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Research Article

Modelling of integrated local energy systems: Low-carbon energy supply strategies for the Oxford-Cambridge arc region

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ABSTRACT

The energy supply system is undergoing enormous change to deliver against cost, security of supply and decarbonisation objectives. Robust decisions on the provision of infrastructure requires integrated models to perform analytics across the entire energy supply chain.

A national level combined gas and electricity transmission network model was upgraded to represent local energy systems. Multiple energy vectors including electricity, gas, hydrogen and heat were integrated within the modelling framework. The model was utilised for a study of the Oxford-Cambridge arc region.

The study assessed how different energy supply strategies, from electrification of heat to use of 'green' gases or local heat networks, could affordably reduce carbon emissions from the Oxford-Cambridge arc region energy system whilst considering constraints from the national system. The modelling process generated a diverse range of options for energy supplies, the choice of supply networks and end use technologies. The analysis illustrated the cost effectiveness and emission reduction potential of electrification of heat despite the requirement for additional network and supply capacity. Additionally, insulation and other energy efficiency solutions were also analysed. Potential barriers to technological change such as upfront costs, lack of awareness and perceived technology shortcomings were discussed in the context of the strategies assessed.

1. Introduction

Meeting the UK net zero carbon emissions target by 2050 is likely to require an electricity power system that is largely decarbonised and heat related emissions from buildings substantially reduced (CCC, 2019). These are formidable objectives and will require laying the foundations for these emission reductions by the late 2020s.

Local energy systems have been identified as being important to meet the "net-zero" emission target in the UK (UKERC, 2019). National energy system decisions and polices have a direct impact on the options available locally. For instance, inflexible generation at transmission may require flexibility solutions from local integrated energy systems (Bell and Gill, 2018; Mancarella and Chicco, 2013).

Heat is the largest energy-consuming sector in the UK, accounting for 44% of final energy consumption, ahead of transport and electricity generation (BEIS, 2018a). The transition to low carbon heat will have considerable impact on how this energy is supplied both nationally and locally. Estimates from (Imperial College, 2019), show that electrification of heat and transport could require renewable generation capacities of 35 GW onshore wind, 45 GW offshore wind and 54 GW solar PV by 2040s. A large proportion of PV capacity is expected to be connected to local distribution systems.

The electricity system operator (National Grid, 2019a) aims to operate the electricity transmission system carbon free by late 2020s. Electrification of heating via heat pumps by using decarbonised electricity is one way to meet the net zero carbon objective. Other possible low carbon decarbonisation options include bioenergy, utilisation of waste heat from industrial and power plants, waste to energy and use of hydrogen (CCC, 2018a, 2018b; ENA, 2019).

Several studies (Chaudry et al., 2014; Qadrdan et al., 2015; Clegg and Mancarella, 2016) have assessed the operation and planning of future low carbon energy systems. However, whole energy system representation, considering spatially distinct local energy systems and connections to national gas and electricity transmission systems model is extremely challenging (Pfenninger et al., 2014). This is mainly due to the modelling of spatially separated generation units and their connection to transmission networks (in the case of CCGT plants, to both gas and electricity transmission networks) in which energy supply and

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demand can be balanced in large number of combinatorial ways. Additionally, further complexity is introduced by regional modelling of electricity, gas and heat distribution systems, increasing interdependencies between systems (local and national) and the emergence of new energy vectors such as hydrogen (Hawker and Bell, 2019).

Existing interdependencies between electricity, natural gas and heat supply systems are likely to increase with the growing use of hydrogen and bioenergy. Several reports (CCC, 2019; National Grid 2019b; UKERC, 2019) argue that these interdependencies could help deliver a secure, affordable and sustainable future energy system.

An integrated energy system model described in this paper is used to provide evidence of the impacts on, costs, operational viability and the environment, of different low carbon options to decarbonise a regional energy system in the context of UK national targets and operational constraints.

2. Multi scale modelling of integrated energy supply systems

There are numerous approaches to simulate and analyse energy systems. Energy system models include generic tools such as MARKAL – (Fishbone and Abilock, 1981) and TIMES (Loulou et al., 2016) to country specific models such as for the UK; DSIM - (Strbac et al., 2012) and CGEN – (Chaudry et al., 2014), and Australia; (Lenzen et al., 2016). Differences between these models are observed in several areas such the objective of the model (planning/operation), sectors modelled (electricity/gas/heat/transport), spatial granularity (network based/input-output), temporal granularity (yearly/seasonally, hourly) and mathematical approach (simulation/optimisation). For example (Chaudry et al., 2014), models both electricity and natural gas networks and their operational interdependencies where as DSIM (Strbac et al., 2012), (Lenzen et al., 2016) and (Li et al., 2020) includes detailed modelling of the electricity system. Furthermore (Lund et al., 2019), and (Loulou et al., 2016) provides analysis of different sectors (electricity, heat, transport), but lack the spatial detail of energy system models as presented in (Chaudry et al., 2014) and (Lenzen et al., 2016).

The technique of using carefully selected “time slices” to represent energy demand is not new in energy policy studies. The UK TIMES model (Daly and Fais, 2014) uses 16 time slices (a typical day for each season is split into daytime, evening peak, late evening and night) to represent annual energy demand and has been used extensively for UK energy decarbonisation policy by both BEIS (Department for Business Energy and Industrial Strategy) and CCC (Climate Change Committee). A recent publication by (Broad et al., 2020) uses this model to analyse decarbonisation of the UK residential sector. The time slice method is discrete rather than modelling continuous number of hours in a day or week. Other examples of similar models that uses the discrete “time slices” technique include ESME (Heaton and Bunn, 2014) and UK-MARKAL (Loulou et al., 2004). The DynEMO model (Barrett and Spataru, 2011) represents a single peak day for each season using hourly time granularity. This adds a level of continuity in time that is especially useful when analysing the use of storage to maximise the energy harnessed by renewables. A representative day may not be sufficient to capture the variations in supply and demand, therefore in our approach we extend to a “representative week”, which comprises full characterisation of actual peaks and includes weekend-weekday variations.

The integrated energy supply system model described in this paper is based on the Combined Gas and Electricity Network (CGEN) model (Chaudry et al, 2008, 2014). This model was significantly upgraded to include characterisation of the energy supply system at both transmission and distribution scales. The integrated energy supply system model performs operational analysis over multi-time periods considering electricity, natural gas, hydrogen and heat supply systems and their interactions (Jayasuriya et al., 2019).

At the transmission scale, natural gas and electricity networks were modelled. A GIS spatial representation of the two transmission networks, assets such as generation plants, gas terminals, storage facilities and definition of energy hub regions (Carbon Brief, 2016; National Grid, 2018a, 2018b) were used during the spatial modelling process. The electricity system operation is represented using a DC load flow model and natural gas systems operation by a detailed gas flow model (Chaudry et al., 2008).

These two transmission networks interact through gas fired power generators. Energy resource supplies, generation technologies and networks are explicitly modelled. Detailed modelling methods are used to represent seasonal gas storage operation, variable generation of renewables and operation of interconnectors. Energy supply at the transmission level meets demands from large industrial consumers and energy flows into distribution systems.

Within energy distribution systems, electricity, natural gas, hydrogen and heat distribution systems are modelled. To form the integrated framework of various energy carriers via energy conversion technologies an ‘energy-hub’ (Geidl, 2007) concept is adopted. The energy hubs are connected with the gas and electricity transmission networks through grid supply points. A GIS representation of the energy hub boundaries and transmission networks were used for this process. Energy hubs utilise regionally distributed energy resources, storage (batteries, hydrogen, and gas) and transmission grid supplies to meet predominantly residential and commercial energy demands. Constraints from each technology and network energy flow capacities were modelled.

A stylised representation of key electricity and gas transmission system components modelled, and a simple illustration of an energy hub are shown in Fig. 1.

Electrical Vehicle (EV) charging demand was modelled within energy hubs. In addition, utilisation of EV batteries for electricity supply and demand balancing, Vehicle-to-Grid (V2G) services were modelled. The modelling of EV demand and charging took into account the differences between weekday and weekends (See Appendix A.3.). These differences were illustrated by (Li et al., 2020). This was further expanded in (Li et al., 2020; Li and Lenzen, 2020) who demonstrated that the impact of wind and solar resource variability and unmanaged EV demand during peak hours exacerbated concerns in balancing the energy system.

Biomethane and hydrogen injection into the gas distribution system was modelled. Injection of hydrogen was kept within pre-defined limits (20% by volume). The impact on carbon emissions by using the gas mixture to produce electricity and heat was modelled by considering the volume of biomethane and hydrogen injected at a given time.

Demand Side Management (DSM) capabilities were modelled within the energy hubs. DSM allows the ability to shift electricity demands (non-heating including demand for EV charging), from peak to off peak hours, such that the total operating costs are minimised (potential reduction of generation and transmission/distribution costs). DSM is implemented by considering user defined inputs, these include, peak hours (t_{p1}, t_{p2}, t_{p3}), off-peak hours ($t_{op1}, t_{op2}, t_{op3}, t_{op4}, t_{op5}$), and maximum potential demand shift (k %) from the electricity demand at a given peak. Additionally, the energy shifted from peak hours must balance the energy assigned to off-peak hours. An illustrative example of DSM operation is shown in Fig. 2.

Given the inputs, demand shifting was modelled using two decisions variables. These are the demand to be shifted from a peak hour (δE_t^{shift}), and the demand to be assigned to an off-peak hour (δE_t^{assign}). These variables were determined such that the total cost of operating the energy hub to meet the adjusted electricity demand was minimised.

The demand to be shifted from a peak hour is constrained by Equation (1). Here, E_t is the electrical energy demand during peak hour t.

i.e. for $t = \{t_{p1}, t_{p2}, t_{p3}\}$,

$$\delta E_t^{shift} \leq \frac{k}{100} \times E_t \tag{1}$$

The shifted demand (δE_t^{shift}) and the assigned demand (δE_t^{assign})

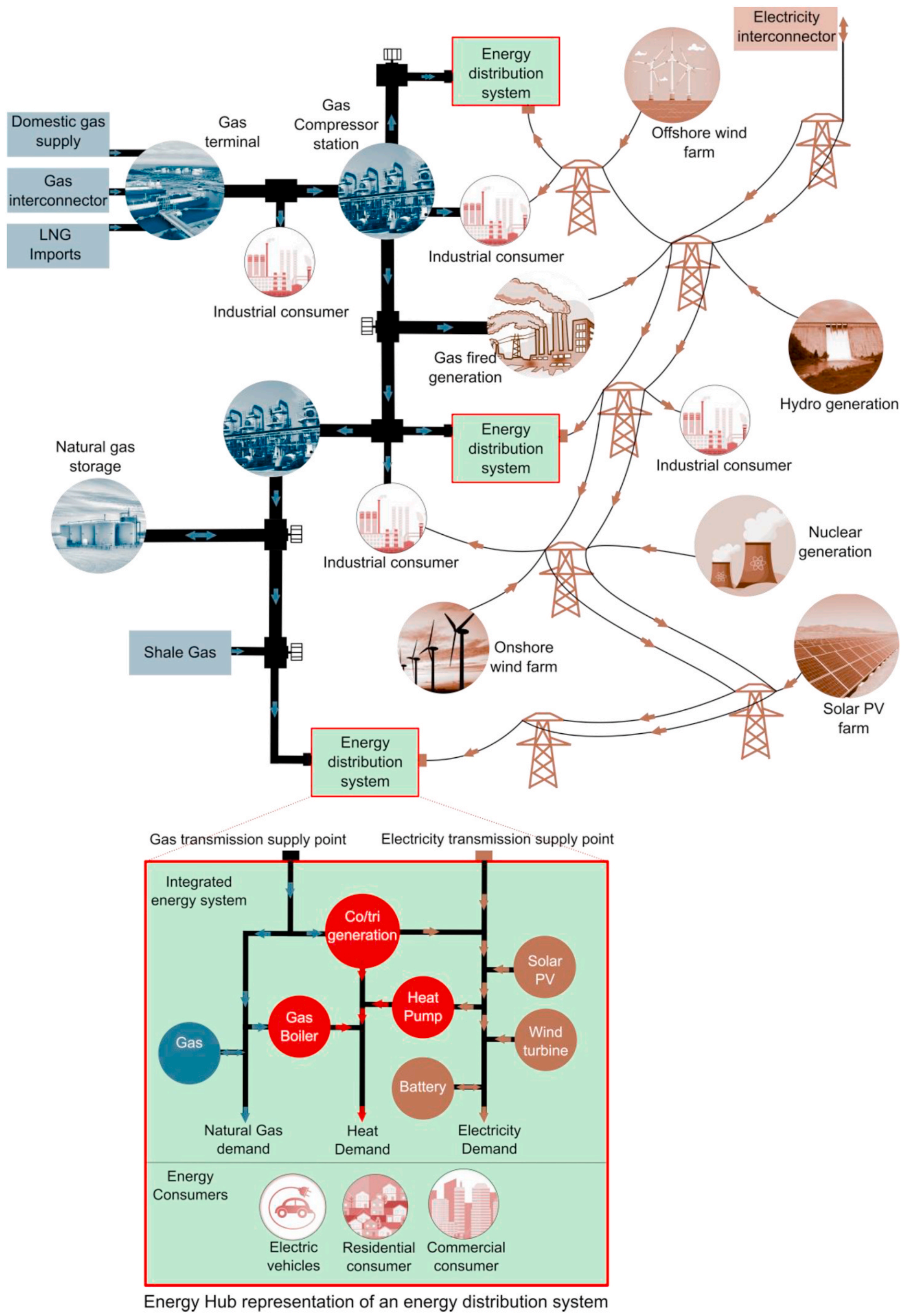


Fig. 1. Stylised representation of electricity and gas transmission systems (top) and an Energy Hub representation of a local energy system (bottom).

satisfies Equation (2),

$$\sum_{t}^{\{t_{p1},t_{p2},t_{p3}\}} \delta E_t^{shift} = \sum_{t}^{\{t_{op1},\ t_{op2},\ t_{op3},t_{op4},t_{op5}\}} \delta E_t^{assign} \tag{2}$$

The adjusted electricity demand is calculated by Equation (3) for peak hours. i.e. For $t = \{t_{p1}, t_{p2}, t_{p3}\}$,

$$E_t^{adjusted} = E_t - \delta E_t^{shift} \tag{3}$$

The adjusted electricity demand for off-peak hours is calculated by Equation (4). i.e. For $t = \{t_{op1},\ t_{op2},\ t_{op3}, t_{op4}, t_{op5}\}$,

$$E_t^{adjusted} = E_t + \delta E_t^{assign} \tag{4}$$

The adjusted electricity demand $E_t^{adjusted}$ is used for energy hub electricity supply and demand balancing.

