages above 25 TWh from 2035 onwards which amounts to 5-10% of total renewable generation. The other metrics - dispatchable generation capacity, distribution grid capacity and total system cost reduction show a similar trend. The first two metrics show a 25GW and 20GW reduction in accumulated capacity, respectively, which in total lead to a £5bn reduction in system costs.

The changes when considering the *Falling Short* scenario are illustrated in Fig 5. Here, benefits appear to occur on a similar magnitude but continue to rise towards 2050, and only then reach the volume seen in *Leading the Way*. In terms of relative magnitude, changes are, however, overall smaller since *Falling Short* starts from a system with more dispatchable generation and less renewable generation. In 2030 and 2035 benefits are much smaller than in the optimistic transition scenario, showing only 10 TWh in enabled renewable generation and negligible changes in dispatchable generation capacity.

The flattening of benefits in *Leading the Way* post-2035 is notable, as electricity demand and renewable generation capacity both continue to rise. We reason that this is due to the increased availability of energy storage at the transmission level in this scenario, such as Compressed-air storage or Carnot batteries. Towards 2050, these systems will likely provide significant flexibility, diminishing the relative utility of demand flexibility. In particular, the changes in dispatchable generation capacity are substantial, amounting to a reduction in capacity of approximately 50%. This is supported by the continued reduction in distribution capacity which does not benefit from transmission level storage. This suggests that domestic flexibility could replace some of the transmission level storage; this should be investigated in a future study. Meanwhile, the changes observed in Falling Short are exactly as expected and reflect the more linear rollout towards 2050 of variable generators and flexible infrastructure, while largely lacking transmission-level batteries from *Leading the Way*.

