Spatial and Temporal Disaggregation of Whole System Energy Models Through Exemplar Local Multi-Carrier Networks

PhD Thesis

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Abstract

Different futures of domestic energy use - in particular, considering options in heat provision - are simulated and analysed within characteristic UK local energy systems (urban, suburban, rural) in order to determine the Delivered Cost of Energy, Emissions Intensity, and Abatement Cost for different technology options across multiple carriers, including both options in electrification and the use of alternative gases. This incorporates the costs and efficiencies of domestic technologies, district heating options, and the necessary levels of network reinforcement. The methodology extends the use of an existing Energy Hub optimisation model into the multi-carrier assessment of domestic heat incorporating high levels of spatial and temporal detail, and determines the respective contributions each technology may make to carbon emissions reduction. The optimal choice of technology is found to differ according to the spatial characteristics of the location, with a greater value for thermal storage and local supply arrangements with renewable energy sources where the per-customer cost of infrastructure reinforcement is higher. The use of resources with a high emissions intensity may be displaced through time-shifting of demand towards the use of lower-intensity carriers to overcome existing network capacity constraints. The results are used to disaggregate infrastructure costs and technical parameters into the domestic heating sector in the UK TIMES model, showing that recognition of a greater diversity of infrastructure capacities and costs entails a greater diversity in technology selections when seeking a least-cost trajectory towards national emission targets, with increased use of district heating systems and night storage over a non-spatially disaggregated formulation. There is a strong potential for the coordination of local renewable output in constrained networks with local heat demand, with total abatement costs reduced where this value can be unlocked through investment in domestic low-carbon heating technologies such as heat pumps and thermal stores.

Every policy is shaped by two forces: background analysis and foreground politics. The political forces are loud, self-serving and, in the case of energy policy, well known. - Donella Meadows

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List of Abbreviations

Abbreviation	Definition	First appearance in text
AC	Abatement Cost	p113
ACER	Agency for the Cooperation of European Regulators	p11
ANM	Active Network Management	p135
ASHP	Air Source Heat Pump	p90
CCC	Committee for Climate Change	p18
CCS	Carbon Capture and Storage	p16
CERO	Carbon Emissions Reduction Obligation	p12
CfD	Contract for Difference	p15
CGE	Computable General Equilibrium	p23
CGEN	Combined Gas and Electricity Network (model)	p33
CHP	Combined Heat and Power	p94
CotP	Conference of the Parties	p7
CoP	Coefficient of Performance	p90
CPF	Carbon Price Floor	p12
CRC	Carbon Reduction Commitment	p12
DCOE	Delivered Cost of Energy	p112
DECC	Department for Energy and Climate Change	p22
DSM	Demand-Side Management	p100
DSR	Demand-Side Response	p101
ECO	Energy Company Obligation	p36
EI	Energy Intensity	p112
EMR	Electricity Market Reform	p15
ENTSO-E/G	European Network of Transmission System Operators for Electricity/Gas	p17
ESI	Energy Systems Integration	p20
ESME	Energy System Modelling Environment	p32
ESP-r	Environmental System Performance Research program	p122
ETI	Energy Technologies Institute	p32
ETS	Emissions Trading Scheme	p10

ETSAP	Energy Technology Systems Analysis Program	p27
EU	European Union	p7
FiT	Feed-in Tariff	p14
GEOS	Goddard Earth Observing System	p59
GHG	Greenhouse Gas	p7
GSHP	Ground Source Heat Pump	p90
HES	Hybrid Energy System	p98
HHCRO	Home Heating Cost Reduction Obligation	p12
HIU	Hydraulic Interface Unit	p95
HV	High Voltage (network)	p120
IAS	International Aviation and Shipping	p11
IEA	International Energy Agency	p27
IMRP	Iron Mains Replacement Programme	p79
INDC	Intended NDC	p9
IPCC	Intergovernmental Panel on Climate Change	p9
IRE	Inter-regional Exchange (processes)	p39
LV	Low Voltage (network)	p120
MAC/MACC	Marginal Abatement Cost (Curve)	p33
MARKAL	Markets and Allocation (model)	p27
NDC	Nationally Determined Contribution	p8
NFFO	Non-Fossil Fuels Obligation	p12
NTM	National Transport Model	p33
OCGT	Open-Cycle Gas Turbine	p140
Ofgem	The Office for Gas and Electricity Markets	p11
OPF	Optimal Power Flow	p43
OSeMOSYS	Open Source Energy Modelling System	p29
PE	Polyethylene (pipe)	p79
POLES	Prospective Outlook on Long-term Energy Systems	p29
PRIMES	Price-Induced Market Equilibrium System	p31
PV	Photovoltaic (solar panel)	p85
RHI	Renewable Heat Incentive	p17
RO/ROC	Renewables Obligation (Certificate)	p13
SCED	Security-Constrained Economic Dispatch	p44

SEEP	Scotland's Energy Efficiency Programme	p18
STPR	Social Time Preference Rate	p150
TES	Thermal Energy Storage	p96
TIMES	The Integrated Markal-EFOR System	p28
ToU	Time of Use (model)	p122
UK	United Kingdom	p9
UKTM	UK TIMES Model	p2
UNFCCC	United Nations Framework Convention on Climate Change	p7
VAR	Vector Auto-Regressive (model)	p54
WACC	Weighted Average Cost of Capital	p15
WSEM	Whole System Energy Model	p1

1 Overview

1.1 Motivation

Energy facilitates our lives. It powers our transport and machinery, heats our homes and workplaces, and eases the difficulty of the everyday in a million distinct ways. But as our society has grown and expanded in its use of energy, so we have gradually learned the negative impacts of our energy use - not least in the form of carbon emissions and the spectre of climate change - on the environment, which is no less key to our survival and success. With this appreciation, so comes the drive to find newer and more sophisticated ways to maintain the ways in which energy supports our lives, but with these externalities mitigated or removed altogether. In order to understand the full range of options at our disposal, we must look holistically at the 'energy system' underlying society and explore the trade-offs and compromises we can choose to make.

Jaccard defines an energy system as "the combined processes of acquiring and using energy in a given society or economy." [1] An energy system includes a number of processes, including resource extraction, refining, transportation, storage and conversion to end-use energy services [2]. This includes consideration of the balance in choices between supply and demand. It involves social and technical concerns, comprising not only pipelines and fuels, but also markets, consumers and institutions, each of which may have a distinct local realisation. At a policy level, governments and national institutions have a deep interest in the 'Whole System' view of energy, which seeks to capture the resourcing and flow of energy across an entire nation.

If a government seeks to fulfil a quantitative goal, such as a fixed relative level of emissions abatement, then the use of quantitative modelling becomes key to capturing and understanding the current-day flows of energy within a system, and from there to project forwards to estimate the required levels of intervention (as well as the necessary policy structures) that will be required to meet a specific future target. This permits policies such as carbon taxation, technology subsidies, or behavioural interventions, to be tested against a known system background, and so can be used to build up a strong evidence base for the implementation of new legislation.

Within this field of inquiry, Whole System Energy Models (WSEMs) have evolved in scope and use over recent years to become a cornerstone of national energy policies. WSEMs are models which attempt to represent the complete set of energy flows – from raw resources through to end consumer demands – for a given spatial area over a given timescale, normally incorporating key metrics such as costs and/or emissions associated with meeting demand. Within the UK, WSEMs such as UK TIMES (UKTM) have been used by policymakers to set carbon budgets and evaluate decarbonisation options under different futures in order to determine the optimum policy mix to meet national targets on emissions reduction out to 2050.

In the case of national models, the requirement to model an entire national energy system means that WSEMs are, by their nature, highly aggregated and may have simplistic representations of particular technologies and energy flows. This may lead to the costs and implications of certain decarbonisation trajectories being understated. In particular, the provision of heating on a local scale may be poorly represented (in terms of capturing the detail of localised energy flows and losses), with the local requirements for network infrastructure investment close to energy consumers entailing substantive change to existing energy systems.

These systems can be alternatively explored outside of WSEMs through the generation of local exemplar models which describe particular representative cases of local energy systems, based on real-world data. If the smaller-scale models can be produced in line with the WSEM assumptions, and produce outputs which may be incorporated into the WSEM through improved spatial and temporal detail (or appropriate representations thereof), then this can be used to extend the scope and impact of the WSEM modelling.

There are three motivations to following this multi-scale line of investigation.

Firstly, if improved understanding can be made of the scale and nature of local changes in energy systems, using localised models which are highly representative of use cases for many end consumers, then this can lead to an increased level of detail in the cost representations with the higher-level WSEM.

Secondly, such modelling allows an exploration of particular trajectories in energy provision. Within a WSEM, selection is made of technologies and investments which may occur across a national energy system at particular time steps. However, this is not closely mapped to specific local cases. Investigation of local impacts of this technology selection allows a detailed evaluation of how a decarbonised local energy system might evolve over time, and allow potential stumbling blocks and shortfalls in secure energy provision to be identified.

Third, local exemplar models also permit a determination - for particular scenarios - of the changes in cash flows, end-user behaviour, and actions by energy system actors that may be required to enable a particular energy transition. This will also assist in further determining the level of intervention that may be required by policymakers in achieving a particular trajectory to decarbonisation, and to assign responsibilities towards meeting those goals.

1.2 Scope

This work describes the current issues around temporal and spatial representation of energy systems in WSEMs, and how this may impact the policy decision-making process. To contribute to the improvement of this granular detail in WSEMs, several exemplar models describing local energy systems, explicitly modelling last-mile multi-carrier network models, are constructed. The main focus is on the UK energy system and the current decarbonisation trajectories proposed out to 2030 and 2050 in order to meet national emissions targets. Due to the breadth of technologies involved, particular focus is given to two subjects. Firstly, an accurate model of wind power incorporating both spatial and temporal elements is proposed as this is a significant technology in the UK energy system with high complexity within those domains. Secondly, the multi-carrier modelling focusses on the issue of domestic heat provision, as it remains one of the key areas for policy development in the UK, and one where spatial and temporal understanding play a key role in conducting meaningful modelling to explore the trade-offs between energy sectors, and to use this insight to inform possible energy policies.

1.3 Structure

In Chapter 2, the nature and form of international agreements on the abatement of greenhouse gases are discussed, following the thread from international to EU to UK targets. The role of WSEMs in creating coherent, quantified national policies around decarbonisation in different sectors is reviewed, followed by a summary of the nature and structure of the major models that have been used to date for this purpose. Finally, some critical analysis is made of the primary weaknesses in the design and application of this form of modelling.

Chapter 3 assesses in more depth the general issue of spatial and temporal disaggregation in WSEMs, and evaluates the computational restrictions which may exist to prevent further detail being intrinsic to those models. Previous approaches to counter this problem are summarised. The local multi-carrier approach developed in this thesis is initially proposed (expanding on a formulation conventionally known as the ‘Energy Hub’ model) and justified, by referring to weaknesses in common WSEMs where an improvement in accuracy and applicability of modelling results may be derived.

Chapter 4 evaluates in detail the particular issue of modelling of wind power, looking at both local and national-scale modelling in terms of correctly representing the spatial and temporal variation in wind power injections into an electricity network. A model for deriving local power injections using the MERRA 2 global reanalysis dataset is described alongside a reduced statistical model, and validation is conducted using the operational history of the Great Britain wind fleet.

Chapter 5 looks at issues and costs around energy infrastructure, and the different impacts that selections of end-use technologies may have on the current network assets, existing and new stakeholders, and patterns of investment. This is used to develop a key set of scenarios for future energy system futures that can be applied to local energy models.

Chapter 6 provides the general formulation of a multi-vector local network used in this analysis, taking into account the technical characteristics described in the preceding chapters. The established ‘Energy Hub’ concept is expanded upon to represent generic local planning and operation optimisations for local energy systems.

Chapter 7 presents 3 local exemplar models (urban, suburban, rural) developed from representative locations of the UK energy system, summarises the data sources, and discusses their representativeness of the wider network. Further detail for these models is provided in Appendix A. Scenarios are selected based on the futures previously generated by the UK TIMES and ETI’s ESME models.

Chapter 8 presents results from the solution of the exemplar models and uses them to present narrative pathways around the potential routes to decarbonisation under each paradigm, and exposes some of the challenges associated with multi-carrier modelling.

Chapter 9 attempts to complete the iterative process previously identified by using the findings of the local energy models to improve the technology representations within the UK TIMES model, and illustrates the potential impacts of such modelling on the outputs of WSEMs.

Finally, Chapter 10 summarises the implications of the above work in terms of potential policy impacts, and presents a potential iterative process that can be used in the interpretation of WSEM results for setting national decarbonisation strategy.

1.4 Contribution

This work makes the following contributions to the field of energy system modelling and policy formation:

First, it proposes a mechanism for validating and improving assumptions made in Whole System modelling via downscaling to real-world high-resolution systems. The specific local models use bottom-up modelling within least-emissions optimisations to determine the delivered cost of energy and emissions intensity of different heat technologies, within different local archetypes, to be explored. This allows the evidence base generated by the Whole System model to be supported by demonstrable systems, which may also indicate additional costs or technical constraints under-represented within the higher-level model.

Second, it extends existing Energy Hub formulations – primarily used to investigate renewable energy systems and storage – into the domestic heating sector, via the integration of bottom-up demand data from a stochastic housing thermal and occupancy model. This demand data more closely represents the behaviours of real-world occupants in known extant housing stock, and so helps in reflecting how different heat technologies being investigated within energy policy scenarios might interact with energy demands at a fine level of detail. This extends the application of both forms of modelling into novel system models.

Third, it reveals policy-facing implications for the future heat transition, seen as one of the main targets of decarbonisation policies out to 2030 and beyond. Examining the technical requirements in local energy networks to facilitate different technology mixes for the provision of domestic heat, it illustrates the roles of different actors and the alternative incentive arrangements that may be required to realise the proposed decarbonisation pathways.

Figure 1 below illustrates the mechanism whereby the scenarios generated by a Whole System model (UK TIMES in this study) can be iterated with a set of local Exemplar Models in order to test and evaluate the real-world implications of the higher level model, and so to use the outputs from the detailed local modelling to improve the input assumptions within the Whole System view. The outputs of the Whole System model are downscaled to the local model inputs, and the outputs of the local model are upscaled to the Whole System model inputs.

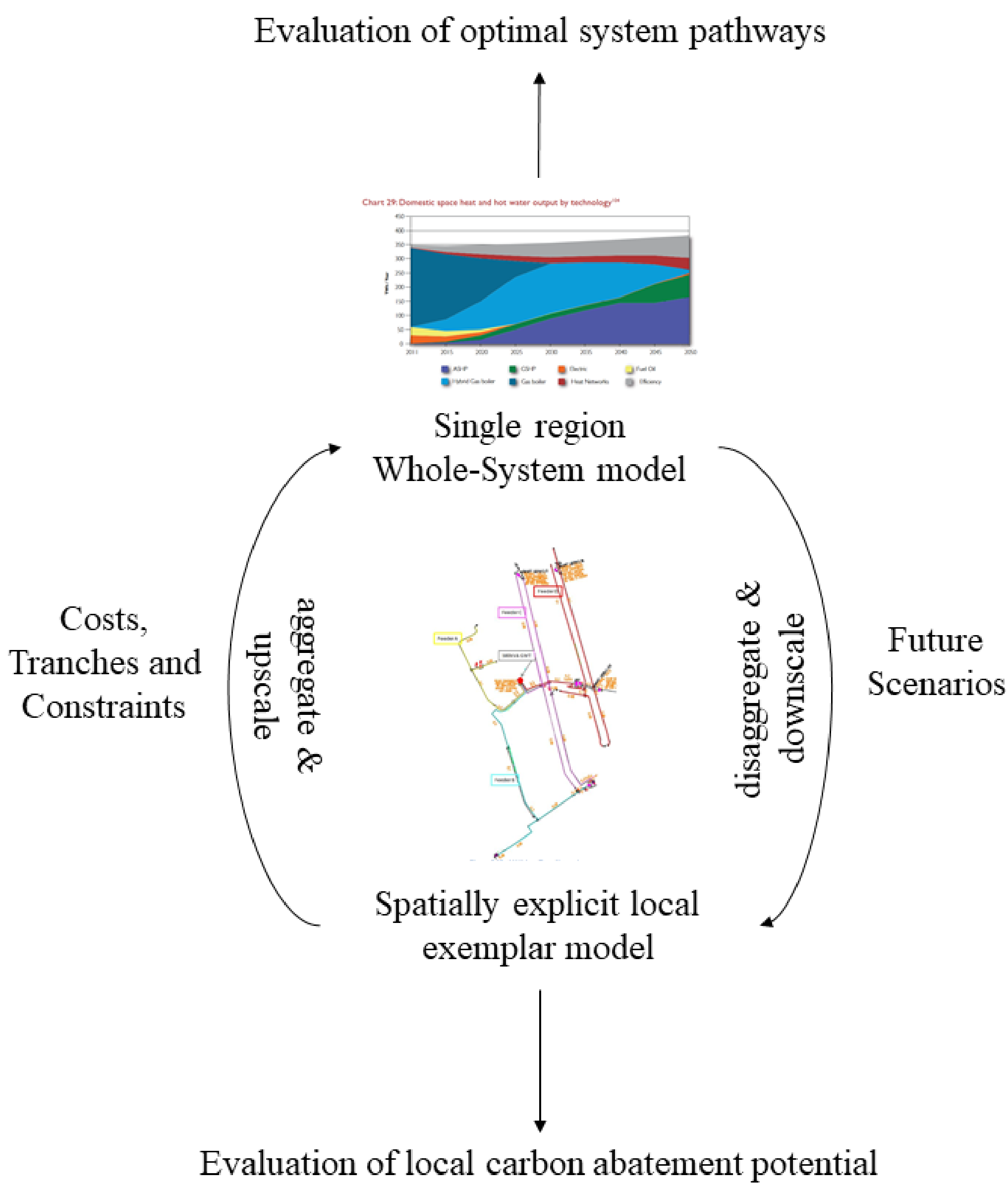

Figure 1 - Interlinking a Whole System energy model with an explicit local exemplar model

2 The Role of Whole System Energy Models (WSEMs) in National Decarbonisation Strategies

2.1 Overview

In this chapter, the background to decarbonisation policy is covered, in order to develop the setting within which WSEMs are used, and the purpose to which they must be constructed. A thread is followed through from international climate agreements, through to national policy instruments that are, and have been, used in the UK, along with a critical evaluation of those instruments to date. Discussion is made of how the determination of these policies is supported by modelling work, with a broad view of the nature of some of the main energy models that have been used in UK energy policy. Finally, the weaknesses in the WSEM approach are summarised, particularly with regard to spatial and temporal issues in energy systems.

2.2 International Agreements on Greenhouse Gas Emissions

Entering into force in March 1994, the United Nations Framework Convention on Climate Change (UNFCCC) became the first international agreement on management of greenhouse gas emissions, setting a target for joint effort to:

> *"…achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner."*[3]

The UNFCCC set no limits on Greenhouse Gas (GHG) emissions, nor established enforcement mechanisms, but outlined the structure of further protocols and/or agreements which may be negotiated to specify action towards this objective. For signatories of developed nations (termed 'Annex I' parties), the convention specifies a stabilisation of GHG emissions at 1990 levels by the year 2000.

Following the signing of the UNFCCC, 23 "Conferences of the Parties" (COPs) have taken place to further discuss and implement agreements towards the meeting of the overall goal of GHG stabilisation/reduction. The first of these was the Kyoto Protocol [4], adopted in December 1997 following COP-3 and entering into force in February 2005. An initial commitment period from 2008 to 2012 committed the European Union (EU) and 38 industrialised countries to a binding target of 5% below 1990 levels, as well as requiring each signatory to implement a "national system for the estimation of anthropogenic emissions by sources and removals by sinks of all greenhouse gases." While the 2009 Copenhagen COP-15 failed to generate a successor to Kyoto, a second commitment period covering 2013-2020 was ratified following COP-18 in the Doha Climate Gateway in 2012, albeit with limited additional commitments beyond those identified in the first period, limited in scope to only 15% of global carbon dioxide emissions [5]. Additionally, the concept of "loss and damage" was introduced – the principle that developed nations failing to reduce their emissions could be held financially responsible for the climate-driven impacts on developing nations, which was formalised at COP-19 under the Cancun Adaptation Framework [6].

COP-21, held in Paris in December 2015, negotiated the Paris Agreement, which entered into force in April 2016 following signature by the United States and China. This extended the original UNFCCC goals with the aims of:

> *"a) Holding the increase in the global average temperature to well below 2 °C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 °C above pre-industrial levels, recognizing that this would significantly reduce the risks and impacts of climate change;*
>
> *(b) Increasing the ability to adapt to the adverse impacts of climate change and foster climate resilience and low greenhouse gas emissions development, in a manner that does not threaten food production;*
>
> *(c) Making finance flows consistent with a pathway towards low greenhouse gas emissions and climate-resilient development."* [7]

The Paris Agreement allows each country to determine their own contribution towards the combined goal, termed "Nationally Determined Contributions" (NDCs), with the requirement on signatories that they should be ambitious, progressive over time, and set with a view to meeting the overall purpose of the Agreement. These contributions are to be reviewed and reported every five years, with each to be more ambitious than the last. As with the overall UNFCCC, there is no binding international law on the Contributions, nor an enforcement mechanism. The Agreement does, however establish a basis for a global carbon market, in recognising cooperative approaches that parties can take within their NDCs, as well as the rights of signatories to meet their NDCs through emissions reductions outside their own jurisdiction. This has the potential for increased use of international carbon trading as an enabler towards the implementation of NDCs, which will be developed as a concept in forthcoming COPs [8].

The current set of NDCs cover up to either 2025 or 2030 (dependent on the signatory). In 2018, there will be a "facilitative dialogue" taking stock of the progress towards achievement, and looking towards the submission of an updated set of NDCs to be provided by 2020. Thereafter, new NDCs will be submitted every five years, along with "adaptation communications" indicating each signatory's priorities and plans. Every two years, developed countries are required to communicate the level of finance they will provide to developing countries via the Green Climate Fund.

In 2023, prior to the third round of NDCs, there will be a "global stocktake" – a review of collective progress towards achieving the long-term goals of the Paris Agreement, both in mitigation and adaptation, with the assessments likely to be undertaken by the Intergovernmental Panel on Climate Change (IPCC), the climate science body of the UN. This will provide the link between individual government policies on absolute GHG emissions with the combined international goal on restricting global atmospheric temperature change. The Intended NDCs (INDCs) submitted for negotiation prior to COP-21 indicate a median warming of 2.6-3.1 degrees Celsius by 2100 [9], indicating that substantial progression in ambition is required in near-term rounds of NDC revision in order for the 1.5 or 2 degree targets to be met.

2.3 Greenhouse Gas Emission Policies of the United Kingdom

2.3.1 International Agreements

The United Kingdom (UK) is a signatory to the UNFCCC Agreements both as an independent country and as a Member State of the EU.

The EU's commitments to the UNFCCC protocols and agreements are summarised in Figure 2. The UK's commitment under the first commitment period of the Kyoto Protocol was for a 12.5% reduction by 2012 against 1990 levels. This target was achieved, with emissions reduced by 27% by 2011.

Under the Doha Amendment [5], the EU has an emission limitation equivalent to 92% of 1990 levels for 2008-2012, followed by 80% for 2013-2020. There is additionally a conditional offer to increase reduction from 20% to 30% "provided that other developed countries commit themselves to comparable emission reductions".

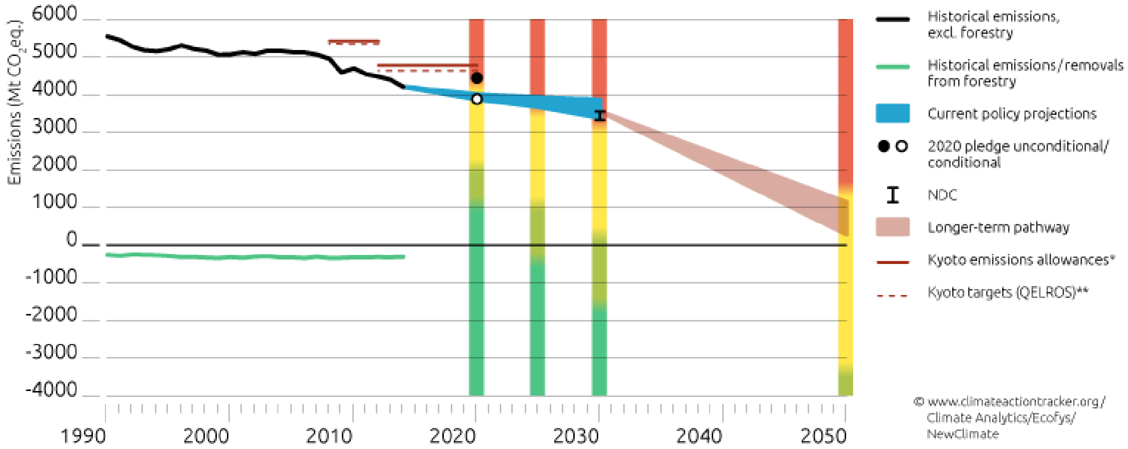

Figure 2 - European CO2 emissions and future pledges from the Kyoto Protocol and Paris Agreement (reproduced from [10])

The UK's contribution is exactly matched to this. Under the Paris Agreement, the UK does not have its own NDC as it is a contributor to the EU's NDC. With respect to Brexit, the UK will remain a signatory to the Paris Agreement regardless of its relationship with the EU. Once the UK officially leaves the EU, it will need to submit an individual NDC, unless there is a joint fulfilment agreement between the UK and EU [11].

The UK is a member of the EU Emissions Trading Scheme (EU-ETS) [12], which was created in 2005 and limits emissions from approximately 11,000 intensive energy installations (mostly power generation plants and industrial sites) and airlines, representing around 45% of EU emissions. It operates under a 'cap and trade' mechanism across 31 participating countries, whereby the total volume of emissions is limited across a multi-year period – the current 3rd trading period extends from 2013-2020, with an annual emissions reduction of 1.74%. Each participant requires an 'allowance' to match each tonne of CO_2 emitted, or the equivalent volume (by warming effect) of N_2O or perfluorocarbons. Allowances may be allocated by local governments, purchased via auctions within the scheme (which sets a carbon trading price), or saved as a surplus between trading periods. The average price of allowances in 2016 was €5.36/tonne, which is seen as being below the level required to drive low carbon investment, and low carbon prices have historically been caused by over-allocation of allowances. However, it is seen to have had a discernible impact on industrial emissions without detrimental impacts on the economic performance of participating countries [13].

2.3.2 National Legislation

Within the UK, there are two main departments responsible for action related to climate change; the Department for Business, Energy and Industrial Strategy (BEIS), which is responsible for leading on policy to reduce emissions; and the Department for Environment and Rural Affairs (Defra), which is responsible for leading on adaptation.

The 2008 Climate Change Act [14] establishes the UK government's framework for development of a plan to reduce GHG emissions on a national basis, and legislates for the UK government to reduce GHG emissions by at least 80% compared to 1990 levels by 2050. It further requires the government to set legally-binding 'carbon budgets', defined as a cap on the amount of GHGs emitted in the UK over a five-year period. The UK's fifth carbon budget, covering the period 2027-2032, was adopted in June 2016. Figure 3 shows the history of UK GHG emissions alongside future targets and budgets.

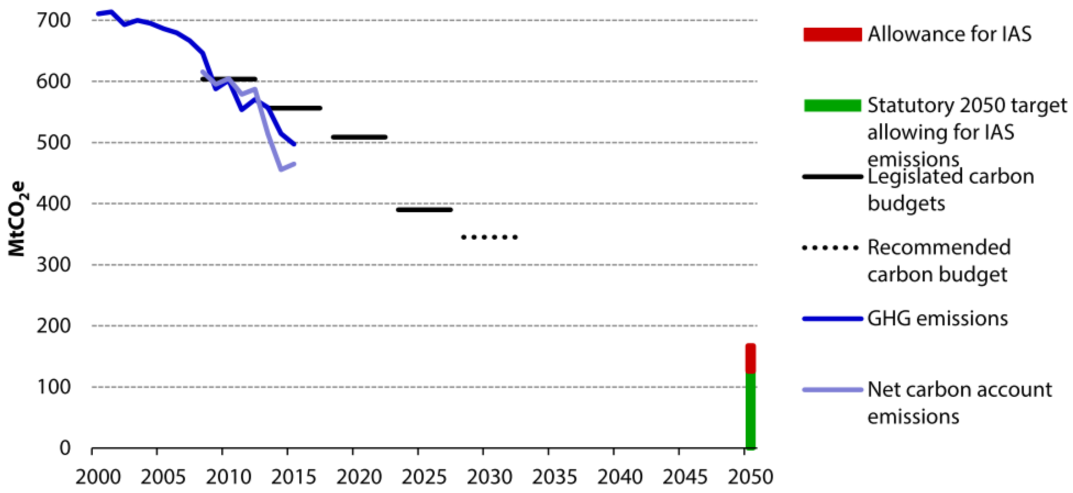

Figure 3 - UK GHG emissions compared to legislated carbon budgets and the 2050 target (reproduced from [15]). IAS = International Aviation and Shipping.

The energy sector of the UK is regulated by the Office for Gas and Electricity Markets (Ofgem), which was formed from a merger of the Office of Electricity Regulation (Offer) and the Office of Gas Supply (Ofgas) following the Utilities Act 2000. Ofgem's remit includes promoting value for money, promoting security of supply and sustainability, the supervision and development of markets and competition and the regulation and delivery of government schemes. Ofgem is a member of the Agency for the Cooperation of European Regulators (ACER), intended to coordinate European energy regulation, particularly with respect to market integration [16].

2.3.3 National Instruments in Emissions Reduction

Some of the key energy policy instruments established in the UK in order to achieve emissions reduction, and which are still active, are listed below. Some instruments which have expired are not included in order to focus on the current policy background.

In order to supplement the EU-ETS scheme described in section 2.3.1, the UK has implemented a Carbon Price Floor (CPF), which has the aim of ensuring that the EU-ETS is underpinned by a price that drives low-carbon investment. A start price of £16/tonne was introduced from 2011, with a target price of £30/tonne by 2020. However, from 2016 to 2021 the floor price is capped to £18/tonne in order to "limit the competitive disadvantage faced by business and reduce energy bills for consumers" [17].

The UK Carbon Reduction Commitment (CRC) Energy Efficiency Scheme began in 2010, and created a requirement for large, non-energy intensive organisations to participate in a cap-and-trade mechanism for the emissions associated with their energy use. The scheme covers organisations with metered annual electricity consumption of more than 6,000 MWh (approx. £500,000), although the emissions audits are not constrained solely to electricity use.

The Energy Company Obligation (ECO) was established in April 2013, and comprises two obligations on suppliers of energy. Under the Carbon Emissions Reduction Obligation (CERO), suppliers must promote 'primary measures' such as loft and cavity wall insulation, with 15% of measures to be installed in rural areas. Under the Home Heating Cost Reduction Obligation (HHCRO), suppliers must promote measures which reduce the cost or difficulty of low-income households (the 'Affordable Warmth Group') to heat their homes. Following a 2016 consultation [18], the ECO has been extended to September 2018, with an annual target spend of £640m, an increase in the number of affordable warmth homes to 4.7m, and a target of 21,000 wall insulation installations per year.

Primarily, however, the decarbonisation that has occurred to date has been achieved through reduction in the carbon intensity of electricity generation. The first mechanism to incentivise renewable electricity generation was the Non-Fossil Fuel Obligation (NFFO) introduced as part of the 1989 Electricity Act, and operating from 1990 to 1998. However, it was fundamentally a funding mechanism for the nuclear industry, and became available for only a brief period due to European Commission competition rules. This shortened time horizon increased the cost of capital. It also rewarded companies who would bid renewable energy at the lowest prices, favouring large self-financing utilities, and it lacked a penalty for bidding but not investing, with bidders securing NFFO contracts and not fulfilling them [19]. It was clear that, at least initially (with the NFFO not fit for purpose, carbon trading ineffective and wholesale prices low while plants operated under the Limited Life Derogation) there was insufficient incentive to generate the financial environment for investment in renewables, and that further intervention would be required in order to meet the UK carbon budget target of 15% renewable sources of energy by 2020.

The Renewables Obligation (RO) was introduced for GB in 2002 to replace the NFFO as a requirement for electricity suppliers to source an increasing proportion of electricity from a renewable source, initially set at 3% in 2002/03 and increasing to 15.4% in 2015/16. Renewable Obligation Certificates (ROCs) are granted by Ofgem to each MWh of electricity generated by an eligible renewable generator, and these can either be bought directly from suppliers via bilateral contracts or bought on an open market. Any shortfall in ROCs against the prescribed volume must be bought from a buy-out fund, which is distributed back to suppliers in proportion to their ROCs. This created a market for ROCs such that if there are less ROCs issued than are required under the obligation, the buy-out payments will increase the value of ROCs and incentivise further renewable generation. In this way, the residual incentive cost for constructing renewable energy projects is paid by electricity consumers whose supply companies fail to generate sufficient electricity to meet the obligation, balancing the obligation against the savings they will have made from supplying a greater proportion of their electricity from conventional plant.

Initially, ROCs were intended to further the commitment to market principles with all technologies competing on price grounds, regardless of their stage of development. This led to wind power being favoured due to its technological maturity and the UK’s wind resource, but with installed capacity held back by planning costs, planning delays and lack of grid capacity in both transmission and distribution networks in key locations. Additionally, low maturity technologies such as wave power received little investment. As a result of reforms, ROCs were ‘banded’ so that different technologies received different levels of ROCs: initially, one MWh from an onshore wind farm was equal to one ROC (reduced to 0.9 ROCs from 2013), whereas, for example, one MWh from a marine renewable source is currently equal to 5 ROCs. This allows the government to control the rate of subsidy in different technologies in order to reflect their maturity, and the MWh/ROC conversion is expected to decline for a given technology over time.

This mechanism does, however, raise the question of how to determine when a given technology is worth investing in further or is unlikely to see a reasonable return compared to other technologies. The move to implementing 5 ROCs per MWh for marine renewables was a governmental response to calls from developers to help stimulate the fledgling market. However, while this has generated seed investment in prototype generators, there has been insignificant interest in commercial-scale investment in wave or tidal projects, and limited progress in reducing costs towards parity with other renewable sources, despite analysis showing that at maturity tidal energy should be able to compete with onshore wind and nuclear costs [20]. The banding of incentive payments then leaves the government and regulator in strict control over which technologies are supported through to commercialisation, in opposition to the original 'technology-neutral' intentions of the RO. It also raises the question of how and when the government can effectively 'kill off' a technology once it is not seen as competitive, and if doing so might be politically toxic due to public support of the idea – if not the implementation – of a technology.