The integrated energy supply system model minimises total operational costs (Equation (5)) to meet energy demands. The operational costs at each time step t, are derived from the natural gas ($C_t^{Gas\ Tran}$) and electricity ($C_t^{Elec\ Tran}$) transmission networks, energy hubs $\left(C_t^{EnergyHub_k}\right)$, carbon costs ($C_t^{Carbon}$) and unserved energy ($C_t^{unserved\_energy}$) over the time horizon. The time step t, is user defined and in this study represents an hour.

The cost minimisation is subjected to constraints derived from the operational characteristics of assets in both national and energy hub systems while ensuring the balance between energy supply and demand.

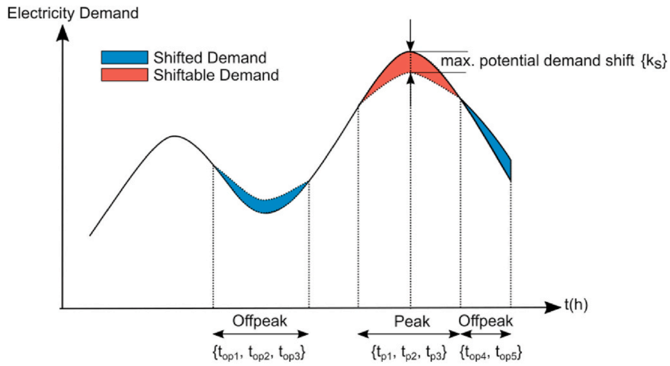


Fig. 2. Illustration of Demand Side Management (DSM) operation.

$$Objective = min\sum_t \left\{ C_t^{Elec\,Tran} + C_t^{Gas\,Tran} + \sum_{k=1}^{N} C_t^{EnergyHub_k} + C_t^{Carbon} + C_t^{unserved.energy} \right\} \tag{5}$$

Where $C_t^{Elec\ Tran}$ (Equation (6)) includes, power generation costs C_j^{gen} such as fuel costs, operational and maintenance costs of power generator j (excluding interconnectors) for generating power $P_{j,t}$; costs of importing power $P_{i,t}^{imp}$ for a unit price C_i^{imp} and the revenues from exporting power $P_{i,t}^{exp}$ for a unit price C_i^{exp} via interconnector link i.

$$C_t^{Elec\ Tran} = \sum_j C_j^{gen} P_{j,t} + \sum_i \left(C_i^{imp} P_{i,t}^{imp} - C_i^{exp} P_{i,t}^{exp} \right) \tag{6}$$

$C_t^{Gas\ Tran}$ (Equation (7)) includes, the cost of gas supply from terminal a at time t calculated by the volume of gas supplied $Q_{a,t}^{sup}$ and gas price $C_{a,t}^{gas}$; the cost of operating a gas storage facility u calculated by the gas volume injected $Q_{u,t}^{I}$ or withdrawn $Q_{u,t}^{W}$ at time t and the cost of gas injection C_u^I or withdrawal C_u^W.

$$C_t^{Gas\ Tran} = \sum_a C_{a,t}^{gas} Q_{a,t}^{sup} + \sum_u \left\{ C_u^W Q_{u,t}^W + C_u^I Q_{u,t}^I \right\} \tag{7}$$

The energy hub (k) costs $\left(C_t^{EnergyHub_k}\right)$ of operating integrated electricity, natural gas, heat and hydrogen distribution systems (Equation (8)), includes operating costs of distributed technologies including fixed and variable costs $\left(C_i^{f\&v}\right)$ of operating technology (i) with respect to energy outputs $\left(E_{i,\ output,\ t}\right)$, and fuel ($j$) costs for biomass $\left(C_{bio}^{fuel}\right)$ and solid waste $\left(C_w^{fuel}\right)$.

$$C_t^{EnergyHub_k} = \left\{ \sum_i^{\{Tech\}} E_{i,\ output,\ t} \times C_i^{f\&v} \right\} + \left\{ \sum_j^{\{bio,\ w\}} E_{j,t} \times C_j^{fuel} \right\} \tag{8}$$

The carbon costs C_t^{Carbon} were applied across electricity generation, heat supply, hydrogen production and non-heating end-uses of fuels (natural gas, oil, solid fuel). Within both national and local energy systems, penalty costs were applied for unserved energy $C_t^{unserved\_energy}$ demand.

As electricity system integration of renewables increases, capturing the variability of the wind and solar resource is crucial for ensuring sufficient back-up and flexibility capacity and services are procured to meet potential 'resource gaps'.

Oswald (Oswald et al., 2008) illustrated the possible impact of large capacity of wind generation on the GB system and the substantial power swings that may occur over a few hours which could result in resource gaps and require frequent cycling of gas fired plants and therefore reduce their reliability. Furthermore, Miskelly (2012) analysed historical wind generation data at 5 min intervals across large geographical dispersed wind farms in Australia which illustrated multiple periods when wind output across the entire grid fell to zero therefore placing enormous strain on grid operations. Typically, modellers have mainly focused on the variability of the wind resource, Trainer (2013) highlighted the potential 'intermittency' from solar power.

Renewables are modelled using weather parameters such as wind speed and solar irradiance through region specific historic data from the Met Office and forward projections from "Weather@Home" (Guillod et al., 2018). Using these inputs, the power output from wind and PV plants were calculated within the model. Therefore, spatial variability of wind speed and solar irradiance was accounted for across the GB transmission network and energy hubs.

The forward projections of wind speed and solar irradiance are available in a daily time granularity for future years across numerous climate change scenarios. The historic hourly weather data from the Met Office is normalised and combined with daily future weather data to create hourly weather patterns which are assigned to each electricity bus bar and energy hub region. Whilst it is preferable to model the full year in hourly time slices (8760 hours), to keep model simulation time reasonable a solution that respects the absolute low and high wind speeds and solar irradiance conditions over several hours and days across seasons was used (based on a normalised historical year). This also allowed extreme cases such as low-wind speeds at peak, and high wind speeds at off-peak hours to inform performance of the energy system to meet demands whilst highlighting 'resources gap' issues. We examined the performance of the energy system given various levels of back-up generation capacity, DSM, storage facilities and V2G services to meet the potential resource gap instigated by variability of wind and solar irradiance.

The modelling approach offers a rich level of disaggregated temporal and spatial representation of energy supply systems. This allows detailed analysis of future energy supply systems under various strategies such as integration of large capacity of renewables, expansion of community and distributed generation, benefits of storage (e.g. V2G), greater consumer participation and the challenge of decarbonising heat and mobility.

Key outputs from the model include the energy supply mix, emissions and cost of operation at various scales (transmission, distribution etc.). Additionally, the model is also able to offer insights into the impacts of user defined infrastructure expansion options.

3. Modelling of the Oxford-Cambridge arc region

The Oxford-Cambridge arc region, shown in Fig. 3, includes four county councils (Buckinghamshire, Cambridgeshire, Northamptonshire and Oxfordshire), 26 district councils and unitary authorities, and the combined authorities of Cambridgeshire and Peterborough.

The region is home to 3.7million people, around 2 million jobs and contributes over £110 billion of annual Gross Value Added (GVA) to the UK economy per year (NIC, 2017). The region has been designated as a key economic priority by the UK Government. Future growth envisages an addition of one million new homes across the region by 2050, the provision of an expressway road, and major improvements to rail routes connecting Oxford, Milton Keynes and Cambridge (Ministry of Housing Communities and Local Government, 2019).

3.1. Oxford-Cambridge arc region growth scenarios

The analyses are based around four contrasting growth scenarios for new dwellings within the region, together with the development of the road and rail networks between Oxford and Cambridge. An outline of the growth scenarios adopted for the analysis is provided in Table 1 (ITRC, 2020):

For the Expansion and New settlements scenarios, the 23K and 30K variants project greater levels of additional dwellings per annum to meet future population growth.

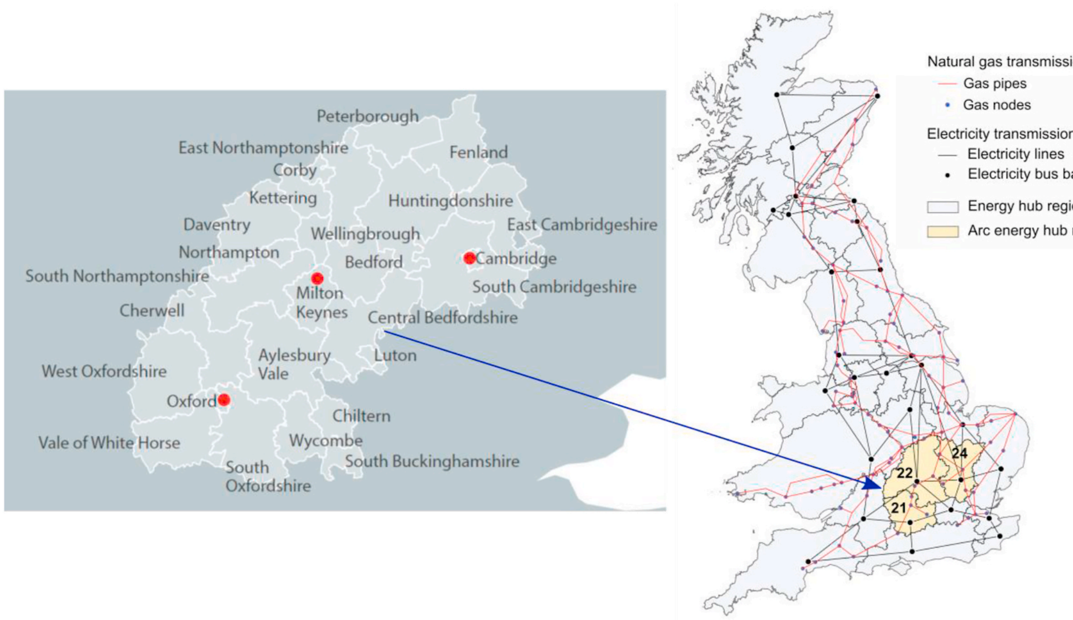


Fig. 3. (left) Outline of the Oxford - Cambridge arc region, and (right) the arc represented by the energy hub regions.

3.2. Energy supply system strategies

The arc scenarios describe the development of the region in terms of population growth, construction of additional dwellings and expansion of transport links. The energy strategies describe the deployment of specific supply side technology capacities (power and heat generation, networks and end use technologies) to meet demand for energy services within the region across each scenario.

Given the uncertainties of decarbonising the energy sector, particularly in relation to heating, the energy strategies were defined as, **1) Electric**, where heating is electrified and zero-carbon electricity is utilised, **2) Heat networks** strategy that utilises combined heat and power units connected to district heating networks, **3) Green gas** strategy that utilises hydrogen and biomethane and **4) Unconstrained** strategy. A summary of the energy supply strategies for the arc scenarios out to year 2050 are shown in Table 2.

The technology uptake across these energy strategies, considered key elements such as maturity, annual build rates, annual and peak heat demand and capacity margin factors (CCC, 2019; National Grid, 2019b; Chaudry et al., 2015; ETI, 2013).

3.3. Energy system modelling and simulation

3.3.1. Spatial modelling

The spatial representation of the GB electricity and natural gas transmission networks, and energy hub geographic regions are shown in Fig. 3. In total, there are 29 energy hub regions that represent GB. These were defined in the model based on Local Authority Districts (LAD) and electricity transmission boundaries (See Appendix A.1.). Each energy hub provides an aggregated view of electricity, gas, heat and hydrogen distribution systems within its regional boundary. Three of these energy hubs (out of 29) are used to characterise energy systems within the arc region (shaded areas in Fig. 3), Western-Oxford, Central-Milton Keynes and Eastern-Cambridge.

The arc region connects to the gas (blue dots) and electricity (black dots) transmission supply points that are within its boundary. The arc region is connected to other surrounding areas through (energy flows) transmission supply points. This assumption reduced modelling complexity and simulation time to solution whilst allowing representation of the whole energy system.

3.3.2. Energy system supply capacity and demand

The data flows for establishing energy supply capacities and demand for the transmission system and the Oxford-Cambridge arc region scenarios across energy strategies are shown in Fig. 4.

The energy supply capacity for the GB electricity and gas transmission system and energy hubs (i.e. excluding the three energy hubs that represent the Oxford-Cambridge region) were adopted from the National Grid 'Two Degrees' scenario (National Grid, 2019b) and sized to ensure that energy demands across all scenarios could be met. Generation connected at the transmission level was updated with the inclusion of BECCS (Bio-Energy with Carbon Capture and Storage) capacity in order to balance emissions from local systems and ensure 'net zero' emissions nationally (See Appendix B.1. -Table B1 for electricity transmission system and non-arc region energy hub capacities).

The Oxford-Cambridge region growth scenarios have different assumptions for population, GVA and dwelling floor areas (NIC, 2017). These high-level assumptions were used in an energy demand simulation (Eggimann et al., 2019) and transport model (Lovrić et al., 2017) that provided heat, non-heating and transport electricity demands for GB out to year 2050 (see Appendix A.2.).