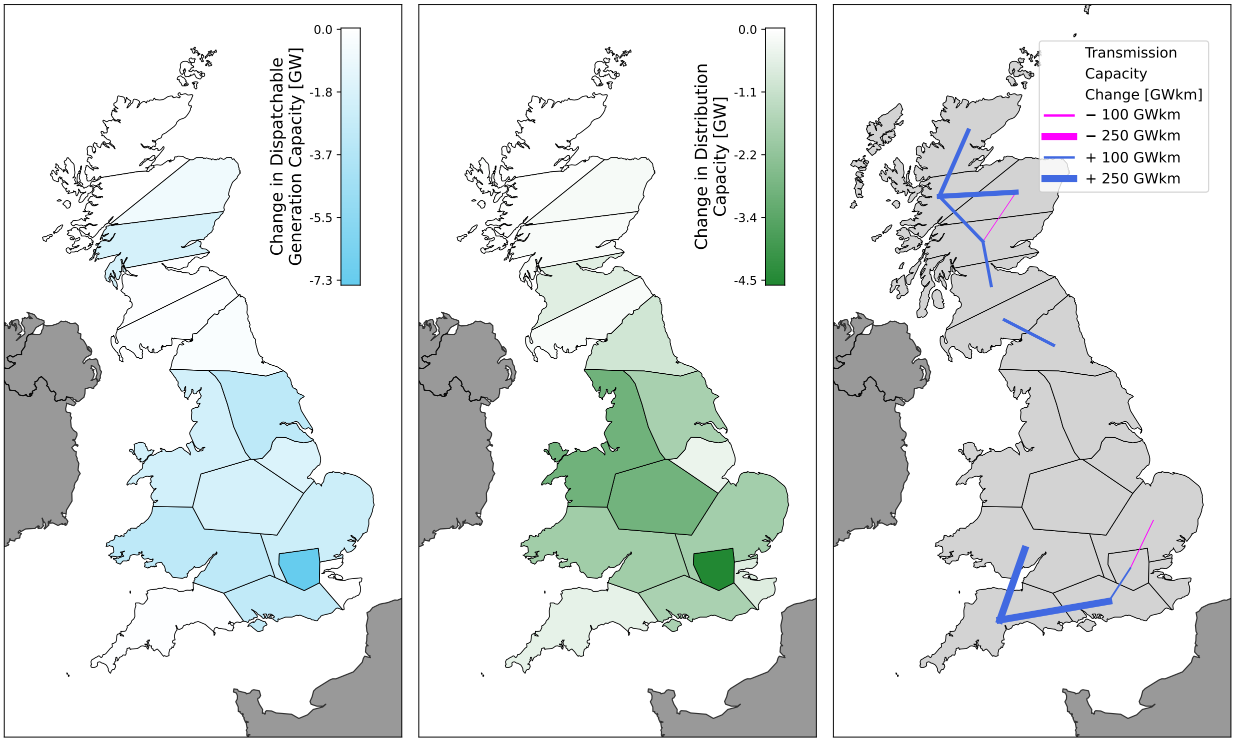

Figure 6: Zonal whole-system changes when comparing a system with domestic flexibilities off versus on in *Leading the Way* in 2040. *(left)* Reductions in firm generation required per zone, including gas turbines, biomass and gas/biomass generation with CCS. *(centre)* Reductions in installed distribution network capacity. *(right)* Changes in transmission network capacity expressed as the product of line capacity in Gigawatts and line length in km. Note that the blue lines represent capacity being *added* when flexibility is activated. Magenta lines refer to *removed* lines.

3.2 Spatial effects of simultaneous domestic transport and heating flexibility

This section expands on the results of Subsection 3.1, and discusses how these changes are spatially distributed in Great Britain in case of *Leading the Way* 2040. The modelling again evaluates changes induced by activating both transport and heating flexibility versus both being switched off.

Fig 6 shows changes in dispatchable generation (*left*), distribution network (*centre*) capacities and the transmission network (*right*). We find dispatchable generation and the distribution network see a spatially smooth reduction in capacity, typically achieving reductions of 4-7 GW and 2-4.5 GW, respectively. However, in both cases, the peak reductions are achieved in and around the London area. Transmission capacity sees a net increase, rather than reduction, with localised expansion accumulating to an approximate total of 1000 GWkm. These changes are concentrated first in Scotland, increasing connectivity within the northernmost regions and the Central Belt. Another small expansion is visible close by in northern England. The other large expansion connects Cornwall to southern central England and Wales. Both of these trends are largely consistent for other modelled years.

The changes in the spatial distribution of renewable generation capacity for the scenario *Leading the Way* in 2040 are shown in Fig 7. The results show that most regions see negligible change, with only four regions having significant capacity removed and only two regions having capacity added.

Both of these are in southern England in direct proximity to London. There is a significant net reduction of capacity from both Scotland and northern and south-western England. Again, similar changes can be seen for the other modelled years.

There is a noticeable similarity in how dispatchable generation and distribution capacities are affected (*left* and *centre* Fig 6). Both seem to reflect the underlying distribution of demand and hence closely approximate a distribution mix. This aligns with reductions in firm capacity not being located directly in centres of demand, and instead in the directly neighbouring nodes. Moreover, the largest reduction of distribution network capacity of 4.5 GW can be seen in the node representing the Greater London area, where demand is highest.

While flexibility should aid the integration of renewables, another crucial component is the expansion of the transmission grid. In order to increase capacity as systems electrify, the building of physical grid infrastructure is often presented in competition with flexibility to maximise the use of existing assets.

We find a more nuanced picture spatially: as shown in Fig 6, the flexible system builds larger transmission capacities within certain regions where this is the more cost-effective way to optimise renewable integration. In line with this trend, proximity between generation and demand sites are prioritised over maximising capacity factors, as suggested by the net removal of variable generation capacity from Scotland and the net addition in southern England. As such, the model creates *local hubs* that are highly connected through transmission and rely less on electricity generated in Scotland.

As such, the modelling suggests that domestic demand flexibility could maximise its utility when complemented by targeted, regional transmission network expansion. Spatial results in linear optimisation models, like the ones discussed here, should be understood in the context of near-optimality, a phenomenon where to achieve marginal gains in the objective function, a model chooses vastly different solution configurations (36). These trends are consistent across modelled years which reduces the likelihood of this being the result of numerical fluctuation.