Separately, a Feed-in Tariff (FiT) mechanism was introduced in the 2008 Energy Act and implemented from 2010. This provides a payment per unit electricity generated (banded by technology type, fixed at installation and index-linked to inflation for 20 years) for installations of 5MW or less, intended to incentivise installation of micro- wind and solar generation, small hydro and anaerobic digestion. The FiT system is the means used to incentivise renewables at all levels in Germany and Spain, both of which have a greater proportional use of renewable energy than the UK. Feed-in Tariffs additionally reduce the volatility of the price signal being offered when compared to the RO. The FiT mechanism has, to date, been very successful in stimulating uptake, which has significantly exceeded predictions, as shown in Figure 4. The FiT subsidies received by solar PV installations were dramatically reduced in 2011 and 2012 following government review.

In 2007, Ofgem found that the RO was "an expensive way of reducing carbon emissions compared to other alternatives" and that customers ended up paying for renewable generation projects which do not get built, and fails to link the level of support to the price of electricity or the price of carbon under the EU ETS. This meant that renewable generators could receive much higher returns than 'required' when electricity prices rise in the future. The RO was stated as costing £184 to £481 per tonne of carbon [21]. Ofgem proposed to move to a system of carbon contracts which would ensure that the subsidy would decline as carbon trading becomes more effective, or if wholesale electricity price rises (as expected under LCPD closures). While expensive, however, the RO has succeeded in delivering the investment in renewables required by the carbon budget, with 14.9% of electricity generation provided from renewable sources in 2013 [22] compared to around 2% before the RO was introduced. It is also important to note that assessing policies like the RO solely in terms of their abatement costs is not appropriate. Like many UK policies, the RO had multiple goals – and was not only a policy intended to reduce emissions. It was also designed to promote innovation and learning and, to a lesser extent, to diversify the UK electricity system away from reliance on fossil fuels.

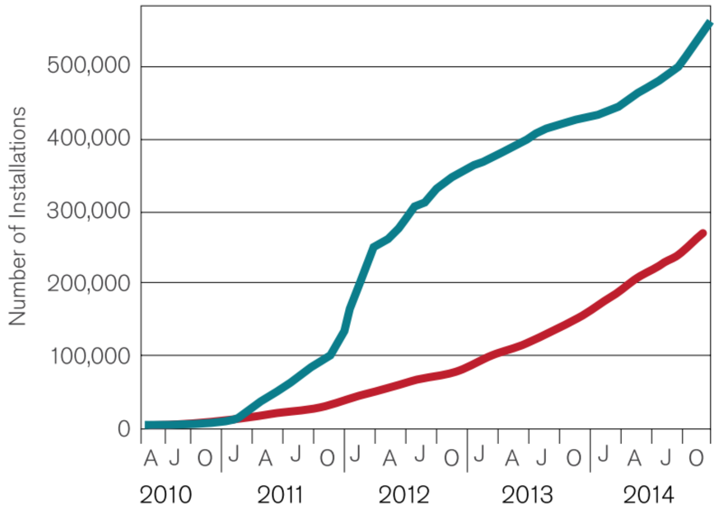

Figure 4 - Feed-in Tariff uptake (blue) against DECC predictions (red) reproduced from [23]

The findings of the Committee on Climate Change, Ofgem's Project Discovery and the DECC consultation on Electricity Market Reform following the change of government in 2010 all agreed that the carbon price was too low to support unsubsidised nuclear power and other low carbon technologies, and that the wholesale electricity price was set by fossil fuel prices alongside the ETS [24]. The cost of meeting the 2020 targets in electricity alone was estimated at £100bn to £120bn, well above the financial capacity of the Big Six, indicating the need for new sources of finance. Hence any policy changes which would lower the Weighted Average Cost of Capital (WACC) would be seen as having significant benefits in lowering this cost and attracting alternative investors.

The Electricity Market Reform (EMR), enacted by the Energy Act 2013 [25], introduced a system of Contracts for Difference Feed-in Tariffs (CfDs) for low carbon generation from 2015, replacing the Renewables Obligation for new generators. Under a CfD, each generator is paid, separately from the markets, the difference between a strike price for their particular technology and a reference electricity wholesale price – the average market price for electricity. The contract is between the generator and the Low Carbon Contracts Company, a company created for this purpose and owned by DECC. The amount paid for CfDs (the difference between the strike price and reference price when the former is larger than the latter) is passed on to electricity consumers through the Supplier Obligation, limited in theory by the Levy Control Framework. The plan is for the final strike price for each annual allocation of contract volume is calculated through a sealed-bid auction grouped by technology, with all eligible generators receiving the strike price of the final generator to be accepted for that technology. CfDs are intended to give investors greater certainty to invest in low carbon generation, while reducing costs to consumers against the RO [26]. This two-way nature of CfDs, with generators paying money back when reference prices rise above strike prices, reduces overall costs to consumers, but is primarily intended to also reduce the cost of capital by ensuring long-run returns to investors. In addition to renewables, Nuclear power and Carbon Capture and Storage (CCS) are also eligible for CfD allocations. While the Government plans that such allocations will eventually be via competitive auctions, the first nuclear contract has been administered directly by the government, with no competition. All generators that receive a CfD are guaranteed a Power Purchase Agreement, with a Backstop PPA mechanism in place to ensure minimum revenues [27].

The structure of CfD delivery was intended to reduce the governmental role, by appointing National Grid as the EMR Delivery Body, and a private company as the CfD counterparty. DECC, however, retained the power to set maximum strike prices, under advice from National Grid. Additionally, DECC/BEIS allowed an uncapped volume of CfD contracts for renewable energy to be awarded early (i.e. prior to the establishment of the auction mechanism) at strike price cap levels, ostensibly to avoid a hiatus in investment and construction. These contracts were awarded to 8 projects (including 5 offshore wind farms) with a total cost of £16.6bn over their lifetimes [28]. While the motivation for this may have been justifiable, the decision to only set budgets after receiving applications circumvented the competitive process, and can be seen as direct intervention into project investment.

A further important feature of the CfD system is the Levy Control Framework. This was imposed by the Treasury (the UK finance ministry) in order to limit the impacts of CfD costs – and the costs of other policies – on consumer bills. The Treasury has set out a trajectory for the maximum annual costs of CfDs plus other policies to 2020. The cap in 2020 is £7.6bn (in 2011/12 prices) which should, according to the government, provide enough funding via contracts for UK climate change and renewable energy targets to be met. However, some in the renewables industry are concerned that the lack of visibility of eligible costs beyond 2020 presents a further political risk to their investment decisions.

Clearly, the success of CfDs in stimulating appropriate investment in low carbon generation is highly dependent on the correct identification of reference prices, and for indices used to adjust those prices once the contract has been signed. These indices introduce a dynamic risk to both investors and consumers, in that an index appropriate today may not reflect true market prices in the future, or the market on which it is based may undergo structural change in the future (such as through European integration mechanisms). If the Secretary of State maintains a discretionary right to change reference price indices, then this will cause investors to be wary of further state intervention, and the structure of reference price determination introduces basis risk [29].

The structure of the Electricity Market Reform separated the requirement for low carbon technology (as a proportion of energy delivered) from the requirement for capacity which can mitigate variability and ensure security and meet the requirements for the delivery of power, through a capacity mechanism as distinct from CfDs. In [30], it is argued that instead of an approach where flexible resources are developed to cope with the pressure of a larger share of passive intermittent RES, there is no major obstacle to complete integration of renewable energy sources into electricity markets with dynamic pricing which reflect the value of flexibility, including negative pricing. Further, energy markets with adequate price boundaries should deliver efficient operation and investment signals, removing the need for capacity remuneration mechanisms such as the Capacity Market. This view is supported by ENTSO-E, the European Network of Transmission System Operators, who recommend that all mature technologies should be exposed to wholesale price signals in the same manner, and that incentives and priority dispatch should be removed for all but emerging technologies [31].

This apparent conflict between sustainability and security is most strongly seen in a policy framework with such strong emphasis on electricity generation, and a comparatively weaker emphasis on energy efficiency and seeking to reduce electricity demand. With fuel poverty an increasing concern, there are calls for policy frameworks to focus more on heating efficiency and building insulation, which represents one of the cheapest ways to cut carbon emissions and to tackle fuel poverty [32]. There are more creative solutions to balancing security needs with emissions targets, such as storage and smarter grid operations, which might be better incentivised under a framework which gives clearer signals about the value of flexibility, as opposed to direct intervention that focuses on generation technologies. The failure of the first capacity auction to correctly value demand-side response as secure capacity, or to provide a clear signal around the value of storage, appears to support this point of view.

In contrast, the Renewable Heat Incentive (RHI) has been the leading UK policy to target the decarbonisation of heat supply, initially opened to non-domestic consumers in 2011 and then to domestic applicants in 2014 [33]. It is currently set to run until 2020 at an annual cost of between £1.3-2.4bn, and has led to the deployment of over 16,000 commercial and 54,000 domestic accredited schemes. The RHI operates in manner similar to a Feed-In Tariff, providing quarterly payments over the first seven years post-installation, but paid from taxation rather than through consumers' energy bills. It covers 4 eligible technologies: biomass boilers, air-source heat pumps, ground source heat pumps and flat/evacuated tube solar thermal panels. The Treasury expects the scheme to fund renewable heat projects equivalent to 500,000 homes by the end of 2020/21. With the abandonment of the Green Deal in 2015 due to a lack of take-up, the RHI remains the only major heat decarbonisation policy in place. In a review of the scheme published in February 2018, the National Audit Office also found that take-up of the scheme has been much lower than originally anticipated and that the cost-effectiveness of the scheme in generating renewable heat and reducing emissions was uncertain.

Separately from Westminster, the devolved administrations of the UK have their own strategic plans for energy – although energy is not a devolved matter, so broadly these reflect a set of targets of greater ambition than as set within the UK Carbon Budgets, and provide more localised detail on government financing and the coordination of Local Authorities. In Wales, the 2012 'Wales Energy' [34] defined the financial co-benefits and opportunities to the region from the energy sector, and the required changes to the local planning regime required to support these developments. Northern Ireland's 2010 Strategic Energy Framework [35] primarily concerns energy security and increasing local revenues from renewable electricity production. The 2017 Scottish Energy Strategy [36] assesses hydrogen and electrification routes to decarbonisation, as well as promoting a significant move towards improved building efficiency through Scotland's Energy Efficiency Programme (SEEP), and incentivising opportunities in local energy systems.

2.3.4 Current Status

The July 2016 Progress Report to Parliament by the Committee for Climate Change (CCC) [15] stated that, while emissions had fallen to 38% below 1990 levels by 2015, almost all of this reduction had been from the power sector due to reduced coal consumption and increasing levels of renewables. However, emissions in any single sector will not be sufficient to meet the fourth or fifth carbon budgets; that is, significant action is required in progressing decarbonising the heat and transport sectors by 2030 in order to meet the required long-term trajectory towards 2050. Currently, the CCC identifies a gap of around 47% of required emissions reduction between the current Government plans and the fifth Carbon Budget in 2030, with a further 24% at risk without strengthened regulation. The CCC found no significant reduction in emissions from transport, buildings or industry during 2015.

In particular, progress in improving building energy efficiency has stalled since 2012, and take-up of heat pumps and district heating (both previously identified as key technologies able to significantly contribute towards the decarbonisation of heat provision) remains at a minimal penetration of around 0.5%. In total, only around 2.5% of heat comes from low carbon sources, compared with more than 45% of electricity. As heat accounts for around 40% of UK energy consumption and 20% of GHG emissions, the decarbonisation of the heat sector is seen as vital for the UK to reach UK emission reduction targets. The 2013 Heat Strategy [37] extended funding for the Renewable Heat Incentive to 2021, and set up the Heat Network Investment Project, making £320m available for heat network projects between 2016-2021. However, the total number of efficiency measures installed under government schemes was down 87% in 2015 compared to 2012, due in part to the removal of existing loft insulation schemes with the ECO and the Green Deal, which was itself abandoned in 2015. Similarly, standards developed from 2005 which would have required new homes to be carbon neutral from 2016 were abandoned in 2015. At this time, the UK was ranked 27th among EU Member States in terms of progress towards the goal defined by the EU Energy Performance of Buildings Directive of near zero emissions in new buildings by 2020 [38]. This indicates a current regulatory gap in effective legislation on energy efficiency, and no clear route to decarbonisation of heat in the near term.

In the absence of an improvement of national building regulations, there is little incentive to incorporate new technologies for heat into new buildings, such as through the use of heat networks. The London Plan [39] requires carbon emissions to be 35% below national building regulations, which incentivises developers to look at options in district heating and CHP, but outside London local authorities must lead in developing opportunities for local heat supply. In Scotland, there is a separate ambition to achieve 1.5 TWh of heat demand to be delivered by district or communal heating from both renewable and traditional energy sources, and to have 40,000 homes connected by 2020 [40]. Currently the levelised energy cost of district heating, CHP and heat pumps is high when compared with gas boilers [41], in particular due to the large upfront capital costs, and this is likely to remain true for some time. This is a major barrier to deployment of heat technologies with a lower carbon intensity than using natural gas. While technological learning will improve this through reduction in installation costs and improvements in efficiency, it is likely to remain a significant barrier to the decarbonisation of heat, and require further government intervention to achieve increased investment in lower intensity heat technologies.

2.4 Generation of Policies for Cross-Sectoral Decarbonisation

In the previous section, the need for a means to project the impacts of potential decarbonisation policies has clearly been identified, both by the existence of both successful and unsuccessful historical policies. In particular, the use of energy system modelling allows the potential results of a government intervention – such as taxation or subsidy – to be predicted. The effects can be explored across multiple linked sectors (such as transport, agriculture, housing and others) in order to explore trade-offs and inter-relationships between areas of the economy which may not be evident from analysis of single carriers or discrete subsets of energy use. In this respect, the use of a cross-sectoral Whole System Energy Model (WSEM) – i.e. one containing representation of all sectors relevant to energy production and consumption - which characterises the totality of energy demand and supply across a nation or continent, allows a government to determine if a particular policy mix will – in terms of total abatement – reach a desired target such as that given in their Nationally Determined Contribution. The use of WSEMs is not, however, intended to give the end answer in terms of the idealised technology and policy mix; instead, modelling should be used to deliver insights. WSEMs and sectoral models allow an assessment of costs, trade-offs and pathways related to achieving emission targets within the constraints of energy security [42]. This process is generally iterative, both in terms of the gradual improvement of the central WSEMs used in the policy-making process (such as MARKAL within the development of the UK Energy White Papers in 2003 and 2007) but also in the incorporation of sectoral and macro-economic models into holistic analyses.

It is, indeed, the role of WSEMs to ensure that a holistic view of the trade-off between sectors can be assessed in a manner that cannot be achieved solely through the separate analyses of each sector. In this manner, the use of a WSEM to cover multiple sectors addresses the challenge of Energy Systems Integration (ESI) – the process of coordinating and planning energy systems across multiple energy vectors and geographical scales to deliver cost-effective energy services while minimising environmental impacts, and considering the interaction with other large-scale infrastructures such as water and transport [43]. For example, a recent government plan on reducing nitrogen dioxide emissions from vehicles acknowledges the close link between carbon emission reduction and desirable air quality improvements, despite having separate causative emissions and distinct scales of impact [44].

There are 4 key stages to policy setting within energy systems [45]:

- Phase I: Preparation and orientation, where the situation is roughly analysed, questions are formulated and targets derived, often with the assistance of relevant stakeholders;

- Phase II: Model design and detailed analysis, where formal tools are established or commissioned, and scenarios for analysis are discussed and derived;
- Phase III: Prioritization and decision, where the outputs of the modelling undergo review by policymakers and stakeholders, in order to assess their relevance to the real-world energy system, and to determine actual policies which are required to realise target scenarios;
- Phase IV: Implementation and monitoring, where the policies are enacted under appropriate institutions, and assessed for success on an ongoing basis, potentially to inform a successive round of policy evaluation.

Within this context, then, the use of WSEMs in the second phase will only be a constructive effort if, firstly, they are capable of appropriately representing the questions and formulations derived in the first phase, and secondly, if their outputs are able to be relevantly assessed in the real-world context in the third phase. This requires those performing the modelling to closely appreciate the needs of their audience, and to avoid ‘modelling for modelling’s sake’.

2.5 Classification of WSEMs

There are a wide range of models which fall within the definition of WSEMs. In this section, the broad forms and categories of different models are discussed in order to distinguish between their potential appropriate application to the various investigations and analyses required to support the energy policy process. Most of the classifications given are not mutually exclusive, and models may fall into multiple categories listed.

2.5.1 Model Purpose

A model may have one of several intrinsic purposes. However, this does not necessarily mean that the model is only, in practice, used for that purpose – the potential for inappropriate application of WSEM outputs is discussed further in section 2.8.1.

A model may be constructed for the purposes of *forecasting* – attempting to predict future patterns of energy transfer, consumption or behaviours in response to projected changes in exogenous factors. Similarly, a model may be used for *hindcasting* – historical patterns are reconstructed as closely as possible, using a deterministic model, in order to correctly identify underlying causes and mechanisms. The Cambridge Econometrics MDM-E3, for example, is an energy-environment-economy (E3) model which can be used to forecast changes in economic structure, energy demand and resulting environmental emissions [46], based on feedback effects from different sectors, in response to energy prices or other stimuli.

Similarly, a model may be constructed for *exploring* energy futures – to determine the potential changes in energy services and provision under different policy options, constraints or pricing. For example, the Department of Energy and Climate Change (DECC) 2050 Calculator [47] allowed members of the public to engage with UK energy policymaking and derive their own UK energy futures based on a range of policy and technology options to meet emissions reduction targets. These futures may include analysis of the specific energy demand from different sources and economic activities, or may investigate the impacts of external energy supply and imports/exports.

2.5.2 Scope

A WSEM should encompass all energy sectors, in order to correctly represent the interactions of all energy users and technologies. The scope may be broader, and represent energy as a sector within a larger economy-wide model. Within the energy sector, subsectors may include heat, transport, agriculture, housing, industry, and commerce. Similarly, the energy sector has many and varied interactions with non-energy sectors. To what extent should these interactions be exogenous, or can a model incorporate them? This particularly comes into scope where the descriptions of energy end-uses are concerned, or for the description of supply-side commodities, where the availability or use of energy is dependent on other economic activity. WSEMs may also consider the environmental impact (beyond simple GHG emissions) such as being coupled with representations of land-use, biodiversity and industrial impacts. This may include, for example, the coupling of the energy system model with a water system model to examine the interdependencies between the two.

This also raises the issue of *endogenisation* – the selection of which of the many elements used within an energy model should comprise part of that formulation, and should be generated implicitly by the model itself, and which should be exogenously defined. Each quantified element of a WSEM should hence either be an endogenous variable or an exogenous parameter. For example, any energy model will have the demand for energy (usually disaggregated by sector) as a key driver – but should this be set as external to the model, or derived within the model by use of other parameters such as economic activity and population? In the former case, the values derived may be set by a more detailed and appropriate model, but the latter case allows for some amount of demand responsiveness to be included (i.e. where demand itself responds to the price and availability of energy services).

The scope also concerns the degree of spatial and temporal disaggregation, discussed in greater detail within Chapter 3. The choice of regional representation will be driven by the model scope – for example, for an international model investigating the global market for energy commodities, it may be sufficient to model entire countries as individual elements in order to model the flow of commodities between them, whereas other security-driven analyses will require finer spatial detail. This similarly applies to the temporal resolution, where long-term decarbonisation strategies are best described on an annual or multi-annual basis out to 2030 or 2050, but higher resolution detail is required to explore particular issues where short-term variability (such as from renewable energy output) is of a key concern.

2.5.3 Methodology

Top-down models look at behavioural realism within a macro-economic framework, with exogenously generated variables representing aggregate properties of the energy system. The analysis seeks to investigate economy-wide responses to policies, such as through changes to income, GDP or competitiveness. For example, the UKENVI model [48] is a Computable General Equilibrium (CGE) model of the UK energy system, economy and environment which is used to investigate the response of the UK economy to improvements in industrial efficiency. *Bottom-up* models, conversely, are technologically explicit and usually include cost and emissions definitions. They may be used to explore technical opportunities and trade-offs between solutions and sectors, as typified by the TIMES modelling framework discussed in section 2.6.3.

As an example, in a bottom-up model, energy demand E might be equal to the sum of the number of people ND demanding an energy service i at a point in time, and the energy consumption EC associated with each service, with both parameters exogenous to the model:

$$E = \sum_i (ND_i \times EC_i) \tag{2.1}$$

This aggregated energy demand then drives the derivation of a mixture of supply-side technologies capable of meeting any formalised constraints around that demanded volume of energy. Generally, bottom-up models are seen as optimistic (as they assume there are no behavioural barriers to the uptake of technologies), whereas top-down models are often pessimistic, over-estimating the cost of future technologies [49].

Alternatively, ‘hybrid’ models may exist between the two and incorporate technological detail into a macroeconomic framework, either by soft-linking top-down and bottom-up models, or by hard-linking into a single integrated model. For example, the Long-range Energy Alternatives Planning system (LEAP) [50] integrates a top-down behavioural demand model with a bottom-up energy supply model. A model (such as PRIMES discussed in section 2.6.6) may also be modular, with different modelling approaches used in a selection of sub-models which are appropriately inter-linked.

In terms of options for the underlying methodology, there are several main paradigms.

An *econometric* model uses statistical inference from historical data to determine relationships between key economic variables, and may have a broad or focussed scope. As an example, in an econometric model, the energy demand might be a function of the electricity price P and the private consumption of the household PC, incorporating elasticities a and b for each term respectively:

$$E = kP^{a}PC^{b} \tag{2.2}$$

$$ln(E) = a \times \ln(P) + b \times \ln(PC) + k' \tag{2.3}$$

The elasticities will measure the demand responsiveness to e.g. price or economic activity (such as the increase in energy consumption that follows from an increase in GDP), and will be calculated by regression against historical values.

Macro-economic models assess the entire economy, with energy as one component, without explicit technical detail, incorporating elasticities as above. Similarly, e*conomic equilibrium* modelling focusses on very long-term growth paths and is used to study the complete economic system. A *general equilibrium* model will have simultaneous equilibrium in supply and demand across all sectors, whereas a *partial equilibrium* model will assume that what happens in one market does not affect other markets, and the equilibrium for each can be modelled independently of others. In this respect, a general equilibrium model will usually have a scope covering all sectors, where the partial equilibrium model will usually restrict scope to the energy sector in isolation.

An *optimization* model will seek to meet either maximise or minimise an ‘objective function’ – often finding the least cost solution – subject to a set of constraints (such as defined by atmospheric emissions, energy security or reliability). There are a number of mathematical approaches within the field of optimisation. Typical formulations might be linear, where each variable takes a continuous monotonic form, or may incorporate more complex mixed-integer variable sets where individual elements may be turned ‘off’ or ‘on’ (such as where deciding whether to invest in individual large elements of infrastructure). Dynamic programming (such as applied to the problem of local energy system management in [51]) allows the exploration of a greater solution space through disaggregation of the system into multiple sub problems.

Fuzzy logic-based ‘blending’ may further allow problem decomposition, though this is primarily applied to the area of energy system control, such as in [52] where it is applied to a home energy management system.

In a *simulation* model, an existing pre-defined configuration of an energy system is operated in a time-sequential manner, in order to determine the actual dispatch and flows of energy for that system. Typical outputs will be the utilisation rates of devices and implied costs. This might be used, for example, to determine if a given configuration (perhaps defined as the optimal investment from a separate model) leads to a secure and operable system when investigated at shorter time horizons. For example, in [53] the Irish Single Electricity Market is simulated for multiple runs over one year in order to validate results within the wider Irish TIMES model.

Within most of the above-described methodologies, *stochastic* variants may be created which aim to describe the impacts of variations in the exogenous variables, such as external energy prices or scenarios around the availability of renewable resources. This variation may either be captured endogenously through formulations which include stochastic optimisation, or reductive methods such as Monte-Carlo simulation may be used which involve multiple model runs with exogenous variables sample from appropriately-constructed random distributions. This sampling methodology may also be used to disaggregate input datasets (such as to determine the contribution from a renewable technology at a specific point in time given an average contribution over a sampled period). In most cases, inclusion of stochasticity within an energy model greatly increases the level of computational complexity.

Within the above classifications, many models will use cost as their main determinant, either as a means of defining the objective function within an optimisation, or to calculate the cost of a particular scenario undergoing simulation. Costs may be exogenous, as in fuel prices, or generated endogenously through market simulation using supply curves generated from technology parameters. Technologies may be represented either through a single levelised cost, or in detail with capital/fixed costs, fixed operational costs and variable operational costs. Transactions (such as transmission of a fuel commodity) may also have associated costs. Lastly, emissions may either be governed by a hard constraint, or simply through the application of a cost per emissions. Models such as TIMES (described in Section 2.6.3) allow the calculation of implied carbon costs based on emissions constraints.

Agent based methods recognise, instead, that a traditional optimization model implies the presence of a long-term strategic planner who does not exist in reality, and instead the uptake of new technologies are governed by decisions made by individual system actors making autonomous decisions. This area of investigation, instead, chooses to model these decisions independently by characterising the e.g. utility functions of each system actor and expecting them to act in a more myopic sense than the strategic planner. Agent-based modelling is commonly used to study interactions among multiple decision entities [54], and typically this assists in determining whether externally optimal decisions will be supported by real-world participants, and to investigate whether proposed policies and incentives may generate a desired set of behaviours that entail uptake of desired technologies. For example, in [55] the interactions between actors in transport and fuel delivery are used to evaluate the potential transition to hydrogen-based transport networks.

Clearly there is a great variety of WSEMs in application, methodology and scope, and as interest in the field increases with ever-growing ambition in decarbonisation, so the number and type of models will continue to grow. In the next section an attempt is made to reduce this diaspora of models to identify the key features which have been previously used to analyse the UK energy system.

2.6 Overview of WSEMs Previously Applied to the UK Energy System

In order to determine the value of existing WSEMs in analysing the UK Energy System, it is first necessary to examine the structure and nature of such models used to date. In this section, the main models used are reviewed and summarised both in their internal detail and the external applications for which they have been used. This in turn allows the existing weaknesses in approach and application to be assessed, allowing a scope for potential improvements to be determined.

A review of models applied to analysis of the UK energy system in the UK from 2008-2016 [56] found more than 100 different models referenced in the literature, ranging from the investigation of a single technology through to integrated WSEMs. 22 models are identified as relating to the Whole System approach, and the most cited/referenced (both in the academic literature and in government policy documents) are discussed in further detail below.

2.6.1 MESSAGE

The Model for Energy Supply Strategy Alternatives and their General Environmental impact (MESSAGE) is a dynamic linear programming model, developed by the International Institute for Applied Systems Analysis (IIASA) in Austria through the late 1970s. Following a standard linear programming methodology, MESSAGE minimizes the total discounted costs of supplying a given set of energy demands over a given time horizon. The original MESSAGE model balances secondary energy demand (disaggregated into sectors and exogenous to the model) against primary energy supply, defined as a set of resource availabilities and disaggregated into cost categories [57]. Secondarily, MESSAGE allows the environmental impact of energy strategies to be incorporated into the objective function. Constraints within the model include the build-up speed up technologies, the annual availability of resources, load regions, and local resources against import availability. It is typically used in conjunction with an econometrically-defined energy consumption module, as depicted in Figure 5.

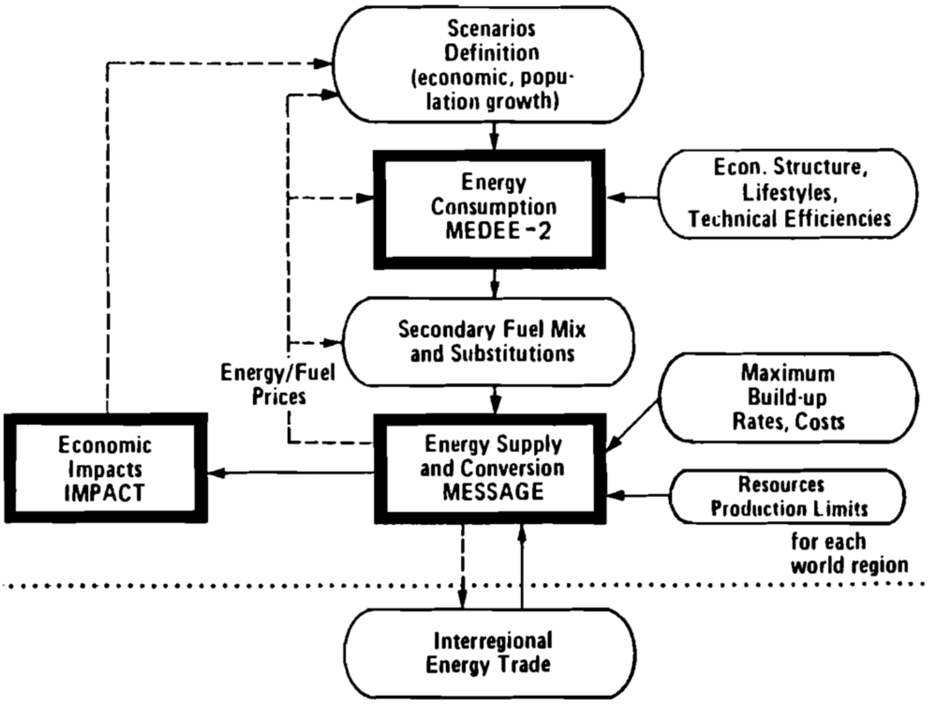

Figure 5 - The IIASA global energy modelling framework incorporating MESSAGE (reproduced from [57])

MESSAGE represents one of the earliest attempts at a broad-scale technologically-explicit WSEM, and formed the basis for the development of MARKAL.

2.6.2 MARKAL (and variants)

The MARKAL (Markets and Allocation) model was developed during the 1970s after the International Energy Agency (IEA) formally initiated the creation of a common tool for analysing energy systems, to be shared for use among OECD nations. MARKAL became a common tool among the members of the Energy Technology Systems Analysis Program (ETSAP), and was used extensively between around 1980 and 2005 [58].

Multiple formal MARKAL variants were developed, including MARKAL-MACRO, a General Equilibrium version of the model incorporating top-down modelling of the national economy; MARKAL-ED, computing a supply demand partial equilibrium alternative to the supply cost optimisation model; and MARKAL-MICRO, using non-linear programming.

A UK MARKAL model was first developed to provide input to the 2003 Energy White Paper [59]. The key use was to provide a measure of costs to the economy of different emissions abatement levels, leading to the conclusion that "the cost impact of effectively tackling climate change would be very small—equivalent in 2050 to just a small fraction (0.5–2 %) of the nation's wealth, as measured by GDP." It was argued that the results underestimated the costs, but a review by the Institute of European Environmental Policy argued that the results helped to overcome a key barrier to emissions reduction acceptance by Parliament, and generated a positive attitude towards carbon policies [60].

A UK MARKAL-MACRO model was developed in order to provide input to the 2007 Energy White Paper [61], analysing a wider range of over 50 scenarios.

2.6.3 TIMES

The Integrated MARKAL-EFOM System (TIMES) is a further development of the MARKAL model produced by ETSAP. The model paradigm is identical to MARKAL. The main structural improvements (i.e. excluding developments intended to simplify model maintenance and data handling) include [62]:

- The introduction of user-defined variable time periods – for example, the model may be run annually for the near-term and then subsequently in 5-year periods out to 2050, reflecting the policy periods and budgets currently set for carbon commitments as described in Sections 2.2 and 2.3;
- Flexible time-slicing and storage processes for any commodity (whereas in MARKAL they are only available for electricity and low-temperature heat) - time-slices are coupled via storage processes which exchange volumes of energy between neighbouring periods, on a daily, weekly or seasonal basis;
- Inclusion of construction/dismantling times and costs for technologies;
- Inclusion of vintaging across all processes (i.e. the ability to define age-dependent parameters such as availabilities and costs) as opposed to only demand-side processes in MARKAL;
- Increased detail on timing of investment cost payments (as opposed to assuming that all investments occur in year 0);
- Endogenised climate variables which allow the calculation of radiative forcings within the model based on calculated emissions.

TIMES is now one of the main models used for national carbon emissions modelling by governments around the world. The Department of Energy and Climate Change (DECC) of the UK Government commissioned a UK TIMES model (UKTM) to supplant the UK MARKAL models, which was completed in 2014 and used as one of the principal tools by DECC and the CCC for setting the Fifth Carbon Budget in 2016 [63]. Recently, the Scottish Government has commissioned and completed a Scottish TIMES model, based on UKTM, which was used to generate the Scottish Energy Strategy released in early 2017 [36].

Due to the importance of UKTM for the setting of UK energy policy, the remainder of this thesis will focus on the use of UKTM and its internal representations of the UK energy system. As TIMES is an exemplar of the bottom-up, technology rich class of least-cost optimisation WSEMs, many of the issues approached in this work can be extended to other WSEM models, and this is discussed further in Section 0.

2.6.4 OSeMOSYS

A more recent development in WSEM has been a significant attempt to reproduce the technology-rich formulation of MARKAL/TIMES but within the open-source community, as represented by the Open Source Energy Modelling System (OSeMOSYS) [64]. A large part of the policy impact of OSeMOSYS has been within developing countries (i.e. where it has been used in place of more established WSEMs) but work such as [65] has seen its application to western energy systems. Due to the significant barriers to entry in using WSEMs such as TIMES, it can be expected that such open source models may grow to a significant user base and see increasing policy relevance.

2.6.5 POLES

Prospective Outlook on Long-term Energy Systems (POLES) is a global-scale energy model with an annual resolution, developed by CNRS / UPMF University, Enerdata and IPTS (Spain, European Commission research centre). It models energy balances for 32 countries across 18 world regions [66]. It disaggregates energy into 15 demand sectors, 12 renewable technologies and 12 power generation technologies, as well as simulating oil and gas discoveries and reserves. Energy markets are modelled endogenously to derive energy prices. It has been widely used by government agencies to simulate oil/gas prices and import/export flows, and so to analyse abatement policies within an international context. Economic variables such as GDP and population are treated as exogenous values to drive local demand and technology investment.

POLES is an example of a global model which can be used to interpret national energy policies within the international context. Within the UK, POLES has been used to project European energy prices and hence the cost of imports of oil and gas against indigenous extraction.