For the Oxford-Cambridge arc region (three energy hubs) energy supply capacity data was calculated for each scenario according to the energy supply strategy selected. Each energy supply strategy contains a mix of technology capacities to meet heat and non-heating demands within the region and takes account of capacity margins (Royal Academy of Engineering, 2013) - (See Appendix B.1. -Tables B2-3 for arc region heat and electricity capacities across energy strategies).

3.3.3. Simulation

Each simulation across arc scenarios and strategies performs operational analysis of the entire GB energy system (transmission and all energy hubs) for a simulation year (2015, 2030, 2050) which consists of four seasons. Each season was modelled by a representative week using hourly time granularity. The representative week respects energy requirements alongside the absolute hourly peaks and troughs in energy demand during a particular season. Although full year (8760) hourly simulation is desirable (and the model gives the user this choice if required), these assumptions allow for much reduced model time to solution, address supply and demand balancing during peak periods and the investigation of potential variability of renewable generation

Table 1
An outline of the scenarios adopted for the analysis.

Arc Scenarios		Scenario description: Additional dwellings per annum	Total Population by 2050 (million)	Total dwelling floor area by 2050 (km^2)	Gross Value Added (GVA) per annum by 2050 (£ Billion)	Spatial development of housing	Development in Transport links
Baseline		14,500	4.3	157.6	139	No new settlements are developed.	No new major transport links are developed.
Unplanned		19,000	4.6	170.1	176.6	Ad-hoc development within the region with market driven responses to housing needs.	Both the Express Way and the East West rail link are developed.
Expansion	**23K**	23,000	4.9	178.5	226.8	Expansion of existing urban developments centred around Oxford, Milton Keynes and Cambridge.	
	30K	30,000	5.3	196.1			
New Settlement	**23k**	23,000	5.6	184.2	226.9	A string of 5 smaller cities along the main transport corridor of the arc.	
	30K	30,000	6.1	202.6			

'resource gap' events (See Appendix A.2.).

The analysis focusses on the three energy hubs which represent the energy system within the Oxford-Cambridge arc region. The impact on key metrics such as electricity and heat supplied, emissions and costs were analysed across scenarios and strategies. Additionally, sensitivity studies were performed to assess the impact of variations in peak heat demand, implementation of demand side management, and dwelling efficiency improvements.

4. Modelling results

The modelling outputs focus on energy hubs that represent the arc region for year 2050.

4.1. Energy supply mix

The energy supply mix across different energy strategies and scenarios are shown in Fig. 5. The stacked bar chart shows the energy supply composition for the Baseline scenario. The total energy supplies for the other arc scenarios are indicated by dashed lines. Additionally, the energy supplied for 2015 is shown for comparison. The energy supply mix consists of electricity, natural gas, biomass, oil, solid fuel and waste fuels, these are either imported into or originate within the region. Several of these energy supplies are converted and stored within the region to meet demands for heating and non-heating end-uses (including electricity generation and hydrogen production).

In almost all arc scenarios and strategies overall energy supplies in 2050 are lower than in 2015. The Expansion 30K and New Settlements 30K scenarios show the highest energy supplies in line with projected population growth by 2050. There is a difference of approximately 10 TWh between the Expansion (highest) and Baseline (lowest) scenarios for total energy supplies across the energy strategies. The energy supply mix composition for all scenarios are similar to the Baseline scenario (see Table C1 in Appendix C).

Most of the gas supply (~80%) in 2015 was used for heating through gas boilers. The choice of energy strategy greatly influences the annual energy supply mix in 2050. The heat supply within each energy strategy essentially replaces gas for heating with alternatives such as electricity, hydrogen, biomass and solid waste.

In Electric and Unconstrained energy strategies, a large amount of electricity is used for heating via heat pumps. Due to greater heat pump efficiencies and better insulated homes, the electricity supply required for heating is reduced. This results in approximately ~30 TWh less annual energy supplies by 2050 compared to 2015, despite an increase in population and number of dwellings. In contrast, less efficient production of heat from hydrogen, biomass and solid waste in the Green Gas and Heat Networks energy strategies results in annual energy supplies being higher than the Electric strategy.

On a per dwelling basis total energy supplies in 2050 across all scenarios and energy strategies are lower than in 2015 as shown in Fig. 6. The results indicate, on average, dwellings consuming less energy due to efficiency improvements in homes and heating technologies in 2050 compared with 2015.

4.1.1. Heat supplies

The energy supply strategies illustrated a multitude of technology options to supply heat in 2050. The end use heat supplied by technology for 2015 and the Expansion 30K scenario across energy strategies in 2050 are shown in Fig. 7(a). For the same scenario, the total input energy supplied by fuel is shown in Fig. 7(b). A similar heat supply mix is seen across the other scenarios.

In the Electric energy strategy across scenarios, heat pumps (mainly air source heat pumps) are deployed throughout the region and account for 75% (including hybrid heat pumps) of total end use heating demand by 2050. The highest deployment rates are found in the 30K growth variants of the scenarios. The rest of the heating demand is met by

Table 2
Summary of energy supply system strategies (2050).

Energy supply sector	Energy supply system strategies			
	1). Electric	2). Heat networks	3). Green gas	4). Unconstrained
Heat	• Heat is supplied completely by electricity using heat pumps, resistive heating and electric boilers.	• Heat supply is mainly from Combined Heat and Power (CHP) driven district heating networks. These utilise natural gas, biomass and solid waste as fuels. • The availability of biomass and solid waste for heating is restricted within the region. • Gas boilers are used in the district heating systems to supplement CHP units during peak periods. • Homes not connected to district heating systems continue to use gas boilers or use heat pumps.	• Heat supplies are mainly from building level gas and hydrogen boilers. • Homes without hydrogen supplies use gas boilers, heat pumps or are connected to a district heating network (via biomass/biomethane CHP units). • Gas boilers produce low-carbon heat as biomethane and hydrogen are injected into the gas mix.	• The optimisation was free to select **any heat technology** modelled to meet demand at **lowest operational costs** whilst adhering to physical constraints. • The availability of biomass and solid waste for heating is restricted within the region.
Electricity	• Distributed generation capacity consists mostly of wind, solar photovoltaic (PV) and CHP units. • EV batteries are available to supply electricity during peak periods (V2G). • Backup gas fired generators are installed to compensate the variability in wind and PV generation. • CHP units in district heating applications supply electricity as they produce heat (heat demand driven CHP operation is assumed).			
Gas	• Transmission grid supplies are available with limited gas storage facilities within the arc region.		• Injection of hydrogen (maximum 20% by volume) and biomethane into the gas grid is made available. • Large scale hydrogen production via Steam Methane Reforming (SMR) with Carbon Capture and Storage (CCS) is assumed. Small-scale hydrogen production is through electrolysis. • Hydrogen is supplied through new hydrogen pipelines and re-purposed gas distribution pipes. • Anaerobic digestion plants are used to produce biomethane.	• Transmission grid supplies are available with limited gas storage facilities within the arc region.

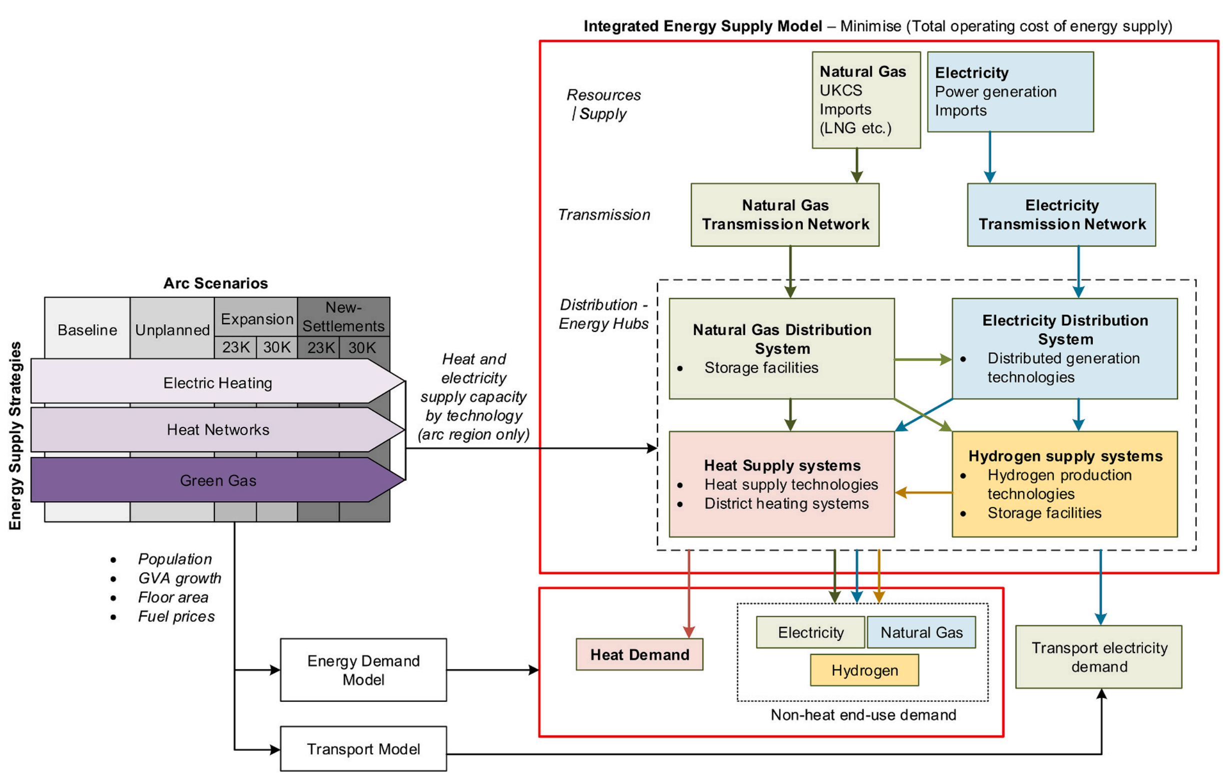


Fig. 4. Outline of energy system data flows for the arc analyses.

resistive heating and electric boilers (mostly used for hot water). Within this strategy all dwellings are expected to be equipped with heat pumps and/or resistive heating towards 2050.

The Heat Networks energy strategy across scenarios illustrates the utilisation of CHP units connected to district heating systems. The CHP units use biomass, natural gas and municipal waste under high overall

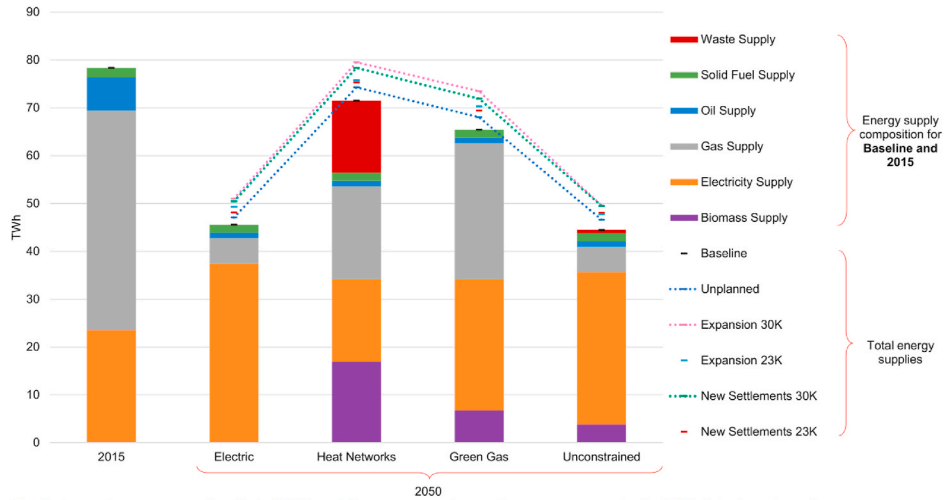


Fig. 5. Annual energy supply mix in 2015 and for arc scenarios and energy strategies in 2050.

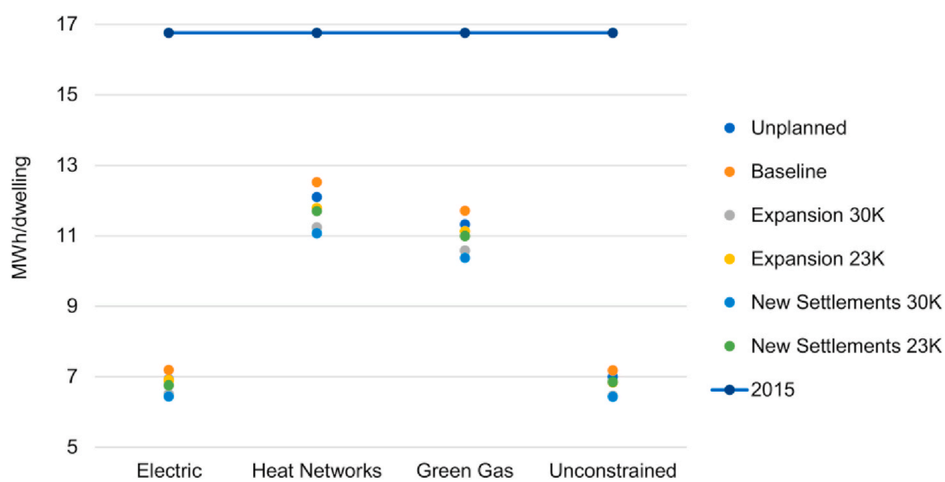


Fig. 6. Total energy supply per dwelling across scenarios and strategies in 2050.