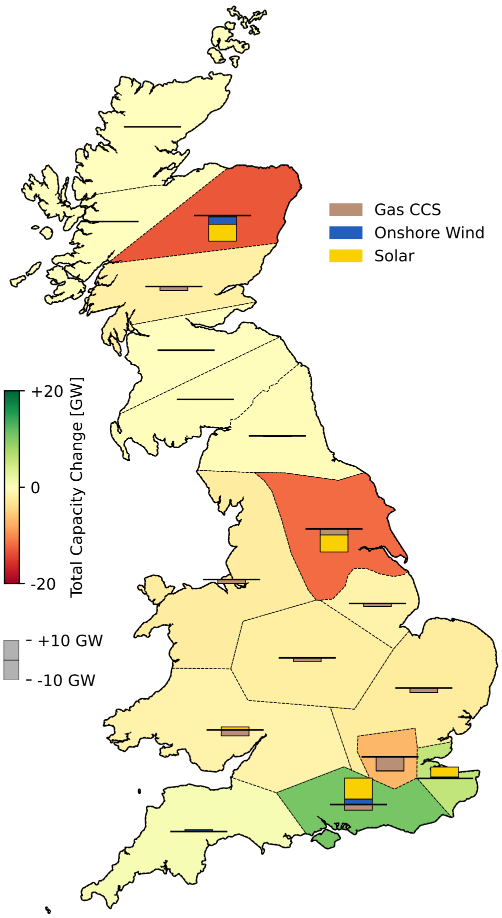

Figure 7: Changes induced by flexibility on the cost-optimal spatial distribution of variable and dispatchable generation capacity. Showing *Leading the Way* 2040.

3.3 Cross-sectoral interactions during gradual rollout of domestic transport and heating flexibility

Intuitively, the first unit of flexibility added to a system has a different utility than the last, indicating a potential for flexibility saturation. This concept is straightforward in a single sector, but its manifestation across two demand sectors, such as smart EV charging and heating, is less obvious. For instance, smart charging helps to flatten the profile of EV electricity demand and, therefore, alleviates grids and capacity markets. In this framing, these benefits should not interfere with the benefits achieved by the flexibility provided in the heating sector. However, what is neglected here is the potential for flexibility to absorb renewable generation that might otherwise be curtailed. It is this context in which bespoke saturation can occur as excess renewable generation is finite. This cross-sectoral competition for a limited resource changes the economic equation of domestic demand flexibility, and it is this dynamic that this section aims to highlight and quantify.

To evaluate this, Fig 8 shows the benefits achieved by incrementally added units of flexibility in the heating and transport sectors. The percentage refers to the share of demand that has access to fully flexible charging in the transport case and heat battery-supported flexibility in the heating case. The lower left of each plot represents all flexibility being switched off.

As before, demand remains unchanged, irrespective of the activation of flexibility. All four metrics - enabled renewable generation, reduced dispatchable generation, and distribution network capacity and total cost reduction - largely show the same trend. The gradient of benefits is largest (i.e. the contour lines are closest together) when the system has access to little flexibility (lower left corners), and reduces as more flexibility activated (upper right corner). In particular, the gradient for total system costs reduces by a large margin after approximately 25% of EVs become flexible.

There is an asymmetry between transport and heating, where the heating case shows an almost linear relationship between the benefits achieved and flexible heating rollout up to the lower right corners. Meanwhile, half of the benefits achievable through EV flexibility appear to be unlocked by the first 25% of rollout, reducing total system cost by £2bn and enabling around 12 TWh of variable generation. The remaining 75% of flexibility adds benefits of a similar volume. Finally, there is a noticeable difference in the geometric pattern shown by the four metrics. For distribution networks, the greatest reduction in capacity requirements is found for low heat flexibility and high transport flexibility. As heating flexibility is added, the system chooses to build more distribution capacity, not less, adding approximately 3 GW of capacity. It is more cost-optimal *overall* to add more capacity to enable the use of more renewable generation - system cost reductions, therefore, remain highest under high heat and transport flexibility. Note that this is consistent with the observations made for partial flexible heating rollout in Fig 4.

The incremental benefits of flexibility differ during different levels of rollout *within a single sector*. The first units of flexible EV charging tap into uncontested renewable generation, unlocking large benefits with a relatively modest flexibility rollout. However, beyond the 25% mark, excess renewable generation becomes more scarce slowing down further gains. The similar patterns between the contours in Fig 8 **a**, **b** and **d** indicate these cost reductions to be driven mainly by additional inclusion of renewable generation and a reduction on costly dispatchable generation capacity.