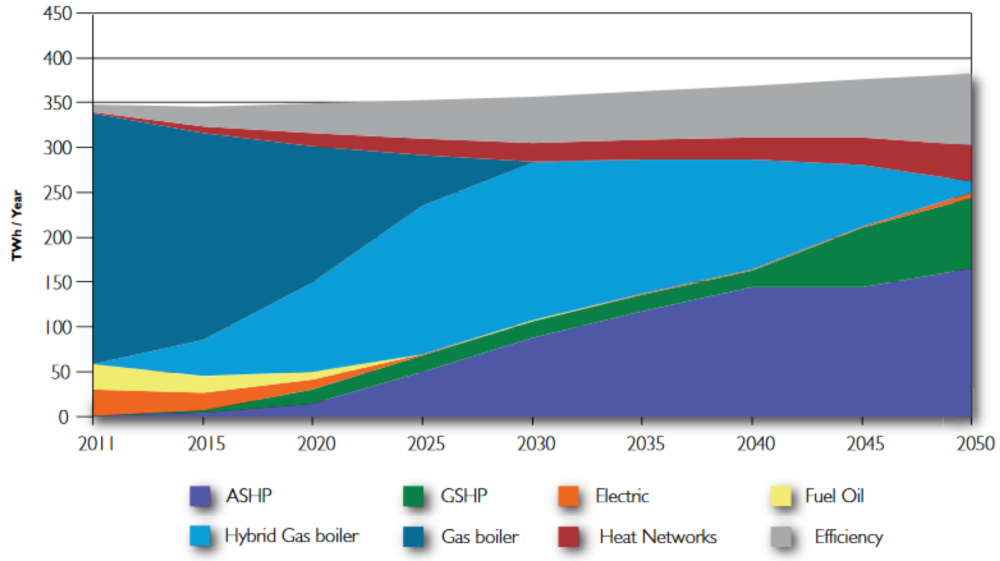

Figure 6 - Projected evolution of domestic space heat provision by technology, based on UKTM analysis (reproduced from [67])

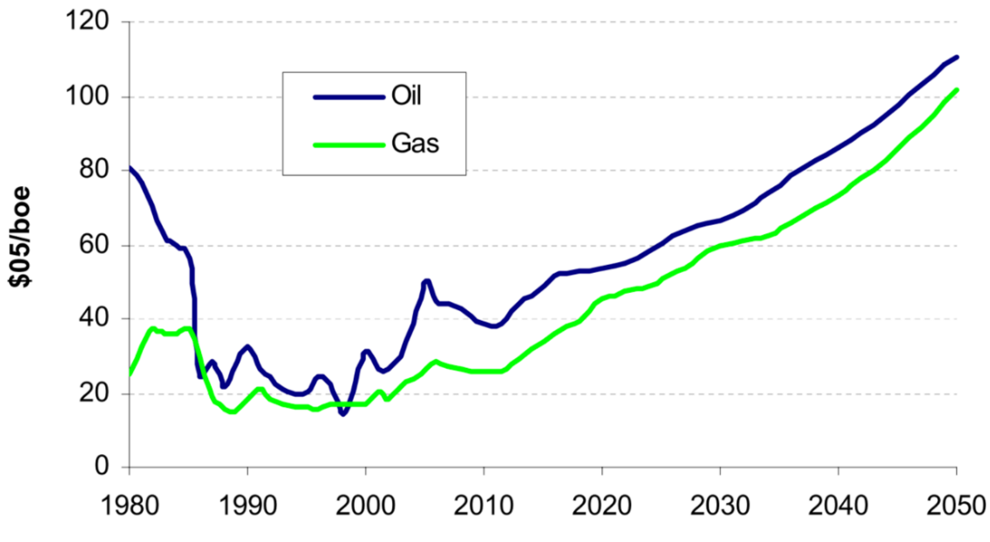

Figure 7 - Example oil/gas price projection from POLES WETO-H2 simulation (reproduced from [66])

2.6.6 PRIMES

The PRIMES (Price-Induced Market Equilibrium System) energy system model has been developed since 1993 through European Commission funding to the Energy-Economy-Environment Modelling Laboratory at National Technical University of Athens [68]. The PRIMES model is a collection of sub-models (illustrated in Figure 8) representing the behaviour of specific agents either demanding or supplying energy, and endogenously modelling energy commodity markets and prices to determine the market equilibria between agents within given balancing and emissions constraints. Each demand agent maximises utility from energy demand and non-energy inputs (such as commodities and production factors) within constraints around activity, comfort, equipment and fuel availability. Each supply agent formulates stylised companies which minimise costs or maximise profits from market competition within the constraints of demand, reliability and emissions. PRIMES is, in this sense, a hybrid model because it captures both technology-rich detail along with behavioural characteristics. It is more aggregated in form than most bottom-up models, but more disaggregated in behaviour than a simple econometric model. Exogenous variables are economic activity, international energy prices, technology parameters and emissions abatement policies. Typical outputs include energy balances, demand projections by sector, electricity/heat production by technology, fuel production and use, sectoral investment, and activity by different energy uses, alongside total atmospheric emissions. PRIMES has a European focus, modelling 35 European countries explicitly on 5 year time steps between 2010-2050, along with the trades between Europe and the rest of the world for electricity, gas and other fuels.

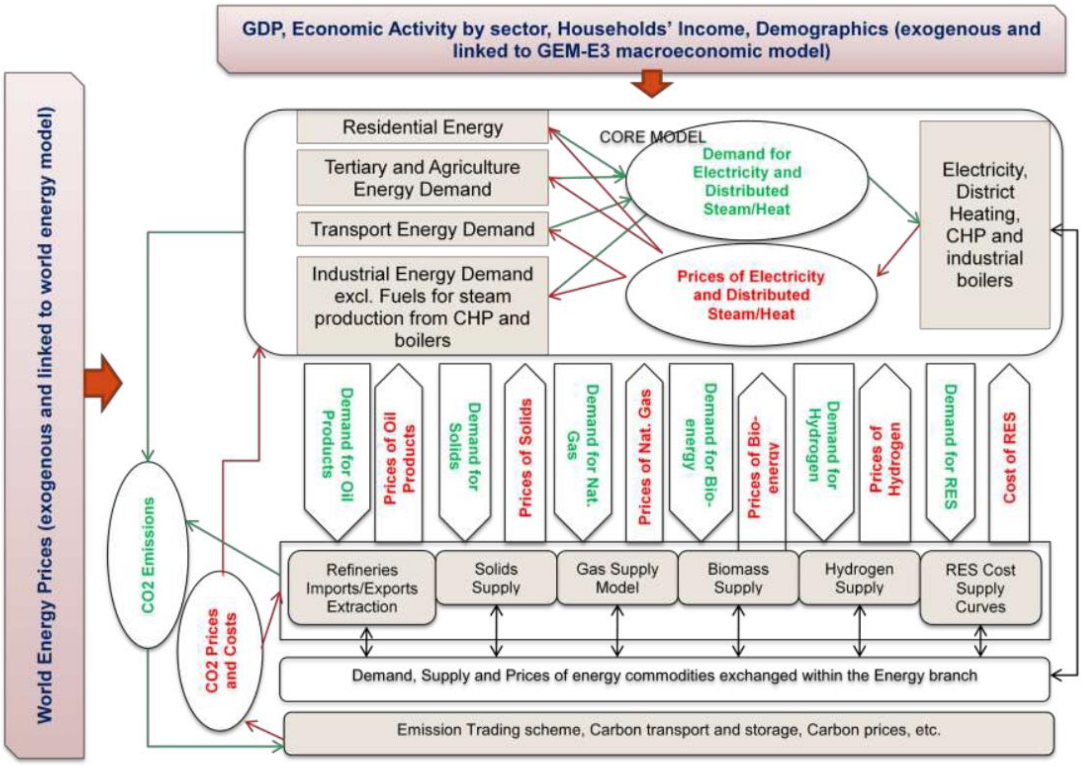

Figure 8 - PRIMES modelling structure, showing individual sub-models and linkages (reproduced from [68])

In the UK, PRIMES has been used to evaluate ETS prices and future energy balances between Member States, informing UK policy objectives out to 2030 based on the implementation of renewable power sources and industrial processes [69].

2.6.7 ESME

The UK Energy Technologies Institute (ETI) has, since 2008, developed the Energy System Modelling Environment (ESME), which is a policy-neutral least-cost optimisation tool to determine the energy system designs which meet stipulated security targets within emissions constraints [70]. ESME considers UK pathways from 2010-2050. Example outputs are shown in Figure 9. ESME incorporates a Monte Carlo model which examines uncertainty, specifically with respect to energy prices and technology performance and costs, which differentiates it from the TIMES/MARKAL models. ESME has an engineering orientation, looking at systems designs which specify capacity and operation of technologies, with around 250 technologies incorporated, including retrofits and efficiency improvements. As a regionally and spatially disaggregated model, it also optimises transmission capacities in planning and the dispatch of energy belonging to different carriers in operation.

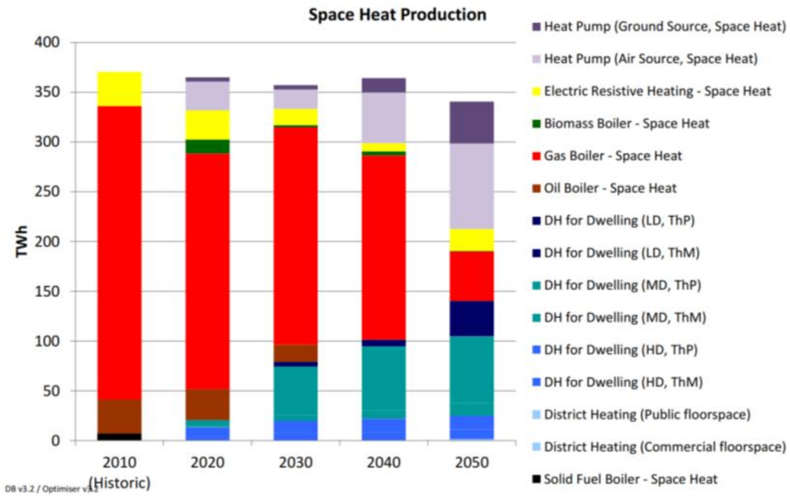

Figure 9 - Projected aggregate space heat delivery technologies for 2050 from ESME analysis (reproduced from [71])

2.7 Other UK Energy Models

WSEMs are far from the only instruments used in setting national decarbonisation policies, and the forms of other tools used historically in the UK are described in brief here.

2.7.1 Sectoral Models

A wide variety of sectoral models have been used to study the UK energy system. Significant models in the policy space include electricity market models such as DSIM [72] used to project costs of future infrastructure based on forecast generation investments; combined gas and electricity models such as the Combined Gas and Electricity Network Model (CGEN) [73] looking at interactions between network expansions in both sectors; the National Transport Model (NTM) used by the Department for Transport to forecast sectoral growth and investigate policy impacts [74]; and the Cambridge Housing Model used by BEIS to predict energy demand in England based on demographic and housing stock data [75]. Each such model will have a sector-specific formulation, and while cross-sectoral coupling of models is common, it may entail soft-linking due to the incompatibility of input and output data structures. In the case of optimisation

2.7.2 Marginal Abatement Cost Curves (MACCs)

The drive to find cost-effective emission mitigation strategies has led policymakers to estimate the total cost of particular mitigation strategies, and to order these by cost in order to determine the total implied cost of a particular level of abatement. These ordered investment representations are termed ‘Marginal Abatement Cost Curves’ (MACCs) and a classical example of a global MACC is given in Figure 10. While MACCs do not fit the definition of a WSEM, as actual flows of energy are not represented, it has remained a widely-used modelling tool for setting policies, in particular within the EU where it allows the interactions between different national economies and the EU-ETS trading scheme to be understood (i.e. to determine the point at which trading of emissions certificates becomes a cheaper option than local mitigation). This also allows the long-run traded cost of carbon to be estimated.

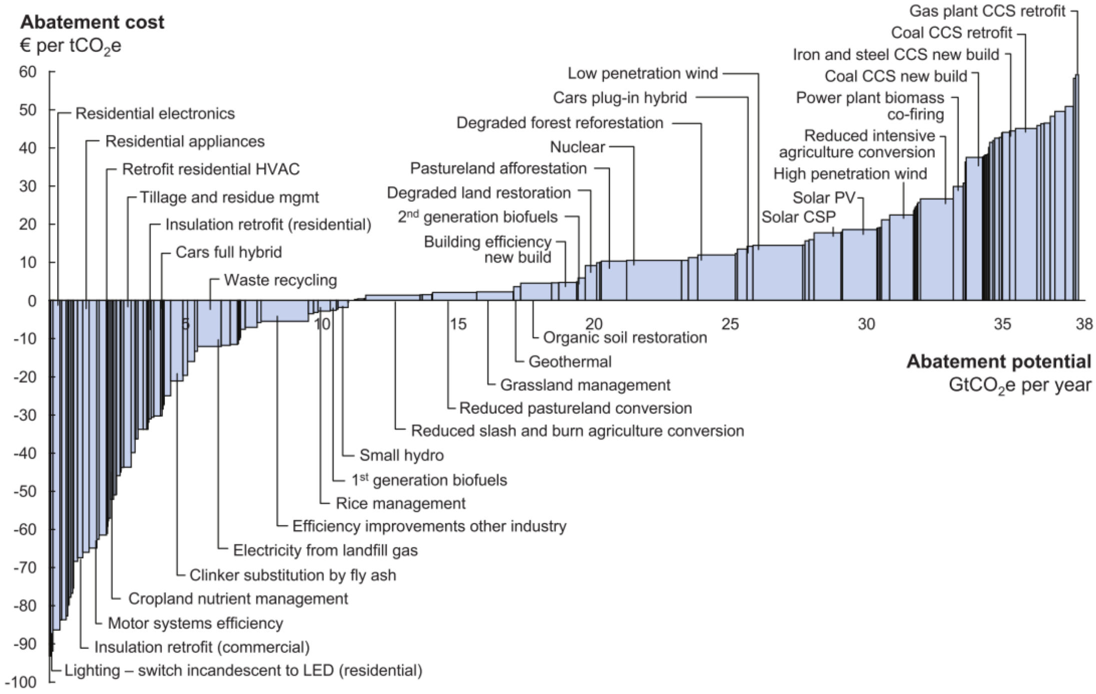

Figure 10 - Global Marginal Abatement Curve for 2030 (reproduced from [76])

As carbon emissions reduce, the marginal abatement cost rises, due to additional effort required to obtain new sources of mitigation. In economic terms, the optimum level of abatement occurs when the social cost of carbon is equal to the marginal abatement cost in a given period. Broadly, it can be expected that the form of policies required to enact investment will be different at the each end of the MACC. Investments with a negative abatement cost usually require ‘command-and-control’ policies which may include placing a ban on the use of specific technologies, such as the EU-wide prevention of the sale of incandescent lightbulbs. Policies with a low positive abatement cost may be best suited to market-based mechanisms, where solutions are well-understood but require competitive procurement to be established. At the right hand end of the MACC, abatement potential requires innovation and R&D investment [77].

The CCC, in setting previous carbon budgets, has described MACCs for multiple sectors, with a particular focus on agriculture [78], as well as using the methodology to explore possible levels of carbon pricing [79].

2.8 Weaknesses in the bottom-up WSEM Approach

Bottom-up WSEMs such as TIMES may exclude many economic costs and behavioural effects, particularly where the demands for energy services are considered exogenous. For example, this will usually ignore the impact of 'rebound effects' whereby energy consumption increases in response to an increased availability or decreased cost of meeting a given energy service, as demonstrated in the case of increasing energy efficiency [80].

While MACCs take into account a significant level of technological detail, and allow a clear understanding of market and technology interactions, they usually do not integrate behavioural factors (such as rebound effects) nor the interaction between mitigation measures. Depending on the specific modelling technique used, they also have no temporal aspect and may be limited in terms of macroeconomic effects [77].

2.8.1 Inappropriate Application

The decision variables within a WSEM may not correspond to a real-world latitude in possible policy – particularly within deregulated markets. Where a WSEM may select a specific technology over another (on a least-cost basis), the actual energy system to which the policies should be applied may involve technology-neutral markets and procurement mechanisms.

For example, Ofgem's approach towards regulating the future energy system seeks to ensure that "… regulation is neutral between different technologies, systems and business models … promoting a level playing field between entrants and existing companies, and between network reinforcement and alternative solutions" through "promoting competition and harnessing market-based mechanisms." [81] This creates a disconnect between modelling and policy, in that the models select technologies based on assumptions of projected costs, whereas the policies which are set define markets which are in turn used to select technologies based on actual, competitively-set costs.

Typical policies which may be enacted involve incentives, subsidies and taxation. In this respect, energy consumers and producers may be 'nudged' towards particular technology selection, but the timescales on which this may occur may be very different to that envisaged by the optimum trajectory within a WSEM. For example, the 'Green Deal' policy introduced in the UK 2012, intended to improve financing for homeowners to invest in energy efficiency improvements, was cancelled in 2015 due to only achieving an uptake of 20,000 homes, compared to a target of 130,000 for the first year alone. In contrast, the Energy Company Obligation (ECO), by placing a statutory requirement on energy companies, has improved 1.4 million homes over the same period [82]. While most WSEMs see investment in energy efficiencies such as wall insulation as a near-term priority (in keeping with the negative cost seen in MACC curves), in the UK 14 million homes still do not have any form of wall insulation, despite this being seen as a key policy area since the 2003 Energy White Paper. In this respect, the inability of WSEMs to represent any non-technical or economic constraints on technology investments may lead to a recommended trajectory which is not feasible when behavioural and political requirements are considered.

2.8.2 Spatial Aggregation

Most WSEMs are highly spatially aggregated, often only considering entire nations or regions of nations. This means that any variation in energy supply or demand (and the additional costs that may result) are disguised.

For example, energy supply and demand are rarely locally coincident – in most countries, the largest demand centres will be urban regions which will have little opportunity for large-scale energy production. This implies the need for bulk transmission infrastructure to move energy from generation centres to demand centres. The raw resources required to be converted to energy products (oil, gas, or renewable sources) may similarly be located at some distance, again resulting in significant costs. For example, in the UK the demand is primarily focussed around the south of England, whereas raw materials onshore are mostly located in the north of England and South Scotland. Oil and gas requires extraction and transport from the North Sea, and wind power has the greatest resource in the North of Scotland at some distance from demand. Hence an energy model of the UK which ignores the heterogeneity of sources and demand is likely to misrepresent the required infrastructure investment. If a WSEM determines that increased utilisation of the gas network is likely to result from hydrogen investment, it would be necessary to disaggregate the result into regions where that network exists from those where it does not.

Similarly, if the WSEM considers relationships with the wider economy or other sectors, it is necessary to determine if these interactions are actually spatially coincident – if, for example, a model determines that additional investment in wind power is likely to reduce unemployment, it may be prudent to investigate whether the additional generation infrastructure investment will occur in areas with an unemployment issue, or even a local population to be unemployed.

As a result, any WSEM which does not achieve regional separation and significantly aggregates energy flows is likely to underestimate transport costs and overestimate external benefits to the economy.

2.8.3 Temporal Aggregation

Generally, WSEMs utilise very low-resolution time steps, often considering only annual or multi-annual stages towards a long-term decarbonisation target. However, this risks disguising many of the key technological features underlying the generation, conversion and consumption of energy.

Seasonal variation in energy is a key element of systems at higher/lower latitudes, where the consumption and production of energy will vary across the year. For example, in northern countries a large proportion of energy consumption will occur during winter months where the demand for heating is greatest. This will also drive international flows of energy commodities and the extent to which their prices vary in time.

Diurnal variation is similarly important in energy demand, with great variation between day and night due to patterns of human activity. The structure and nature of many real-world energy assets are driven not be mean demand, but by the peak, which may be several times greater, and occur only for a brief period each day. For example, the GB National Grid uses the Average Cold Spell (ACS) winter demand peak to determine the level of electricity capacity required for system security [83], recognising that this is driven by the volume of energy demanded at the key seasonal and diurnal point. An energy model which considers only the bulk averaging of demand risks significantly underestimating the capacity and cost of the energy system required to deliver security.

In the following chapter, previous approaches towards the improvement of spatial and temporal resolution in WSEMs are assessed.

3 Spatial and Temporal Interpolation in Whole System Energy Modelling

3.1 Overview

The previous chapter established that, due to the high level of complexity in WSEMs, and the large variety of technologies and energy vectors they seek to represent, that they may be highly aggregated both in spatial and temporal dimensions. However, this is not to say that these issues have not been recognised or addressed, and this chapter summarises some of the main approaches taken to date to deal with this issue. The scope is here restricted to discussion around 'TIMES-like' WSEMs – that is, technologically-explicit, bottom-up techno-economic least-cost optimisations. This section attempts to examine in more detail the requirements that may exist for more detailed modelling of spatial and temporal constraints, and then to review existing methodologies – and their weaknesses – for meeting these requirements. This in turn informs the improvements that can be made when attempting to correctly interpret outputs from WSEMs and to conduct additional modelling which may verify their applicability to real-world systems.

3.2 Requirements of Spatio-temporal Energy Models

In order for an energy system model to represent spatial and temporal characteristics of energy supply and demand, it must contain the following properties, each of which may be subject to differing levels of aggregation.

Firstly, a representation of *space*. This may mean that the region being studied is subdivided into distinct, mutually-exclusive elements representing different geographical locations – either specific points or areas. Each element may have different demands and available resources, and be constrained on technological diversity.

Secondly, a representation of *time.* The model needs to be conducted over discrete temporal elements, which may or may not be continuously related to each other. The nature of temporal representation, and the resolution used, can be determined by the scope of the model, such as whether long-term strategic issues or short-term operational issues or dynamics are of interest.

Third, the model should contain *resources* that relate to any material or energy which is available to be consumed or to supply energy processes. A resource may be consumed or produced by a technology, or converted to another resource or carrier. A resource might be a store of fossil fuels, a natural renewable resource such as wind energy, or latent heat stored by the air.

Fourth, the model should allow for transport of energy between spatial and temporal elements through *carriers.* These are carriers such as electricity, heat or gas which may be transmitted between spatial elements by transport infrastructure (such as power lines) or stored between temporal elements by storage (such as electrochemical batteries). In some models, carriers are a subclass of resources, and there may be little distinction between the two.

Fifth, the model contains *technologies* which may perform one of several roles:

- The *conversion* from an energy resource to an energy carrier (e.g. the conversion of wind energy to electrical energy via a wind turbine), or between carriers (e.g. the conversion of natural gas to domestic heat in a condensing boiler);
- The *storage* of an energy carrier (e.g. the storage of that electrical energy in a lithium-ion battery);
- The *transport* of an energy carrier (e.g. movement of electrical energy between two locations via a high-voltage power line).

As each of these five characteristics are disaggregated into particular separate elements, so must the complexity and (in the case of space and time) dimensionality of the model increase. This further adds to the computational complexity of the problem. In the case of a WSEM attempting to model an entire national energy system, the problem can quickly become intractable if significant disaggregation is included. This means the level of disaggregation in a WSEM must be carefully selected, and the increase in disaggregation in one of the above must be balanced by aggregation in another. The choice made should reflect the aims and scope of the model in questions. Previous approaches to this compromise in WSEMs is included in the following sections.

3.3 Regional Disaggregation in TIMES-like Models

The TIMES modelling framework includes the capability to define regions and inter-regional exchange processes (IRE) which permit bilateral and multi-lateral trading of commodities between defined regions. Regions can have distinct currencies, discount rates, and time-slice definitions. The number of regions in a model is limited by solving time for large linear programs.

UKTM is a single-region model with no disaggregation. The only explicit spatial data is within the investment cost required for transmission and distribution technologies, where the average cost of network reinforcement is calculated and applied on a per-unit capacity basis for additional energy flows for each vector. For example, in the case of electricity, the price control submissions for TOs and DNOs are assessed to create a levelised cost per kW for additional network capacity for transmission and distribution. Similar calculations are used for the gas network, and for additional hydrogen conversion and infrastructure. One implication of this simplification is that 'easy wins' – where little additional infrastructure is required – are ignored, such as in the case of heat pump installations in rural areas where electrical distribution networks may be capable of absorbing additional demand capacity without any requirement to upgrade cabling.

Table 1 – Decision variables in the TIMES modelling framework incorporating spatial and temporal dimensions [58].

Attribute	Description
$VAR\_NCAP(r,v,p)$	New capacity addition for process p in period v and region r
$VAR\_RCAP(r,v,t,p)$	Capacity retired at period t of vintage v
$VAR\_SCAP(r,v,t,p)$	Total capacity retired in period t, reducing the available capacity of vintage v
$CAP(r,v,t,p)$	Total installed capacity of process p in region r and period t (optionally with vintage v), as derived from other capacity variables
$VAR\_CAP(r,t,p)$	Total installed capacity of technology p in region r and period t across all vintages
$VAR\_ACT(r,v,t,p,s)$	Activity level of technology p in region r and period t (optionally of vintage v and in time-slice s)
$VAR\_FLO(r,v,t,p,c,s)$	The quantity of commodity c consumed or produced by process p in region r and period t (optionally of vintage v and in time-slice s)
VAR_SIN / $VAR\_\_SOUT(r,v,t,p,c,s)$	The quantity of commodity c stored or discharged by storage process p in time-slice s, period t (optionally with vintage v) and region r
$VAR\_IRE(r,v,t,p,c,s,exp/imp)$	Quantity of commodity c sold (exp) or bought (imp) by region r through process p in period t (optionally in time-slice s)
$VAR\_DEM(r,t,d)$	Demand for end-use energy service d in region r and period t. In the reference scenario, this is set by the user, but may differ in alternate scenarios due to responsiveness of demands to their own prices, based on each demand's own-price elasticity

The ETI ESME model includes some spatial disaggregation, representing the UK with 12 onshore and 12 offshore regions, with location of technologies included as a set of decision variables. The topology is shown in Figure 11, including results for electricity generation investment.

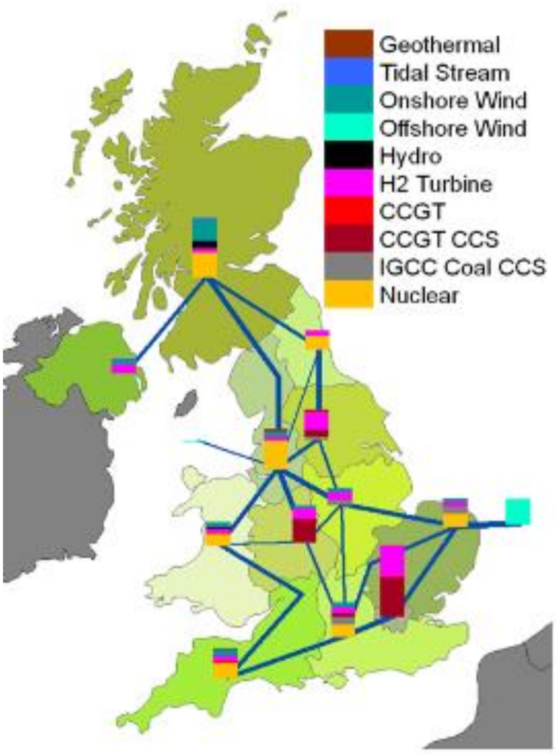

Figure 11 - example output from the ETI ESME model, showing the geographical variation in electricity generation investment for a given time period (reproduced from [70])

3.4 Temporal Disaggregation in TIMES-like Models

There are 3 temporal attributes of WSEMs:

Firstly, the time-horizon over which the model runs (e.g. 2010-2065 for UKTM) has a significant effect on the interpretation of long-term energy challenges. Resource depletion may occur over a long-term horizon, requiring assessment of increasing extraction costs. Rates of infrastructure investment and operational lifetimes must be assessed. Over such timescales, economic growth and technology developments must be considered. A review of past UK energy scenarios [84] found that "scenarios tend to reflect contemporary discussions, concerns and expectations", rather than exploring the full range of "unexpected knowns" – scenarios which are not considered as being likely under current framings, but which are within the conceptual space.

Secondly, there may be flexibility in period definition. For example, in UKTM, from a base year of 2010 annual time steps are used initially in order to explore the near-term issues of decarbonisation, moving to 5-year time steps from 2015 through to 2065. This allows increased uncertainty at more distant time intervals to be represented.

Lastly, the intra-annual time resolution must be considered, particularly in the case of commodities which cannot be easily stored (such as electricity) or where the storage capacity is limited with respect to the magnitude of total consumption (such as gas).

A typical national TIMES model, such as UKTM, will adopt a long time horizon but have very limited intra-annual time resolution. The trade-off between these two dimensions is driven by computational limitations (i.e. the need for the model to be solvable within a timeframe appropriate for investigating a wide range of scenarios), the capabilities of the solver in use, and the availability of data which may be appropriately disaggregated.

TIMES inherently contains the ability to contain a high level of temporal disaggregation. For example, in [85], a Swiss TIMES electricity model with hourly resolution is developed (but with a single spatial region) covering resource supply through to end use. This incorporates 4 seasonal, 3 weekly and 24 daily time slices totalling 288 time periods, with a long-term horizon of 110 years. It is noted that while this provides insight into the generation schedule, it does not account for stochastic characteristics of the electricity system, reliability or unserved loads. However, the use of small intra-annual time slices does reduce the effect of averaging of capacity demands and the possible underestimation of demand peaks. Alternatively, this can be addressed through the use of uneven seasonal and daily time splits to capture the key peak periods; for example having a single time slice representing a single 'peak' winter month rather than a full winter season of 3 months.

A second approach which may accurately represent the impact of large variations in demand is to add a user constraint in the shape of a defined share between dispatchable and non-dispatchable technologies, as defined by the tails of the load-duration curve for a particular energy vector. This ensures that sufficient reserve exists to serve peak demands even where that specific peak is not fully represented within the demand data. However, if this demand peak shifts in future years then the constraint may over-procure dispatchable energy sources across the whole modelling period.

UKTM contains 4 seasonal and 4 daily time slices equalling 16 periods in total per annual period modelled. The 4 seasonal periods are of equal length, with unequal daily time periods split into 7, 10, 3 and 4 hours respectively for the Night, Day, Peak and Early Morning periods. This allows a trade-off against computational and data complexity, while acknowledging the key role that seasonal variation and daily demand peaks have in driving the design of a secure UK energy system.

3.5 The ‘Energy Hub’ Formulation

In this section, the optimisation problem known as the ‘Energy Hub’ formulation is introduced, as an established methodology for evaluating spatial energy systems that overcomes many of the issues described in this chapter.

3.5.1 Multi-carrier Dispatch in Spatial Energy Systems

Many of the formal methods in energy dispatch derive from the electricity sector. A summary of power system analysis formulations is given in Table 2. Optimal Power Flow (OPF) is a general term for a collection of methods relating to determining, for a given set of electrical power sources and loads under a specific set of constraints (such as being spatially constrained by a power network) the dispatch of those sources in order to best meet a specified objective function (typically a minimisation of total cost). This allows, for example, a power system planner to project the likely flows that a future power system might undergo under the assumption that there is an efficient market-based dispatch of those sources.

A typical OPF formulation consists of an objective function minimising the total cost of generation, within the constraints of: a) minimum and maximum power output from each generator; b) flow along transmission lines being with limits; c) total generation exceeding total demand after transmission losses; d) voltage and inertia considerations. The OPF may be run for a single point in time (a steady-state model) or run across multiple time periods coupled by additional constraints on e.g. generator ramp rates and minimum/maximum on/off times, in which case the OPF calculation extends into the remit of ‘unit commitment’ problems. Security-constrained OPF further extends the problem to consider the reliability of individual system components (such as generators and network assets) where the objective also includes latitude to allow for expected failure rates, meeting a defined security parameter such as the Loss of Load Expectation (LoLE). This allows a more practical formulation to be used which respects the real-world requirement for reserve generation and network redundancy to ensure security of supply, as opposed to an analysis which assumes that all listed components are in full operation. In turn, this means that the full costs of energy provision are calculated, taking into account the necessary additional expenditure necessitated to cover for failures in system components.

Table 2 - Summary of Power System Analysis problem formulations (adapted from [86])

Formulation		Constraints				Parameters		
General Problem	Sub-Problem	Voltage Angle	Bus Voltage Magnitude	Contingencies	Transmission	Losses	Generator Costs	Assumptions
OPF	ACOPF	✓	✓		✓	✓	✓	
	DCOPF				✓	(✓)	✓	Constant voltage magnitude
	Decoupled OPF	✓	✓		✓	✓	✓	P-V angles are independent
	Economic dispatch	✓			✓	✓	✓	
	Security-constrained Economic Dispatch (SCED)	✓		✓	✓	✓	✓	Constant voltage magnitude
	Security Constrained OPF	✓	(✓)	✓	✓		✓	Various
Power flow			✓		(✓)			

A conventional DCOPF formulation (i.e. ignoring multiple phases) takes the form:

$$\min_{g,\delta}\{C(g)\} \tag{3.1}$$

Subject to:

$$\boldsymbol{g} - \boldsymbol{d} = \boldsymbol{P} = \boldsymbol{B\delta}; (\boldsymbol{\lambda}) \tag{3.2}$$

$$-\boldsymbol{g^L} \leq \boldsymbol{g} \leq \boldsymbol{g^u}; (\boldsymbol{\sigma_L}, \boldsymbol{\sigma_U}) \tag{3.3}$$

$$-\boldsymbol{f^L} \leq \boldsymbol{H\delta} \leq \boldsymbol{f^U}; (\boldsymbol{\gamma_L}, \boldsymbol{\gamma_U}) \tag{3.4}$$

Eq. (3.1) indicates the objective is to minimise the total cost of generation of energy across all generators at a particular point in time, subject to the requirements that the sum of generation, demand and losses is equal to zero (3.2), the output of each generator is within its minimum and maximum limits (3.3) and the flow of energy along each network component is within the determined limits (3.4). This relatively simple formulation is stated in matrix form to cover the spatial definition of generators and demands at different nodes connected by specified transmission assets, and there are a variety of computational methods such as Newton-Rapheson utilised to identify the optimal point in such problems.

However, the modelling of such systems becomes more complex where multiple energy vectors (here termed energy carriers[1]) are under consideration. For example, there may be interdependencies between the dispatch of electricity and gas within the same region, in order to meet demands by gas turbines for energy production.

A natural extension of the OPF formulation is into cases of co-generation; i.e. where two energy carriers are dispatched simultaneously and a conversion process between the two is available.

Generalised approaches to the operational optimisation of systems concerning multiple energy carriers include approximated flow models, such as in [87] where a multi-carrier flow is decomposed into separate OPF sub-problems; and detailed steady-state flow modelling, such as in [88] where a gas and electric joint power flow is optimised via the use of approximation natural gas load flow problem. In [89], a coupled electricity and gas formulation is given which

[1] The term 'energy carrier' is here used in preference to the alternative common form 'energy vector' in order to avoid confusion with the mathematical term

estimates steady-state parameters for each network, including real and reactive power flows and mass/volume flows in pipes.

As an extension of these modelling concepts, the 'Energy Hub' is a formulation first formally proposed by Geidl and Andersson in 2005 [90] as an extension of previous frameworks on optimal power flow in systems with multiple energy vectors, originally targeted at small distributed resource systems, but expanded to the consideration of transnational energy networks [90] and, generically, towards any spatial multi-vector energy system. The technique has been adapted to studies at a wide variety of scales, from local, kW-scale domestic conversion systems such as in [91], through urban networks incorporating renewable energy sources such as in [92], to national-scale modelling such as in [93].