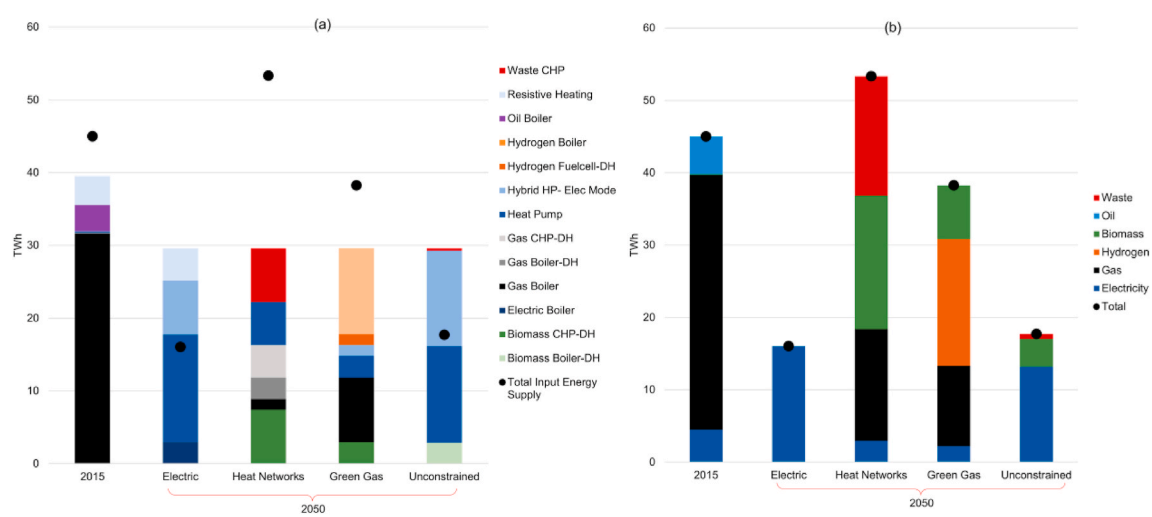


Fig. 7. (a) Annual end use heat supplied by technology and (b) Annual input energy supplied by fuel for heating technologies across the energy strategies in 2050 for the Expansion 30K scenario and 2015.

efficiencies. In this strategy, biomass and municipal waste are supplied regionally. The CHP units are supplemented by gas boilers. On average, by 2050 across the scenarios, district heating networks supply ~70% of the total heating demand within the region. The remainder of heating demand from dwellings that are not connected to the heat network are supplied by a combination of gas boilers and heat pumps.

Partial decarbonisation of the gas grid takes place with the injection of hydrogen and biomethane within the Green Gas energy strategy. Therefore, across scenarios the use of building level gas boilers continues to meet 30% of the heating demand by 2050. As hydrogen production continues to grow with new infrastructure support, building level hydrogen boilers are deployed across the region to replace gas boilers. In Green Gas energy strategy, a combination of building level technologies – hydrogen boilers, heat pumps systems and gas boilers supply 85% of the annual heat demand. The availability of biomass and large-scale hydrogen production has encouraged the use of district heat connected technologies such as biomass CHP units and fuel cells for the remaining 15% of heat supply.

In the Unconstrained strategy, full availability of different heating technologies is provided to the model. The technologies are chosen by minimising operational costs including fuel and carbon costs. As electricity production becomes predominately low carbon (both nationally and regionally), the use of electric heating technologies is favoured. In 2050, heat pumps and hybrid heat pumps account for almost 90% of end use heating demand. The remaining 10% of the heating demand is met by biomass and waste to energy heating systems due to lower carbon emissions and therefore operational costs compared with natural gas fuelled heating technologies.

4.1.2. Electricity generation

Annual electricity generation for heating and non-heating end-uses, hydrogen production and transportation in 2050 is shown in Fig. 8.

Electricity generation in 2050 is greater than in 2015 in all scenarios. The New Settlements 30K and Expansion 30K scenarios show the highest annual electricity generation of ~42 TWh in 2050. Across scenarios, Baseline has the lowest annual electricity generation due to lower population and dwelling growth.

In 2050 compared to 2015, the annual electricity supply has increased by 25% in the Heat Networks strategy and 83% in the Electric strategy (largest increase, mainly due to the use of heat pumps). Electrification of the heating sector varies across energy strategies according to the level of prominence given to other vectors such as natural gas, hydrogen and deployment of district heating systems.

The increase of EVs is projected to be in line with the growth in population across the scenarios. Similar growth patterns are observed across all scenarios, where the New Settlements and Expansion 30K scenarios have the highest requirement for electricity generation (18.5 TWh) as shown in Fig. 9 to meet annual EV charging demand. There is only 1.5 TWh difference between the highest (New Settlements 30K) and lowest (Baseline) requirement for electricity generation to meet annual EV charging demand in 2050.

The annual electricity generation by technology for the Expansion 30K scenario in 2050 is shown in Fig. 10(a). Between scenarios, the types of technologies and their share of overall electricity generation is similar. Variations in distributed generation and electricity supply from the transmission network only become significant across the energy strategies.

Fig. 10(b) shows the use of Vehicle-to-Grid (V2G) electricity supply in the Expansion 30K scenario. In all scenarios and strategies by 2050, V2G services perform a significant role in supplying electricity during peak hours. V2G services accounted for ~18% of the electricity supply during the peak hour and ~10 TWh annually across all scenarios and strategies (See Appendix A.3. for V2G modelling assumptions).

Local wind and PV generators supply electricity at their maximum capacities (as long as the resource is available - wind and sunlight). No curtailment occurs in any of the scenarios regardless of the energy strategy chosen.

The use of CHP units in the Heat Networks energy strategy contributes to the local electricity supply mix up to their maximum capacities. Consequently, there is a significant decline in grid electricity imports from the transmission network into the region. Contribution from biomass CHP and hydrogen Fuel cells[1] are seen in the Green Gas energy strategy.

Electricity from the transmission system remains vital in all scenarios in 2050 by performing a prominent role in balancing electricity supply and demand within the region. As the national electricity system decarbonises (nuclear, offshore wind and PV), the use of local non-renewable generation is not economically viable due to high carbon costs (99 £/tCO_2) in 2050 (BEIS, 2018b), unless used for flexibility purposes.

4.1.3. Natural gas supplies

Annual natural gas supplies by 2050 in all scenarios are lower than that in 2015 (~45 TWh). In Electric and Unconstrained energy strategies in 2050 natural gas supplies decline significantly to 5 TWh/year and are 90% lower than in 2015. As natural gas has no significant role in these electric heating dominant energy strategies, the variation in population and dwellings has little or no impact on the requirement for gas supplies (clustered points in Fig. 11). Whereas in the Heat Networks and Green Gas energy strategies, there is a greater variation in total gas supplies between scenarios (e.g. 3 TWh between Baseline and Expansion 30K in the Green Gas energy strategy).

Annual natural gas supply is highest (~30 TWh) in the Green Gas energy strategy as natural gas is largely used to produce hydrogen in addition to heating through gas boilers. In the Heat Networks strategy, natural gas is only used for heating through gas CHP units and boilers and hence annual natural gas supply declines to 20 TWh.

4.1.4. Hydrogen and biomethane supplies

Hydrogen is produced primarily from Steam Methane Reformation (SMR) with carbon capture and storage (CCS).[2] In addition, hydrogen is produced by electrolysis using the excess renewable electricity from distributed wind and PV plants. The annual hydrogen supply within the region is 18 TWh in the Expansion 30K scenario (highest) and 17 TWh in the Baseline scenario (lowest).

From the hydrogen produced ~8% is injected into the existing gas network (20% by volume). The remaining hydrogen is supplied via repurposed natural gas pipelines and newly built hydrogen pipelines. The hydrogen supply meets the demand for heating in boilers and fuel cells, and high temperature industrial applications.

Biomethane is produced by anaerobic digestion of organic waste within the region. Biomethane injected into the gas network averages 5 TWh across all scenarios for the Green Gas energy strategy.

4.2. Emissions

The emission calculations presented include equivalent carbon emissions emitted locally from heat supply, electricity generation, hydrogen production, and local non-heating uses of fuels (natural gas, biomass, solid waste, oil and solid fuel). The emission values therefore do not include transmission related emissions. Within the region, across all scenarios, the annual emissions decline from 10.96 MtCO_2 (Million

[1] Fuel cells are used in the Green Gas strategy as a heating technology (heat driven). Fuel cells are preferred for their co-generation of electricity and heat which makes it cost effective compared to dedicated hydrogen fuelled power generation.

[2] Large scale hydrogen production by Steam Methane Reforming (SMR) is equipped with CCS to capture ~95% of emissions (CCC, 2019). The role out of national CCS infrastructure is assumed alongside the regional deployment of large scale SMR facilities.

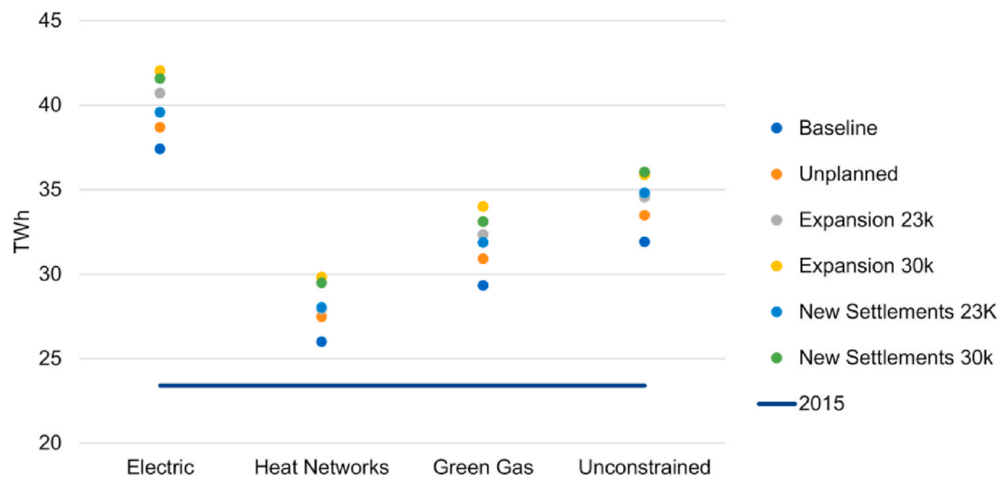


Fig. 8. Annual electricity generation for heat and non-heat end use, hydrogen production and transport in 2050.

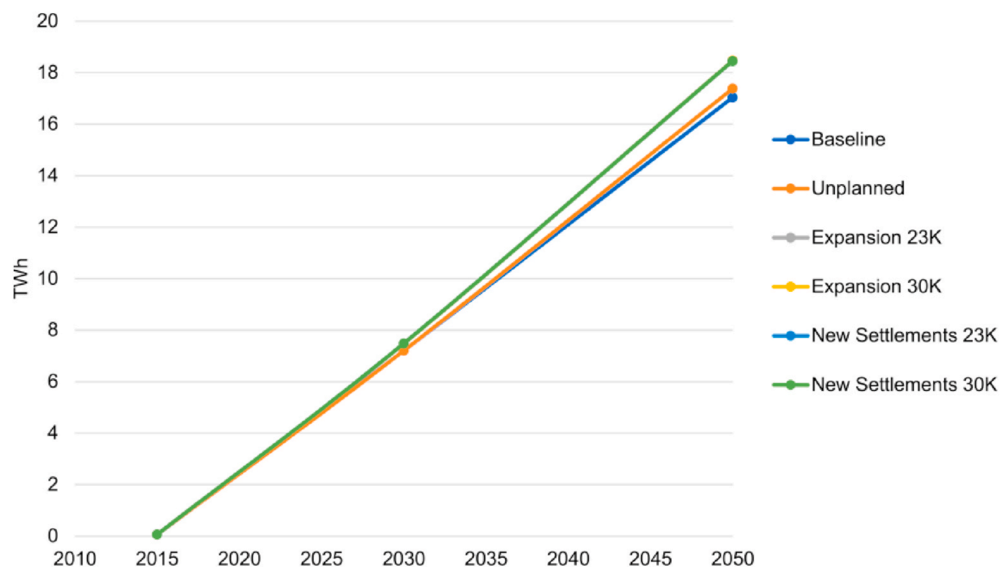


Fig. 9. Annual electricity generation to meet EV charging demand across scenarios.

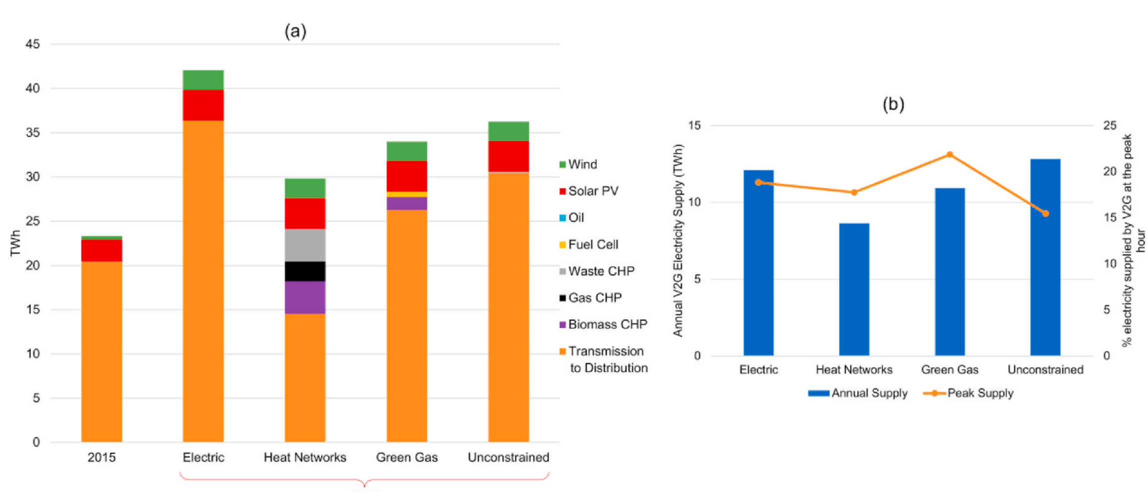


Fig. 10. (a) Annual electricity generation by technology and (b) the use of V2G for the Expansion 30K scenario in 2050 across energy strategies.