There is a strong interaction *between the two sectors of flexibility*, causing even more pronounced saturation when flexible heating is added. Tapping into the same pool of otherwise curtailed energy, the renewable generation enabled through flexible heating differs by around 9TWh depending on the activation of EV flexibility. Moreover, the remaining enabled generation (moving from the top left corner to the top right corner) is conditioned on the system's access to additional distribution network capacity. It appears the financial value of the enabled renewable generation pays for the expansion of distribution capacity; however, it weighs on the overall economic benefits indicated by total system value reduction. Here, the value added by heat flexibility is reduced by more than a factor of two depending on the activation of flexible EV charging. In contrast, the value added by EV flexibility is reduced by only 50% on the activation of heat flexibility.

The results indicate that even a low rollout of EV flexibility of around 25% achieves outsized benefits. While consumers who invest in flexible heating will be rewarded with cheap electricity, particularly during early rollout. Policy should make these benefits more accessible to end users. In terms of heating, the expected benefits should be seen in the context of the rollout of EV flexibility. Not shown here is the expansion of the transmission grid, which, beyond distribution network reinforcement, is used by the model to maximise renewable integration. It remains unclear if without such network expansion, saturation could be even more severe. Further work could answer this.

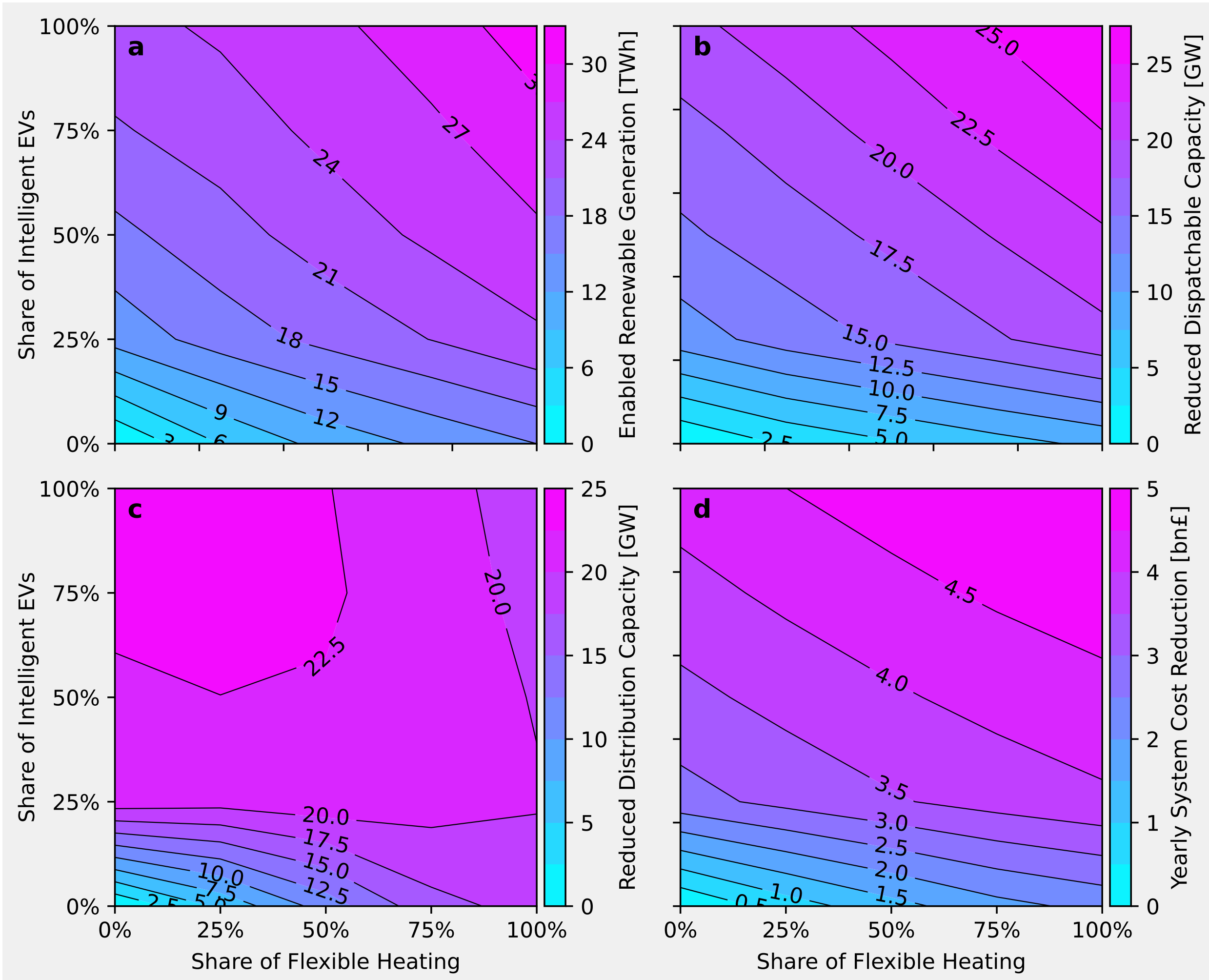

Figure 8: Benefits achieved during the simultaneous rollout of flexibility in heating and transport in *Leading the Way 2040.* Implications on **a** enabled renewable generation, **b** reduction in dispatchable generation and **c** distribution network capacity, and **d** reduction of total system cost.

3.4 Reducing the temporal extent of domestic flexibility

Both in transport and heating, flexibility options explored by utilities include tariffs that offer cheaper electricity during typically 2-4 hour windows. This section compares how, in both transport and heating, the reduction of the temporal extent of flexibility affects the benefits achieved for the system, expressed as increases in variable generation the system is able to use, dispatchable generation capacity, distribution grid capacity and total yearly system cost reductions. For the two domestic sectors, two *constrained* flexibilities are simulated, limiting EV charging optimisation to a time window of 4 hours and removing heat batteries for heating, allowing only heat pump pre-heating.