3.5.2 Model Description

The Energy Hub concept concerns a set of energy carriers $\alpha, \beta, \ldots \in \mathcal{E}$ (e.g. electricity, gas, heat) and a set of hub numbers $i, j, \ldots \in \mathcal{H}$ and a set of network nodes $m, n, \ldots \in \mathcal{N}$.

A conversion device which converts energy carrier α to carrier β will have input and output power flows P_α and L_β coupled by a co-efficient which represents a conversion efficiency $c_{\alpha\beta}$ as in Eq. (3.5).

$$L_\beta = c_{\alpha\beta} P_\alpha \tag{3.5}$$

For a non-constant efficiency (such as the temperature-dependent performance of a heat pump discussed in section 5.4.1) the coupling factor may be replaced by an appropriate function e.g. $c_{\alpha\beta} = f(P_\alpha, temp)$.

A general model describing all such couplings can be stated in the form $\boldsymbol{L} = \boldsymbol{C} \times \boldsymbol{P}$ as in Eq. (3.6):

$$\begin{bmatrix} L_\alpha \\ L_\beta \\ \vdots \\ L_\omega \end{bmatrix} = \begin{bmatrix} c_{\alpha\alpha} & c_{\beta\alpha} & \cdots & c_{\omega\alpha} \\ c_{\alpha\beta} & c_{\beta\beta} & \cdots & c_{\omega\beta} \\ \vdots & \vdots & \ddots & \vdots \\ c_{\alpha\omega} & c_{\beta\omega} & \cdots & c_{\omega\omega} \end{bmatrix} \begin{bmatrix} P_\alpha \\ P_\beta \\ \vdots \\ P_\omega \end{bmatrix} \tag{3.6}$$

$\boldsymbol{C}$ is the coupling matrix, and maps powers from the inputs to outputs of the converters.

The spatial Energy Hub formulation given here follows that described in [92], which extends the general formulation to consider networks defined in 2 spatial dimensions. An energy system under consideration consists of a number of nodes representing specific locations with a local set of technologies. Each node is indexed by i and j relating to the node's spatial location in the x and y dimensions respectively, and may be connected to adjacent nodes via branches Each node contains energy consumption Q, energy production E, storage S and transmission ϕ to and from neighbouring nodes, as illustrated in Figure 12, for a set of three energy carriers: electricity, gas and heat.

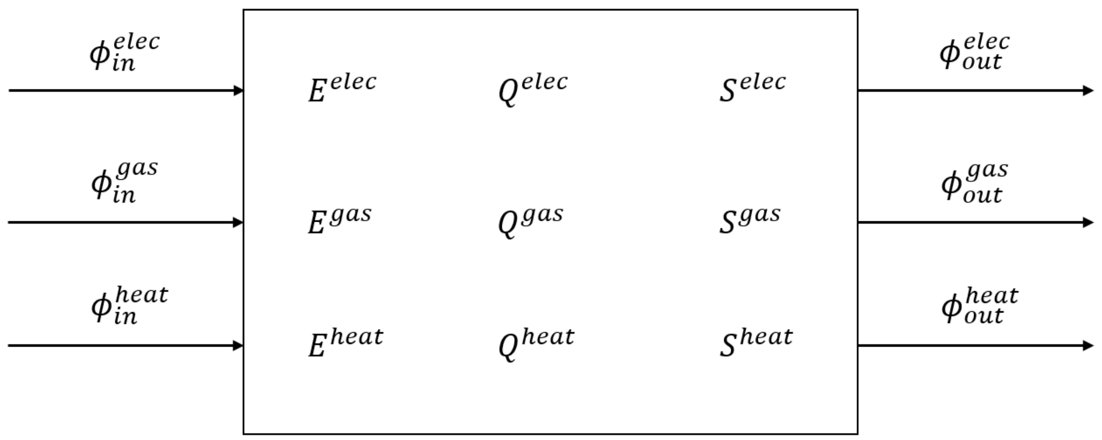

Figure 12 - Generic energy node schematic for three carriers

For a specific energy node ij and a single energy carrier l, then excluding loss terms the energy balance and conservation law is given in Eq. (3.7):

$$E_{ij}^{l}(t) + \phi_{ij}^{l}(t) + S_{ij}^{l}(t) + C_{ij}^{l}(t) \pm C_{ij}'^{l}(t) - Q_{ij}^{l}(t) = 0 \tag{3.7}$$

Where C and C' represent the conversion to and from the energy carrier l respectively. In other words, the energy consumption of a particular energy carrier at a particular node must be met by a balanced combination of local energy production, transmission, storage discharge, or conversion from another energy carrier. In order to compensate for a potential surplus of generation (such as from a renewable and non-dispatchable generation source) then additional terms may be added to represent an energy sink (equating to curtailment of an energy source), or an inequality term may be used to change such sources into a potential maximum utilisation rather than a fixed value that must be used. These options are expanded further in Section 6.3.5.

If the conversion efficiency between carriers k and l are known then the total contribution from energy conversion to carrier l in node ij is given in Eq. (3.8), and the contribution from carrier l to other carriers is given in Eq. (3.9):

$$C_{ij}^{l}(t) = \sum_{\substack{k=1 \\ k\neq l}}^{3} \eta_{k\to l} q_{ij}^{k}(t) \tag{3.8}$$

$$C_{ij}^{\prime l}(t) = -\sum_{\substack{k=1 \\ k\neq l}}^{3} \eta_{l\to k} q_{ij}^{l}(t) \tag{3.9}$$

where q^k represents the volume of energy allocated for conversion from carrier k to carrier *l*.

The energy transmission into or out of the node is given in Eq. (3.10) and, for a non-looped network, each node delivers all the energy to the nodes downstream of it as in Eq. (3.11).

$$\phi_{ij}^{l}(t) = \phi_{in,ij}^{l}(t) - \phi_{out,ij}^{l}(t) \tag{3.10}$$

$$\phi_{out,i}^{l}(t) = \sum_{i'=i+1}^{end} \phi_{i\prime}^{l}(t) \tag{3.11}$$

Energy conservation laws may then be applied in order to expand Eq. (3.7) to determine the constraints for the flows of different carriers within the network. For example, Eq. (3.12) applies Kirchoff's Current Law to the electrical flow into and out of each node, where I is the current and U is the voltage. Eq. (3.13) describes a mass flow law for gas flow, with H being the specific enthalpy of the gas and $\dot{m}$ the mass flow rate. FinallyEq. (3.14) describes thermodynamic coupling for e.g. a heat network with c_p the heat capacity of the circulating medium and ΔT the temperature difference between incoming and outgoing pipes [92].

$$\sum_{\substack{i=i'-1 \\ i\neq i\prime}}^{i'+1} \sum_{\substack{j=j'-1 \\ j\neq j\prime}}^{j'+1} I_{ij}(t) = U^{-1} \sum_{\substack{i=i'-1 \\ i\neq i\prime}}^{i'+1} \sum_{\substack{j=j'-1 \\ j\neq j\prime}}^{j'+1} \phi_{ij}^{elec}(t) = 0 \tag{3.12}$$

$$\sum_{\substack{i=i'-1 \\ i\neq i\prime}}^{i'+1} \sum_{\substack{j=j'-1 \\ j\neq j\prime}}^{j'+1} \phi_{ij}^{gas}(t) = H \sum_{\substack{i=i'-1 \\ i\neq i\prime}}^{i'+1} \sum_{\substack{j=j'-1 \\ j\neq j\prime}}^{j'+1} \dot{m}(t) = 0 \tag{3.13}$$

$$\sum_{\substack{i=i'-1 \\ i\neq i\prime}}^{i'+1} \sum_{\substack{j=j'-1 \\ j\neq j\prime}}^{j'+1} \phi_{ij}^{heat}(t) = C_p \Delta T \sum_{\substack{i=i'-1 \\ i\neq i\prime}}^{i'+1} \sum_{\substack{j=j'-1 \\ j\neq j\prime}}^{j'+1} \dot{m}(t) = 0 \tag{3.14}$$

Similar energy conservation laws may be appropriately constructed for other potential carriers.

The above formulations allow for any spatial multi-carrier energy system to be modelled for optimal, least-cost dispatch, such that the total system is balanced at each time step (i.e. that no one hub is either in net deficit or excess of any vector). However, the scope of the decision variables are restricted to operation only; that is, the precise mix of technologies used must be defined exogenously, and the formulation does not contain a planning objective which can 'design' a least-cost energy system in the manner of a TIMES-like WSEM. In order to do so, some compromise must be made on the complexity of the modelled energy carriers. In chapter 6, a simplified formulation of an energy hub model is outlined which permits the use of a computationally tractable planning mode, which forms the basis of the modelling work here undertaken.

3.6 Reference Networks

In addition to defining the formulation of the problem which must be solved, the topology and nature of the system represented must be defined. In order to evaluate energy systems at a more granular level, a computationally tractable solution is to model a particular location on the network across multiple vectors. However, it is difficult to extrapolate the results of any one of these studies to a useful point within the scope of WSEMs, as by their nature such localised studies do not easily scale to provide useful understanding of the wider national-scale energy system.

As opposed to looking across multiple vectors, a number of studies of electricity distribution networks have involved the use of 'reference' networks which are either invented constructs or representations of 'real-world' networks that are held to be highly representative of the general nature of distribution networks belonging to particular paradigms. These are discussed further in Section 7.2.

Historically, this has been conducted in a number of studies restricted to particular archetypes; in particular urban energy systems have been evaluated in detail. In [94] five key areas of practice are identified: technology design, building design, climate, systems and policy.

While analysis of an urban energy system in isolation is not considered within the scope of this study to be a 'whole system' analysis – on the basis that an urban system is tightly coupled with its surroundings and has significant externalities – the field of urban energy has comprised much of the focus to date in spatially explicit modelling of energy systems. Typical analyses of an urban area will disaggregate the urban space into land zones, based on primary land use (e.g. industrial, residential and commercial) and may describe the key infrastructure and transport links between zones. Such models are often coupled with other models such as water supply or transport.

For example, in [95] a multi-vector analysis of heat provision in the UK city of Bristol is undertaken, using a zonal representation based on local authority data, as shown in Figure 13. The model is used to capture trade- offs between heat supply, end use technologies, and gas, electricity and heat network infrastructure at a high spatial resolution, and finds that, due to relatively low network costs, electrification of heating is generally the cheapest long-term options; and of those, due to economies of scale, district solutions based on heat exchanger technologies are a lower cost opportunity than individual heating systems.

Such urban analyses provide a useful compromise between simplistic single-region models and those which model the full depth of energy networks, providing a tractable model which permits solutions to be found for large-scale systems while appropriately allowing the costs and benefits of solutions which require additional infrastructure investment to be compared to 'in situ' technologies. However, zonal models do still contain some level of aggregation, and this means that the identified networks costs may not always be equal between zones. In the Bristol study, every zone is assumed to have the same cost of increased electrification, which ignores that some zones will require more expensive undergrounding of additional cabling than other areas where overhead cabling can be used, as well as lengths of cabling varying between zones. These cost assumptions are reviewed further in Chapter 5.

In [2], a number of challenges for urban energy system modelling are identified, including technical complexity, data uncertainty, and the difficulties of policy relevance. While these challenges are common to most fields of energy system modelling, in particular this is of issue to local systems considered in isolation where it is typically expected that the models and their results must be linked with the wider 'whole system' view.

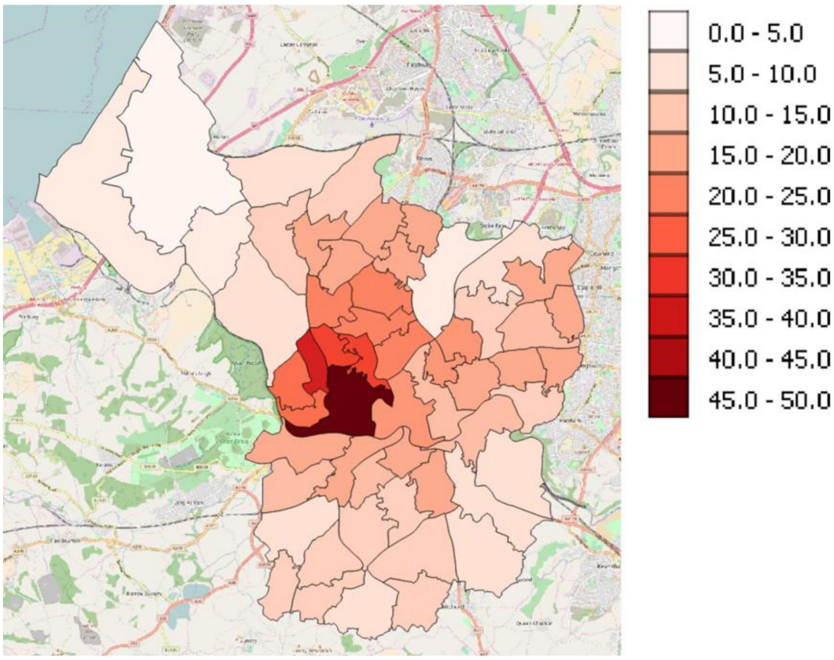

Figure 13 - Heat density (kWh/m2) for the 55 spatial regions of the City of Bristol, as analysed in [95]

3.7 Selection of Exemplar Models

In Chapter 2 it was established that the decarbonisation of heat is potentially poorly represented within existing Whole System models due to spatial and temporal aggregation. Following the options set out in this chapter, one avenue of inquiry which would allow inspection of this problem would be to apply future heat decarbonisation scenarios to real-world networks (as described in Section 3.6) using an Energy Hub-like formulation (as described in Section 3.5). This would appropriately balance the costs and requirements in infrastructure for future end-use heat technologies across different sectors, achieving the same ends as the higher-level system model, but demonstrating the local systems and their planning/operation in real-world levels of detail. This would mean that the forms of local energy systems implied by the higher-level model, and which would be stimulated by WSEM-informed policy, would have a greater validity when interpreted by stakeholders. Conversely, if it were shown that the infrastructure requirements of particular technology mixes were greater than as represented in the WSEM, with greater investment costs required by different energy actors, this would provide a mechanism to improve those same cost assumptions and iterate the higher-level model.

Many of the opportunities in heat decarbonisation require the increased utilisation of renewable energy sources or, in the case of heat pumps, decarbonised electricity. The interactions between such local energy systems and weather-driven renewable generation sources hence becomes an important area of analysis. In the next Chapter, the particular issue of wind power modelling across an energy system is assessed and a statistical methodology proposed to reduce computational complexity. This will permit an improved assessment of the specific contributions that can be made to decarbonisation of local systems from variable low-carbon renewable energy resources, by appropriately representing them in space and time and allowing their relationships to energy demands and conversion technologies to be explored. Wind power simulation is explored in detail in the following chapter to uncover specific improvements that can be made to the relevant methodologies, while solar power simulation is covered in less detail in Section 7.4 due to having a well-established and proven simulation methodology in the literature.

4 Simulation of wind power injections across a national energy system

4.1 Overview

Exploitation of renewable energy sources (RES) is seen as a key requirement of energy decarbonisation in the UK [72]. This increases the complexity of energy system simulation, because the non-dispatchable nature of weather-driven sources of energy means that the spatial and temporal variance of such sources must be correctly represented in order to avoid under- or over-representing the contribution they can make to meeting end consumer demands.

As detailed in the preceding chapter, one particular issue regarding the modelling of the UK energy system is the representation of wind energy, which has significant complexity in both spatial and temporal dimensions. Further, wind energy is already one of the most significant sources of electrical energy in the UK energy system, with Britain's wind farms producing 18.8% of electrical energy in the first quarter of 2018 [96], exceeding nuclear power for the first time.

Generally, the variability of renewable generation sources are poorly represented within WSEMs due to spatial and temporal aggregation. Within UKTM, the average annual potential of off-shore and on-shore wind generators (treated separately) to supply energy is calculated for each of the 16 time slices previously described. This however, does not reflect either the temporal variability which may cause under- and over-supply of energy at any particular point due to a mismatch with actual demand, or the spatial variability which may occur under different scenarios for the development of wind generation assets. In addition, the siting of wind generators will have varying impacts on the required level of network capacity to allow the transfer of energy to areas of demand, with wind generators being sited further from areas of population than conventional generation.

In order to accurately simulate the injections of wind power into a wide-area power network, two key elements must be reproduced:

- The temporal behaviour of wind power, in terms of rates of change and local autocorrelation, in order to accurately capture the timescales over which wind power might vary and by what extent;
- The spatial behaviour of wind power, in terms of how strongly different wind power generators within a network correlate to one another. It is well-understood that wind is spatially correlated over large scales [97], and a failure to correctly model such

correlations in power system simulations will lead to an over-smoothing of aggregate wind power and an underestimation of the required reserve capacity and inter-area flows on an electricity network [98].

Previous approaches to this problem may be divided into 3 broad categories.

Firstly, historically metered wind power data may be used directly. For example, in [99], the Irish transmission operator uses data from 3 wind farms to analyse and quantify the impact of increasing levels of wind generation on the operation of conventional plant, based on analysis of the frequency of ramp-up and ramp-down events. The principal shortcoming of this approach is that the captured data history does not necessarily represent the full distribution of temporal variations for the sites captured, and neither do those sites necessarily represent the full geographical variation between other sites.

Secondly, wind speed data (either from historical or reanalysis data) may be converted to wind power values through a deterministic conversion process which reconstructs (potentially long-term) patterns of generation for a historical period. For example, in [100] 33 years of data from the NASA MERRA model is used to quantify the frequency of extreme wind power generation scenarios – namely prolonged periods of low generation and high ramp rates – to determine the potential impact on secure operation of the Great Britain electricity network. Such approaches have become common since large meteorological datasets have become more openly available in recent years, but have a significant computational burden due to the amount of data involved in computing outputs across high spatial and temporal resolutions for multiple year datasets.

Lastly, statistical approaches may be applied which reduce the temporal and geographical variation to a representative set of functions, or by sampling appropriately from an existing dataset. For example, in [101] wind speed series are reduced via wavelet decomposition to calculate autoregressive integrated moving average (ARIMA) models which represent the time series behaviour, and compared to measured output for a set of wind generators in China. This approach solves the computational complexity problem, but may introduce additional uncertainty where the underlying meteorological trends are not well represented.

In this chapter, the main properties of wind power in time and space are first summarised (Section 4.2) to set the context and aims for a wind power synthesis method. Two approaches to the synthesis of wind speed values are then covered, firstly through the direct use of a national-scale ‘reanalysis’ dataset (Section 4.3) and then through the creation of a statistical Vector Auto-Regressive (VAR) model which seeks to represent the same dataset in a reduced form. Techniques for the conversions of wind speed to wind power at a generator level are then discussed, and a pragmatic methodology proposed which can be trained against available wind power data. A combined simulation model for wide-area wind power synthesis is then described (Section 4.4). The resulting combined simulation model is then constructed and validated for the Great Britain electricity system (Section 4.5).

4.2 Characteristics of Wind Power

In order to correctly represent the spatial and temporal characteristics of potential wind power injections into an energy system, we must first look at the characteristics of wind in terms of how it varies in space and time. Each of these are considered here in turn.

4.2.1 Temporal Characteristics

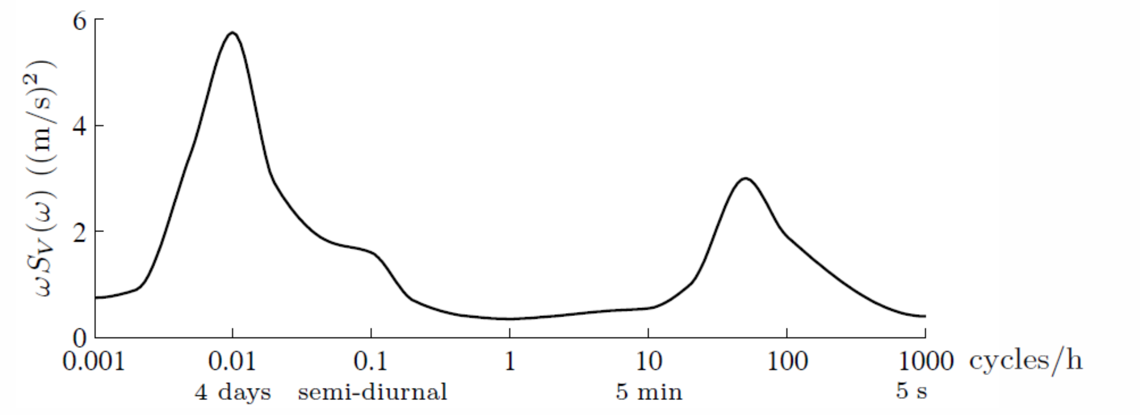

Figure 14 - typical Van Der Hoven spectrum of horizontal wind speed (reproduced from [102])

Figure 14 shows a typical Van der Hoven spectrum for horizontal wind speed, as originally described in [103]. This spectrum contains 4 main features:

- A long-term ‘synoptic’ peak at around 4 days, representing the movement and impact of weather systems;
- A diurnal peak, representing local effects which may occur due to the daily variance in temperature – the extent of this will vary considerably between locations, with coastal regions experiencing adiabatic/katabatic patterns seeing a more significant effect;
- A short-term peak corresponding to the effects of turbulence;
- A large spectral gap between the diurnal and turbulence peaks.

As a modern wind turbine control system typically responds to variance in wind speed at a 1 Hz level or faster, features as seen in the frequency domain for wind speed measurements will be reproduced in the frequency domain for wind power. Figure 15 shows the power spectrum derived from the aggregated SCADA output of the 140 turbines at Whitelee 1 wind farm in Scotland between from January 2014 to December 2015. As the sample rate is 6/hour, the rightmost extent of the horizontal axis falls in the spectral gap shown in Figure 14. The leftmost peak corresponds to a rate of approximately 42 hours between samples, corresponding to the synoptic peak in Figure 14. No significant diurnal peak is seen for this site, which is in keeping with the inland location and the absence of local diurnal wind patterns.

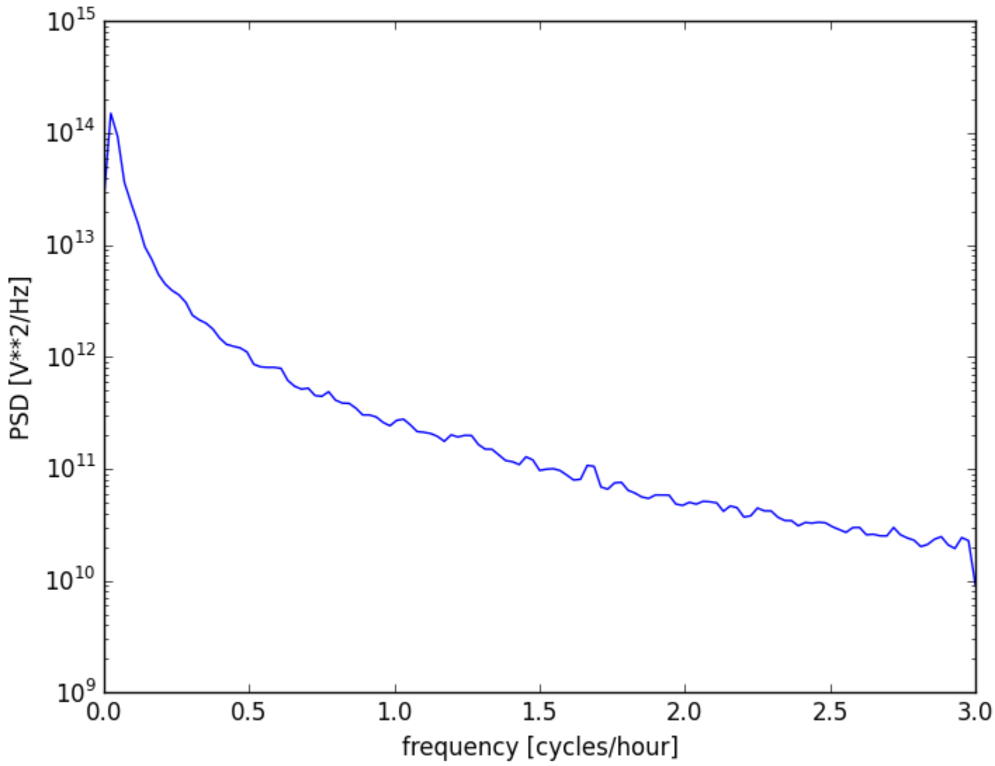

Figure 15 - Power spectrum for total power output from Whitelee 1 wind farm 2014-15 (sample frequency = 6/hour)

4.2.2 Spatial Characteristics

It is well-established that wind speed values correlate over large distances, as illustrated in Figure 16. Any model which seeks to correctly characterise wind power must also contain this spatial correlation. To underestimate it (such as by simulating individual locations independently from each other) would lead to aggregate wind power across a large area tending strongly to a mean value, rather than e.g. varying *en masse* in response to a particular meteorological event. This would in turn underestimate the magnitude of swings in total wind power across time. In the reverse case, if locations are represented as being too highly correlated, then those rates of change will be exaggerated.

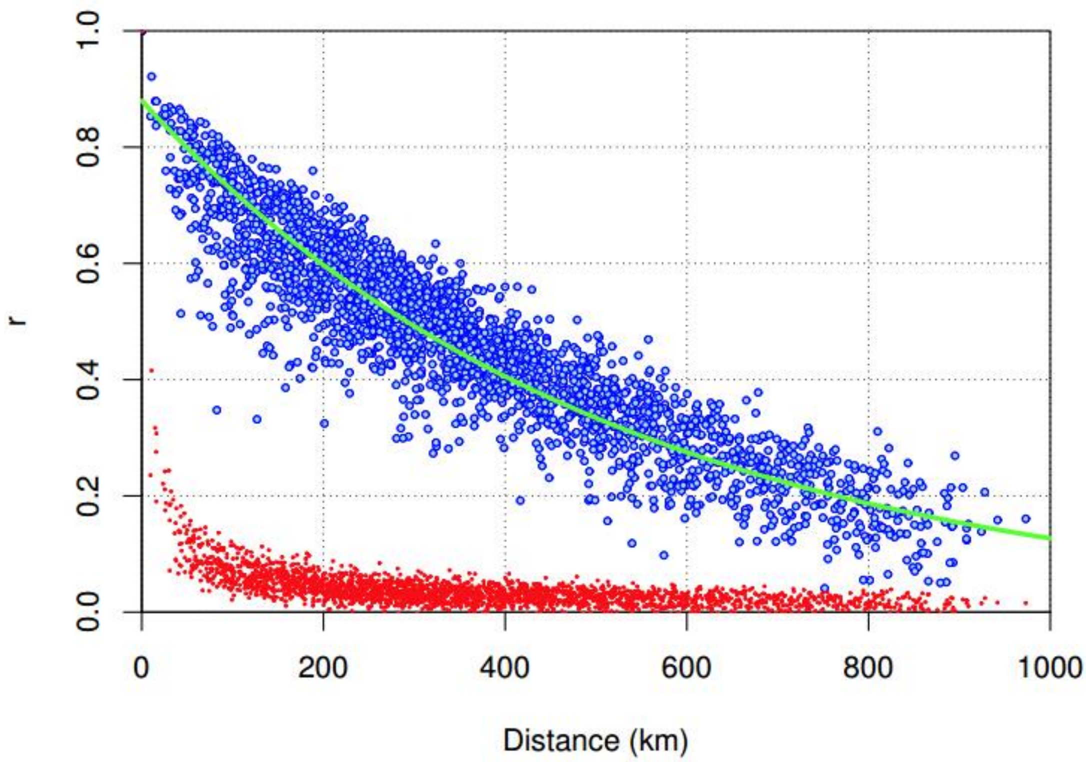

Figure 16- The relationship between wind speed measurement locations across UK Met Office stations, showing cross-correlation of the wind speed data across pairs of stations (blue) and the corresponding cross-correlation of the hour-to-hour wind speed changes (red) (reproduced from [104])

4.2.3 Choosing an appropriate simulation unit

A simulation of wind power can occur on multiple scales:

- The simulation of individual wind turbines. This is commonly conducted either for the optimisation of wind farm layouts, or for commercial and financial wind yield analyses, where this level of detail is required. In order to effectively differentiate between turbines, a local topological model is required which allows the localised wind flow regime to be emulated (such as in software tools like WindFarmer and WaSP). The advantage is that this permits the performance of each turbine to be accurately modelled and reflects the true aerodynamic characteristics of the generation kit. The disadvantage is that this requires a substantial volume of characterising data for each wind location, and a great deal of computation to derive individual outputs.
- The simulation of a set of turbines in aggregate composing a wind farm. In this case, as the turbines are usually all of the same make and model, and arranged at a similar altitude with a common hub height, it is reasonable to assume a similar performance profile. However, as with the previous case, there will be a variation in incident wind

speed between turbines at any particular point in time – due again to variations in flow across a site – and it is not suitable to simply scale the individual turbine power curve by the number of turbines. This scale of synthesis allows individual network power injections to be modelled, but removes the requirement to model each site in detail, providing that the flow regime can be appropriately summarised so as to correctly represent the total wind to power conversion.

- The simulation of aggregate regional output. If the key output required from a wind power model is the total power injection from a large area (such as a distribution network zone connected to a single Grid Supply Point on the transmission network), then it may be sufficient to characterise regional output by synthesising the total variance in wind speed over a given geographical area, and convolve the result with the aggregate wind-to-power conversion for multiple sites spread over that area. This approach has been taken in [105]. This aggregate method will disguise aspects such as the number and actual geographical spread of wind farms, the types and heights of turbines in use, and the nature of differences in wind regime between locations. However, it has the potential to impose a greatly reduced computational burden for models requiring multiple sets of wind power simulations.

The decision on which scale to simulate depends on the balance between the desired resolution of the output and the complexity of data handling in doing so. It is apparent that, on a national scale, it is infeasible to model the output of every individual turbine with appropriate flow modelling that would justify such a high-resolution model. However, it seems as though it may be possible to simulate individual wind farms within a national model, providing that the characterisation of each site can be done in terms of simple parameters which do not require much manual determination. In this chapter, two methods for performing wind farm-scale simulation for multiple sites across a national-scale energy system are proposed, and applied to Great Britain; the first using historically-driven reanalysis data, and the second a reduced statistical representation of the same data. In both cases, the models are designed to be ‘pragmatic’ to run – that is, no expert analysis of specific locations is required, and the parameterisation of the model can be conducted entirely from the available weather data and from publically-available databases of wind farm parameters.

4.3 Deterministic Reanalysis-Driven Modelling

In this section the means of simulating wind power from a bottom-up reanalysis-driven dataset is covered.

4.3.1 Reanalysis Data

The NASA Modern-Era Retrospective Analysis for Research and Applications (MERRA) [106] is a state of the art historical reanalysis of global atmospheric observations from the Goddard Earth Observing System (GEOS-5), covering 36 years of observations from weather stations, balloons, satellites, ships and aircraft, and resolved to a gridded global model covering all major meteorological parameters.

The MERRA 2 dataset contains nodes corresponding to a gridded mesh with resolution $\frac{1}{2}$ degrees latitude by $\frac{5}{8}$ degrees longitude. In the latitude of the British Isles, this corresponds to a grid of approximately 41km (west-east) by 56km (south-north). The dataset includes a set of 3 wind vectors averaged across each grid square at 2m, 10m above the displacement height[2] and 50m above ground level, with a temporal resolution of 1 hour. A snapshot of this data for the British Isles is shown in Figure 17.

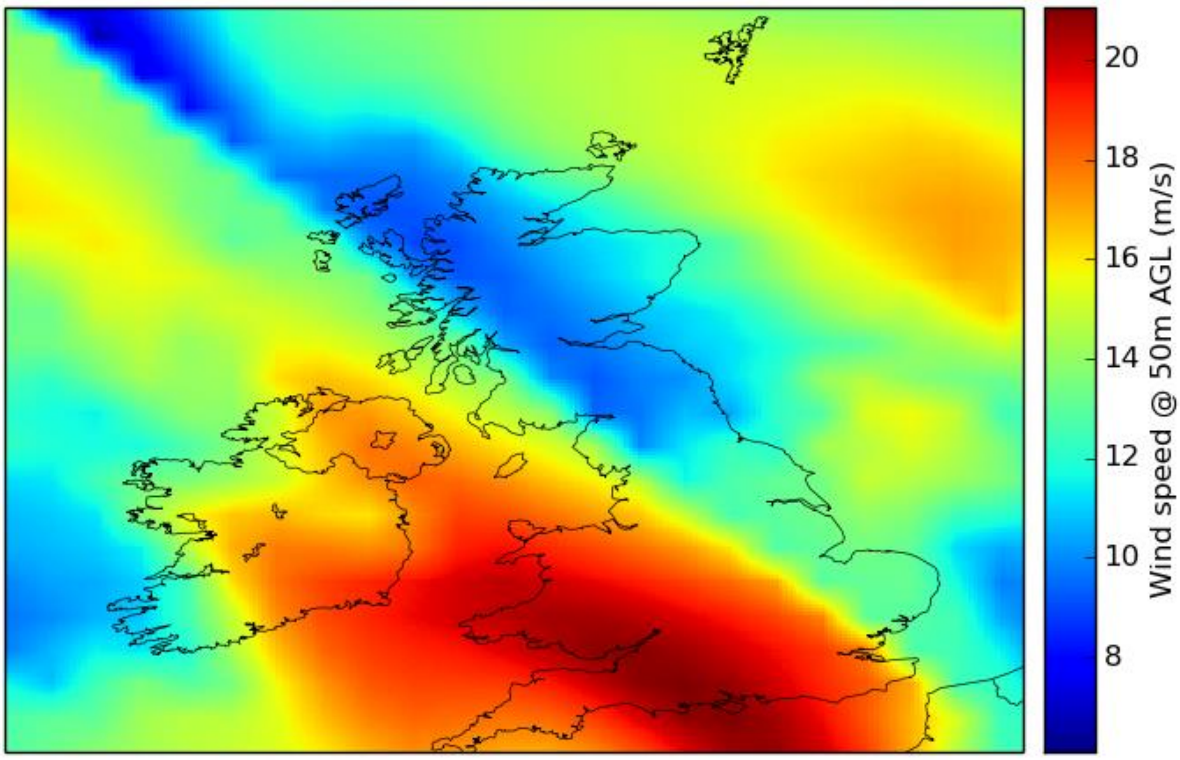

Figure 17 - Snapshot of wind speeds at 50m AGL over the British Isles at midnight on the 1st of January 2015

The MERRA datasets have, since the model was made generally available in 2011, been widely used in energy and power systems modelling and found to validate well against

[2] A seasonally-varying height above sea level governed by a vegetation model incorporated into the terrain

measured data. For example, in [107] the data is used to reconstruct time series of all GB wind farms in order to detect the degradation over time, and is validated with sufficient sensitivity to conclude that there is an annual degradation factor of around 1.6%.