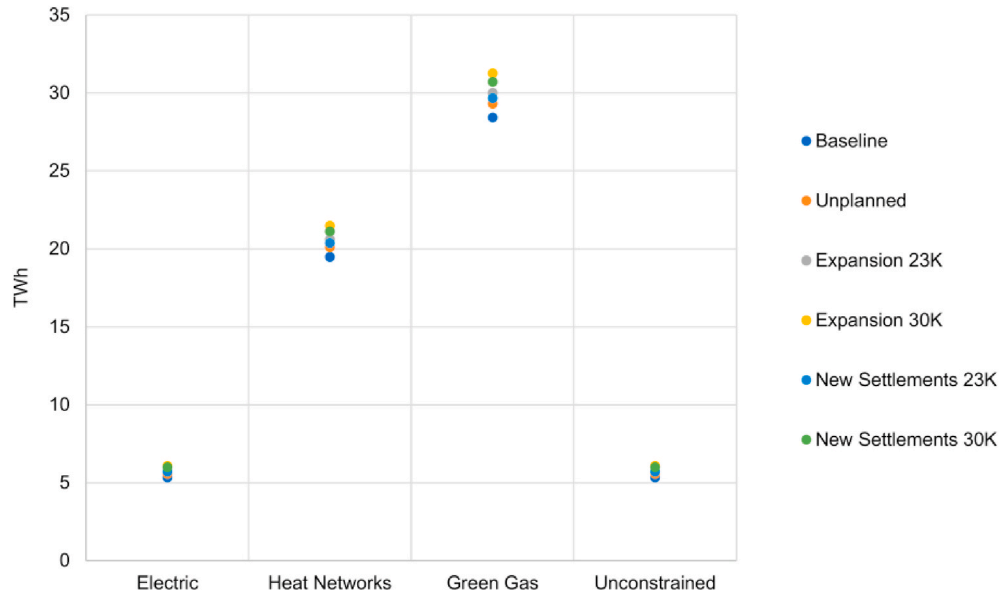


Fig. 11. Annual natural gas supply in 2050 across energy supply strategies.

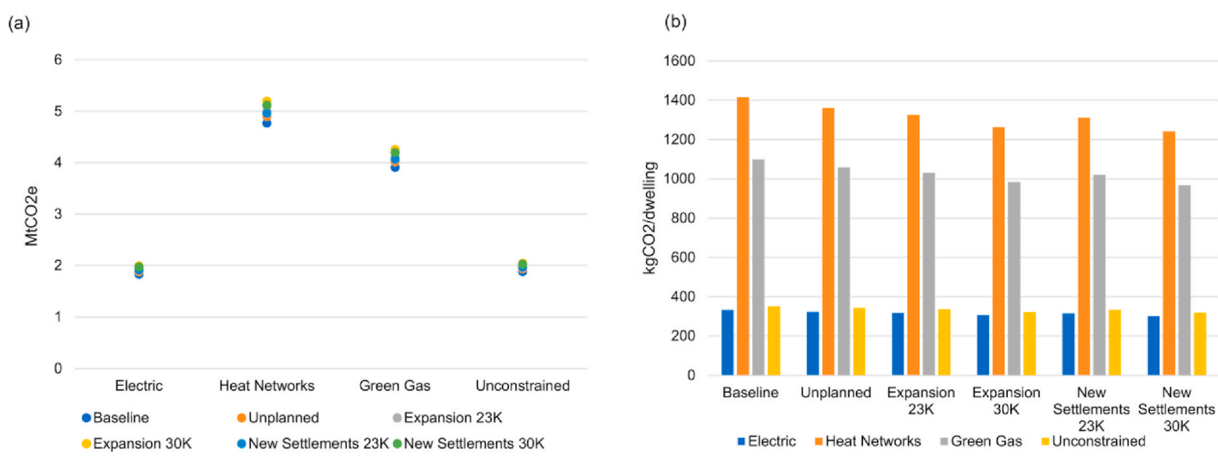


Fig. 12. Emissions calculated for year 2050 across scenarios and energy strategies (a) Annual Emissions – MtCO2 and (b) emissions calculated as $kgCO_2$/dwelling.

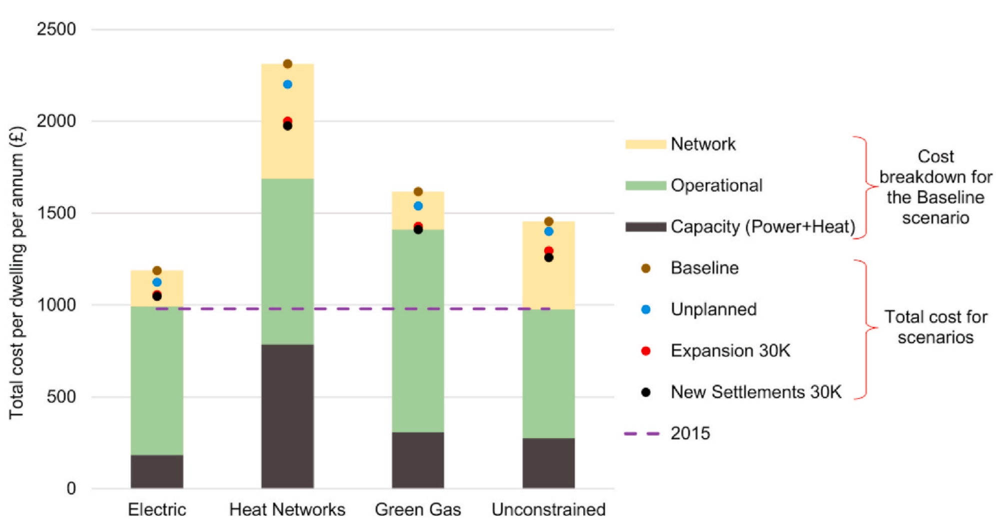


Fig. 13. Annualised cumulative (2015–2050) costs per dwelling.

tonnes of CO_2 equivalent) in 2015 to under 2 $MtCO_2$ for electric heating dominated energy strategies by 2050. In contrast, the Heat Networks energy strategy accounts for the highest emissions with an average of 5$MtCO_2$ and Green Gas strategy averaging 4$MtCO_2$ across the scenarios as shown in Fig. 12(a).

The Expansion 30K scenario shows the highest annual emissions in 2050 especially for the Green Gas and Heat Networks energy strategies. The Baseline scenario annual emissions are the lowest, where the difference between it and the Expansion 30K scenario in the Heat Networks energy strategy is ~420ktCO_2 and in Green Gas is ~344ktCO_2. The emissions produced per dwelling show far more variations than the annual emissions between the scenarios, this is shown in Fig. 14(b). The Expansion scenarios (both 23K and 30K variants) in 2050 produce on average ~1300kgCO_2/year/dwelling emissions for the Heat Network strategy, almost 7% lower compared with the Baseline scenario.

By 2050 in the Electric and Unconstrained energy strategies across all scenarios, emissions from the residential and commercial sectors decrease to nearly zero as electricity accounts for more than 90% of overall energy supplies and is mainly supplied from the transmission network (almost carbon free) and renewables. The remaining emissions are from the non-heating use of fuels in the industrial sector. Further replacement of these non-renewable fuels with biomethane, hydrogen or decarbonised electricity would most likely result in the achievement of 'net-zero' emissions for the region. From a national perspective, any emissions from local systems across scenarios and strategies are mitigated by negative emissions produced by BECCS plants, use of which is lowest in the Electric and Unconstrained strategies.

4.3. Scenario and strategy total costs

The annualised cumulative (2015–2050) total costs of implementing energy supply solutions across energy strategies and selected arc scenarios on a per dwelling basis are shown in Fig. 13. Operational costs were determined by the model (objective function). These include costs for primary and secondary energy resources such as natural gas and generation of electricity (including supplies from the transmission system into the region), technology variable costs and carbon costs. Network costs such as for new power lines, pipes and investment costs in new power and heat generation capacities within the region are included in the calculation of overall costs. Network and generation capacity reinforcements outside the arc region (transmission and other energy hubs) are not considered.

4.3.1. Operational costs

Operational costs are determined by the model and take account of all aspects of energy flows from transmission systems, through a multitude of interconnected distribution systems (multi-vector approach) to meet end use demand. Operationally, the Green Gas energy strategy shows the highest costs. This is mainly due to higher fuel resource costs associated with natural gas and biomass, and costs of producing hydrogen. The model results show that more than 70% of hydrogen is produced by using SMR. All renewables are fully utilised to support the electricity system and there is limited 'free' electricity available, hence limited production from electrolysis systems.

The Heat Networks energy strategy operational costs across scenarios are competitive with Electric and Unconstrained strategies. This is mainly due to the use of highly efficient co-generation units where local electricity generation replaces more expensive transmission grid electricity during peak hours when only higher marginal cost plants are available to balance the system. The capacity of co-generation units under high overall efficiencies allows it to meet both heat and electricity end use demand within the region without heavy reliance on the electricity transmission network.

Operational costs are lowest in the Unconstrained energy strategy across all scenarios. This is to be expected as the model can choose among several technologies to achieve low overall operational costs for power and heat supply.

The Electric energy strategy across all scenarios has among the lowest operational costs, as the system decarbonises mainly through the use of nuclear and near zero marginal cost plants for the production of electricity supplying high efficiency electrical heating systems by 2050.

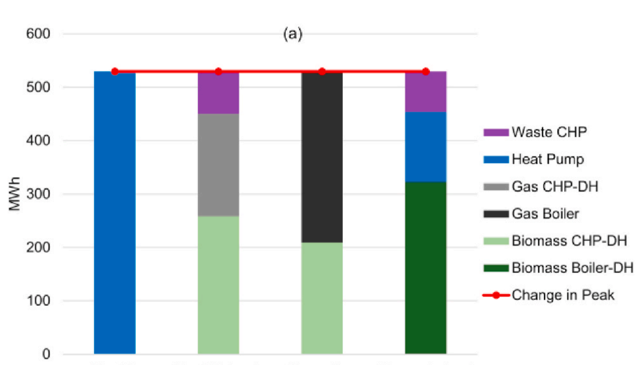
4.3.2. Network and capacity expansion costs

Costs associated with 'power and heat' generation capacity are largest in the Heat Networks energy strategy irrespective of scenario, this is due to the use of expensive CHP (gas, biomass, waste) systems. The Electric energy strategy shows the lowest power and heat capacity costs, mainly due to the continual reductions in heat pump capital costs from 2030s onwards. Lower annual costs per dwelling are shown in the Green Gas strategy compared with Heat Networks where cost effective gas boilers (using a mixture of natural gas, hydrogen and biomethane fuels) and hydrogen boilers are deployed.

Low operational costs do not imply that power and heat capacity costs are also economical. This is observed in the Unconstrained energy strategy across all scenarios which largely consists of the deployment of air source and more expensive hybrid and large heat pumps and costly CHP systems that are mainly utilised during peak demand periods.

Network related costs are almost three times larger in the Heat Networks energy strategy when compared with the Electric and Green Gas strategies across the scenarios. This is primarily due to high costs related to civil engineering works (digging trenches of approximately three times deeper than electricity/gas lines and pipes), pipe deployments and connections (hydraulic interface units) within buildings.

Heat networks are deployed alongside waste CHP units and biomass boilers in the Unconstrained strategy in addition to the reinforcement of the electricity grid incurring high network costs. When capital costs for network, and power and heat capacity (including installation of small and large air source and hybrid heat pumps) additions are included, the



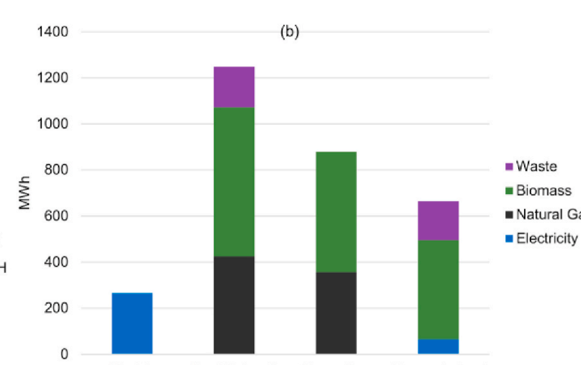


Fig. 14. (a) Change in heat supply by technology to meet increased heat demand, and (b) input energy supply required for end use technologies at the peak hour (7pm) across energy supply strategies over an average winter's day in 2050.

total annualised costs per dwelling to implement the Unconstrained energy strategy rises above the Electric energy strategy.

With decarbonisation of the gas system (Green Gas energy strategy) it was assumed that given the ongoing IMRP (Iron mains replacement programme - replacement of iron pipes with polyethylene ones), sections of the gas distribution system would be repurposed for the use of hydrogen alongside up to 20% (by volume) of hydrogen injection into the remaining gas distribution system. The repurposing of the gas distribution system had the impact of reducing excavation/civil work and therefore overall network costs. For the New Settlements and Expansion scenarios a multiplier was added to the cost of laying new hydrogen pipes as no existing gas pipes would be available for repurposing.

Network costs in the Electric energy strategy are largely due to the reinforcement of the electrical distribution grid. Despite the high deployment costs attached to underground power lines (for densely populated areas) as opposed to over-ground power distribution and transmission lines, overall network costs remain lower than the other energy strategies.

4.3.3. Total costs

In 2015, given a central gas price outlook (BEIS, 2018c), dwelling energy costs within the region were ~£980 per annum. In the Baseline scenario, implementation of the Heat Networks energy strategy has the largest annualised costs per dwelling, approximately £1330 more than in 2015 and at least £700 per annum greater than the next costliest energy strategy, Green Gas. Costs in the Unconstrained strategy are on average second lowest, due to the impact of heat network connected technologies (Biomass/Waste CHP/large heat pumps). The Electric energy strategy across all scenarios has the lowest average annualised costs of £1200 per dwelling.