In the transport case, Fig 9 shows that in all cases the temporally *constrained* flexibility (*constrained* flexibility in the transport sector refers to automated charging during night time, see Subsection 2.6) achieves at least half of the total achievable benefits. This is the case both given heating flexibility switched off (*left bars*) and on (*right bars*). Short time windows of flexibility mainly reduce peak loads, evident in reductions of distribution grid capacity and dispatchable generation capacity (Fig 9, *right*). In terms of the progression from 2025 to 2050, a trend similar to results from Subsection 3.1, can be seen, with benefits increasing between 2025 and 2035, and then flattening out. Interestingly, removing the temporal constraints from smart charging only marginally changes distribution and dispatch capacity, removing only approximately a further 2-3 GW of capacity in both cases (*upper right and lower left*). Meanwhile, the benefit of unlocking renewable generation becomes much larger as flexibility is enhanced, adding another $\sim$7 TWh of renewable generation (*upper left*). Observations for distribution capacity fully depend on the activation of flexible heating, echoing the results from Subsection 3.3 and Fig 8.

In the case of heating, shown in Fig 10, strong deviations from this behaviour can be observed. It appears that temporally *constrained* pre-heating achieves only a small minority of the benefit, with only around 1TWh of renewable generation made available and around 1GW of dispatchable generation capacity prevented. The same trend holds for the other two metrics. However, the share of benefits achieved by pre-heating is larger for distribution capacity than for enabled renewable generation. The transport sector is also highly dependent on the backdrop in terms of flexibility, with benefits reduced substantially if smart heating is activated. However, this is not true in the case of dispatchable generation capacity, where the change induced by transport sector flexibility is small relative to the overall capacity reduction.

Pre-heating, in particular when compared to the benefits achieved by *constrained* flexibility in the transport sector, has relatively small benefits, with most impact being observed in reducing distribution and dispatchable generation capacity needs. We explain this through the limited temporal flexibility and thermal losses of buildings: pre-heating can only be applied in the hours before the actual demand and increases the total demand due to the increased losses which lowers the utility of temporal shifts. The addition of heat batteries substantially reduces these losses. Moreover, pre-heating allows access to generation during times of medium demand, but not the demand troughs during night time. It is the highly renewable mix of generation that is available during the night to *constrained* flexible EV charging, unlike *constrained* heating flex which operates with a backdrop of reasonably high demand.