Table 3 - description of NASA MERRA 2 model output variables used in the wind power model [108]

Variable Name	Description
DISPH	Displacement Height
U2M	Eastward wind at 2 metres above the displacement height
U10M	Eastward wind at 10 metres above the displacement height
U50M	Eastward wind at 50 metres above ground level
V2M	Northward wind at 2 metres above the displacement height
V10M	Northward wind at 10 metres above the displacement height
V50M	Northward wind at 50 metres above ground level
T10M	Temperature in Kelvin at 10 metres above ground level
PS	Air Pressure

4.3.2 Extrapolation to turbine height

In the case that only a single measurement is available at a given location, the Hellmann exponential law (more commonly known as the Power Law) can be used (Eq.(4.1)):

$$\frac{v}{v_0} = \left(\frac{H}{H_0}\right)^a \tag{4.1}$$

where v is the wind speed at height H, v_0 is the reference wind speed at height H_0, and a is the Hellman exponent. The origins of this equation are in boundary layer fluid mechanics [109]. This exponent varies according to local topography, with a value of $a \approx 1/7$ is often assumed for open areas. It will also vary temporally with wind speed and temperature, and use of such an assumed value may introduce significant errors into wind speed estimation [110]. In this respect, the Power Law is only suitable where no other information other than a single wind speed measurement is available.

The Monin-Obukhon method is given in Eq. (4.2).

$$v(z) = \frac{v_f}{K}\left[ln\frac{z}{z_0} - \xi\left(\frac{z}{L}\right)\right] \tag{4.2}$$

where $v(z)$ is the wind velocity at height z, v_f is the friction velocity, K is the von Karman constant, z_0 is the roughness length and L is the Monin-Obukhov length. Under the assumption of neutral atmospheric conditions (that is, the actual temperature lapse rate equals the dry adiabatic lapse rate, so a parcel of air will be neither heavier nor lighter at a different altitude), $\xi\left(\frac{z}{L}\right) = 0$, and the logarithmic law Eq.(4.3) results, which may be expressed in a form relating the wind speed at two different heights (Eq. (4.4)):

$$v(z) \approx \frac{v_f}{K} ln \frac{z}{z_0} \tag{4.3}$$

$$v(z) \approx v_{ref} \frac{ln\left(\frac{z}{z_0}\right)}{ln\left(\frac{z_{ref}}{z_0}\right)} \tag{4.4}$$

4.3.3 Horizontal interpolation

As reanalysis data is typically provided on a grid basis, any individual wind generator location will fall within a bounding grid box comprising 4 individual reanalysis nodes. Bilinear interpolation is not suitable as the grid will be curvilinear rather than rectangular. Instead, spline interpolation allows the exact locations of the bounding nodes to be incorporated into the calculation. The algorithm presented in [111] is used here as implemented in the Python package Scipy.interpolate[3].

4.3.4 Correction for local topology

A key weakness in the use of low-resolution reanalysis datasets such as MERRA is the inability to capture the effects of local topography, compared to dynamical downscaling approaches [112]. However, the latter approach is computationally expensive. It is necessary, however, to correct for local wind effects as this will introduce a systematic bias into the calculation of power output; in other words, the synthesised wind speed will be systematically higher or lower than the 'true' wind speed incident at the turbines.

A linear correction factor may be introduced to allow for this local correction; that is, the instantaneous wind speed value at a particular generation site u_g is multiplied by a site specific 'bias correction' factor to give a corrected wind speed value. Use of such a correction factor on a continental scale, with different correction factors applied on a per-country basis to scale output appropriately, is demonstrated in [113]. However, as the variation in topology which

[3]http://docs.scipy.org/doc/scipy-0.14.0/reference/generated/scipy.interpolate.interp2d.html#scipy.interpolate.interp2d

drives this scaling is likely to be affected strongly by local conditions, a per-generator bias correction factor is desirable.

Derivation of this bias correction factor is possible either by conducting the aforementioned dynamical downscaling, or through comparison to actual metered data for a known generator. If the sensitivity of the total energy output to a linear change in wind speed can be determined, then the bias correction factor value required to scale the total synthesised output to a known metered value can be derived. This sensitivity factor can be derived by applying a set of Weibull distributions with differing means to the aggregate power curve.

4.3.5 Conversion of Local Wind Speed to Wind Power

A typical multi-MW wind turbine power curve is shown in Figure 18. Such power curve specifications are usually provided as point values of power output for given integer m/s wind speeds (or, in some cases, 0.5m/s speeds).

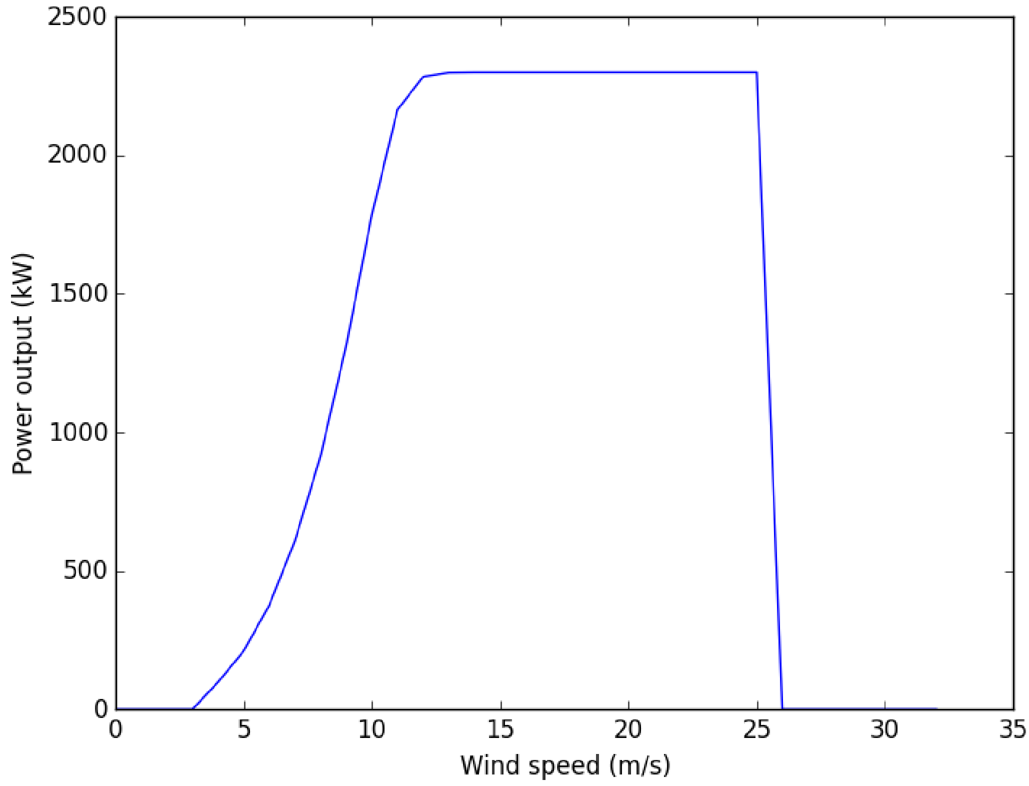

Figure 18 - Piecewise linear power curve specification for a Siemens SWT-2.3-93 turbine [114]

If a piecewise linear power curve function is defined as a set of wind speed/power pairs $u_{pc}(m), p_{pc}(m)$ ordered by increasing wind speed (i.e. $u_{pc}(m+1) > u_{pc}(m)\ \forall\ m$) then the function for deriving the power output p_t for a given turbine t at a given wind speed u_t is shown in Eq. (4.5).

$$p_g(u_t) = p_{pc}(m) + \frac{u_t - u_{pc}(m)}{u_{pc}(m+1) - u_{pc}(m)}\left(p_{pc}(m+1) - p_{pc}(m)\right) \tag{4.5}$$

where: $$u_{pc}(m) \leq u_t < u_{pc}(m+1)$$

4.3.6 Correction for air density

The power output of a turbine is related to not only the speed of the air mass passing through the rotor disc, but also to the density of that air. Air density in a specific location may vary between 10-15% over the course of multiple seasons [115]. Failure to consider the variation in air density measured over a 2 year period at a location in Hungary to an Enercon E-40 turbine introduced a systematic error of 16% in wind power estimation [116].

A turbine power curve is normally defined for a standardised air density, usually $1.225\ kg/m^3$, corresponding to the mean atmospheric pressure at sea level. Turbine manufacturers may provide specifications for lower standard air densities (corresponding to installation at greater elevations), but use of such power curves still does not allow for the effect of temporal variation in air density.

IEC Standard 61400-12 introduced the air density correction formula (Eq. (4.6)) which adjusts the measured wind speed to a new value according to the recorded simultaneous air density, which can then be applied to the turbine power curve at a standard air density,

$$u_{site} = u_{std}\left(\frac{\rho_0}{\rho}\right)^{\frac{1}{3}} \tag{4.6}$$

where u_{site} is the corrected local wind speed, u_{std} is the measured value, and ρ and ρ_0 are the measured and reference air densities respectively.

This correction, however, makes the assumption of constant turbine efficiency at all wind speeds, which may lead to a 4-5% overestimation in energy yield, as demonstrated in [117]. An alternative methodology is proposed by the authors which does not presume a constant exponent, and the following values are instead used:

"the exponent in eq. 2 is not constant at 1/3 for all wind speeds. Instead, the exponent is made a function of wind speed. For wind speeds lower than 7-8m/s the exponent is 1/3 as for the IEC method. Between 7-8m/s and 12-13m/s, the exponent is smoothly stepped from 1/3 up to 2/3. Above 12-13m/s the exponent is constant at 2/3."

The result of this adoption (for a non-specified illustrative scenario) is shown in Figure 19.

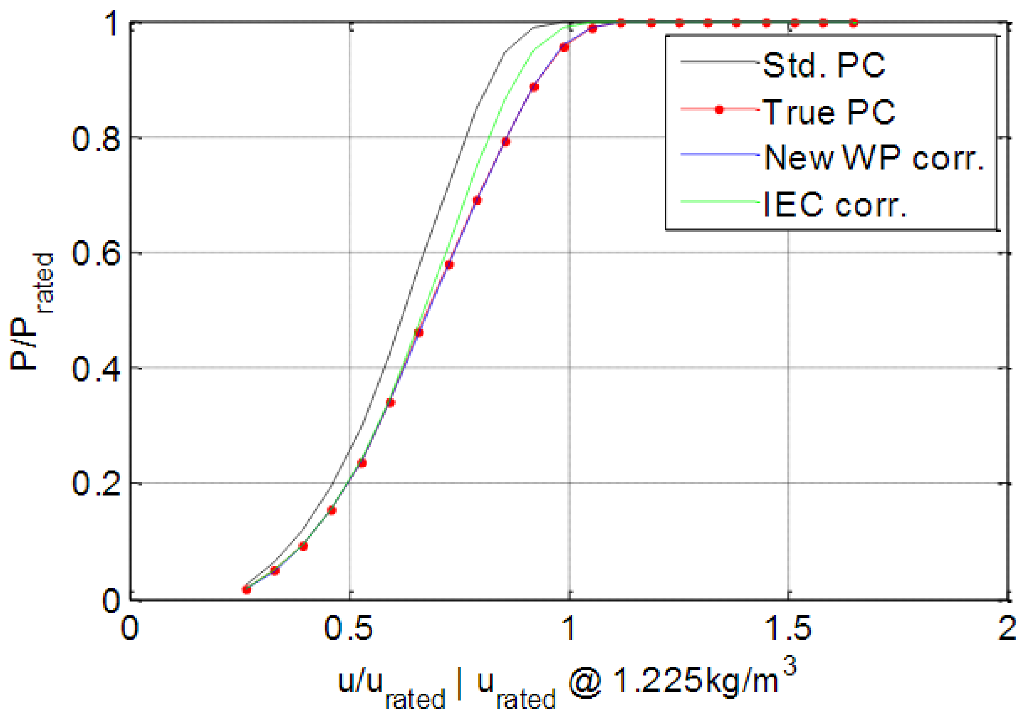

Figure 19 - Demonstration of difference in power performance assessment between constant exponent air density correction (green line) and dynamic exponent correction (purple line) against 'true' power curve (red line) (Reproduced from [117])

As no specific mathematical formulation is provided, this is interpreted as a non-analytic smooth function (in order to avoid discontinuities in the resulting power performance profile) given in Eq.(4.7) and shown in Figure 20.

$$u_{site} = u_{std} \left(\frac{\rho_0}{\rho}\right)^{\alpha} \tag{4.7}$$

where

$$\alpha = \frac{1}{3} + \frac{1}{3}\left(h\left(\frac{u - 7.5}{5}\right)\right)$$

and

$$h(x) = \frac{g(x)}{g(1-x) + g(x)}$$

and

$$g(x) = e^{-\frac{1}{x}}$$

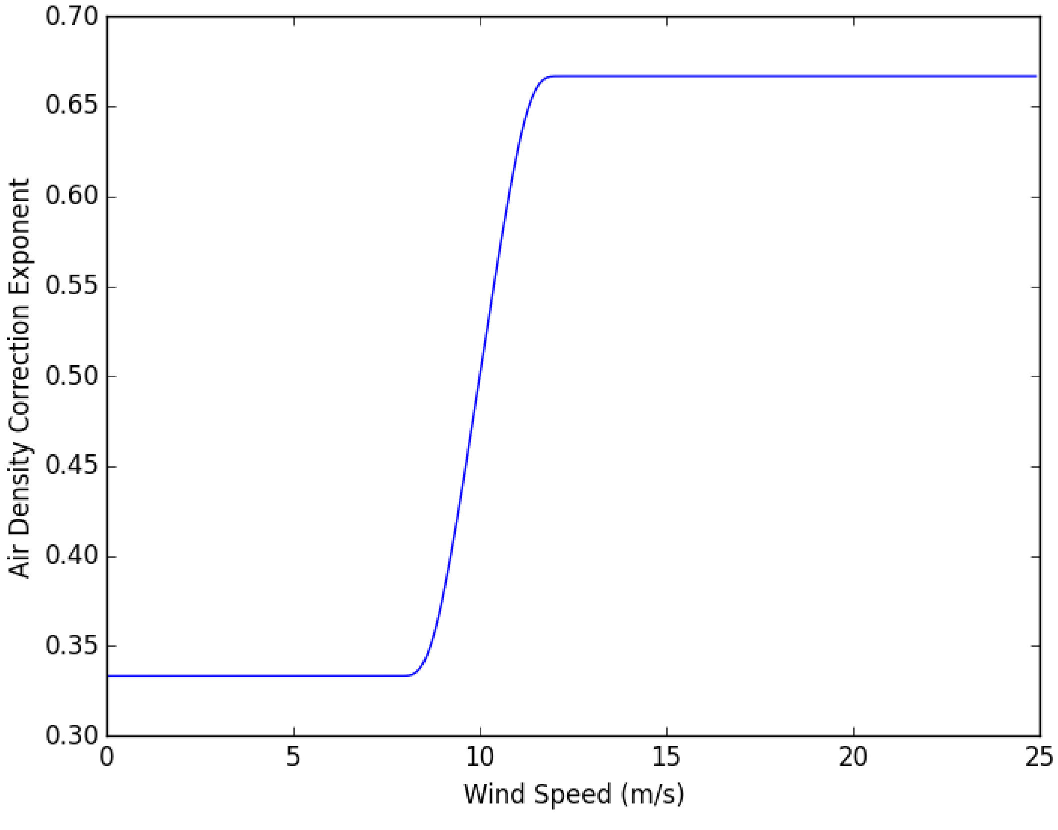

Figure 20 - Smoothed pressure correction exponent from Eq. (4.7)

4.3.7 Aggregation across multiple turbines

As detailed in Section 4.2.3, the simulation unit chosen is the wind farm, composed of multiple individual turbines across a local geographical area typically within 1 to 10 square kilometres (the largest wind farm in the UK by area, Whitelee, covers approximately 55 square kilometres for 215 turbines).

In [118], the assumption that geographical variation in wind speed can be approximated using a Gaussian distribution is used to derive a generic methodology for creating a power curve representative of a number of turbines spread over a geographic area. The methodology involves the identification of a representative standard deviation in wind speed representing the typical variance across the turbines under consideration, and then resampling from the individual turbine power curve across the Gaussian distribution of wind speeds this implies for a single wind speed measurement at a point in time. The work carries little validation, using only data from 3 turbines in Denmark, a nation with characteristically flat terrain.

In order to evaluate the assumption that a constant standard deviation in wind speed across a wind farm, irrespective of wind speed, is appropriate, the 10-minute averaged wind speed measurements from the 140-turbine Whitelee 1 wind farm were compared for simultaneously recorded values, in order to evaluate the relationship between the mean site wind speed and the standard deviation in wind speed across all turbines. The point values and the binned averages are shown in Figure 21. This indicates that, as might be expected, the deviation in wind speed across an area increases with the wind speed.

The methodology proposed here uses the same resampling method as in [118], with the calculated wind speed value u_g for the generator location g (as derived in the methodologies in Sections 4.3.2 and 4.3.3) extrapolated to multiple turbines through the creation of a Gaussian wind speed distribution (evaluated across the entire wind speed domain $[0, \infty]$) with a mean of the derived value (Eq. (4.8)). The mean of the Gaussian is the calculated wind speed value, but rather than assuming a fixed standard deviation, an asymptotically increasing standard deviation is applied across the wind speed profile (Eq. (4.9)).

$$p_g(u_g) = \sum_{i=0}^{\infty} \left(\frac{1}{\sqrt{2\sigma^2 \pi}} e^{-\frac{(i-u_g))^2}{2\sigma^2}} \right) p_t(i) \tag{4.8}$$

where

$$\sigma = k e^{-\lambda u_g(t)} \tag{4.9}$$

The piecewise linear turbine power curve function $p_t(i)$ is as described in Eq. (4.5), and parameters k, λ are site-specific, describing local variance in wind speed between turbines.

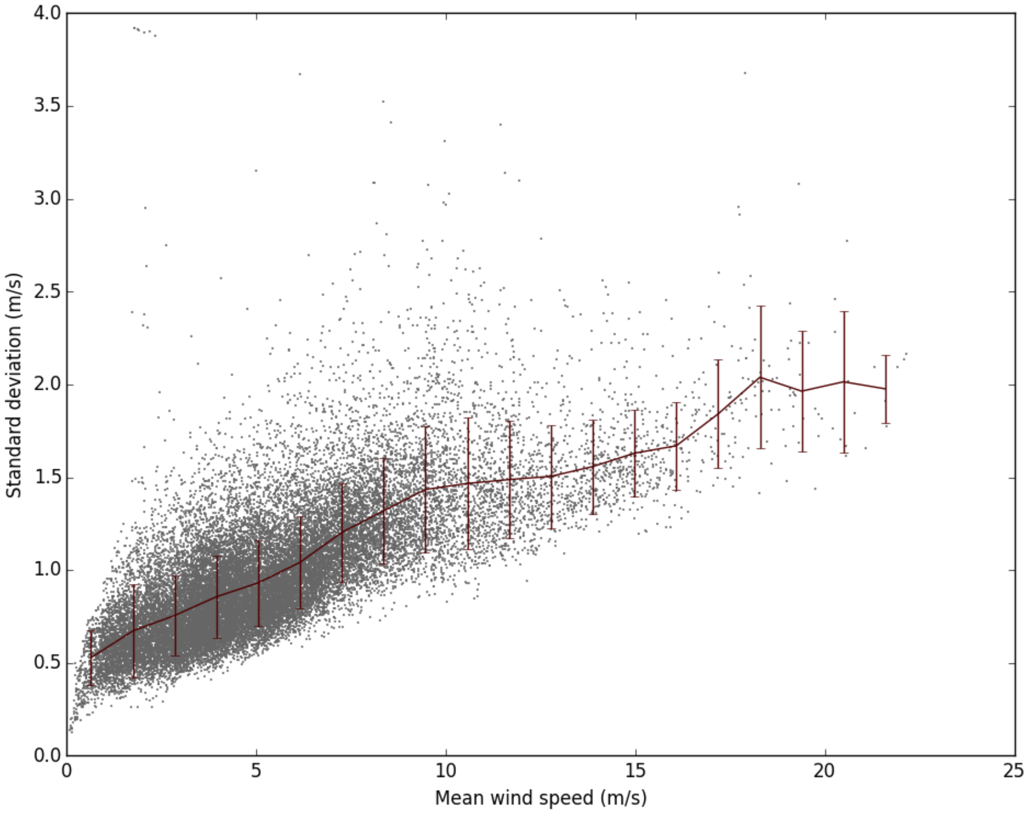

Figure 21 - Relationship between mean wind speed and standard deviation in wind speed across 140 turbine anemometers at Whitelee 1 windfarm (binned means and deviations shown in red)

4.4 A Vector Auto-Regressive Model Wind Power Model

The use of historical or reanalysis meteorological data makes the assumption that historical conditions adequately represent all future operational conditions, which is dependent on the length of the dataset in use. In particular, within power system analyses which aim to identify edge cases (such as contingency scenarios for network adequacy studies) the tails of the distribution of possible operating conditions are of particular interest, and these may not be captured within existing data [119].

A statistical model, alternatively, aims to synthesise wind time series from a set of equations which correctly characterise the auto-correlative nature of the wind resource, and potentially allowing the generation of much larger amounts of time series data than may exist in historical datasets. This can also greatly reduce the computational burden, by allowing wind power data to be created as it is required by a wider simulation, rather than having to handle and store data in bulk. However, in such approaches it is key that the temporal and spatial correlations of the natural resource are correctly characterised, in order that the variability of wind injections across an electrical network adequately captures the variety of likely operating states.

The suitability of auto-regressive processes to modelling wind speeds, in order to preserve such correlations, has been previously demonstrated in e.g. [120] and extended to modelling of wind power in e.g. [121], [122], [123].

4.4.1 Model Description

An n -variable vector autoregressive model of order p, termed $VAR(p)$, is a system of n linear equations, with each equation describing the dynamics of one variable as a linear function of the previous p lags of every variable in the system, including its own p lags [124]. As a VAR model assumes stationarity of the underlying process, it is necessary to remove cyclically varying components of the wind speed. In [123], an inspection of seasonal and diurnal components is undertaken in the context of auto-regressive models, and that de-trending process is followed here.

The wind time series is modelled as including two deterministic components (Eq. (4.10)), representing the annual and diurnal trends respectively. For each measured wind node, harmonic analysis is used to derive an annual function (Eq.(4.11)) with Fourier terms $\Omega, 2\Omega$ and 3Ω, with Ω representing the annual angular frequency. This is subtracted from the raw dataset, and a diurnal function (Eq.(4.12)) with Fourier terms ω and 2ω derived from the residuals with ω representing the diurnal angular frequency. The remainder is termed the 'de-trended' value y_{dt}.

$$y_{dt}(t) = y(t) - y_a(t) - y_d(t) \tag{4.10}$$

$$y_a(t) = a_0 + a_1 \sin(\Omega t + b_1) + a_2 \sin(2\Omega t + b_2) + a_3 \sin(3\Omega t + b_3) \tag{4.11}$$

$$y_d(t) = c_0 + c_1 \sin(\omega t + d_1) + c_2 \sin(2\omega t + d_2) \tag{4.12}$$

Further partitioning of data prior to the application of Eq. (4.12) may be appropriate for locations subject to seasonal variance in diurnal trends - this is discussed further in [125]. The generalised vector auto-regressive (VAR) process of order p for the de-trended data at n nodes can be expressed by Eq. (4.13):

$$\overrightarrow{y_{dt}(t)} = \overrightarrow{\Phi_1}\overrightarrow{y_{dt}}(t-1) + \overrightarrow{\Phi_2}\overrightarrow{y_{dt}}(t-2) + \cdots + \overrightarrow{\Phi_p}\overrightarrow{y_{dt}}(t-p) + \vec{e}(t) \tag{4.13}$$

where $\overrightarrow{y_{dt}(t)}$ is the vector is size n comprising the detrended values for all nodes at time t, and $\overrightarrow{\Phi_1}, \overrightarrow{\Phi_2} \dots \overrightarrow{\Phi_p}$ are the $n \times n$ matrices describing the inter-relationships between the nodes at time lags $1,2 \dots p$. Lastly, $\vec{e}(t)$ is a Gaussian noise term.

Through the use of equations (4.10) through (4.13), a model of time lag p capable of synthesising time series data for a wind field comprising n nodes, including initial values for $\vec{y}(t-1), \vec{y}(t-2) \dots \vec{y}(t-p)$, can be represented by $pn^2 + (p+12)n$ parameters.

Simulated wind data from a parameterised model is synthesised iteratively, by deriving the next term of the 'de-trended' process via Eq. (4.13) and adding the annual, diurnal and noise terms at each node.

4.4.2 Conversion of Wind Speed to Power

In order to derive wind power output for a given location, firstly the weighted average $u_g(t)$ of the wind speeds at time t at the nearest k weather nodes is calculated from a set of weightings $w_1, w_2, \dots, w_k$, as in Eq. (4.14).

$$u_g(t) = \frac{\sum_{i=1}^{k} w_i u_i}{\sum_{i=1}^{k} w_i} \tag{4.14}$$

The conversion of this weighted average wind speed to site power output follows the same formulation as for the deterministic model, given in Eq. (4.5). However, this is not determined from the turbine power curve, but instead a best-fit power curve is trained from high-resolution metered data, and this is demonstrated in the next section.

4.5 Parameterisation and Validation for the GB Electricity Network

For this study, only the 50m above ground level MERRA 2 values are used, as these are closest to the hub heights of modern wind generators. As a statistical wind-to-power conversion is used, extrapolation of wind speed to actual hub heights is not necessary - however, if this was required for a deterministic wind power model then the wind model presented here could be repeated for the 3 height measurements and extrapolated at the site location following the methodology presented in [107].

Five years of data spanning the whole years 2010 to 2014 inclusive was retrieved from the MERRA dataset for the 552 nodes covering the British Isles as depicted in Figure 17. For each node, the best-fit parameters for Eq. (4.11) were derived, and the best-fit parameters for Eq. (4.12) derived from the residuals. As the diurnal trends in the British Isles appear to vary significantly between seasons [123], the annual residuals were first partitioned into 4 3-month datasets in order to derive separate diurnal trends for each period - these are shown for an example node in Figure 22. The summed annual and diurnal trends for one year are illustrated against the raw values for a sample node in Figure 23. Figure 24 illustrates the normality of the data once after de-trending, which is required as the VAR process assumes normality. The matrices for a $VAR(3)$ model were then fitted to the remaining residuals across all nodes, using the Python Statsmodels package. 10 years of data was simulated from the fitted model, using the final value of the training dataset as initial values, and added to the annual and diurnal trends at each node to produce the simulated wind time series for each node.

In order to derive the node weightings and power curve speed/power pairs, metered energy data (on a half-hourly resolution) for wind generators participating in the GB Balancing Mechanism was retrieved for the period 1st January 2013 to 31st March 2015 [126]. This includes all transmission-connected wind generators, as well as larger embedded wind generators.

The geographical distribution of the sites for which data was available throughout this period is shown in Figure 25. Six further sites were excluded from the dataset due to being subject to significant export constraints during this period, leaving 46 generators totalling 4869MW of installed capacity. The data was aggregated by hour to match the resolution of the MERRA wind model. Two filters were applied to the data in order to ensure, as far as possible, the dataset captured normal generator operation:

1. A curtailment filter was applied to remove all hourly data points where sites were subject to external constraints by the GB System Operator, using reported Bid-Offer Acceptance instructions from the published Balancing Mechanism data.

2. A coarse availability filter was applied to remove hourly data points where it appeared that the site was unable to generate at non-nominal levels. This was achieved by performing an initial run of the power-curve fitting described below, and then filtering all points where the total output of the site was below 20% of the expected value, and the site was expected to be producing more than 10% of its rated power.

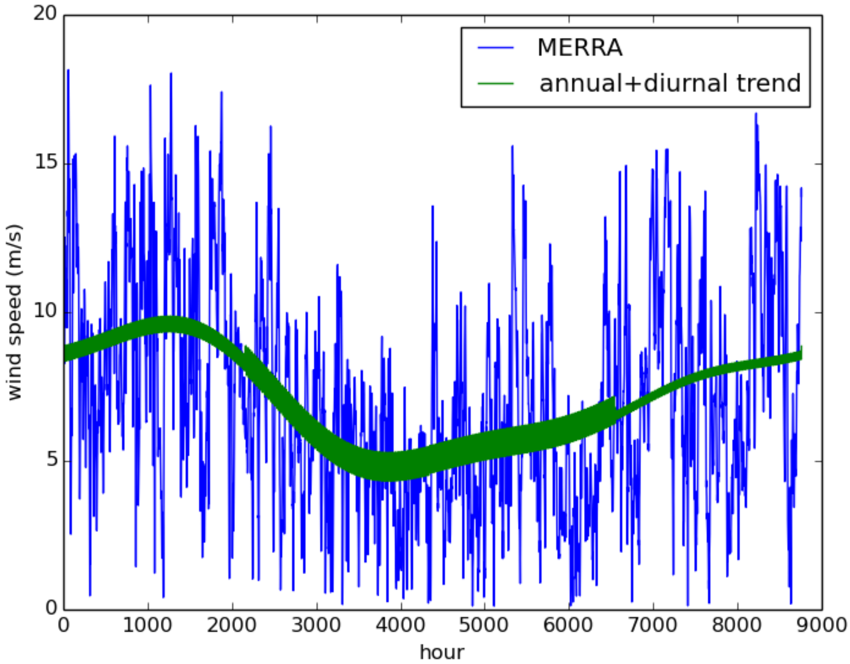

Figure 22 - Raw MERRA wind data from 2014 for node located at 55.5N, 4.0W compared to the summed annual and diurnal trends identified via the de-trending process

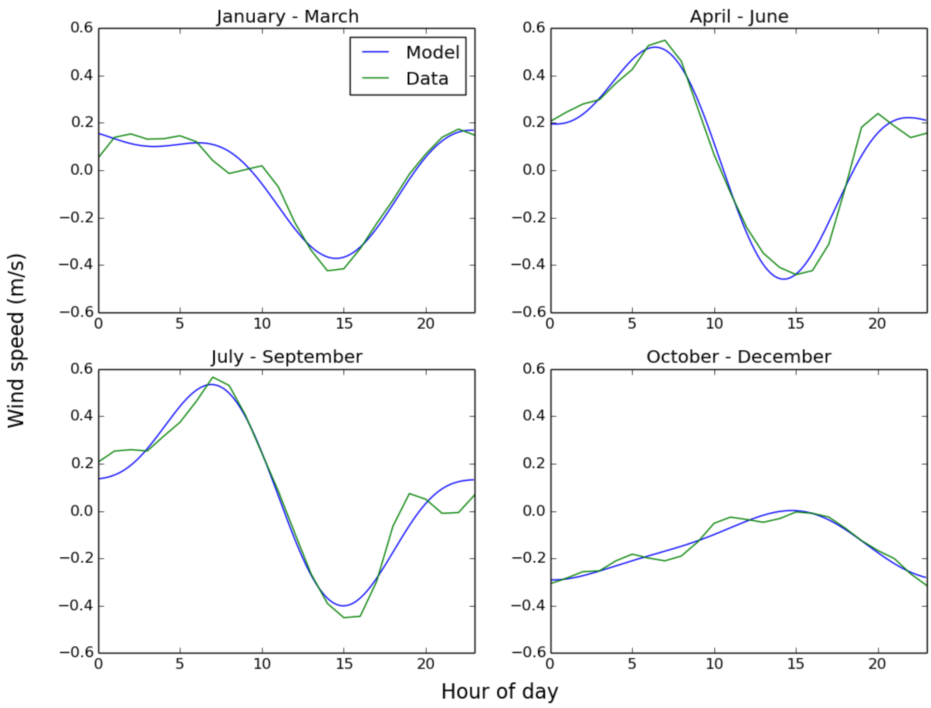

Figure 23 - Fitted diurnal trends, partitioned by season, against hourly averages after annual de-trending for MERRA node located at 55.5N, 4.0W

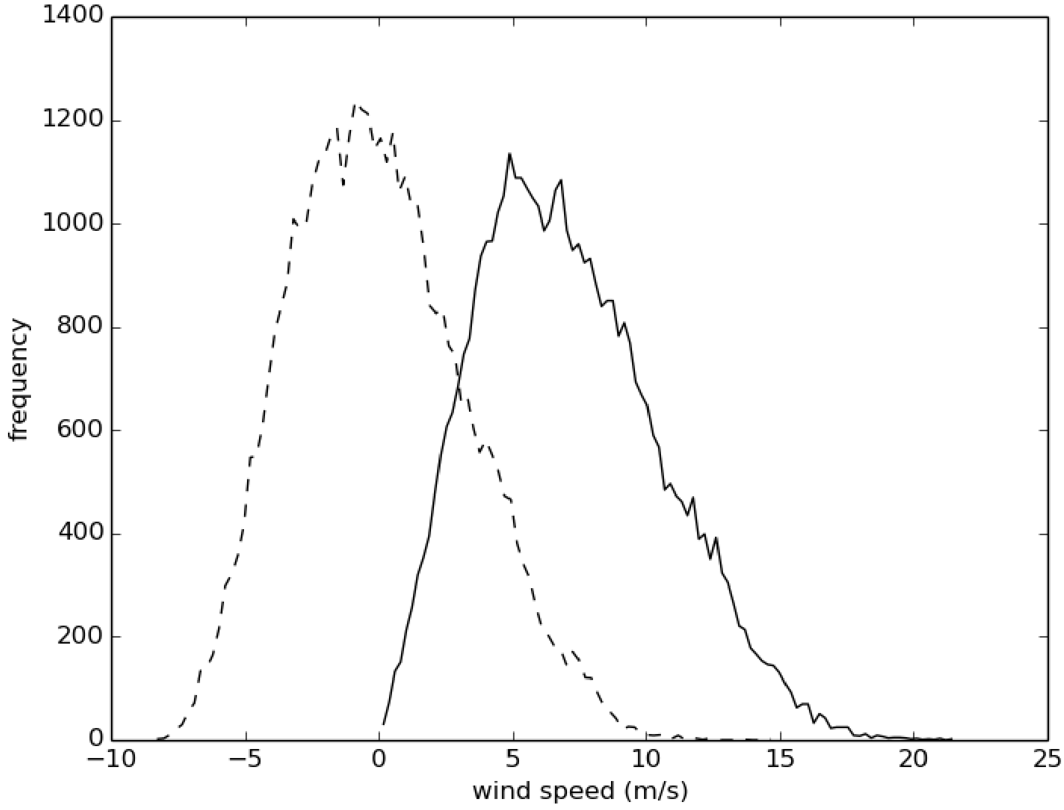

Figure 24 - Distribution of wind speeds for node located at 55.5N, 4.0W before (solid line) and after (dashed line) de-trending

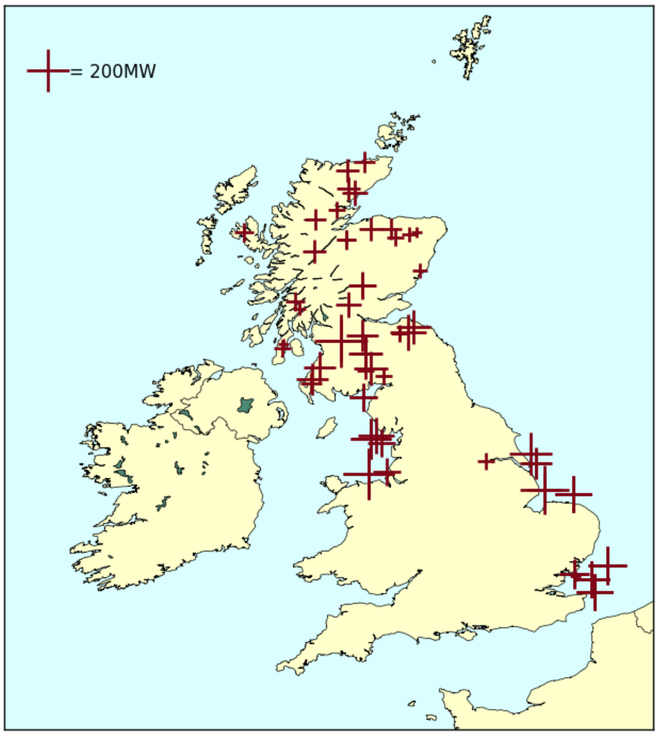

Figure 25 - Distribution of wind generators used in validation

The dataset was split into training data covering 1st January 2013 to 30th June 2014, and validation data covering 1st July 2014 to 31st March 2015. The power curve and wind weightings were derived by least-squares fitting against the filtered training data using the Levenberg-Marquardt algorithm. The 4 nearest weather nodes were used for each site, corresponding to the bounding points of the gridded model. Initial node weightings were set to being equal $\omega_i = 0.25 \; \forall i \in [1,4]$, and the initial wind/power pairs are for a current pitch-regulated wind generator, aggregated across multiple turbines, as published in [105]. Power values outside of the domain of this power curve are assumed to be zero. An example of a power curve generated by this process for one wind generator is given in Figure 28, illustrating the data points which were removed either due to being during periods of external curtailment, or through the coarse availability filter described above. In order to synthesise power time series for each generator, the derived node weightings and power curve values were applied on a per-site basis to the wind time series generated from the $VAR(3)$ model.