Across scenarios and strategies, the annualised costs per dwelling are reduced from Baseline values. This is in part due to improved insulation and efficiencies decreasing the demand for energy services per dwelling despite an increase in overall population and homes. Additionally, there are benefits to denser heat demand locations, these can accrue economies of scale especially with regards to heat network infrastructure. The impact of this is illustrated with the '30K' scenario variants in the Heat Networks strategy, where reductions in dwelling costs of up to £300 per annum can been observed.

5. Sensitivities

Sensitivity studies were performed for the Expansion 30K scenario in year 2050 across all energy strategies. The results are presented with respect to the outputs of the Expansion 30K scenario in the main study.

5.1. Impact of an increase in peak demand

A 10% increase in heat and non-heating demands during peak periods (5pm–8pm) was applied. The impact on energy supply at the peak hour (7pm) during an average winter's day in 2050 is explored.

The heat demand across all strategies increases by 530 MWh at the peak hour (7pm). The additional heat output from a mix of technologies to meet this end use heating demand across energy supply strategies is shown in Fig. 14(a).

The increase in input energy supply for end use heat technologies is shown in Fig. 14(b). The Electric strategy shows the lowest requirement for additional input energy supplies. This is due to reduced electricity requirements for use in highly efficient heat pumps. Conversely, the combination of natural gas, biomass and waste used in boilers and CHP units results in a greater requirement for additional input energy supplies in the other strategies. The Heat Networks energy strategy requires the largest additional input energy supplies which more than double its end use heat demand.

The change in peak electricity demand (for heating and non-heating end-uses) and electricity generation across energy strategies is shown in

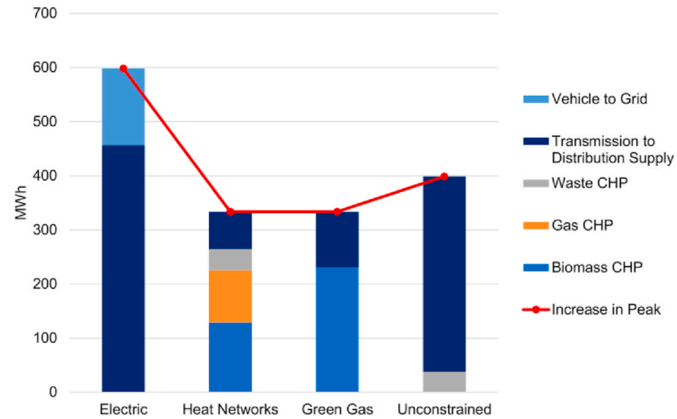


Fig. 15. Change in electricity demand and generation at the peak hour across heating strategies over an average winter's day in 2050.

Fig. 15. The largest increase in peak electricity demand (~600 MWh) occurs in the Electric energy strategy where 260 MWh is for heating via heat pumps and 340 MWh for non-heating end-uses. The Heat Networks and Green Gas strategies have less electricity demand for heating (Fig. 14(b)), therefore electricity generation meets the increase in non-heat electricity demand.

The increase in peak electricity demand in the Electric energy strategy is met by electricity from the transmission system and vehicle to grid (V2G) supplies as local renewables are fully utilised. Given the uncertainties regarding consumer behaviour, sufficient electricity generation from the transmission system needs to be available to supplement the potential shortfall in V2G supplies (Payne and Cox, 2019).

Cogeneration of heat and electricity has the advantage of meeting the increase in both heat and electricity demands during peak hours. This is shown in the Heat Networks and Green Gas strategies where additional electricity generation is provided by CHP units that ramp up to meet the increase in peak heat demand. The remainder of electricity demand in Heat Networks and Green Gas strategies is met by electricity from the transmission system.

5.2. Impact of demand side management (DSM)

A Demand Side Management (DSM) scheme that allows the ability to switch non-heating electricity demands (including EV charging demand) from specified peak (5–8pm) to off-peak hours (9am to 2pm and 9pm to 12 midnight) was implemented. The DSM scheme allowed a maximum shifting capability of 10% from total non-heat electricity demand at each hour over the peak period. The total demand shifted from peak to off-peak hours is balanced over 24 h (to achieve energy balance). An illustration of the actions performed by the DSM scheme over an average day in winter, across different heating strategies in 2050 is shown in Fig. 16. It shows the additional demand assigned (positive) and demand shifted (negative) with respect to non-heat electricity demand in the Expansion 30K scenario.

Across all strategies, on average around 3 GWh of electricity demand is shifted from peak to off-peak hours. Approximately ~70% of the shifted demand is assigned to the period between 10pm and 12am across Electric, Unconstrained and Green Gas energy strategies. In the Heat Networks strategy, the electricity demand is assigned equally between 9am - 2pm and 9pm - 12am periods. This allows cost-effective electricity generation from CHP units (already running for heat supply and includes the limitations imposed by ramping rates) in combination with electricity from the transmission system to meet the assigned demands.

The total change in electricity supply from the transmission system and electricity generation from distributed generators over the off-peak hours is shown in Fig. 17(a). The reduction in demand during peak hours results in decreased electricity generation from distributed generators

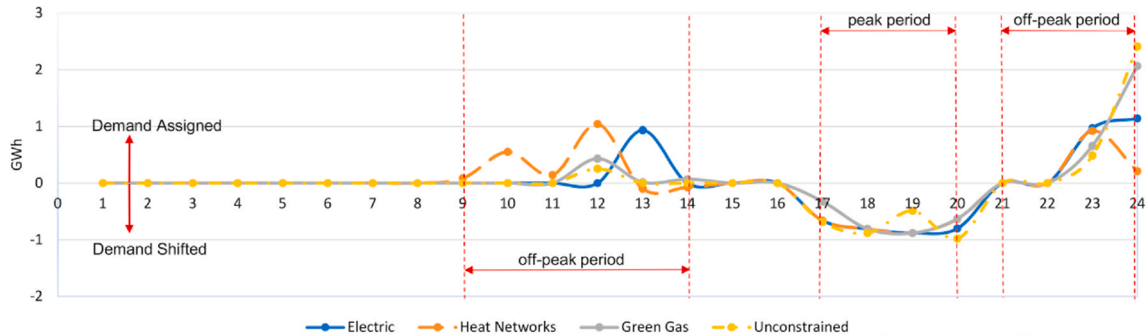


Fig. 16. Change in non-heat electricity demand due to implementation of DSM scheme in 2050.

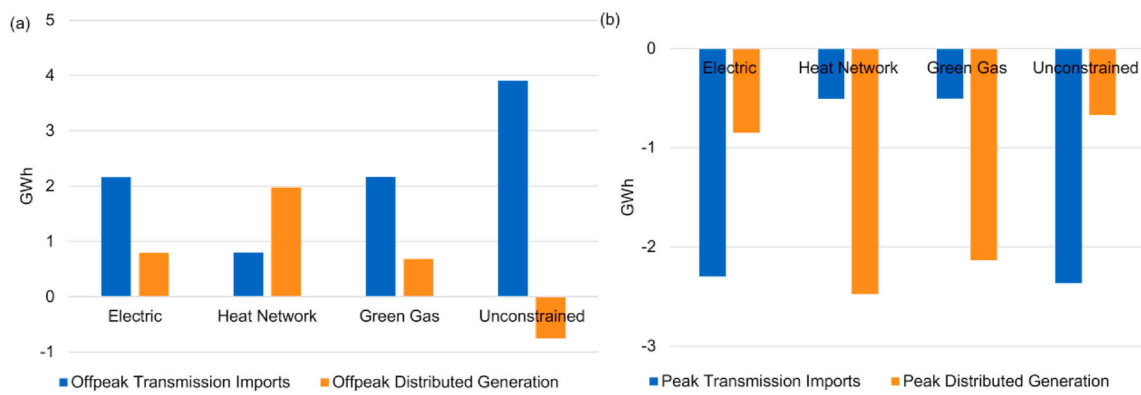


Fig. 17. Change in electricity supply from the transmission network and distributed generators in 2050. (a) during off-peak hours and (b) during peak hours, where (+) ve → increase in electricity generation and (−) ve → decrease in electricity generation.

and electricity supply from the transmission system as shown in Fig. 17 (b).

The electricity supply from the transmission system is generally cheaper during off-peak hours, compared to operating non-renewable distributed generators (distributed wind and PV are fully utilised in the region). In the Unconstrained strategy, off-peak electricity from the transmission system is used entirely to meet the additional demands. The Electric and Green Gas strategies use a combination of electricity supplies from the transmission and distributed systems (e.g. V2G) to meet demands.

In the Heat Networks strategy, there is a large capacity of CHP units installed compared to the other strategies. These CHP units are ramped up to their maximum generation capacity in combination with electricity supplied from the transmission system to meet the demands. The Heat networks strategy makes the greatest use of distributed generators to generate electricity to meet demands assigned to off-peak hours.

The annual cost savings accrued by utilising the DSM scheme are shown in Table 3.

In both Electric and Unconstrained energy strategies, the cost savings are high due to the reduction of expensive electricity supplies from the transmission system during peak hours.

The Heat Networks and Green Gas strategies show the lowest cost savings as the distributed generators (CHP units) that are switched off during peak hours (~2 GWh shifted), are then used to generate a similar amount of electricity during off-peak hours. The cost of operating CHP units is largely impacted by the cost of fuel (gas, biomass and waste) which does not change considerably within a day. Consequently, the net savings in operating CHPs are smaller in these energy strategies.

Table 3
Annual operational cost savings using the DSM scheme in 2050.

Strategy	Annual operational cost savings (£million)
Electric	7.18
Heat Networks	0.24
Green Gas	0.84
Unconstrained	3.39

5.3. Impact of demand reduction due to dwelling efficiency improvements

Additional ambitious efficiency improvements in dwellings and appliances which are expected to reduce heat and non-heating demands by 10% are modelled. The reduction in annual energy supply in 2050 across energy strategies with respect to Expansion 30K scenario in the main study are shown in Fig. 18(a).

The impact of efficiency improvements in dwellings is a reduction in annual energy supplies of ~8 TWh in the Green Gas and ~7.5 TWh in the Heat Networks strategies. In the Electric energy strategy, the annual energy supplies are reduced by approximately 5 TWh.

Across strategies, efficiency improvements have reduced electricity consumption in consumer appliances and heating through the use electric heating technologies. This has greatly diminished the reliance on electricity supplies from the transmission system into the region. Across all energy strategies, the annual electricity supply into the region decreases by 2 – 4.5 TWh.

End use heat demand met by hydrogen and gas boilers are significantly reduced in the Green Gas strategy, and therefore annual natural gas supplies for heating and hydrogen production are reduced. This results in the largest fall (3 TWh) in annual natural gas supplies among the energy strategies. In the Heat Networks strategy, a sizable decrease in the utilisation of almost all-natural gas fired heat technologies is observed.

Dwelling efficiency improvements and the use of efficient appliances results in overall decrease in energy supplies across all energy strategies. This results in the reduction of overall operating costs and emissions

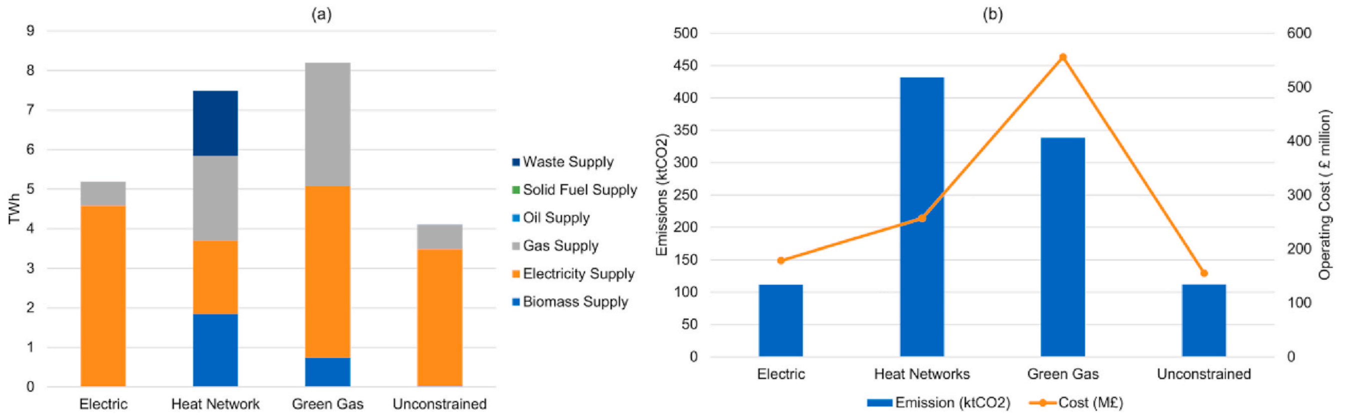


Fig. 18. Reduction in annual (a) energy supply, and (b) operating costs and emissions due to ambitious dwelling efficiency improvements in 2050.

across the energy strategies in 2050 as shown Fig. 18(b).

The implementation of efficiency improvements in the electric heating dominant energy strategies – Electric and Unconstrained, show cost savings of ~£150M. Far larger cost savings are possible in the Heat Networks and Green Gas strategies. This is due to the reduction in the use of CHP units, hence, operational savings associated with fuel (gas, biomass, and solid waste) and carbon costs are accrued.

6. Conclusions and policy implications

Modelling of the Oxford-Cambridge arc region generated a diverse range of energy supply strategies to meet future energy demands and contribute to the national 'net zero' emissions target. The choice of heat supply technology within these strategies influences the energy supply mix and therefore ways of meeting demand for heating within the region. The performance of these energy supply strategies was analysed using a holistic modelling approach in which local energy supply systems were considered alongside the backbone national gas and electricity transmission systems across several scenarios.

A summary of key modelling metrics in 2050 such as energy supply, emissions and costs (operational and capital) within the region are shown in Fig. 19.