We conclude that thermal losses prevent pre-heating to attain benefits that are comparable to the ones achieved by EVs charging flexibly over night. The vastly different outcomes of *constrained* flexibility in heating versus transport emphasise that the temporal extension through heat batteries is crucial to unlocking benefits for power system planning.

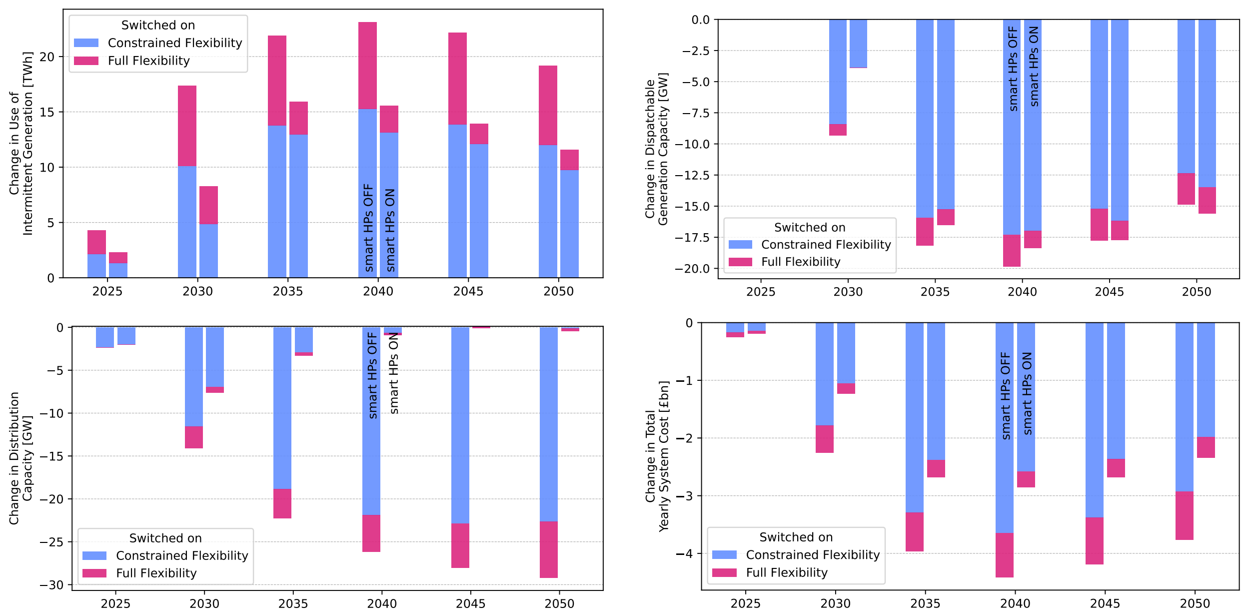

Figure 9: *(top left)* Unlocked renewable generation, *(bottom left)* changes in total distribution network capacity, *(top right)* reduction in dispatchable generation capacity and *(bottom right)* reduction in total costs when smart charging is added to the system, as flexible charging is first switched on during a short time window. *Constrained* smart charging refers to a tariff under which the utility can freely choose when it is optimal to charge during a 4-hour time window during the night. The left bars refer to the impact of smart charging switched on in a system where all other sources of domestic demand flexibility are switched off. All other flexibility is switched on in the right bars.