The validation dataset specified in the previous section was used to determine the accuracy of the derived power curves to the metered wind generator output. The average R^2 value across all 46 wind generators was 0.839, with a range of 0.770 to 0.899. A large proportion of the error appears to be generated around the rated power of the site, where a small change in wind speed can have a large effect on the power output, from turbines shutting down due to high wind speeds. Other sources of error will include time-variant properties such as site operational availability (other than that captured by the data filter), local terrain effects in combination with wind direction, and local turbulence conditions. An interesting outcome was that the average r-squared value improved by 0.02 if the wind weightings used in Eq. (4.14) were not constrained to positive values - this may reflect the temporal lag in weather fronts moving across neighbouring MERRA nodes.

The outputs of the VAR simulation must be validated according to two criteria: the extent to which spatial correlations between wind locations are preserved, and the extent to which rates of change of power are reproduced. It is not possible to directly compare the VAR synthesis to measured data and extract e.g. a Mean Absolute Error (such as for a traditional forecasting methodology), as only the starting vector of wind speeds $\vec{y}(t0)$ is derived from physical data. Hence the distributions of linear and spatial correlations are compared to that of the original data instead. Figure 26 shows the spatial correlations between randomly sampled wind node pairs in the original MERRA dataset compared to the outputs of the $VAR(3)$ model. This demonstrates a close reproduction of the extent of spatial correlation observed in the reanalysis data. While the $VAR(3)$ model shows a slightly lower spatial correlation for node pairs located at significant distances, the correlation values have a lower variance around the best-fit line. One possible explanation for this difference is that large-scale wind patterns are often driven by complex weather systems which may lead to increased correlation over significant distances during particular events - as the VAR model is a statistical model rather than a meteorological one, it is incapable of reproducing these events. Figure 27 shows the ramp rates at each wind generator, and the total ramp rates for all generators in the system, derived as a proportion of rated power (either for the individual site or the total capacity of 4869MW). This shows that the distributions of ramp rates for the simulated data are very similar to that of the raw metered dataset. The simulated distributions show a slightly higher variance (i.e. display proportionately greater ramp rates) than in the original metered data.

The statistical wind power model presented here demonstrates a means of representing wind injections into a power network using a relatively low number of parameters with few computational requirements compared to direct use of large-scale numerical weather models. Similarly, the iterative nature of the process of synthesising time series data means that it can be used for ’just-in-time’ simulation without the need for storage of large volumes of data. This makes it particularly suitable for power system studies concerned with issues such as network and reserve adequacy, which may require the simulation of many years of operation in order to analyse all possible operational scenarios. The statistically-derived wind-to-power conversion model provides a good fit against metered data, but use of, and validation against, data from extant wind generation remains difficult in terms of quantifying the impact of local conditions both in terms of wind flow/turbulence and operational availability of turbines. While theoretical wind-to-power models provide some ability to quantify these factors in power system simulations, validation of such models against national-scale datasets still requires these issues to be addressed. It is noted that in this study, and others which use similar data sources, large-scale wind datasets have (by necessity of computational burden) a low temporal resolution, and a power system planner may be interested in ramp rates and correlations on a sub-hourly resolution. However, spectral analysis of wind speeds shows a significant spectral gap at a frequency of around 1 hour [103], suggesting that it may be suitable to utilise a separate statistical model - likely with a high proportion of noise - to interpolate between hourly values derived from a model such as has been presented.

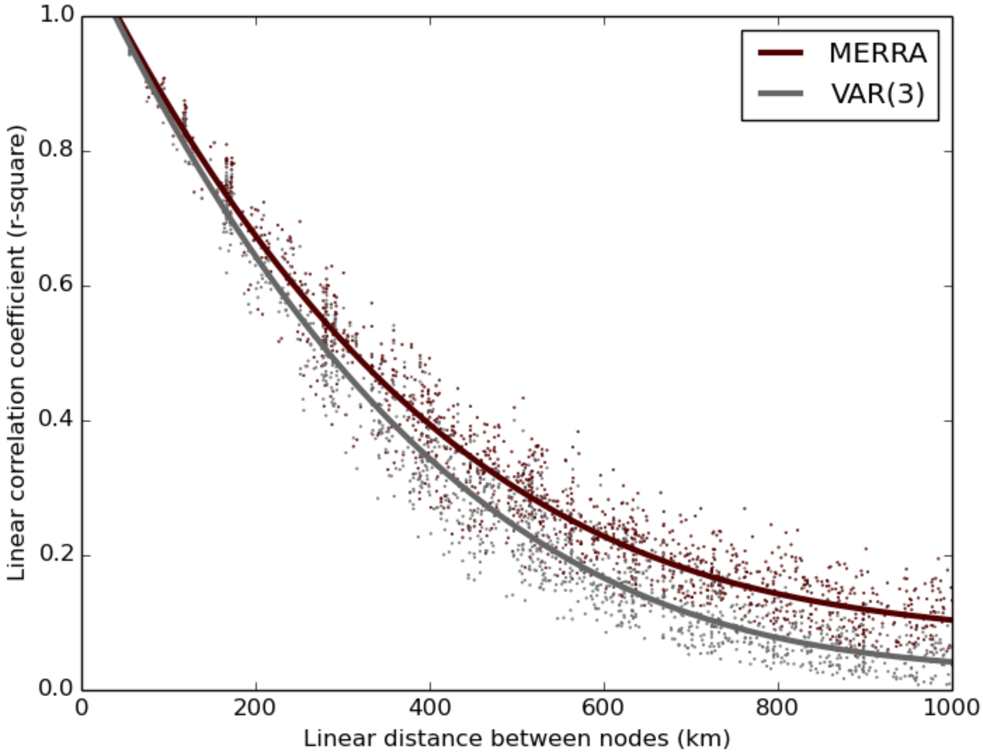

Figure 26 - Comparison of spatial correlation between randomly-selected node pairs in the original reanalysis data and the reduced VAR(3) model

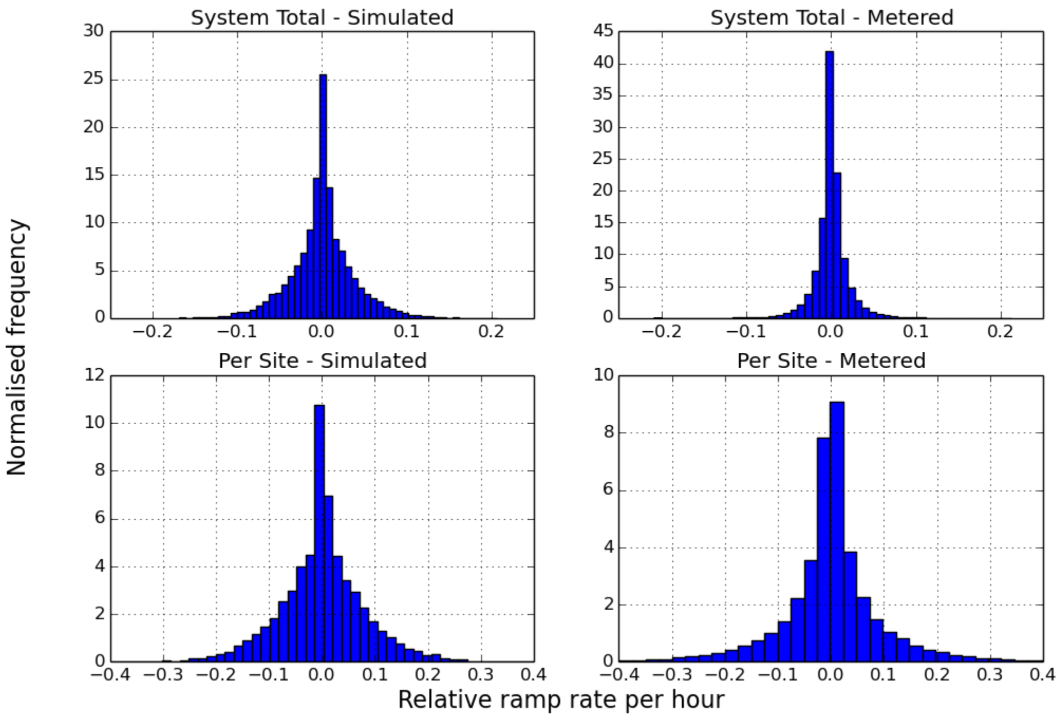

Figure 27 - Ramp rate distributions as a proportion of total rated power

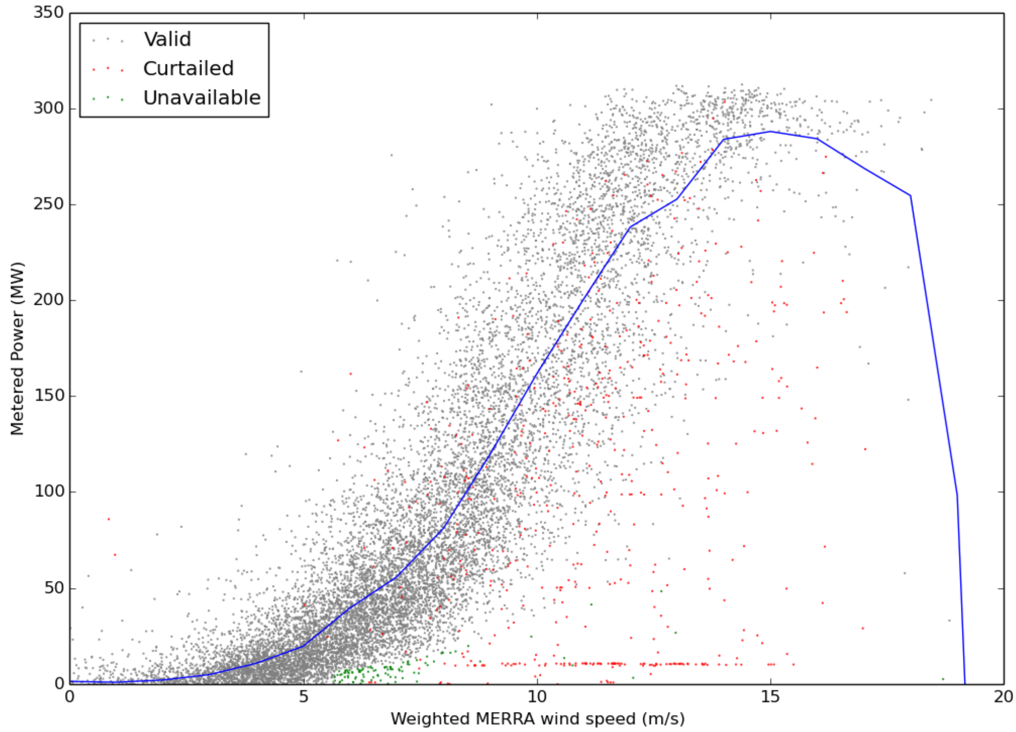

Figure 28 - Derived power curve for Whitelee 1 Wind Farm, showing filtered data points

4.6 Application to WSEMs

The contribution of this modelling is two-fold: firstly, to improve the wind speed-to-power output conversion process over existing methodologies used for the simulation of wide-scale wind power injections into a power network; and secondly, to introduce a statistical methodology using derivation of VAR process in order to be able to generate time series of wind power output which, while driven by the characteristics of recorded wind speed data over multiple years, is not intrinsically linked to specific historic years of recorded data. This assists in improving the extent to which the simulated data will correctly represent a broad range of historic conditions (as opposed to one specific recorded period, which may or may not adequately display the full range of meteorological characteristics).

The methodologies described in this chapter allows either the simulation of hourly power outputs for a single wind farm location, or to produce simultaneous time series for multiple wind farms across a large geographical area, with appropriate reproduction of both spatial correlation between locations, and temporal auto-correlation. This can either by driven by a deterministic model which uses historical reanalysis data or a statistical model which can extrapolate from that data to provide longer-term time series, or to provide a similar synthesis with a reduced volume of initial data to handle. This means that where time series of wind power is required to be input either into an WSEM or a local energy model, the variance between sites and within a site location is correctly represented, and any interdependencies with other weather-driven variables (such as energy demand being partially driven by temperature) is correctly captured. In addition to this section, a formulation for synthesis of solar photovoltaic power is given in Section 5.3.1.

These improvements in wind power synthesis are used later in the multi-carrier simulation (chapters 7 and 8) to drive exploration of the possible synergies between intermittent renewables such as wind and residential energy provision, through optimisation of the energy system (in theoretical terms) and creation of local supply agreements (in practical and commercial terms).

5 Distribution Network Futures

5.1 Overview

Based on the analysis of Whole System models presented in Chapter 2, and the need for spatial and temporal detail to be included within such modelling as detailed in Chapter 3, we can see that an understanding of the local application of technologies, their contexts of operation and the networks in which they exist, must be carefully examined in order to ensure that inappropriate simplification of technical and economic realities do not occur. In order to achieve this, it is necessary to look at the detail of possible technological futures for meeting energy demand at a local scale; i.e. in distribution networks (be they for electricity, gas or heat). In this chapter, the technologies and futures which may be utilised in current decarbonisation policy in the UK are examined in detail in order to build up a quantified understanding of each technology and its dependencies.

In this study, following the policy gap indicated in Section 2.3.4, it is proposed that a key focus of current modelling effort should be on the provision of domestic heat and the impact of different energy futures on the requirements of the distribution networks. Heat has a particularly complex spatial and temporal character than other energy carriers, due to the magnitude of losses in both dimensions, and hence is a key sector for deeper evaluation than is currently conducted within WSEMs. In this chapter, the different technological options for the provision of heat are examined, as well as the underlying infrastructure requirements to enable their use. In order to facilitate the construction of representative models, the existing literature is reviewed and representative costs of technologies and infrastructure summarised. Where additional technology-specific methodologies are required to complement the existing formulations around spatial energy systems and wind power, these are presented based on existing literature. The future of gas and electricity distribution networks is discussed, and the costs and technical characteristics of various options in future heat provision are discussed, with the aim of sufficiently characterising the relevant technologies in a manner which allows their incorporation into a multi-energy carrier model.

This chapter includes discussions of the technical constraints and cost parameters for different heat provision technologies, so that these can be incorporated into the following techno-economic models presented in Chapter 7.

5.2 Gas Network Futures

Gas has been delivered to UK buildings via pipelines for over 200 years. Originally 'Town Gas' - a mixture of hydrogen, carbon dioxide, methane and other gases manufactured from coal – was supplied to consumers. Due to the high cost of laying pipes (relative to the volume consumed) residential demand was not supplied until approximately the 1840s, and initially mainly used for cooking due to the poor combustion of town gas and the accumulation of soot. With the discovery of natural gas in the North Sea in the 60s, a national programme lasting 10 years converted the gas system to the higher energy density fuel, and created a national transmission network. Currently the gas transmission network consists of 7600km of pipeline, injecting gas into a distribution network of 280,000km (of which 233,000km is low pressure) at 175 locations [127].

The use of gas as an energy vector is particularly well-suited to the heat sector, as heat demand undergoes significant daily and seasonal swings – significantly more so in comparison to transport and electricity [128], illustrated by Figure 29. The current gas system has a high degree of flexibility, and the natural buffering due to line pack (the effective use of the system as an energy store by increasing pressure through adding greater gas than is being demanded) assists in reducing the impact of these swings, in comparison to provision of heat through electrical sources, where current storage capacity is negligible and balancing must be conducted on a near-instantaneous basis. While there are additional options to help ameliorate this issue (such as improving building efficiency, peak demand management and improved designs for heating equipment) there are limitations on what can be achieved, particularly due to conservative attitudes in home owners [129]. Gas boilers also have strong financial attractions, such as low capital and operational costs, alongside high power output, reliability, and responsiveness. This makes the continued use of gas-fuelled boilers for a substantial proportion of heat demand a likely ongoing requirement in the short and medium term.

A not insignificant proportion of the gas network is composed of iron pipes, which may be 40 to 100 years old. A 30 year Iron Mains Replacement Programme (IMRP) is currently underway to replace around 100,000 km of low-pressure iron distribution and service pipes with polyethylene (PE), predominantly for the purposes of safety [130]. Since 2001, the Health and Safety Executive has required gas distribution network operators to accelerate the replacement of all case iron and ductile mains within 30 metres of buildings. In 2010, Ofgem questioned whether the program was still "proportionate and sustainable" [131] given that costs of the programme reached £24bn by 2010, and that the first 25% of the replacement programme may have removed 60% of the modelled risk, with the majority cost benefit of the remainder of the programme being in reduction of losses ('shrinkage'). The IMRP represents a significant investment in the UK energy system which will substantially increase the value of the network by the time of completion in 2032.

While natural gas is seen as a potentially increasing contributor to the UK's energy mix in the near-term (for example, as a greater proportion of the electricity generation mix in order to substitute for coal plant while reducing carbon emissions per unit energy), it remains that natural gas cannot be used as a major energy source under deeper decarbonisation scenarios [132]. However, the IMRP programme means that there is the potential for infrastructure lock-in, where an existing high-carbon infrastructure may prevent low-carbon alternatives from entering the marketplace. If the desirability of the gas network as a means of transmitting energy, in particular for meeting heat demand, remains a focus of the energy system, then the nature of the actual gas being delivered will require change, and several possible futures for the gas network are described below.

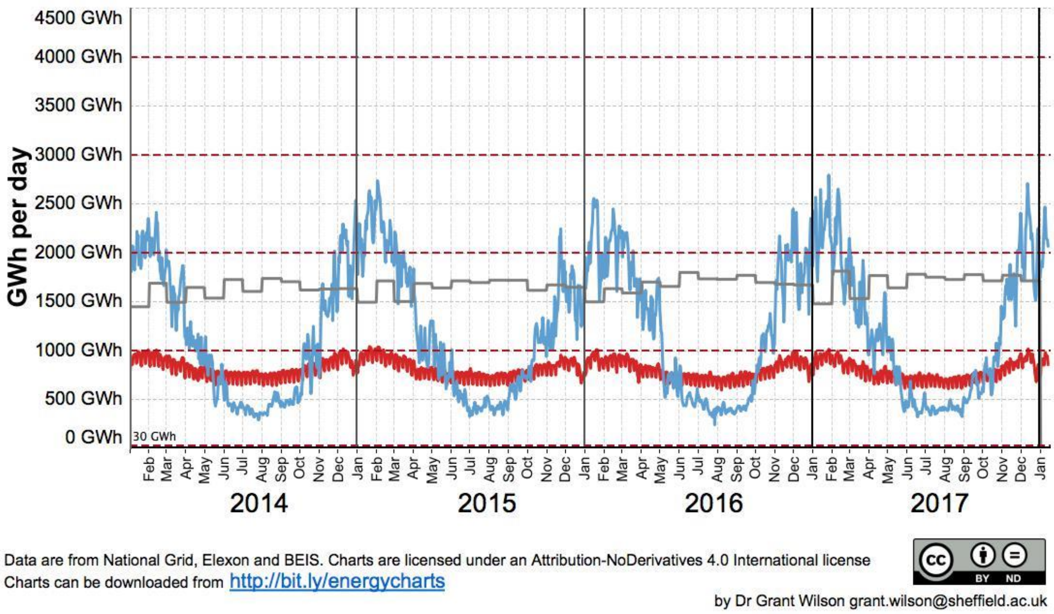

Figure 29 - Relative levels of total energy demand by primary sector 2014-2017

5.2.1 Biomethane injection

One route to decarbonisation of the gas system, permitting its ongoing use, is to replace natural gas with biomethane, produced by upgrading biogas from anaerobic digestion or synthetic gas plants, which already accounts for 1% of gas within the network [133]. However, the potential is limited by the availability of feedstocks, limiting biomethane to supplying up to one fifth of the UK's gas demand, and requires carbon capture equipment. However, due to the similarity in composition to natural gas, this would have little to no impact on end consumers.

Within this study, the source mechanisms for biomethane are not analysed, and it is assumed that decarbonisation of the gas grid occurs outside the scope of this work. While there is potential for local provision of biomethane based on local opportunities (such as close to sources of waste or agricultural by-products), it is assumed here that all biomethane is imported from the gas transmission network, and is otherwise comparable to natural gas, varying only in costs per unit and the emissions intensity of production. These values are assessed from the literature below.

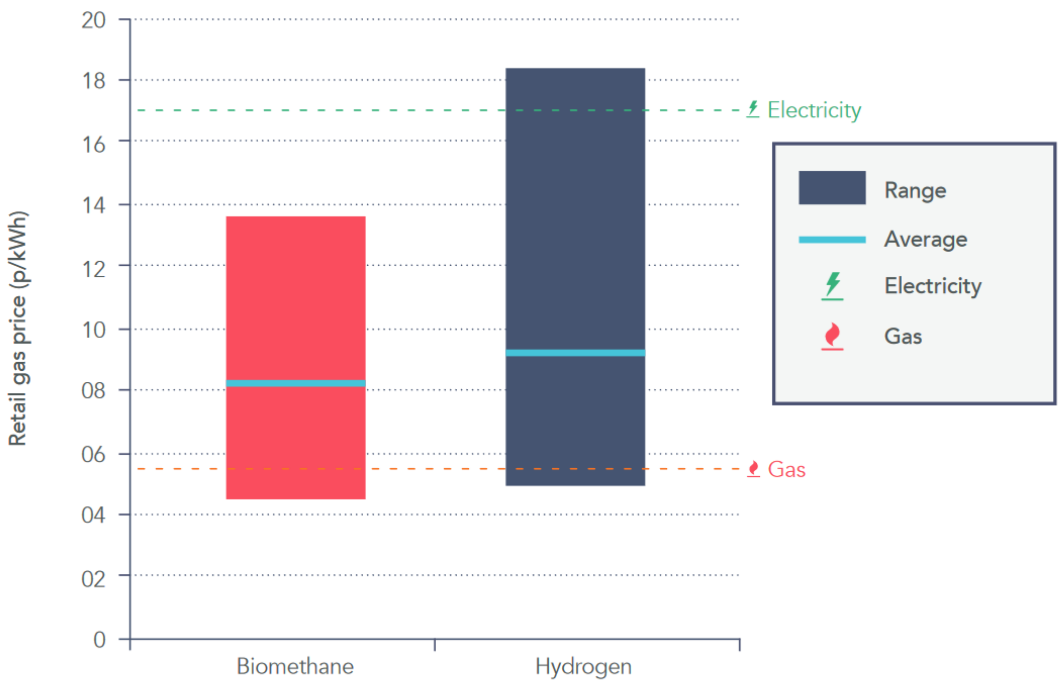

Figure 30 - Cost estimates of biomethane and hydrogen compared to the current cost of natural gas (reproduced from [132])

5.2.2 Hydrogen injection

Pure hydrogen does not occur naturally, and must be produced either through the reforming/gasification of other fossil fuels, extraction from biomass, or via electrolysis. Additionally, it has a lower energy density than natural gas and fewer materials are suited to its transport (due to e.g. embrittlement and corrosion).

However, much of the extant gas network is suited to the transport of hydrogen. In 2002, the IMRP was instituted to accelerate decommissioning and replacement of the aging cast iron gas pipework. While this was predominantly instituted in order to improve safety and reliability, it has had the secondary impact of replacing significant amounts of metal pipework unsuited to hydrogen transport with plastic piping (such as PE) which is relatively impermeable to hydrogen.

Similarly, end use equipment (boilers, cookers etc.) contain gas burners which are able to operate with a non-negligible volume of hydrogen in the gas flow. This means that it is possible to inject a certain volume of hydrogen into the existing gas network without any requirement for changing either transport or end-use technologies. Estimates indicate a soft limit for hydrogen injection of around 5% to 15% by volume (equivalent to 1% to 3% by proportion of energy) without significant impacts on safety, durability or integrity of the existing natural gas network, depending on the exact mix of materials and technologies in use [134]. A recent UK-based study indicated that there are “no show-stoppers forming a significant barrier to a hydrogen/natural gas utilisation demonstration project for domestic customers” [135] and a demonstration project at Keele University campus, involving natural gas / H_2 blends of up to 80/20%, began in April 2017 [136]. Typically end-use requirements are the most restrictive conditions on increasing hydrogen blend levels in natural gas.

In terms of losses, a calculation is presented in [134] for the US gas network, based on use of PE pipes, which suggests that the majority of gas loss would occur in distribution mains smaller than 2 inches and operating at 5 bar or above. For a network with 20% hydrogen injection, within the US system this would result in a gas loss of about 43 million ft^3/yr, with about 60% of the losses being hydrogen and 40% being natural gas. This is approximately double the loss as for natural gas transport only, but is considered economically insignificant as it only equates to a total loss by volume of 0.0002%. For this reason, gas transport losses are ignored within this study.

It is also possible to extract hydrogen from blended gas, using technologies such as pressure swing adsorption, membrane separation, and electrochemical hydrogen separation. This means that the gas network can be used to transport pure hydrogen without it being used by existing end-use technologies. This can defray the cost of building dedicated hydrogen pipelines, particularly as a means to early development of a hydrogen market. However, this does occur additional costs and inefficiencies due to the additional extraction required [134]. For the purpose of this study, this opportunity is ignored as it is assumed that any such separation takes place prior to the ‘last mile’ network, and is a means of transmission rather than distribution of hydrogen.

5.2.3 Conversion from natural gas to hydrogen

For the gas network to support higher concentrations of hydrogen, or to transport hydrogen exclusively, more fundamental changes in technology are required. However, it is noted that 'town gas' contained 30-50% hydrogen by volume, so this is far from a new challenge. While much of the gas distribution network would require minimal change, a new high-pressure transmission network would be required both to avoid embrittlement in existing pipework and to supply the high-pressure transport sector. This would require substantial investment and creates the 'chicken-and-egg' situation often associated with hydrogen futures – sales of hydrogen-based end-use technologies (such as fuel cell vehicles) are restricted by the lack of a sufficient supporting infrastructure, which in turn does not have a feasible business model without sufficient demand.

However, some low-cost strategic investments can be made which provide a route towards increased use of hydrogen within the UK energy system [128], and the 'hydrogen economy' is not necessary for investment in e.g. fuel cells to occur. For example, on-site hydrogen production can use existing infrastructure, and a local energy system which depends only on the distribution network need not entail significant new investment.

5.2.4 Upgrade Costs

Appendix B gives gas distribution network pipe sizes and replacement costs, assuming extant iron pipework and replacement with polyethylene. The predominant pipe sizes in 'last mile' networks will be 5" for transport along utility trenches, along with <3" pipework connecting through to households. Each pipe type has a £69.6/m and £63.8/m cost respectively. It is assumed that the extant network requires full replacement in all heat provision scenarios, as the IMRP programme will likely continue to completion before a significant movement to non-gas heating is achieved.

In terms of conversion from natural gas to the above options, for biomethane no change would be required at a local level. For hydrogen, there are a number of conversion costs, including a change of metering, boiler parts and oven parts, assessed as totalling around £490 per household including labour [137]. The main boiler change would be to the burner to allow safe operation with the higher flame velocity of hydrogen, but it is noted that this could be built into the specification of new condensing boilers to allow switch-over with no additional cost beyond the normal boiler upgrade cycle. While conversion would entail significant changes to both the supply and transmission sectors, with significant issues around the changeover at a higher distribution level, this study is only concerned with costs applied at the local scale, so does not incorporate these costs. The £490 cost is assumed to apply on a typical gas condensing boiler size of 24kW, so equates to £21.6/kW in 2016 prices.

5.2.5 Emissions and cost estimates

The range of carbon emissions estimates for the different methods to produce low carbon gas is extremely wide, ranging from -371 to 642 gCO_2/kWh for hydrogen and -50 to 450 gCO_2/kWh for biomethane [132]. The carbon negative values correspond to biomass gasification accompanied by carbon capture and storage, whereas the highest values correspond to use of fossil fuels in e.g. coal gasification. The different cost and emissions scenarios are presented in Table 4 below, and the values are taken from steam methane reformation for biomethane, and electrolysis for hydrogen, representing the most likely technologies in the near future under scenarios seeking to meet decarbonisation targets.

Table 4 - Projected costs and emissions from biomethane and hydrogen [132]

	Biomethane		Hydrogen	
Scenario	**Emissions (gCO2/kWh)**	**Cost (p/kWh)**	**Emissions (gCO2/kWh)**	**Cost (p/kWh)**
Low	23	4.4	25	4.9
Central	87	8.1	102	9.3
High	150	13.6	178	18.4

These cost and emission values, alongside the costs and emissions for existing fuel sources (as shown in Table 7) can be used within an optimisation model to drive an objective function which seeks to minimise total costs or emissions, or a combination of those. This hence allows a direct comparison to be made between the value of different energy carriers. This is developed further in Section 0. These values include all upstream supply cost, but are treated separately from the cost of transmission infrastructure required to supply end user demand. This means that in the optimisation the costs of local infrastructure for different carriers are correctly identified, as it is important to appropriately compare energy carriers where the transport infrastructure already exists (as a sunk cost) and those where new transport infrastructure must be built.

5.3 Electricity Network Futures

A significant proportion of UK network is operating near its capacity, which limits a) capacity to absorb additional demand; b) the use of electricity as a replacement for other vectors for the provision of energy service demands such as heat; and c) the capacity to permit the connection of additional renewable generation on a distributed basis. Even the maintenance of the status quo involves significant investment - approximately 10% of the switchgear and 6% of the 132/33 kV transformers in GB's distribution networks need to be replaced between 2010 and 2015 [138]. This in turn creates a significant incentive to find alternatives to traditional network replacement and/or reinforcement that can offset costs or provide additional energy security.

5.3.1 Increased Embedded Generation

As the investment into low carbon sources of power has increased, so has the proportion of decentralised electricity generation connected into the distribution network. In particular, at a domestic level, there has been a substantial increase in the volume of solar photo-voltaic (PV) installations, which are generally unmetered. Additionally smaller wind farms are connected into distribution networks (as opposed to most conventional generators connecting directly to the transmission network) and as a result many distribution networks are highly constrained to the entry of new renewable generation capacity.

One alternative to traditional reinforcement of distribution networks to overcome this constraint is to find additional opportunities to use such generation outputs to meet demand locally (and hence avoiding any constraints that may occur between the generation plant and the transmission grid), which additionally reduces losses.

Within this study, the injection of wind power into a local distribution system is conducted using the simulation method described in Chapter 4, and incorporated into particular local energy models as described in Section 7.4, which also describes the use of an established methodology for simulation of solar PV generation.

5.3.2 Upgrade Costs

The upgrade costs for LV electricity networks are assessed on a per-component basis, and costed according to the values given in [139]. This will typically include the secondary transformer replacement, additional LV cabling (underground/overhead), LV pillars and link cabling. Within this work, the total cost is determined according to the specific LV system being considered, and defined for each model according to the specific components and cable lengths required, as set out in Chapter 7.

Deeper reinforcement is not explicitly considered within this work, as the analysis is restricted to LV systems. There will be associated costs with the upgrades required at higher distribution voltages, and on the transmission network, but it is here assumed that the local networks being modelled have no impact (in isolation) upon higher voltage levels. For a more complete inclusion in WSEM inputs, this deeper network reinforcement should be modelled and a per-household cost applied. This is discussed further in Chapter 9, where the costs of network reinforcement are disaggregated by system archetype, including deep reinforcement costs, which are assumed to be equal for all locations.