The requirements for energy supply are greatest in scenarios with the highest population growth rates (30K variants) to meet heating and non-heating end-use demands in 2050. In the Heat Networks strategy, the energy supply is 79 TWh and 73 TWh in Green Gas for the Expansion 30K scenario. This is an additional 8 TWh of energy supply compared to the Baseline scenario in both strategies. Energy strategies with electricity dominant heating systems, have an overall energy supply in 2050 which is far lower than 2015. This is mainly due to the utilisation of highly efficient heat pumps. In contrast, the Heat Networks and Green Gas strategies predominantly utilise CHP plants and boiler systems for heating. These heat supply systems do not deliver the performance provided by heat pumps. This results in final energy supply in 2050 that is approximately 25 TWh larger than the Electric strategy.

Electricity generation has almost doubled annually and at peak hour due to the combination of EV charging and electrification of heat in 2050 across all scenarios compared to 2015. The largest increase in electricity generation, annually (~42 TWh) and at peak hour (~11 GW) is observed in the Expansion and New Settlements 30K scenarios. EV battery utilisation through vehicle to grid services provided approximately 18% of the total electricity supplied during the peak hour. In the Heat Networks and Green Gas strategies additional electricity generation is from natural gas, biomass and waste CHP units. The national electricity transmission system maintains a prominent role in balancing electricity generation and demand within the region across all scenarios and strategies.

Annual natural gas supply drops significantly across the scenarios by 2050 compared to 2015 (~45 TWh). In energy strategies with electricity dominant heating systems in 2050 (Electric and Unconstrained) the gas supply declines to 5 TWh/year (90% lower). The natural gas supply is highest (~30 TWh) in the Green Gas strategy in 2050 as it is largely used to produce hydrogen in addition to heating via gas boilers. In the Heat Networks strategy natural gas supply declines to 21 TWh as natural gas is only used for heating in CHP units and gas boilers.

Annual end use heat demand declines by 2050 across all scenarios due to ambitious 25% savings from improved insulation, thermal comfort in the building stock and near 100% smart meter rollout across the region. In line with the population and dwelling variations, the Expansion 30K scenario has the highest heat supply at ~30 TWh which is an additional 3 TWh compared to the Baseline scenario.

The impact on overall emissions within the arc region and its contribution to the national 'net zero' target alongside annualised costs per dwelling varied across the energy supply strategies modelled. There are several areas where policy and regulatory support has yet to develop such that emissions within the region could be affordably reduced. Each energy supply strategy highlights key issues related to the electrification of heat, decarbonisation of the gas network and use of heat networks, these are summarised as follows:

i). Electrification of heat

Decarbonisation of heat could be achieved by switching from a system with predominately gas boilers to a system built to accommodate heat pumps (dwelling level units and larger scale units connected to a heat network), resistive heating and storage, and running these on decarbonised electricity. The outputs of the Electric energy strategy across all scenarios showed that this would require significant additional electricity generation and network capacity.

The electrification of heat (Electric and Unconstrained strategies) in the arc demonstrated the largest regional contribution to meet the national net-zero emissions target. Given the overall costs alongside near zero emissions in the residential and commercial sectors, the Electric strategy performs strongest across the key metrics.

The implementation of an Electric energy strategy would experience many practical challenges. For instance, in scenarios where retrofitting of existing buildings is required this would entail the requirement of radical change in infrastructure at the end user level, such as each dwelling either acquiring a heat pump, resistive heating system or electric boiler. It becomes a great deal easier to incorporate this change on new dwellings proposed in the scenarios, especially in New Settlements and Expansion.

The public's knowledge of technologies such as heat pumps is still limited. Awareness could be increased by government and industry through promotional exemplars. Confidence could be further enhanced by ensuring that installers abide by high standards during the design and

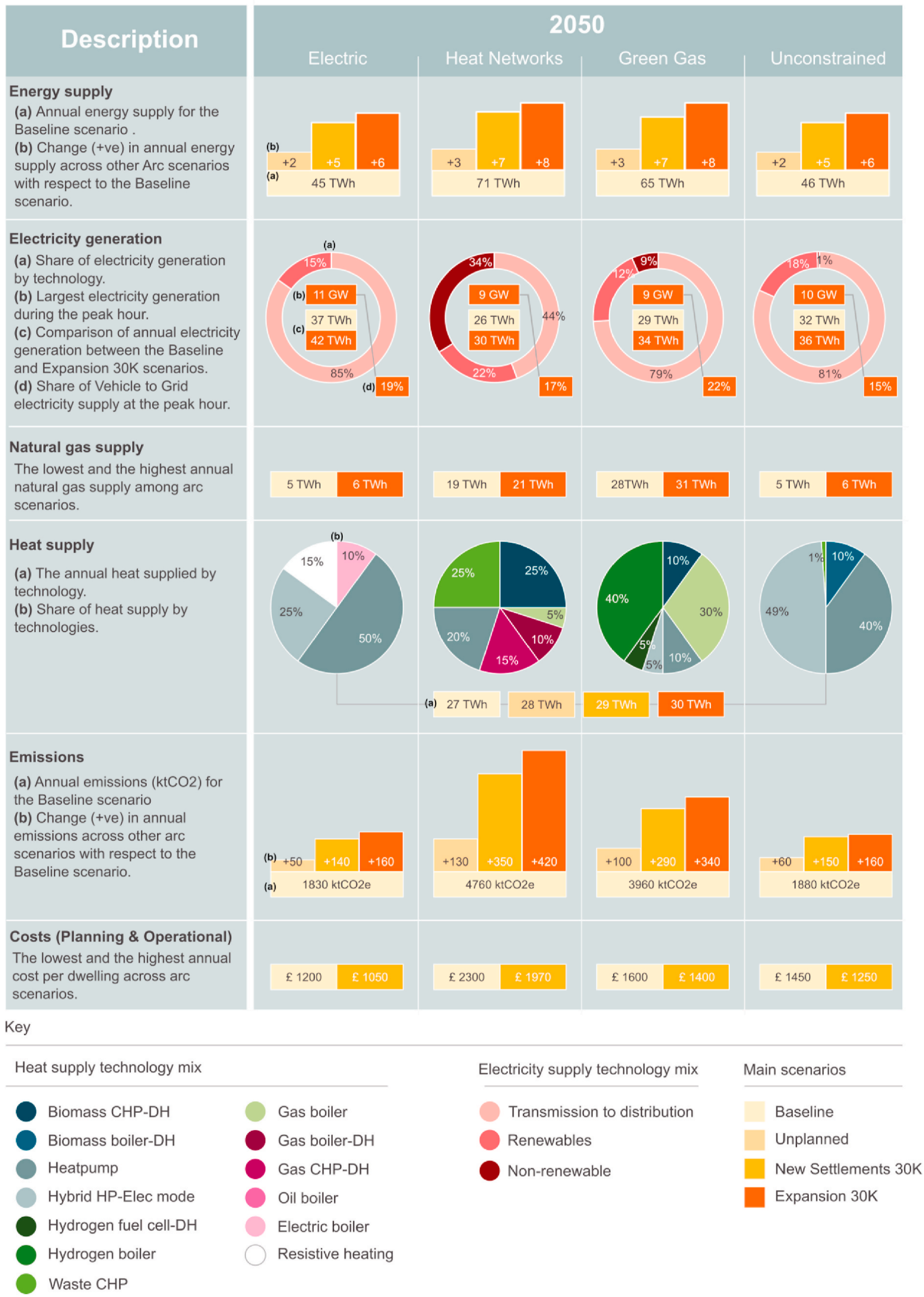


Fig. 19. Summary of key output metrics across energy supply strategies and scenarios within the arc region in 2050.

installation process.

ii). Decarbonisation of the gas distribution systems

Great Britain is fortunate to a have an extensive gas transmission and distribution system. Regionally, the gas system is made up of 250,000 km of underground pipes. Much of these assets are approximately 100 years old. Partial decarbonisation of the gas network can occur by mixing natural gas with hydrogen (20% by volume) and biomethane. This has the advantage that the changes for the end use appliances such as gas cookers and boilers can be kept to a minimum.

The Iron Main Replacement Programme (IMRP) (HSE and OFGEM, 2011) which started in 2002 has now reached the mid-point with the aim of completion by 2030. Safety is the primary concern of the IMRP, a side benefit is that the new polyethylene pipes are suitable for full hydrogen flows and therefore the prospect of near zero carbon emissions alongside relatively low network conversion costs becomes a possibility. The challenge of producing hydrogen at such scale and to do so commercially and carbon free is one that is modelled within the Green Gas strategy for the scenarios. The Green Gas strategy outputs show hydrogen production using SMR with CCS, which is expected to be technically viable in the 2030s to sustain the hydrogen supplies to be used in heating and non-heating end-uses. The use of electrolysis within the region is limited due to the low capacity of renewable generation, hence, less "free" electricity is available to cost effectively produce hydrogen. Large scale hydrogen production using SMR adds a substantial amount of operational costs annually. Therefore, the overall annualised costs per dwellings are the second largest (~£1600) for the Baseline scenario when compared with the other strategies. Annual emissions in 2050 are over 65% lower than in 2015 across all scenarios.

iii). Heat networks

The Heat Networks strategy for the scenarios focussed primarily on CHP based heating technologies although a heat network is technology and fuel source neutral. Within the scenarios and especially with New Settlements and Expansion, given higher demand (for heat) densities and the possibility of synergies during the construction of heat networks and new dwellings, potential reductions in annual costs per dwelling are feasible. The implementation of this strategy has overall costs that are the highest across all scenarios whilst emission reductions are not as large as other strategies (~55% reduction from 2015 levels). Alternatively, if heat networks were attached to an equal capacity split between large heat pumps and CHPs, this would reduce heat technology capacity costs by over 25%. Although the addition of heat pumps would require strengthening of the electricity system which would undo some of the costs savings.

The implementation of a Heat Networks strategy was shown to be feasible but there are several areas where progress needs to be made to fully realise the advantages offered by a heat source agnostic energy vector. These include:

- Economics: The Heat Networks strategy was shown to have the highest overall total costs including on a per dwelling basis. This is mainly concentrated around the high capital costs for CHP plants, digging and laying of hot water pipes and connections to dwellings. Cost reductions would have to take place across all these areas for a heat network-based solution become be competitive with alternative solutions.
- Lack of standardisation: There is no national organisation (such as National Grid) to drive standardisation across the industry. There are several companies (which can be good for innovation) driving distinct operations regionally and locally. But currently there is no universal approach to design layout or treatment of risks. This can lead to poor quality installations (BEIS, 2018a).
- Perceived technological shortcoming: Whilst well established abroad (especially within Europe), heat networks are still relatively new to the average UK consumer. Reports of poor service by energy services companies or others results in disproportionate bad publicity like the one published by the Competition and Markets Authority (CMA) in 2018, "there were instances of poor service quality and cases where customers were paying 'considerably more' than for non-network heat" (CMA, 2018). Furthermore, there is a distinct lack of knowledge about heat networks (heating capabilities) including the charging methodology and awareness of the services offered.
- Complexity: This can range from ownership issues such as who owns the network, who operates and regulates it, to what the grievance procedures are. In contrast to heat networks, natural gas networks are regulated, and most people are comfortable in the knowledge that they are protected by a regulator.

In addition to the energy supply strategies, a Demand Side Management (DSM) scheme was evaluated for year 2050. It assumed a maximum shifting capability of 10% electricity demand at peak to off peak periods. The DSM scheme, either through EVs, appliances and smart meters within dwellings reduced peak electricity demand by an average of 0.75 GW across all energy strategies. This was translated into cost savings with minimal negative impact on emissions (despite the use of non-renewable based generation technologies).

DSM seems like a panacea, benefits include the possibility of reduced operational costs, relieving strain on the electricity network at times of stress and the potential of delaying or circumventing upgrades to network and generation capacity. However, there are several areas that need to be addressed, including issues around increases in control complexity which could lead to an overly complicated management system and uncertainties regarding consumer behaviour and their interactions with DSM appliances.

The impact of a further 10% reduction in overall heating and non-heating demand in 2050 due to better insulation and efficiency improvements in dwellings was assessed across all energy strategies. This showed a reduction of annual heating demand of ~8 TWh in both Green Gas and Heat Network strategies. In electric dominant strategies the annual energy demand was reduced by 4.5 TWh. The simulation outputs clearly show that before considering sophisticated and often expensive energy infrastructure solutions, the low hanging fruit of energy efficiency and insulation should be considered.

The analyses using the integrated energy supply system model illustrated that electrification of heating in the Oxford-Cambridge arc region was the most cost-effective way to reduce emissions related to heating in all scenarios despite requiring significant additional generating and electrical network capacity. For existing dwellings this will entail radical change in infrastructure at the end user level such as installation of heat pumps and will be disruptive to householders. Most low-carbon heat technologies across the scenarios and strategies analysed have high upfront capital costs in comparison with incumbent technologies and networks, such as gas distribution networks and boilers. This is a barrier for early deployment, but decision makers (local governments, utility companies etc.) would need to implement processes to absorb these early costs so that technological learning (costs and efficiencies) can be made, and the workforce can be sufficiently trained to allow a relatively smooth transition to a low-carbon pathway.