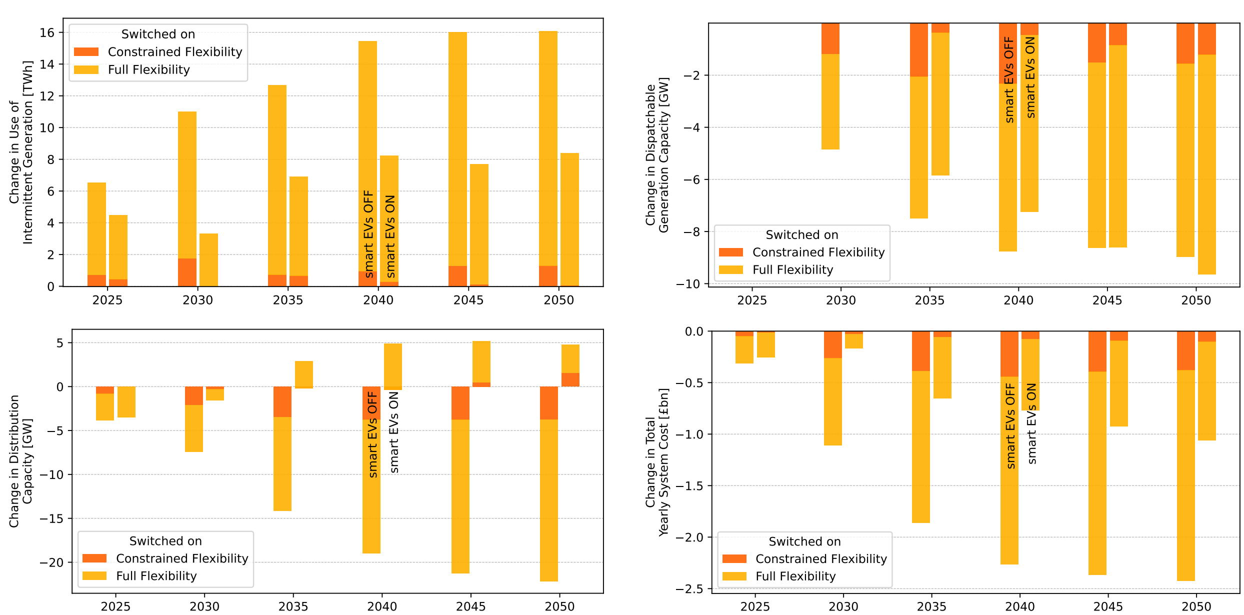

Figure 10: The same metrics as in Fig 9 for the case when heat demand is considered flexible. *Constrained* flexibility here refers to the option to pre-heat homes by two hours before morning and afternoon peaks. This temporal extent is expanded by 12-hour thermal storages in the fully flexible case.

3.5 Limitations

The scope of this work is limited to flexibility in the residential sector, and is based on observations made of today's consumer behaviour. Future changes in consumer behaviour and how they could affect the utilisation of flexible assets are not included in the model.

Further, it has the following limitations on system modelling and market design:

First, a set of common assumptions for large-scale energy system modelling were implemented. The model includes countries directly interconnected to the UK to simulate opportunities for electricity trading with mainland Europe. This moves the majority of load and generation in the model outside the UK and thereby exacerbates a problem known as *near-optimality* (36), where linear models can hide the fact that vastly different system configurations could lead to almost identical system performance. When the cost function weight of a system part becomes small relative to the overall system cost, the issue is compounded. The analysis is most vulnerable in the distribution of generation and transmission capacity expansion, as regional effects are numerically more arbitrary. Nevertheless, observing similar findings across modelled years reinforces the confidence in the findings, especially regarding the spatial distribution of renewable assets and transmission reinforcement. The model achieves computational feasibility by omitting physical details. This is most problematic in the distribution grid, which is well-known to pose substantial problems for numerical approaches and is modelled in PyPSA-FES as a simple bottleneck between transmission level and demand. In this context, the presented findings with regards to distribution grid capacity should only be interpreted as coarse approximations.

Second, the model implicitly makes assumptions about the market design and policy framework that potentially favour flexible assets, without accurately reflecting future market conditions. It has been noted that the national pricing framework in the UK complicates the effective utilisation of demand flexibility (37). This is because accurate, early price signals are crucial to planning for flexible assets' operation in accordance with consumer needs. Instead, the current market design sends price signals based on overly optimistic estimations of available renewable generation, requiring adjustments once transmission constraints are factored in. It is unclear what share of benefits are only accessible within a locational marginal pricing framework. The model implicitly assumes such a framework in addition to perfect foresight, removing two layers of complexity that operators realistically face. However, Teng et al. (5) has shown that the potential for flexible assets persists even under uncertainty, and the ongoing Review of Electricity Market Arrangements (REMA) consultation (38) suggests the potential for a shift to a market design more favourable to domestic demand flexibility.