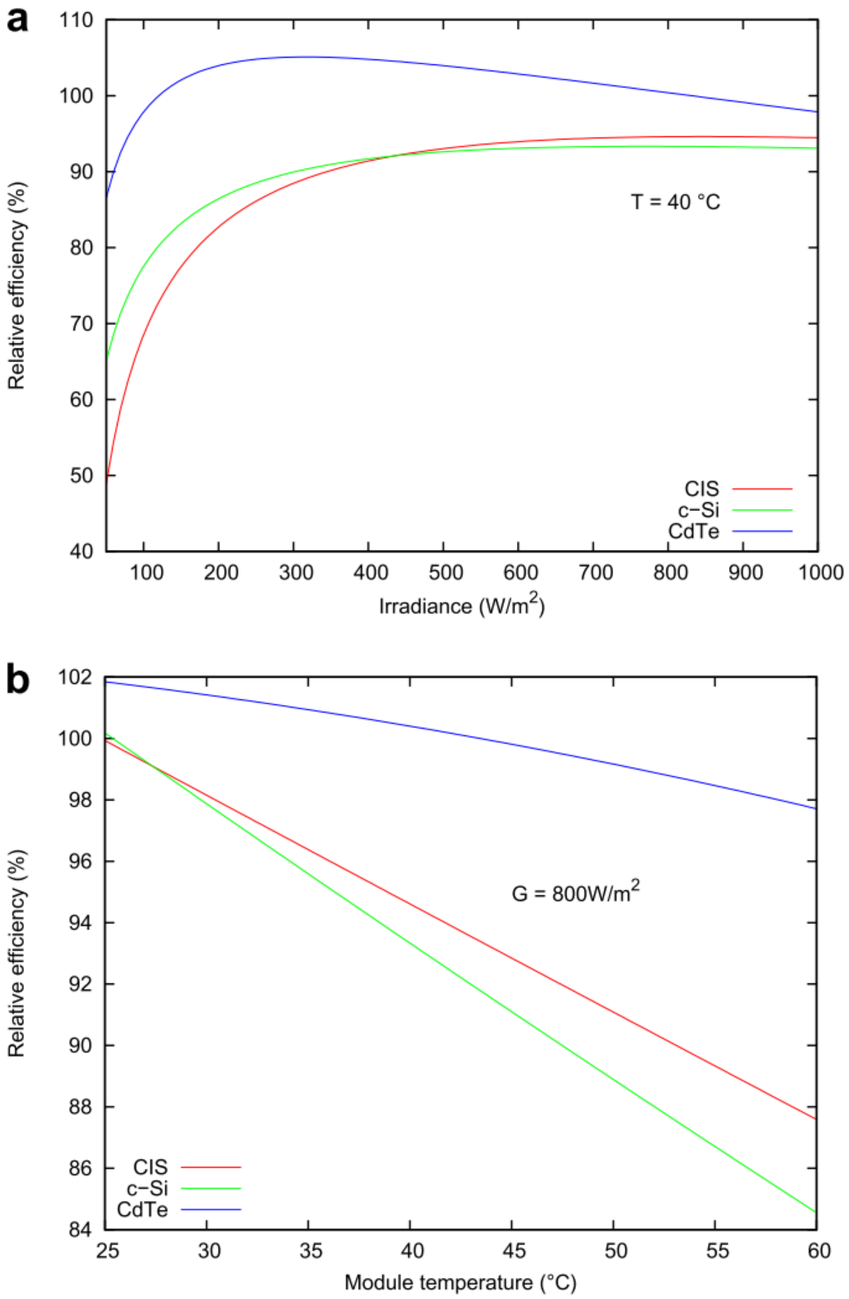

Figure 31 - Output curves for PV technologies, a) for varying irradiance at a fixed temperature of 40C, and b) for varying temperature at a given irradiance of 800W/m^2 (reproduced from [140]).

5.4 Heat Futures

As discussed in Section 2.3.4, the rate of decarbonisation of heat in the UK has been significantly below target, and this is seen as an area where increased attention is required.

The vast majority of homes in the UK meet their heat supply through the use of small boilers. While many incentives exist to remove inefficient boilers and to reduce consumption through their replacement with e.g. condensing boilers, there has been little development in the use of alternative heat sources. Some of these alternative options are listed here.

Table 5 shows that, in 2012, 79.8% and 8.9% of domestic heat provision was sourced from natural gas and electricity respectively. Figure 32 illustrates this within the context of all sectors, showing the significance of the domestic sector, and its potential role in national emissions reduction.

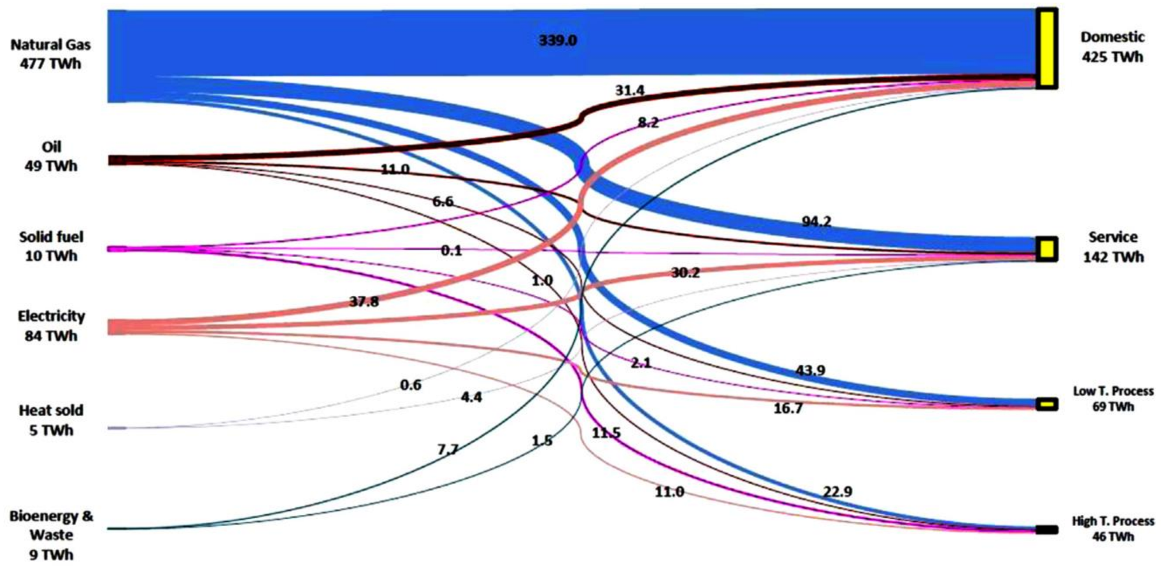

Figure 32 – UK heat demand by sector and fuel source (reproduced from [41])

A number of UK government-sponsored studies have been undertaken in recent years to determine costs and technical parameters for heat technologies, in order to help setting of heat policy instruments, as well as updates from industry. These include:

- A 2011 "Review of technical information on renewable heat technologies" conducted by AEA on behalf of DECC to inform the initial RHI consultation, based on published data for ASHP/GSHP/Solar Thermal and Biomass installations [141].
- A 2012 "RHI Phase II – Technology Assumptions" comprising data gathering and technology assessment carried out by AEA for DECC as part of the RHI Phase II project and used to inform the modelling work to be carried out by NERA [142]. This is based on industry stakeholder engagement, manufacturer specifications and market reviews, and updates the 2011 review with several added technologies.

- A 2013 "Research on the costs and performance of heating and cooling technologies" report commissioned by DECC and carried out by a consortium led by the Sweett group [143].
- A 2013 "Pathways to high penetration of heat pumps" study by Frontier Economics on behalf of the CCC which derives levelised costs for heat pumps across a number of scenarios for heat pump uptake [144].
- A 2016 "Evidence Gathering – Low Carbon Heating Technologies" summary report prepared for BEIS by The Carbon Trust and Rawlings Support Services, which uses stakeholder surveys to derive a broad evidence base (including costs) for the potential surrounding high temperature heat pumps, domestic hybrid heat pumps, and gas-driven heat pumps [145].

The following subsections describe the technical details of each base and alternative heat source in turn, along with a summary of cost projections based on these studies. These technical parameters and costs are later incorporated into the Exemplar Models developed to explore UK heat futures.

5.4.1 Base Cases – Natural Gas Boilers, Resistive Heating and Oil Boilers

As shown in Table 5, 96% of UK domestic demand in 2012 was met from three long-established sources – natural gas (primarily in condensing boilers), electricity (primarily in resistive heaters, often incorporating storage) and by the use of heating oil in oil boilers. As, historically, natural gas has been the cheapest supply option of those 3 for end consumers, the tendency in the UK has been for the use of domestic gas boilers in areas of sufficient population density to cover the costs of transport, and for oil/electric heating in off-gas-grid rural areas.

Table 5 - UK domestic heat demand by fuel, 2012 [146]

	2012 TWh	
Natural Gas	339.0	79.8%
Electricity	37.8	8.9%
Oil	31.4	7.4%
Solid Fuel	8.2	1.9%
Biofuel/waste	7.7	1.8%
Sold heat	0.6	0.1%
Total	**424.7**	

The heating base case is for a continuation of use of the same technologies, with like-for-like replacement. More recent legislation has focussed on establishing higher minimum performance standards for gas and oil boilers, and this means that condensing boilers are likely to be the majority of new installations. Resistive electrical space heating, with immersion heating for hot water, would see a continuation of use in off-gas-grid rural locations.

The technical characteristics and costs of each base case technology are summarised in Table 6. In Table 7, the associated fuel cost projections for 2030 are given under 3 different modelled scenarios. Lastly, Table 8 lists the gross carbon emissions associated with each fuel. The carbon intensity of electricity generation is dependent on the generation mix, which in turn is dependent upon the policy interventions in the intervening period. In [147], the Committee for Climate Change highlight the likely carbon intensity of electricity for future years based on different levels of policy activity: a baseline with little intervention, the introduction of known low-risk government policies, the introduction of known higher-risk government policies, and an identified 'cost-effective' path taking into account the full decarbonisation targets of the UK and comparing costs between sectors.

Table 6 - Technical characteristics and costs of base case heating technologies. Values summarise those found in [147], [141], [148], [149]. All costs are adjusted to 2016 values.

	Scenario	Condensing gas boiler	Resistive electrical space heater	Condensing oil boiler	Immersion heater
Average Annual Efficiency	Low	92%	100%	87%	100%
	Central	93%	100%	91%	100%
	High	94%	100%	95%	100%
CAPEX (£/kW including installation)	Low	£137.50	£192.50	£132.00	£205.70
	Central	£151.25	£192.50	£174.00	£222.75
	High	£165.00	£192.50	£217.00	£239.80
OPEX (£/kW/year excluding fuel cost)		£9	£0	£9	£0
Lifetime (years)		15	15	15	15

Table 7 - Fuel cost projections for 2030, p/kWhe, adjusted to 2016 prices [147]

	Natural Gas	Electricity	Heating Oil
Low	1.30	4.53	3.38
Central	2.12	5.58	4.53
High	2.46	5.99	6.38

Table 8 - Emissions by heating fuel source in 2030, kgCO2/kWh [147]

	Natural Gas	Electricity	Heating Oil
Cost-effective path	0.184	0.094	0.268
Higher risk		0.175	
Low-risk		0.229	
Baseline		0.263	

The gas boilers can either continue to be supplied from natural gas, or for reduced carbon emissions use natural gas with hydrogen injection, or transition to biomethane or hydrogen as described in sections 5.2.1 and 5.2.2. In rural areas off the gas grid, the equivalent continuation is for oil-fired boilers to continue to be used, with biofuels used to replace extracted kerosene, or for use of electrical resistive heating with an increased proportion of electrical energy being sourced from renewables.

5.4.2 Heat Pumps

As an alternative to the above, heat pumps may be used to exchange heat from a lower temperature source to warm a building – either air-source (ASHP) or ground source (GSHP). In the case of ASHP, heating may either be air-to-air or air-to-water. In the former case, the temperature difference between the ambient air temperature and the desired air temperature is relatively low, and heat is output directly into the volume of air within the building. Air-to-water heat pumps, or high-temperature heat pumps, instead heat water to a higher temperature suitable for use within secondary heating systems, such as at a temperature to be fed into underfloor systems, radiators or hot water storage tanks. High temperature heat pumps are a variant of ASHP where the output temperature is sufficient to be directly pumped into central heating or heat exchanges via a fluid medium (as opposed to base ASHP which generates warm air only) [143]. High temperature heat pumps are particularly appropriate for hard to heat, older or listed properties which need higher heating water temperatures or where upgrades to the existing system is difficult, with particular application off the gas grid.

Heat pumps have a Co-efficient of Performance (COP) which defines the ratio of input electricity to output heat, and this will typically vary in the range of 1.0 to 4.5, depending on the difference between the water return temperature and the ambient temperature, as shown in Figure 33 for an air-to-air heat pump and in Figure 34 for an air-to-water high temperature heat pump. An annual averaging of the COP over an expected temperature range is termed the Seasonal Performance Factor (SPF). A COP of 1.0 is equivalent to resistive heating; that is, the direct conversion of electrical energy to heat energy through heating coils. Many modern heat pump designs include a resistive heating element which is used at times when the COP of the heat pump process falls to a very low efficiency (i.e. a large difference between ambient and return temperature). This provides the operational minimum COP, with the maximum subject to considerable variance between models and installations.

Reversible Air-to-Air heat pumps are also a growing technology, with the capability to provide cooling as well as heating, but these are primarily under use within the commercial and industrial sectors in the UK [150] and are hence excluded from this analysis. High-temperature heat pumps are another technology which may be used in conjunction with existing high temperature radiators, and may be combined with existing boilers / heat tanks. However, currently this technology represents only 2% of total heat pump sales (i.e. a few hundred units per year across the UK), usually within large, old properties off the gas grid [145].

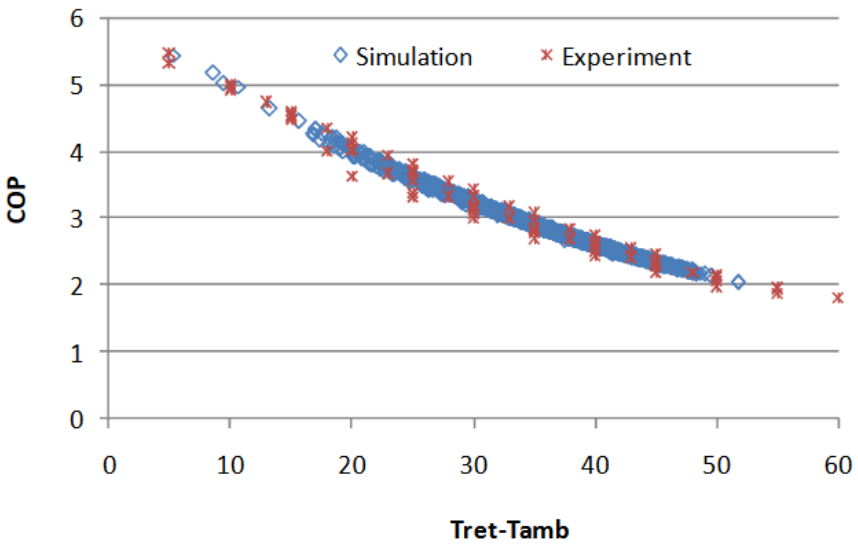

Figure 33 - Simulated and measured COP of air-source heat pumps against difference between ambient temperature (Tamb) and return temperature (Tret) (reproduced from [151])

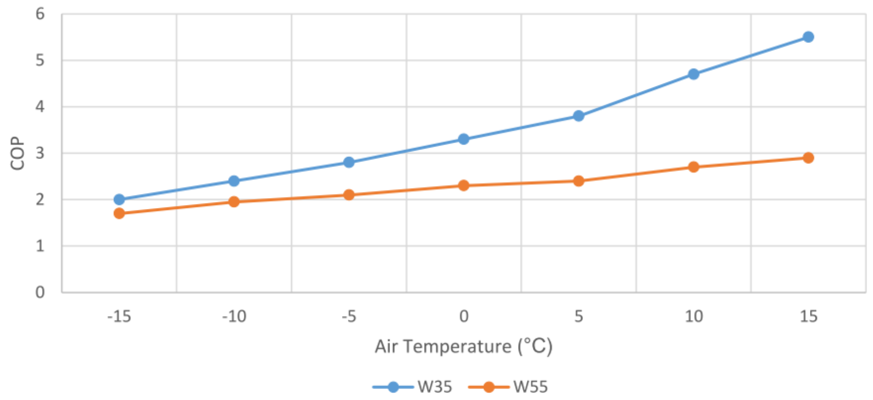

Figure 34 - COP of air-to-water heat pump against ambient air temperature for output temperatures of 35C and 55C (reproduced from [145])

In the case of ASHP, performance of devices in the field appears to be below that expected. An examination of field trial data from domestic ASHPs in West Lothian indicated an average COP of 2.7 [151]. A similar trial undertaken in 2011-12 commissioned by the CCC gave average SPFs of 2.68 and 3.10 for ASHPs and GSHPs respectively. In [41], the COP is found to be a key uncertainty in heat decarbonisation scenarios – a increase in ASHP and GSHP performance to the higher bounds modelled (4.0 for ASHP and 5.0 for GSHP) would equate, within the context of the modelled uptake in the 4th Carbon Budget, to a saving to customers of £500 million annually. Similarly, a COP of less than 2.5 would equate to additional emissions of around 2Mt CO_2 (against an abatement target of 27Mt CO_2 from domestic heat by 2030). Additionally, the emissions of heat pumps per unit heat is determined by the carbon intensity of the electricity system, and this failure in emissions reduction would be further exacerbated if the average emissions per unit electricity are not also reduced in line with heat pump uptake.

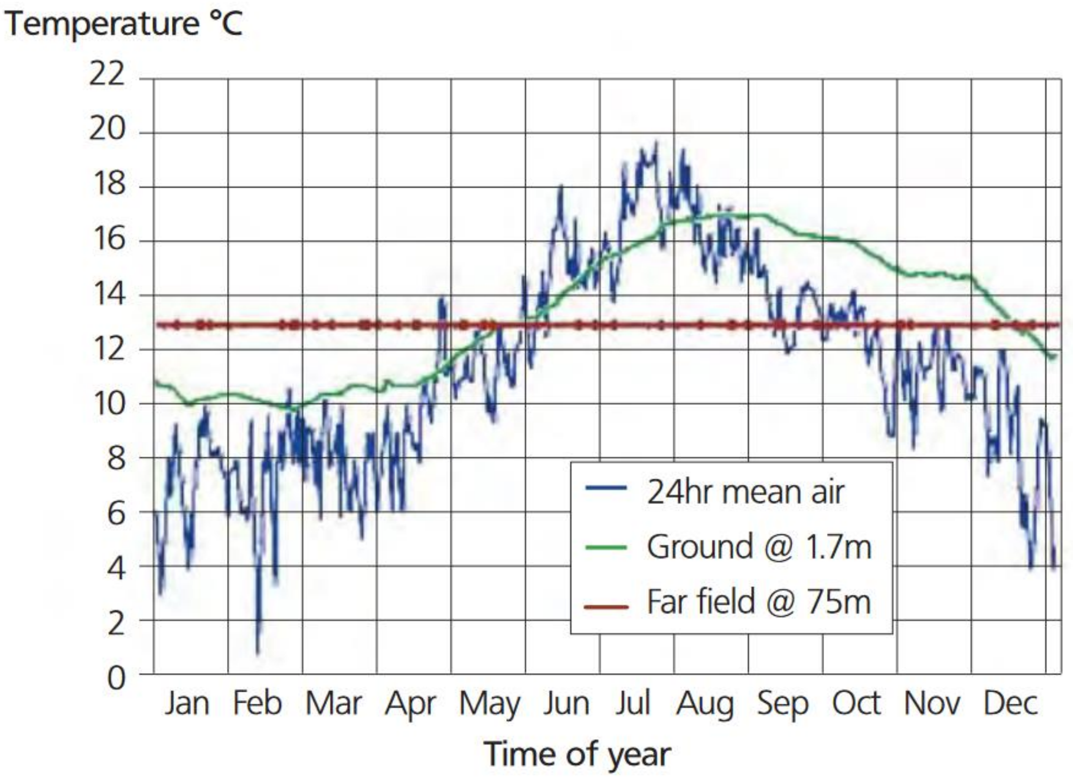

Figure 35 - Relationship of ground temperature to air temperature, measured at Falmouth in 1994 (reproduced from [152])

Ground source heat pumps have a generally higher COP rating in part due to the heat buffering effect of the ground – as shown in Figure 35, only a seasonal pattern is found and this is time-shifted approximately one month behind the seasonal pattern in air temperature.

A newer technology available on the market are gas heat pumps, which is in the process of being developed for the domestic market. These burn gas to generate heat at greater-than-unity efficiency, and are proposed as a potential market solution where consumers are accustomed to gas provision for heating. However, the current unit cost is very high and there is significant uncertainty over the learning rate for the technology. Additionally, the effective COP is much lower than for electrical heat pumps. Indicative studies show, however, that modest cost savings may be made against condensing gas boilers [145].

Heat demand may also be supplied by hybrid solutions which can source different energy vectors according to their availability. Hybrid heat pumps are one design concept, where the majority of heating demand is fulfilled by consumption of electricity, but during periods of potential electrical constraint and/or high prices (i.e. when electrical demand is at a peak), may consume natural gas or hydrogen as a secondary vector. A hybrid heat pump system combines an electric air to water or ground to water heat pump with a gas boiler with a means to input heat into an existing heat distribution system with a dedicated control system to switch between the two sources [145]. The gas component may also be used to reach higher temperatures than the air-to-air heat pump component, fulfilling the role of a high-temperature heat pump.

As systems increase in size, the boundaries defining air to air heat pumps and large-scale Variable Refrigerant Flow/Volume systems become less defined [143]. This study is restricted to current heat pump technologies which are applicable at a domestic scale.

Based on the above review, 5 heat pump technologies are determined as relevant within the UK domestic context:

1. Air-to-air heat pumps
2. Ground source heat pumps
3. High-temperature air-to-water heat pumps
4. Hybrid heat pumps
5. Gas heat pumps

The technical and cost characteristics of each are summarised in Table 9. It should be noted that there is a far lower uncertainty in standard ASHP costs due to the large evidence base, as opposed to other technologies with far lower installed capacity, and where much of the performance evidence is based on lab assessments.

Table 9 - Costs and technical parameters of main heat pump technologies [141],[142],[145],[41]

Parameter	Scenario	Air-to-air heat pump	Ground-source heat pump	High temperature heat pump	Hybrid heat pump	Gas heat pump
COP	Min	120%	300%	247%	217%	103%
	Average	280%	395%	299%	268%	115%
	Peak	400%	490%	336%	323%	126%
CAPEX (£/kW including installation)	Low	500	1,000	500	500	500
	Central	684	1,600	950	1,150	650
	High	867	2,200	1,400	1,800	800
OPEX (£/kW/year excluding fuel cost)	All	11	8	9	9	11
Lifetime (years)	All	20	20	20	15	15

5.4.3 District Heating and Combined Heat and Power

A district heating system carries hot water from centralised heat plants to buildings with heat exchangers, with the resulting cooled water flowing back to the plant. It is commonly found in densely populated areas at Northern latitudes, particularly in Europe and Asia. This permits reduced cost through use of large fuel boilers, as opposed to individual heating systems. Demand may also be met by Combined Heat and Power (CHP) plants. District heating has been deployed in the UK since the 1950's, but currently provides less than 2% of UK heat demand [41]. In this context, district heating can be viewed as a relatively mature technology (and is used on a widespread basis in countries at a similar latitude such as Sweden, Finland and Denmark), but has not been greatly recognised in the UK context due to the low price of natural gas and the low installation costs of gas boilers, creating a significant financial barrier to investment. This is beginning to change with recognition of the potential role such systems can play in decarbonisation of heat and fuel poverty. It is, however, costly to retrofit heating networks to existing building stock, and new neighbourhoods are a better target for small-scale networks. Nevertheless, a retrofit district heating system is included within this modelling for comparative purposes.

In 2013, around 1765 heat networks were identified in the UK, but only around 75 classified as large (more than 500 homes or 10 non-domestic buildings) [153]. The majority of these are CHP and utilise natural gas.

In order to transfer heat from the network to the individual premises, a Hydraulic Interface Unit (HIU) is required, which may take the form of a heat exchanger integrated into the central heating system.

Capital and operational costs for typical UK heat networks are given in Appendix C and used on a case-by-case basis in the modelling presented in Chapter 7. The internal pipework costs are relatively high, and may have large potential losses due to the length of pipework involved, particularly in blocks of flats. The requirement for heat metering also adds a significant cost. However, as opposed to other sources of heat provision, heat networks have an expected economic lifetime of 50 years.

CHP systems may utilise a variety of fuel sources, including:

- waste heat from (for example) an industrial source;
- natural gas;
- mine/landfill gas;
- distillate oils/heavy fuel oils;
- external combustion via a Stirling engine, such as from a furnace;
- solid biomass;
- bioethanol/biodiesel;
- fuel cells utilising hydrogen as an input fuel.

Due to the case-specific nature of sources such as mine/landfill gas, and waste heat (requiring proximity to industrial sources) these cases are ignored within this domestic study. Many of the alternative low-carbon cases (biomass and hydrogen) have limited operational capacity, with an unknown future in terms of likely cost evolution. For the purposes of this study, district heat systems are restricted to the established case of a gas-supplied turbine/engine CHP. Typical operational parameters are given in Table 10.

Table 10 – Gas CHP costs and technical parameters [154], [155],[156]

Parameter	Unit	Scenario	Reciprocating Engine	OCGT
Capacity	MWe	All	0.5-3.7	3.7+
Electrical efficiency		Low	30.8%	28.6%
		Central	29.4%	25.0%
		High	27.9%	21.4%
Heat efficiency		Low	81.4%	71.5%
		Central	78.7%	64.3%
		High	75.9%	57.1%
CAPEX	£	Low	814	1235
	£	Central	880	1382
	£	High	1036	1760
OPEX	£/MWh	All	13.81	10.36
Lifetime	years	All	25	25

5.4.4 Thermal Storage

Flexibility in the heat sector can potentially be provided by the relatively low cost of storing heat through the use of Thermal Energy Storage (TES) compared to e.g. electricity storage through the use of batteries [43]. Thermal storage technologies include [157]:

- Water-based storage, either in tanks, pits, boreholes or aquifers;
- Phase change materials, which store heat energy in the change of phase, such as between liquid and gas, but may also include organic wax-like materials with multiple phases;
- Thermochemical stores, normally achieved by the separation of two different substances containing binding forces.

Thermal stores may either be standalone, or include the potential for heat storage to be built into the fabric of buildings – 'fabric integrated thermal storage'. [157] indicates tank and phase change materials as potentially best suited to domestic diurnal storage, though notes that multiple other technologies are perhaps suited to seasonal storage.

Traditionally the use of hot water tanks in homes has been very common, as the instantaneous demand for hot water can be significantly higher than for space heating. This also permits charging of a hot water storage supply to be conducted overnight, such as through the use of off-peak electricity tariffs.

However, changing of the timing of heat demand in this manner increases the cost and complexity of domestic energy systems, using up valuable space within properties, and overall increasing energy use due to parasitic losses [158]. Additionally, the background trend in recent UK history has been away from sources of domestic heat storage (mainly hot water tanks) towards on-demand gas boilers [159].

In spite of this, thermal storage provides a useful ancillary technology for the implementation of heat technologies which have a high capacity cost, such as heat pumps. If the peak energy requirement can be reduced through the use of storage, then the sizing is reduced. This is particularly important for electrical heating technologies which may be expensive to size to peak demand, or may be incapable of serving peak demand due to local network constraints. In this way, the optimal cost may include heat storage either through reduction in heating technology capacity, or by deferral of network reinforcement.

A range of costs and efficiencies for the two main domestic thermal storage technologies are given in Table 11.

For larger tank-based systems, such as might be used alongside a district heat network to buffer heat output, the efficiencies are likely to be similar, but with reduced cost of storage capacity (highly dependent on store capacity) in the range £1-£150/kWh. Phase-change materials are not seen as suited to centralised heat provision in the same manner.

Table 11 - Costs and efficiencies for domestic thermal storage, based on diurnal charge/discharge cycling [157]

		Technology	
Parameter	**Scenario**	**Tank based**	**Phase change**
Cost (£/kWh)	Low	25	250
	Medium	103	325
	High	180	400
Efficiency	Low	50%	75%
	Medium	70%	83%
	High	90%	90%

5.4.5 Micro-CHP

Micro-CHP systems cogenerate heat and power on a per-building scale, and there is a small scale market for domestic CHP systems capable of outputting around 5-20kW of electrical power and 10-100kW of thermal power. Economic assessments of domestic scale CHP, such as in [160] and [161] indicate that the energy requirements of residential properties are too low to permit the installation of large micro-CHP systems. This restricts the technological choices for Stirling engine or hydrogen fuel cell systems. In 2011, the Carbon Trust performed a field trial of micro-CHP in residential and commercial properties, which found an average install cost of around £5000, and an average electrical efficiency of only 6% and total efficiency of 80% [162]. Only larger detached houses (greater than three bedrooms) were seen as a potential market for such systems. Table 12 shows indicative cost trajectories for the evolution of fuel cell CHP.

Table 12 - Costs and efficiencies for domestic-scale fuel cell CHP [161]

Parameter	Unit	Today	2030	2050
CAPEX	£2010/kW	19540	4669	4178
Fixed OPEX	£2010/kW_yr	300	150	150
Efficiency combined	%	88%	95%	95%
Efficiency thermal	%	52%	53%	53%
Efficiency electric	%	36%	42%	42%
Heat-to-power ratio		1.44	1.26	1.26
Lifetime	years	10	15	15

As the cost figures for heat provision are significantly higher than - for example - heat pumps, and the electrical efficiencies potentially extremely low, domestic-scale CHP is not seen as a viable competitor to other heat technologies, nor a cost-optimal means of decarbonisation, and is excluded from this study. The main benefits of micro-CHP are realised where it provides an alternative source of low-carbon electricity in comparison to the transmission network, but the emissions intensity of electricity in the UK has fallen significantly in recent years and the policy background looks set to continue this trend.

5.5 Hybrid Energy Conversion Systems

An energy conversion system which can provide flexibility by switching between input resources and output vectors, in response to operational and economic signals, is termed a hybrid energy-conversion system (HES) [163]. Such a system provides benefits in the form of two types of flexibility:

- Operational flexibility, whereby variable loads can be met from multiple sources, or that use of certain appliances can be kept within specified operational bounds (for example, keeping constant conversion rates in electrolysers or similar chemical processes);

- Economic flexibility, allowing arbitrage between input resources and output demands subject to physical constraints, and allowing the system to meet a set of demands at least cost.

HES systems include concepts such as combined heat and power fuelled by multiple sources (e.g. biogas supplemented by natural gas), or the hybrid heat pumps discussed in section 5.4, but more advanced concepts have been proposed and demonstrated, such as through the use of anaerobic digestion alongside storage of biogas, which may then be used to meet heat demand or to generate electricity at peak hours.

Another HES concept involves the use of electrolysers which can produce synthetic natural gas or hydrogen, with the conversion process fuelled by electricity. The products can be either stored locally or fed into the appropriate network. Low cost electricity (or electricity that would otherwise be curtailed in the case of wind or solar behind a network constraint) can be used to create higher-value products. This then allows the storage of excess electricity as a gaseous fuel, utilising the natural storage capacity of the gas network, or other means of transportation, and providing additional operational flexibility. For example, the 'Surf and Turf' project on Orkney [164] will generate hydrogen from a 500kW electrolyser connected to a 900kW wind turbine, with the resultant gaseous product shipped by lorry to be used at a local port in a fuel cell to generate electricity.

As HESs are highly dependent on the opportunities afforded by specific local systems – i.e. they provide a convergence between industrial, commercial and domestic energy uses within a spatial area – their configuration is case-specific. For this reason, their contribution is not assessed within this study.

5.6 Demand-Side Management

One of the issues highlighted by the analyses in this section is that many of the perceived benefits of implementing specific end-use technologies are not directly felt by the consumer. Indeed, reduction of the emissions intensity of heat provision brings, by itself, no benefits to the consumer, and in the absence of incentives it cannot be assumed that any consumer will invest in low-carbon technologies other than where they themselves reduce the delivered cost of energy. To this end, then, financial incentives are required to realise investment in domestic heat technologies which reduce emissions.

However, there are other benefits which may be provided to other system actors. For example, if domestic investment in a specific heat technology (such as thermal storage) reduces the reinforcement requirement for the local electricity network, through the reduction of peak demand, then a cost benefit is felt by the Distribution Network Operator (DNO) as a result of investment by a domestic consumer. While the total system cost might be reduced, some form of commercial arrangement is required to pass through the cost savings to the consumer to incentivise that investment. This may be simply in the form of a payment for capacity, or if the benefits are accrued in a time-dependent manner (such as dispatch of storage at a time beneficial to the network or system) through time-of-use tariffs. Payments may be further subdivided into those for service availability and actual dispatch.

If a domestic consumer is required to alter the timing of use of different devices in their household, then this may have a substantial administrative overhead, along with requirements for settlement and invoicing afterwards. This means that such systems often require the existence of an Aggregator who can mediate between the owner of the asset which benefits from the altered dispatch, and the multiple households providing the dispatch service. This relationship is summarised in Figure 36, showing one such paradigm. Here, the Distribution System Operator (DSO) (an active network manager as distinct from a passive DNO) forecasts the state of the local distribution network based on assumed demand levels, weather driven renewable generators, and other embedded generators' scheduled dispatch. This creates a requirement for local balancing to keep flows across the network within secure limits. A balancing market (or bilateral contract) may exist within which the DSO can purchase balancing services from an aggregator, and through this sends a request for a certain volume of energy to be absorbed or exported during a particular time horizon. The aggregator then takes responsibility for coordinating this response across multiple households through e.g. local controllers, which may respond with signals to indicate availability and service response.

An example of heat-based Demand-Side Management (DSM) is in use on the Shetland Islands through the NINES project [165] where domestic electrical storage heaters are dispatched by the local DSO in order to manage the local distribution network. The optimum unit commitment schedule is determined across a daily horizon for different network topologies, including variable levels of wind generation, storage and demand-side response – primarily storage heaters and water tanks controllable by the Distribution System Operator (DSO) via Active Network Management. This informs the level of wind generation which may be accepted onto the network during any given time period, with wind power curtailed by the DSO as a part of their management. Alongside non-firm generation contracts, this allows a greater level of demand to be supplied by non-thermal sources, such as wind power, through the time-shifting of demand against the availability of the wind resource. Support of the grid through reserve and response is also managed alongside the DSM implementation, through third-party contractual arrangements [166].

The use of DSM is not restricted solely to the electricity sector, although this is where the benefit is most evident due to the difficulties and costs of bulk storage of electrical energy. For example, in [167], the impact of DSM (specifically Demand-Side Response - DSR) on both the electricity and gas transmission systems is investigated using the Combined Gas and Electricity Networks expansion model (CGEN). The use of DSM shows a significant reduction in the use of both gas-fired power and gas import capacity. While this is additionally shown to increase gas supply security, it is not found to achieve a significant cost saving in the gas network. However, as the gas network utilisation rate is increased, this does in turn mean that investment in the network is more favourable. While this study was focussed on the transmission system, the key learning can similarly apply to the gas and electricity distribution networks, where the use of DSR can offset electricity network reinforcement through

For the purposes of this study, DSM as a form of real-time management is not directly modelled, and instead the optimisation presented in the next chapter assumes that some form of control regime exists which permits an omniscient operator to dispatch local technologies in the most cost-efficient manner possible considering all operational and network costs. The ramifications of this assumption, and the implication it has for possible design of DSM mechanisms, is discussed in section 10.4.