CRediT authorship contribution statement

Modassar Chaudry: Software, Methodology, Formal analysis, Data curation, Writing – original draft, Writing – review & editing, Visualization. **Lahiru Jayasuriya:** Software, Methodology, Formal analysis, Data curation, Writing – original draft, Visualization. **Nick Jenkins:** Supervision, Writing – review & editing, Project administration.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A

A.1. Energy hub geographic boundaries

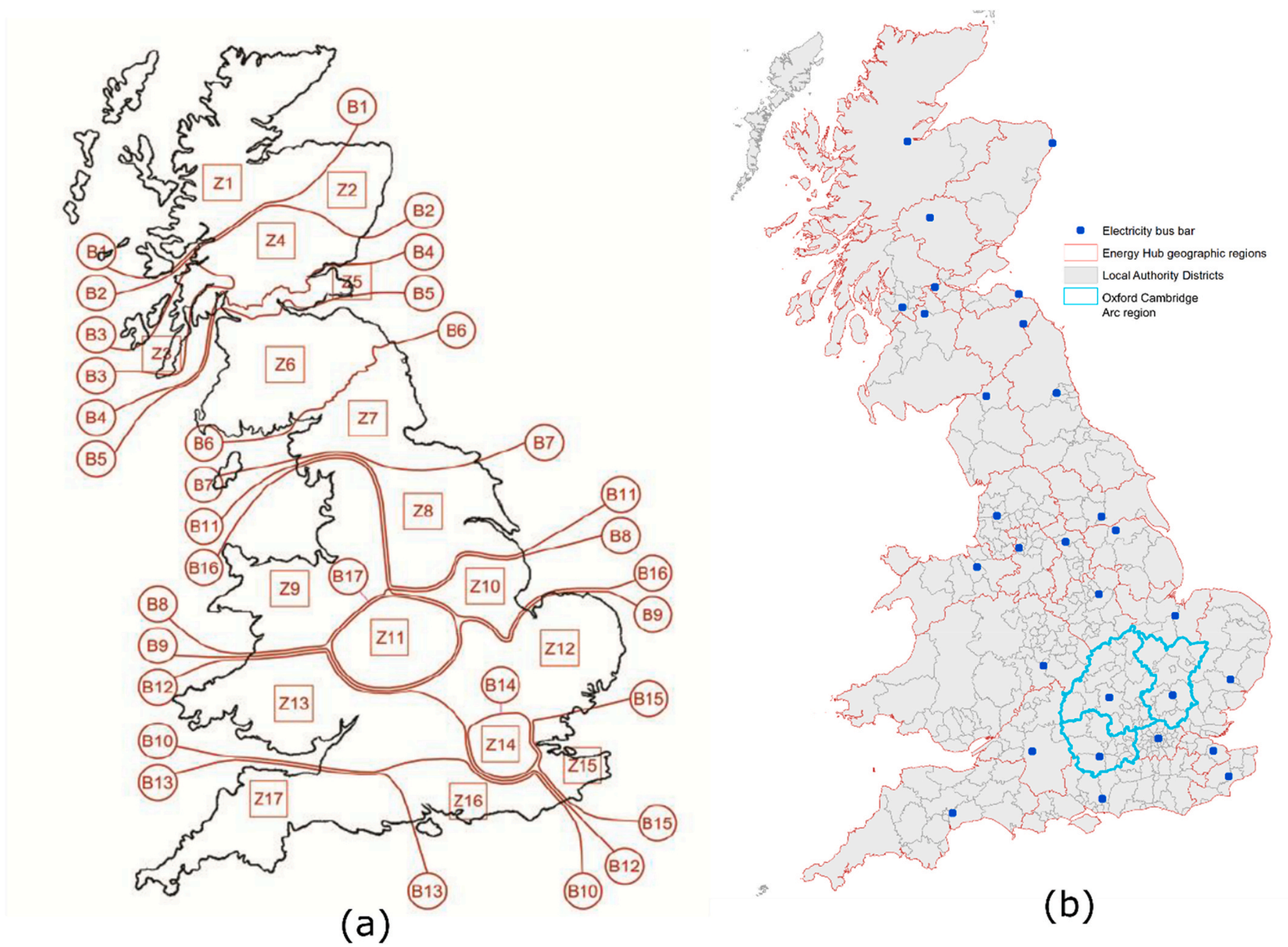

Fig. A.1. Design of energy hub geographic regions using (a) Electricity transmission network boundaries and (b) Local authority districts in Great Britain.

The electricity transmission network boundaries shown in Figure A1 (a) are defined by the national electricity system operator in GB (National Grid, 2019a). The electricity transmission network boundaries in Figure A1 (a) were mapped on to the Local Authority Districts in GB (grey areas) shown in Figure A1(b) to develop the boundary of each energy hub region (shown as the red lines). The electricity transmission network boundaries correspond to the electricity bus bars (blue dots) in Figure A1 (b) and are the points at which electricity transmission is connected to an energy hub region.

A.2. Energy demand modelling and temporal simulation set-up

The GB heat and non-heat demands (excluding transport) for years 2015, 2030 and 2050 are outputs from an energy demand model (Eggimann et al., 2019). The electricity demand for transportation (EVs) was determined by a GB transport model (Lovrić et al., 2017). Energy demand including the demand for transport were used as inputs to the integrated energy supply model. From these inputs, the heat and non-heat demand (including transport) within the Oxford-Cambridge region for year 2050 across the arc scenarios are shown in Fig. A2.

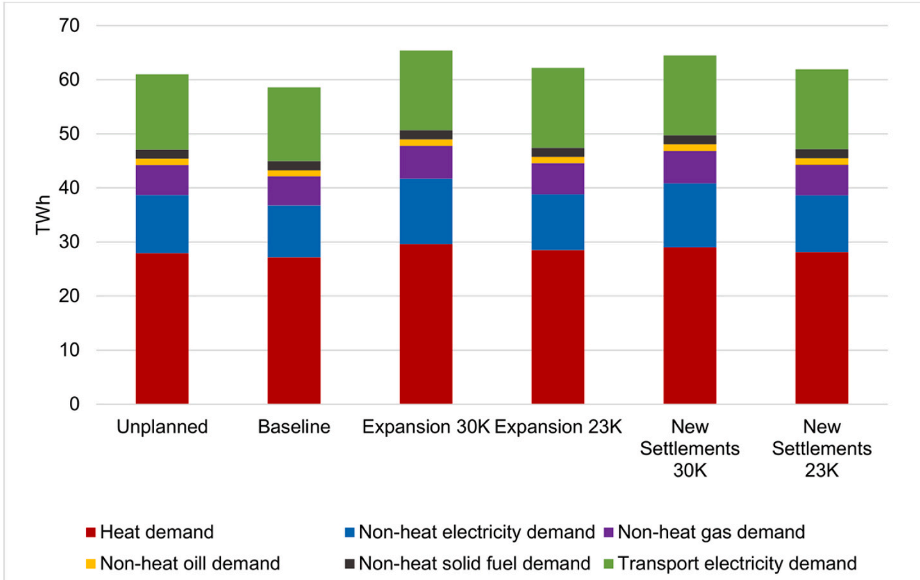

Fig. A.2. Heat and non-heat demand in the Oxford-Cambridge region for year 2050 for the arc scenarios

Given the complexity of the energy supply model and in order to maintain a reasonable optimisation solution time for each simulation year whilst ensuring accuracy, energy demand was approximated as follows:

The GB energy demand model was simulated and validated against historical energy demand years (2010–2018). Each energy demand year was modelled using 8760 hours. Four seasons are used and a week which characterises each season is chosen for the simulation. This is defined as a 'representative week' and has hourly time granularity for the simulation years (2015, 2030 and 2050).

The demand (8760 hours) data set is first split into 4 seasons with duration of ~3 months (Winter – Dec to Feb, Spring – Mar to May, Summer – Jun to Aug, Autumn – Sept to Nov). Then for each season a representative week that matches closely the seasonal energy requirements but utilises 'actual' demand peaks and trough characteristics is chosen. These 'representative weeks' when aggregated across the number of weeks in a season estimates the overall energy demand over a season. The aggregated energy demands are within ± 5% of actual seasonal demands but crucially the peak demands match exactly. This allows us to address 'resource gap' events and ensures no underestimation of energy capacity requirements.

Whilst the ideal scenario is to simulate the full 8760 hours in a year these modifications allow the energy supply model to simulate within a reasonable timeframe whilst ensuring energy demand volumes and pattens especially regarding actual peak requirements are retained.

A.3. Temporal EV charging demand and Vehicle to Grid modelling assumptions

Transport related inputs were provided by a national transport model (Lovrić et al., 2017). The model simulates changes in traffic levels in response to changes in population, vehicle engine types, economic activity, travel time and cost, using an elasticity-based framework.

The transport model provides outputs such as number of trips in each hour by vehicle type (EV/Fuel Cells), and the energy consumed by the vehicle (electrical energy, hydrogen energy) for each trip across weekdays and weekends.

Given that the transport model provides the energy consumed for trips at each hour, this is aggregated to obtain the overall energy demand for transport for weekdays and weekends across seasons. Daily demands are then superimposed on normalised EV charging profiles obtained from National Grid Future Energy Scenarios datasets (National Grid, 2019b) characterised by weekday/weekend travelling patterns. This accounts for the temporal changes in EV charging behaviour and makes allowances for differences between weekdays and weekends.

It was assumed that a battery electric vehicle (BEV) has a 30 kWh battery pack and once the vehicle is stationary, 20% of the unused battery capacity is available to provide V2G services at a power output of 7 kW (Imperial College, 2019). Given the number of EVs assumed in 2050 produced by EV trips from the transport model (Lovrić et al., 2017), this would represent around 2.5 GW of battery storage in the Expansion 30K and New Settlements 30K scenarios (other scenarios average around ~2 GW).

V2G services are made available within residential and commercial sectors. With the continuous growth of EV uptake by 2050, V2X (V2G and V2H - vehicle-to-home) services become more commercially attractive than further investment in non-renewable distributed generation (Payne and Cox, 2019), especially within new development regions. Within the arc region, this becomes a prominent option in dense areas for example in the Expansion 30K scenario.

Appendix B

B.1. Energy system capacity assumptions

The installed capacity is the same across all scenarios for the electricity transmission system and energy hubs excluding the Oxford - Cambridge arc region.

Table B.1
Installed power generation capacities for the national electricity transmission system and electricity distribution regions (excluding the arc region).

Generation Type	Generation Capacity – GW		
	2015	2030	2050
Transmission			
Oil	0.8	0.4	0.1
CCGT with Carbon Capture and Storage (CCS)	0.0	6.1	11.6
Coal	13.8	0.0	0.0
Gas (CCGT + OCGT)	28.9	15.7	5.2
Hydro	1.2	1.3	1.3
Pumped hydro	2.8	4.7	5.9
Interconnectors	4.2	15.2	21.2
Other (tidal and marine)	0.0	3.1	5.8
Nuclear	9.0	11.8	15.8
Onshore wind	5.4	11.6	15.2
Offshore wind	4.3	34.0	54.2
Solar	0.5	0.7	0.9
Battery	2.7	2.7	2.7
BECCS	–	–	7.0
Total	*73.5*	*107.2*	*146.7*
Distribution - Excluding capacity for the arc region			
Gas (non-CHP)	1.3	3.1	4.1
Onshore wind	4.0	7.4	9.9
Offshore wind	0.5	0.7	0.8
PV	12.3	28.4	40.9
CHP gas	4.9	4.4	4.1
Oil (diesel etc.)	0.6	0.2	0.0
Biomass other	2.6	2.8	2.4
Biomass CHP	0.1	1.2	1.9
Waste other	0.8	1.0	1.0
Waste CHP	0.5	0.7	0.9
Fuel cells	0.0	0.002	0.003
Vehicle to grid	0.0	4.2	8.0
Storage (battery)	0.001	6.0	10.7
Other	0.012	1.0	1.7
Total	*27.5*	*61.3*	*86.1*
Total capacity	**101.1**	**168.5**	**232.8**

The electricity and heat generation capacities within the arc region for the Baseline scenario across energy supply strategies are shown in Tables B2 and B.3.

Table B.2
Installed power generation capacities for the arc region in the Baseline scenario

Generation Type	2015	Generation Capacity (MW_e) – 2050 *Baseline*			
		Electric	Heat Network	Green Gas	Unconstrained
Gas (non CHP)	131	366	366	366	366
Onshore wind	141	333	333	333	333
Offshore wind	0	15	15	15	15
PV	2547	8644	8644	8644	8644
Gas CHP	465	391	388	391	391
Oil (diesel etc.)	0	0	0	0	0
Biomass CHP	7	267	739	267	267
Waste CHP	68	130	739	296	130
Fuel cells	0	0	0	148	0
Vehicle to grid	0	2453	2204	1760	2547
Transmission supply capacity	3333	6176	3542	3333	4270
Total (GW)	*7*	*19*	*17*	*16*	*17*

Table B.3
Installed heat supply capacities for the arc region in the Baseline scenario

Technology	Heat Supply Capacity (MW_{th}) – 2050 *Baseline*				
	2015	Electric	Heat Networks	Green Gas	Unconstrained
ASHP + GSHP	25	1725	690	345	1725
Gas boiler - Building	4018		173	1035	1035
Electric boiler - Building		388			388
Resistive heating - Building	502	518			518
Hydrogen boiler - building				1553	1553

(*continued on next page*)

Table B.3 (*continued*)

Technology	Heat Supply Capacity (MW_{th}) – 2050 *Baseline*				
	2015	Electric	Heat Networks	Green Gas	Unconstrained
Hybrid heat pump - building		970		194	970
Oil boiler - Building	594				
Gas CHP - DH	3		582		582
Biomass CHP - DH	6		1109	444	444
Waste CHP - DH			1109		260
Gas boiler - DH	3		388		388
Heat pump -DH					
H2 fuel cell - DH				222	222

Appendix C

The energy supply mix composition for all scenarios is similar to the Baseline scenario as given in Table C1.

Table C.1
Energy supply mix in 2050 for the Baseline scenario

Energy Strategy	Share of total energy supplies (%)					
	Biomass	Electricity	Natural Gas	Oil	Solid fuel	Waste
Electric	0.0	82.1	11.7	2.5	3.7	0.0
Heat Networks	23.7	24.0	27.2	1.6	2.3	21.1
Green Gas	10.4	41.9	43.5	1.7	2.6	0.0
Unconstrained	8.5	71.6	12.0	2.6	3.8	1.5

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