4 Conclusion

This research quantifies the implications of simultaneous domestic demand flexibility associated with EVs and electric heating in the Great British power system under different scenarios. The method is based on the high spatiotemporal resolution PyPSA-FES model, a novel linear optimisation model designed to simulate any year of National Grid ESO's Future Energy Scenarios: *Leading the Way* (optimistic) and *Falling Short* (pessimistic). The analysis includes five metrics that aim to capture the implications of demand flexibility for the system: enabled renewable generation, prevented dispatchable generation capacity, reduced distribution grid capacity, total system cost, and transmission grid capacity.

When electric vehicle flexibility is activated, the model matches times of charging with low electricity prices, while respecting constraints on the minimal state of charge imposed by consumers. For heating flexibility, the model couples demand with thermal storage that allows about 12 hours of temporal shifting (12 hours without electricity consumption) and then applies the same method as in the electric vehicle case to optimise heating demand profiles. The experiments also explore *constrained* flexibilities, limiting EV charging optimisation to a time window of 4 hours and removing 12-hour thermal storages, allowing only pre-heating. Based on the results, the following conclusions are drawn.

Overall, the benefits from domestic demand flexibility in heating and transport reduce system costs by around £5 billion annually from 2035, broadly aligning with literature results for the *Leading the Way* scenario. These cost reductions are achieved by enabling approximately 30 TWh of additional renewable generation and reducing required dispatchable generation and distribution capacities by about 20 GW each. These benefits are delayed by around 10 years under the pessimistic *Falling Short* scenario.

Spatially, flexibility leads to a net increase in transmission grid expansion. Contrary to the inverse relationship sometimes presented between building grid infrastructure and maximising assets with flexibility, the findings here suggest a synergy in certain regions as the model maximises flexibility utilisation via grid expansion. This transmission is especially focused on sub-regions of the UK, in particular Scotland and southern England, rather than between them (e.g. from north to south of the country).

The whole-system benefits per flexibility added depend on the current rollout and differ between transport and heating. For heating, the model shows a nearly linear dependency: rollout of the last 25% of flexible heating offers comparable gains to the initial 25%. In contrast, the first 25% of flexible electric vehicle charging achieves half of the maximal achievable benefits, indicating a certain saturation in terms of the system's demand for flexibility.

Flexibility in heating and transport substantially affect each other. In particular, the activation of flexible electric vehicle charging greatly reduces the benefits achieved by thermal storage-supported flexible heating. For the latter, in *Leading the Way* 2040, the model shows an approximately £2bn system cost reduction through flexible heating alone. However, when electric vehicle flexibility is activated, this value reduces to less than £1bn.

Comparing these ideal flexibility scenarios with *constrained* scenarios (time window of 4 hours for transport and removing thermal storages for heat pumps - only pre-heating), it was found that while transport benefits are only reduced by 10-40%, heating benefits are reduced by 90% across all metrics.

The results presented provide novel insights into the utility of domestic demand flexibility but should be read in the context of the locational marginal pricing framework assumed in the model. It is generally presumed that the current national pricing regime limits the efficient operation of flexible assets. As such, the presented results are a motivation to update the UK electricity market to a locational framework to maximise the leverage that could be provided through the flexible assets that will be added to the system. Further work could evaluate the interaction between market design and achievable benefits in a more detailed fashion.

Cross-sectoral interactions of flexibility also require further research. As noted here, the benefits achieved by flexibility vary with population participation. In the heating case, the costs of thermal storage, which are neglected in this work, indicate the presence of tipping points in electric vehicle and heating flexibility rollout, where benefits no longer offset flexible infrastructure costs. A more granular experimental setup could investigate this.

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Acronyms

BASt Bundesanstalt für Straßenwesen

CCS Carbon-capture and storage

ENTSO-E European Network for Transmission System Operators for Electricity

ERA5 European Centre for Medium-Range Weather Forecasts Reanalysis v5

ESO Electricity System Operator

ESPENI Elexon Sum Plus Embedded Net Imports

ETYS Electricity Ten Year Statement

EV Electric Vehicle

FES Future Energy Scenarios

GB Great Britain

HVDC High-Voltage Direct Current

OFGEM Office of Gas and Electricity Markets

PyPSA Python for Power System Analysis

REMA Review of Electricity Market Arrangements

UK United Kingdom

V2G Vehicle-to-Grid

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