5.7 Incorporation of Diverse Technologies into Whole System Models

The above technological descriptions demonstrate the significant complexity involved in creating multi-carrier models. Each technology has its own sophisticated technical modelling methodologies – for electrical networks, voltage and current considerations, both static and dynamic. For gas networks, line pack and gas flow laws. For heating systems, complex thermodynamic interactions. For renewable energy systems, climate and weather dependencies. This means that the joint analysis of any two such systems can become extremely complex, and correct representation of all physical aspects of a multi-carrier system is practically unattainable. On this basis, the common carrier of all technologies – ‘energy’ as a generic concept – is used with the broad parameterisations (efficiencies, losses) that allow different technology forms to be represented within an optimisation. In the next chapter, the model framework used – developed from the Energy Hub concept – is described, including how these disparate technologies are represented within a single unifying model. It is accepted that this brings with it necessary simplifications, not least the removal of thermodynamic constraints and the failure to consider exergy. However, these simplifications permit the comparison of a large number of technological options in models of high dimensionality, which can provide the basis for more detailed, physically accurate models of specific technology options.

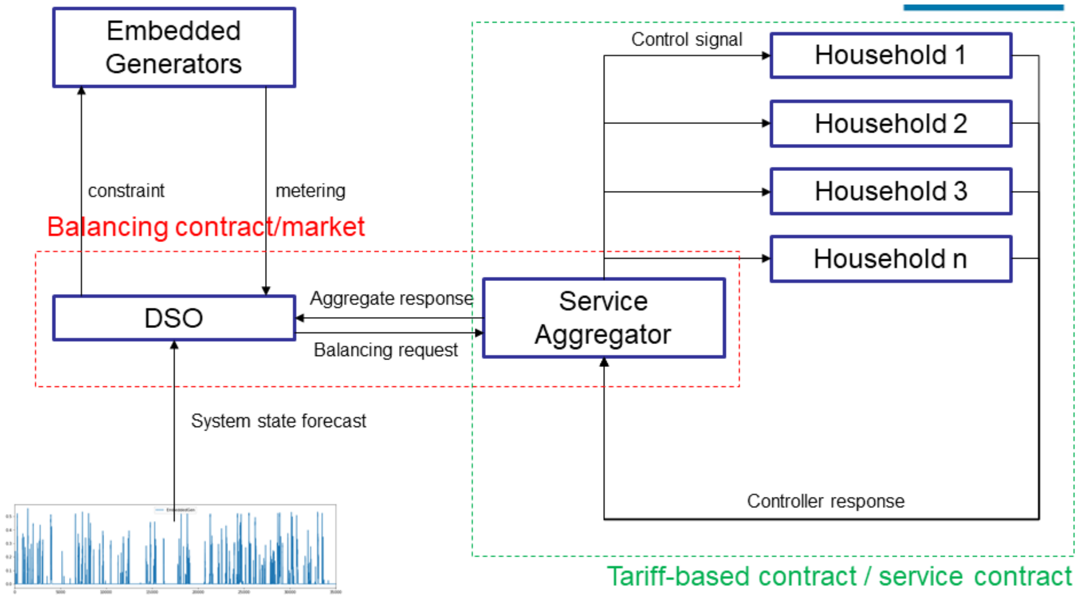

Figure 36 - Schematic of demand-side response involving aggregator

6 The Local Energy System Model

6.1 Overview

In this chapter, the energy modelling framework chosen to represent the spatial and temporal simulation of local energy systems is described and justified:

- The scope within which decisions should be enacted is described to form a basis for discriminating between local decision variables and extrinsic values used to create specific scenarios;
- the optimisation framework is presented, including detailed constraints, as well as the use of cost / emissions minimisation to drive the optimisation;
- Finally, the computational process and limits of processing power are discussed.

6.2 Scope

The local energy system model depicts only technological decisions which are within the remit of local energy actors. These include:

- Distribution Network Operators for extant electricity and gas networks;
- Local hydrogen network operators;
- Local authorities with oversight for energy planning;
- Home owners selecting technologies within their own homes;

The broader 'national' energy system – comprising large scale, utility-driven investment in energy sources, generation, conversion and transmission – is instead considered to set scenarios for costs of importing energy from different vectors into the local system.

In terms of local energy planning, it is considered that the exemplar system is a price-taker with regards to the wider system – decisions made at a local level do not have a measurable impact on the costs and technology mix of the wider energy system. In reality, if multiple local systems follow a similar trajectory, then this will have a discernible impact on external costs and utilisation rates of supply-side technology. However, under scenarios in which a particular form of heat provision is supported by national policy, it might be expected that this will be matched with appropriately supportive policies on the supply side, and that this may mitigate the cost impacts. This concept is discussed further in Section 9, within the context of centralised planning incorporating local energy actors.

Figure 37 illustrates the modelling scope further. There are 3 levels of energy system considered:

- The centralised system, consisting of utility-scale energy resources and producers, exporting energy to a transmission system for their particular carriers. This system also contains markets for delivery and creation of capacity, and so is capable of providing large volumes of energy resources at bulk prices.

- Regional energy systems, consisting of distribution networks and local authority areas, which traditionally have only been involved in the throughput of energy from transmission systems through to localised end consumers. However, under decarbonisation scenarios, as discussed in Chapter 2, there is increasingly a move towards managed local systems incorporating both embedded supply and demand, both from the point of view of distribution networks (managed by Distribution Network Operators and/or Distribution System Operators), and by Local Authorities, who may lead efforts to find local opportunities in decarbonisation beyond that available on a national, centralised basis.

- Domestic energy systems, consisting of the technologies installed in individual homes. This may include both technologies used to convert energy to end energy service demands, and technologies which generate energy from local resources – the case of prosumers as opposed to consumers.

The scope of the modelling here relates to the second two levels of system planning. That is, it is assumed that the centralised system exists and has a fixed set of energy carriers and associated costs, but that these are set for each scenario and not within the model solution space. Instead, the model may choose between technology sets and use of technologies at local levels – either at the level of individual consumers (and the technologies they are using to meet their particular service demands) or at the level of local energy systems facilitated by the DNO or Local Authority. The point of delineation between the external and local systems is considered to be the smallest single network supply point which encapsulates the entirety of the energy system being considered, and this is discussed further in the individual model specifics given in Chapter 7.

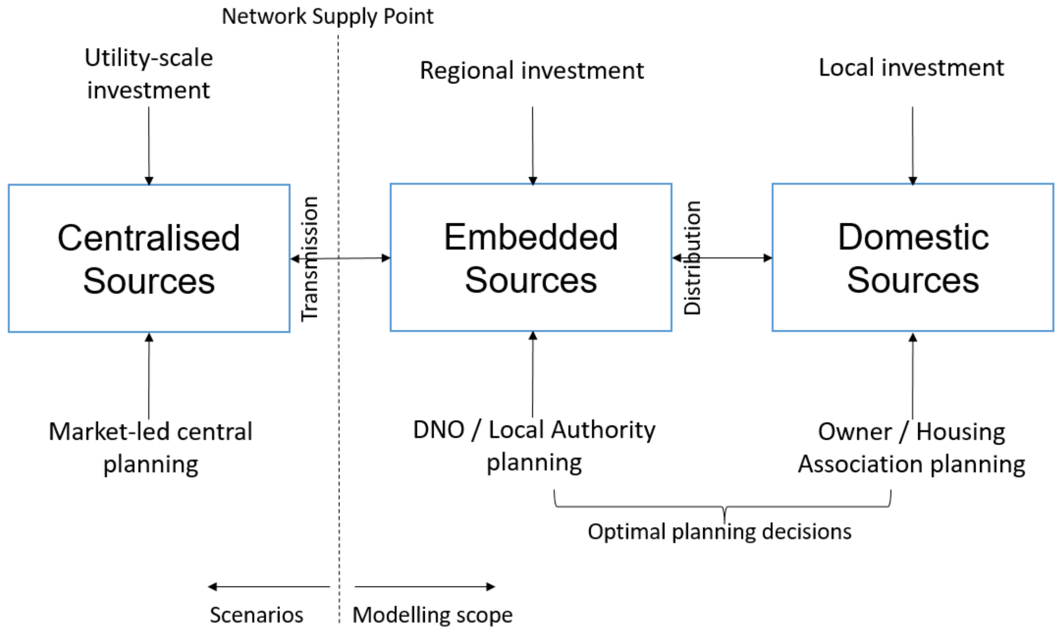

Figure 37 – Conceptual overview of modelling scope and relevant decision-makers

6.3 Formulation

The model here proposed follows the 'power nodes' formulation originally proposed in [168] for the case of electricity storage, and expanded to a regional description of the UK electricity system in [169].

A set of nodes x (equivalent to hubs in the Energy Hub model described in Section 3.5) are modelled over a set of time steps t. There are a number of technologies y which may be installed at each node, or connecting each node. Energy is contained within specific carriers c. Examples of each of these terms are given in Table 13.

Table 13 - Indices used in model formulation

Index	Description	Examples
x	Node	House 1, Grid Supply Point, UK
t	Time-step	2020-01-01 00:00, Day 1, Year 1
y	Technology	Gas power station, heat pump, HVDC transmission line
k	Cost class	£, CO_2-equivalent emissions
c	Energy carrier	Electricity, gas, heat, hydrogen

6.3.1 Technology Definition

A technology y may be one of:

- A supply technology, creating energy in the form of a specific carrier, and may be tied to a specified resource;
- A conversion technology, changing energy between two carriers at a node;
- A transmission technology, able to transfer energy between two nodes;
- A storage technology, able to transfer energy between time steps at a node.

Demand is defined as an inverse supply technology with a time-variant negative resource – in other words, an energy sink corresponding to a particular energy carrier (e.g. hot water). Each demand 'technology' has an associated unmet demand technology, to which a (large) cost may be ascribed. This permits solution of the model to be achieved even when a complete energy balance is not possible, with the use of unmet demand as a final resort which the model will (under a least cost objective) seek to minimise.

A technology may have one or more of a set of definitions and constraints that describe the functioning of that technology, and the domains within which they may be defined. These are listed in Table 14.

Nodes are linked via transmission technologies which connect two nodes and utilise a single energy carrier (for example, an HVDC cable with electricity as the carrier). Note that within the model context, transmission is used generically to mean any energy-transporting technology, rather than relating to bulk transmission networks (e.g. electricity and gas distribution network are also classified as transmission technologies).

6.3.2 Decision Variables

The model can be run in 3 modes, designed to answer particular research questions:

- *Operational mode*: for a given fixed configuration and capacities of supply, conversion and transmission technologies, what is the optimal dispatch?
- *Capacity mode*: for a given set of supply/conversion technologies and a base amount of infrastructure, what is the optimal capacity of each technology, and how much network reinforcement is necessary to achieve it?
- *Planning mode*: with prices assigned to all supply, conversion and transmission technologies, what is the least-cost energy system?

Table 14 - Technology parameters used in model (excluding some cost parameters detailed below)

Term	Description	Domain
r_{avail}	Resource (+ve) or sink (-ve) for energy (supply)	y, x, t
c_{con}	Carrier consumption (supply/transmission)	c, y, x, t
c_{prod}	Carrier production (supply/transmission)	c, y, x, t
s_{cap}	Storage capacity (storage)	y
s_{loss}	Storage loss rate per unit time (storage)	y, t
e_{eff}	Efficiency of conversion from resource or between carriers (supply/conversion)	y, t
$e_{eff,perdistance}$	Per-distance efficiency (transmission)	$y, x{:}x$
c_{in}	Carrier in (conversion)	y
c_{out}	Carrier out (conversion)	y
e_{cap}	Technology export power capacity	y, x
s_{cap}	Technology storage energy capacity	y, x
$e_{cap,max}$	Maximum technology export power capacity	y, x
$s_{cap,max}$	Maximum technology storage energy capacity	y, x
$cost_{con}$	Fixed capital cost of construction	y, x, k
$cost_{om,fixed}$	Fixed O&M costs	y, x, k
$cost_{om,frac}$	Fractional O&M costs	y, x, k
s	Storage state of charge	y, x, t

In the operational mode (in other words, the capacities of technologies at each node are fixed), the decision variables are the volumes of energy to produce, convert or store at each node, or transport between nodes, while meeting the overall energy balance defined by the demand technologies. In this case, only the dispatch is calculated.

In the capacity and planning modes, the capacities of technologies between and at each node (or in the case of capacity mode, only between) are included in the decision variables. In this case, the technology mix and its subsequent dispatch is jointly optimised in order to design and operate the least-cost energy system meeting the overall energy balance defined by the demand technologies.

6.3.3 Objective Function

The objective function minimises total cost within a particular chosen cost class k (e.g. minimising total cost or total emissions):

$$min: z = \sum_{y} \left(weight(y) \times \sum_{x} cost(y, x, k = k_m) \right) \tag{6.1}$$

$weight(y)$ is an arbitrary weighting that can be introduced on a per-technology basis, such as to examine the influence of particular policies on the least-cost energy system. The costs per technology include CAPEX, fixed OPEX and variable OPEX.

Note that while the model can optimise the location and capacities of technologies at/between each node (within the constraints of the defined mode), all technologies are installed at $t = 0$. In other words, the model defines the least cost static energy system within the defined constraints, but cannot vary the timings of investments or produce a gradual trajectory. The objective function does contain a measure of operational costs, so the model can still be considered dynamic, but the planning horizon is a single point in time as opposed to covering the entire time domain.

6.3.4 Energy Supply

A supply technology defines a relationship to a resource (such as a fuel) which may be infinite (such as grid-supplied gas), have a constant value (such as a waste heat source), or be time-variant (such as wind or solar energy). The production of the supply technology is then set to:

$$\frac{c_{prod}(c, y, x, t)}{e_{eff}(y, x, t)} \leq r_{avail}(y, x, t) \tag{6.2}$$

where $c_{prod}(c, y, x, t)$ is the production of the carrier c by supply technology y at node x during time period t, and $r_{avail}(y, x, t)$ is the available resource at that location, with $e_{eff}(y, x, t)$ being the efficiency of conversion from the resource. Note that this may be time variant, such as in the case of temperature-dependent heat pumps. The inequality may be fixed to equality in the case of a technology which must use all available resource and cannot 'spill' energy, such as solar PV.

6.3.5 Node Energy Balance

The transmission balance (for the subset of transmission technologies) is given by:

$$c_{prod}(c, y, x, t) = -1 \times c_{con}(c, y_{remote}, x_{remote}) \times e_{eff}(y, x, t) \times e_{eff,perdistance}(y, x) \tag{6.3}$$

where $c_{prod}(c, y, x, t)$ is the export of a particular energy carrier c for along a particular transmission technology y from a node x at time t. x_{remote}, y_{remote} are x, y for the node located at the remote end of the transmission technology. This incorporates an efficiency which may be time-dependent $e_{eff}(y, x, t)$ and/or distance-dependent $e_{eff,perdistance}(y, x)$.

The conversion balance (for the subset of conversion technologies) is given by:

$$c_{prod}(c_{out}, y, x, t) = -1 \times c_{con}(c_{in}, y, x, t) \times e_{eff}(y, x, t) \tag{6.4}$$

Which follows the principle that the output from a conversion process must be equal to the input before efficiency losses.

For conversion technologies with multiple carriers in and out, the balance is given by:

$$\sum_{c_{out_n}} \frac{c_{prod}\left(c_{out_n}, y, x, t\right)}{carrier_{fraction}(c_{out_n})} = -1 \times c_{con}\left(c_{in_n}, y, x, t\right) \times carrier_{fraction}(c_{in_n}) \times e_{eff}(y, x, t) \tag{6.5}$$

Where c_{in_n} and c_{out_n} are the input and output carriers, with the relative contribution stated in the technology definition. As an example used in this work, a hybrid heat pump may take either natural gas or electricity as its input carrier, and produces differing proportions of space heat or hot water depending on the demand carrier being supplied.

For storage technologies, the energy charge, discharge and energy stored is balanced:

$$s(y, x, t) = s_{t-1} + c_{prod} - c_{con} \tag{6.6}$$

Where $s(y, x, t)$ is the state of charge of the storage technology at a given node, with c_{prod} and c_{con} the volumes of energy produced and consumed for its particular carrier, and s_{t-1}

being the state of charge at the previous time step. This is further constrained by the maximum storage capacity:

$$s(y, x, t) \leq s_{cap}(y, x) \tag{6.7}$$

An identical constraint is applied to conversion technologies on a per-carrier basis, as well as to transmission technologies on a per-binary-location basis – i.e. the specific capacities of each defined link.

6.3.6 Node Build Constraints

The capacity of a technology which may be installed at a node is constrained either by an upper value, or by setting the capacity to an exact value (corresponding to either the capacity or operational modes above). This capacity may be specified as the energy import/export capacity (in power units), or a storage capacity (in energy units), or both, as in Eqs (6.8) and (6.9). Similarly, for a conversion technology the constraint may be applied to the rate of energy conversion (for example, the rate at which a gas boiler may convert gas to heat at the given efficiency).

$$e_{cap}(y, x) \leq e_{cap,max}(y, x) \tag{6.8}$$

$$s_{cap}(y, x) \leq s_{cap,max}(y, x) \tag{6.9}$$

Where a technology is tied to a given resource, a resource conversion capacity may be specified which implicitly limits the power capacity of that energy supply process. For example, if the resource is a finite fuel delivered per unit time, then a supply process with a given efficiency will have its maximum power capacity constrained directly by the fuel source.

There is additionally a per-technology constraint requiring transmission capacity of energy to be symmetric:

$$e_{cap}(y: x_1, x_2) = e_{cap}(y: x_2, x_1) \tag{6.10}$$

6.3.7 Cost Calculations

The depreciation rate for technology y within a cost class k with an interest rate i is calculated as

$$d(y,k) = \frac{i \times (1 + i(y,k))^{plant\_life}}{(1 + i(y,k))^{plant\_life} - 1} \tag{6.11}$$

The total cost of a technology at a particular node is given as the sum of fixed and variable costs:

$$cost(y,x,k) = cost_{fixed}(y,x,k) + \sum_{t} cost_{var}(y,x,k,t) \tag{6.12}$$

Where the fixed costs include construction costs, annual O&M costs and O&M costs which are a fraction of the construction costs:

$$\begin{gathered} cost_{fixed}(y,x,k) = cost_{con} \times \left(1 + cost_{om,frac}\right) \\ + cost_{om,fixed} \times e_{cap}(y,x) \times \frac{\sum_t timeres(t)}{8760} \end{gathered} \tag{6.13}$$

$cost_{con}$ is calculated from individual costs of energy capacity, storage capacity, resource capacity and (in Mixed Integer formulations of the model) per-unit cost of purchase.

Transmission technologies include a per-distance cost in the capacity cost calculation, with the cost split equally between the two connected locations:

$$\begin{aligned} & cost_{e\_cap,transmission}(y,k) \\ & \qquad = \frac{cost_{e\_cap}(y,k) + cost_{e\_cap,per\ distance}(y,k)}{2} \end{aligned} \tag{6.14}$$

Variable costs are calculated for each time step:

$$cost_{var} = cost_{op,var} + cost_{op,fuel} + cost_{op,resource} + cost_{op,export} \quad (6.15)$$

With each term relating to the variable operational costs, the fuel costs, the non-fuel resource costs and the cost of export respectively.

The use of multiple cost classes allows different objective functions to be constructed. For example, the default mode might be for minimisation of total cost, whereas there might be a separate cost class for emissions, which may be utilised with an objective function for minimisation of emissions. Alternatively, an artificial merit order can be constructed, whereby the preferential order of dispatch (and/or investment) for different technologies can be set while including accounting for cost within the model. In this case, the 'merit' cost class values can be set as increasing several orders of magnitude for each technology in the merit stack. One minor consideration is that when non-cost objective functions are in use, additional appropriate constraints around either security limits or the cost on non-supplied demands must be set – for example, in a least-emissions optimisation, the global optimum is to supply no energy demands at all.

The delivered cost of energy (in £/kWh) is calculated as the sum of all energy demand divided by the total monetary costs:

$$DCOE = \\ = \frac{\sum_{y,x} cost_{fixed}(y,x,k = monetary) + \sum_{y,x,t} cost_{var}(y,x,t,k = monetary)}{-1 \times \sum_{c,x,t} c_{prod}(c, y = demand, x, t)} \quad 6.16$$

Similarly, the emissions intensity (in $kgCO_2/kWh$) is the ratio of carbon emissions generated (defined by fuel consumption, and ignoring embedded energy) to the energy demand supplied:

$$EI = \\ = \frac{\sum_{y,x} cost_{fixed}(y,x,k = emissions) + \sum_{y,x,t} cost_{var}(y,x,t,k = emissions)}{-1 \times \sum_{c,x,t} c_{prod}(c, y = demand, x, t)} \quad 6.17$$

The abatement cost (in $£/kgCO_2$) is calculated by comparing the DCOE and emissions intensity to the base defined scenario:

$$AC = \frac{DCOE_{scenario} - DCOE_{base}}{EI_{base} - EI_{scenario}} \tag{6.18}$$

This allows quantification of the benefit of higher-cost technology mixes which facilitate a lower carbon intensity. This avoids comparison on a least-cost basis only, which would ignore the additional contribution that may be made from high abatement (but high cost) technologies. This may be of value if, instead of seeking to define the least-cost energy system within a fixed emissions constraint, it is desirable to explore a range of technology options to determine their possible contribution to decarbonisation on a comparative basis, which may then be utilised within a higher-level Whole System model. This is the concept utilised in the assessment used in the following chapters.

6.4 Model Building Process

In order to construct a multi-carrier local model, the following steps are followed:

1. The known, and prospective, energy carriers for the location are defined. End-use carriers should be specified as closely as possible to the final carrier (e.g. space heat as opposed to gas) and supply carriers selected appropriately.
2. A set of discrete nodes is created corresponding to locations containing supply and demand (these need not be exclusive of each other). These nodes are intended to best represent the topology of the system, and should identify key bottlenecks and appropriately characterise the decision points of the system, such as by separating out the points at which different actors may be active. Nodes are created which represent a homogenous ‘external’ system (e.g. the gas transmission network).
3. The nodes are linked by transmission technologies, and allocated extant capacities.
4. Additional transmission technologies are defined which represent the potential costs of upgrading or replacing networks between nodes.
5. Demand nodes are identified and allocated a per-carrier time series of demand.
6. Supply technologies are identified and characterised in technical capacity and cost, and allocated to appropriate nodes.
7. Conversion technologies (including those that convert to end-use demand carriers) are defined and characterised in technical capability and cost, and allocated to appropriate nodes.
8. Storage technologies are defined and characterised in technical constraints and costs, and allocated to appropriate nodes.

In the formal model definition, the capacity of all technologies at all nodes is forced to zero. Scenarios are defined by fixing capacities of particular technologies at specified locations away from this value, or by allocating capacities as decision variables.

6.5 Model execution

In this section, the specific computational requirements of the model are discussed.

6.5.1 Code and Execution

The model structure is coded within Python 3, within the open-source energy modelling framework *Calliope*[4], to which the author is a contributor.

Specific model formulations (technology definitions and time-variant properties) are defined within YAML configuration files and CSV time series, intended to be portable and adaptable for other modelling purposes and further work.

The model problems are constructed within the Python library *Pyomo* and 2 commercial solvers are used:

- CPLEX for linear models;
- Gurobi for mixed-integer models.

Separate Python code is written to handle the solver outputs and to generate summary files and graphics; this is predominantly based on the use of the *NumPy*, *SciPy*, *pandas* and *matplotlib* libraries, amongst others.

The solving was conducted primarily on a desktop PC with an Intel i7 6700K processor and 48GB of DDR4 RAM running Linux Mint. Typical model solution time was around 20 minutes to 4 hours, scaling approximately linearly with the product of the number of nodes, locations and time steps. Parallelisation was attempted successfully, but the key model constraint was on memory consumption (due to the high dimensionality) making this impractical on the given hardware. It is noted, though, that for the purposes of sensitivity studies or similar, the models would port easily to parallel solving on HPC hardware.

6.5.2 Time masking

As the size of the optimisation problem being solved is proportional to the product of the number of nodes, technologies and time steps, using a high temporal resolution can be

[4] https://www.callio.pe/

extremely costly to the execution of the model. On the other hand, it is both desirable to cover a long time period (in order to assess the effect of e.g. seasonal variation) and to do so with a high resolution (in order to capture the short-term variation that might drive the capacity of different technologies).

One solution to this issue is to apply ‘time masking’ – that is, rather than executing a simulation with a fixed time step, instead varying the temporal resolution according to the importance of the time period being studied. This is achieved by allowing the temporal resolution of each time step to vary, but preserving the sum energy within each step. By identifying the peak period with relation to the key demand technology under analysis, the high temporal resolution can be preserved for a set period around this peak (in order to drive capacity sizing), and the remainder of the simulated period is reduced to total volumes of energy over an aggregated time step.

7 Description of Exemplar Networks

7.1 Overview

This chapter describes the topology of the 3 example networks (suburban, rural, urban) developed to explore heat futures, the methods used to derive disaggregated demand time series, and the technical assumptions made to represent different relevant technologies and so drive domestic heating scenarios.

Figure 38 illustrates the overall concept used to define the models, construct and operate them, and how the inputs and outputs relate to the wider system model context. This includes the following components:

- A local energy system specification, which includes:
    - A set of available technologies which may meet local energy service demands, with quantified technical and economic characteristics corresponding to those already reviewed and defined in Chapter 5;
    - A set of energy service demands, based on the building stock and expected occupancy profiles, using an external demand model described in Section 7.3;
    - A definition of extant (electricity and gas) and buildable (heat and hydrogen) network topologies, as based on surveys of available network data and local maps, as described further on a case-by-case basis for each local network model and in Section 7.2;
- An external energy system specification, which includes:
    - A set of scenario definitions, which allocates which of the technologies are available with defined capacities, which are available with capacities as decision variables, and which are unavailable;
    - A set of external energy costs and availabilities;
    - Time series of production for renewable generation, following the methodology for wind power from Chapter 4 and the methodology for solar power from Section 7.4;
    - A definition of the external system state (in terms of time-variant characteristics such as price and availability of energy);
- A formal model of the local energy system, following the optimisation framework defined in Chapter 6, incorporating:
    - A capacity planning mode, used to determine the optimal capacities of each of the technologies (where these are set as decision variables);

- An operational mode, used to determine the optimal dispatch of each energy service-providing technology (where this dispatch is set as a decision variable).

The solution of the resulting model allows key metrics (e.g. costs, efficiencies, unit dispatch, capacities) of each scenario to be determined following the calculations given in the framework definition.

This methodology also permits iterative solution, through adjustment of the external system assumptions based on the results of the modelling. This is important if, for example, it is assumed that the dispatch of technologies within a single local system is being simultaneously replicated in multiple locations across the whole energy system, then this may impact external costs and constraints (for example, during periods where there is a large volume of low marginal cost electricity being injected into the system). Under such a scenario, it may be necessary to readjust external parameters (such as time-based energy costs) based on the results of the local modelling, and then to re-execute the local model.

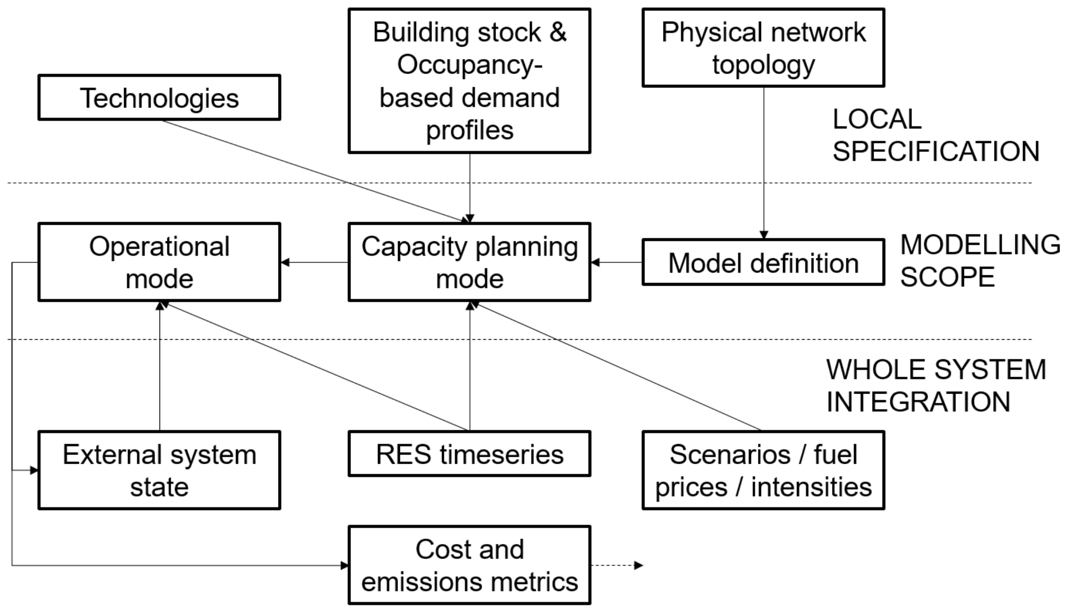

Figure 38 - Description of exemplar model scope, indicating links to local system definitions and assumptions concerning the wider energy system within which it is contained. RES = Renewable Energy Systems, which within this work concerns wind power and solar PV systems.

7.2 Model Selection

Previous UK government studies on heat provision such as [37] have divided the provision of domestic heat into several spatial archetypes:

- Rural locations, where houses are not typically closely clustered, and may be off the gas grid, with higher-cost forms of heat provision such as heating oil and electrical storage heaters. Such locations also have a higher availability of land and potential for microgeneration, and may be in the same parts of the network as embedded renewable generators such as wind farms. Housing quality is generally low and inefficient.
- Suburban areas, with a mixture of housing types and limited land availability as well as a medium population density. Such areas are mostly located on the gas grid and serviced by individual boilers. Housing stock age and quality may vary considerably.
- High density urban locations, with smaller housing types (such as flats) and limited land availability, with shorter infrastructure distances enabling / requiring centralised systems for energy provision.

Figure 39 shows the broad categorisation of these archetypes by potential usage of low-carbon heating sources. This indicates that from a policy perspective, there are a number of target audiences for different heat technologies, with each having a potential separate trajectory towards decarbonisation. It is also identified that there may not be a strong delineation between each of the archetypes, with different households falling into or between the three classifications.

As these archetypes, in combination, represent in some manner the majority of household contexts within the UK, they form a useful base definition of 3 models which can be used to further explore the local requirements for decarbonisation of domestic heat.

There have previously been 3 projects in the UK to define reference electrical distribution networks, and as the key constraint restricting technological selection in local systems is the capacity of the distribution network, it is suggested that these networks are a good basis for defining multi-carrier systems. The three projects are:

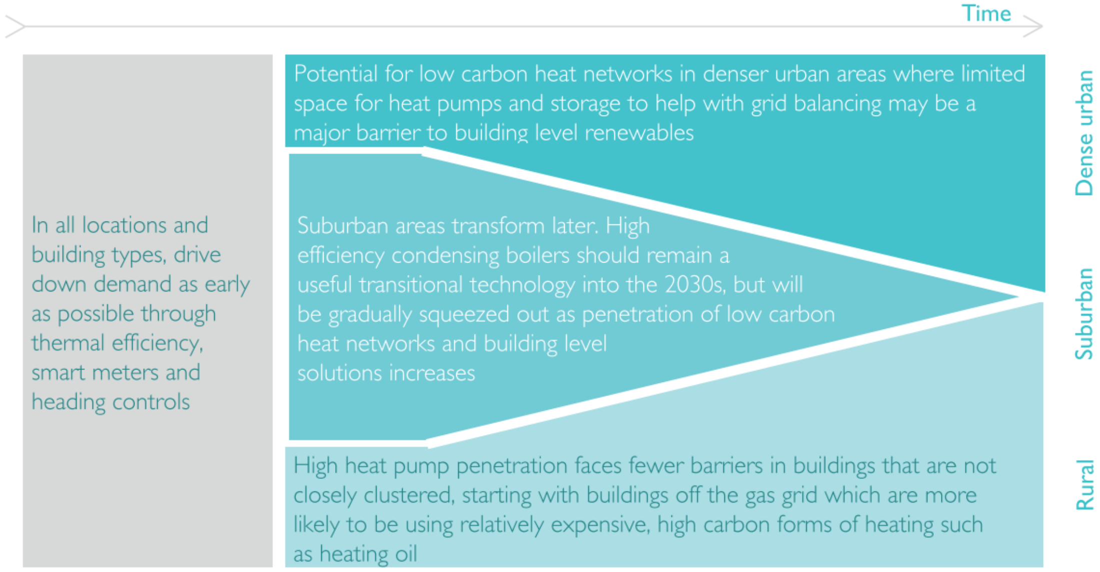

Figure 39 – UK domestic heating archetypes (reproduced from [37]), indicating different potential routes to domestic heat decarbonisation based on technological opportunities and infrastructure costs.

The UK Generic Distribution Systems (UKGDS)

These are a selection of 6 power system network models which are representative of the UK distribution networks, and were created in 2005 by the Centre for Sustainable Electricity and Distributed Generation. For example, these have been used by studies such as [170], which generates a spatio-temporal representation of electric vehicle charging across a typical urban network (EHV6).

Transform

Set up by DECC and Ofgem in 2011 as Work Stream 3 of the Smart Grid Forum, the Transform model was generated through the Energy Networks Association (ENA) to inform and evaluate the RIIO ED1 price control review submissions [171]. It represents the entire GB distribution network in a parametric manner, aiming to describe the impact of future scenarios, based on real data from DNOs and technology providers. It includes 2 variants: a GB model based on DECC scenarios, and a licence area model for DNO-specific analysis. In this respect it does not contain (in its base form) any specific network locations available for modelling in the academic community.

DS2030

As an extension to Transform, Work Stream 7 of the Smart Grid Forum aimed to explore through network studies how the Transform solutions might be applied to actual nodal models. These have been studied to demonstrate networks which are potentially viable to 'meet the needs of 2030 users'. Through this process a selection of detailed distribution models were created, and these have been made publically available. The models were selected in order to reflect typical aspects of Great Britain distribution networks that might be applicable to all distribution areas. They are all based on real networks which have been designed to industry standards, using the concept of ‘depth not breadth’. Acknowledgement is made that the networks may have many possible arrangements, and so in favour of depth there is some compromise made in representativeness, but that the choice of system parameters should enable analysis performed on them to be extrapolated to all areas of the GB network. For this reason, these are seen to be a useful starting point for attempting to compile useful Exemplar Models for the investigation of heat provision.

The models include:

- A rural base network;
- An urban base network;
- An interconnected base network in the Scottish Power MANWEB distribution area consisting of an urban network with interconnected 33kV, High Voltage (HV) and Low Voltage (LV);
- A central London UKPN urban network with interconnected LV.

Each model contains a full representation of one Grid Supply Point (GSP) with related 132kV circuits and Bulk Supply Points (BSP), with equivalent downstream models of all but one primary substation, which is modelled explicitly; this is repeated at the HV and LV levels, down to termination at consumers’ properties.

In this Chapter, the case studies for the suburban and rural models are developed from the electricity distribution network case studies used for the DS2030 project, conducted by the Energy Networks Association, and which was conducted between 2014 and 2015. The DS2030 project aimed to analyse the planning and operation of distribution networks in 2030, based on projected scenarios of electrification of demand services, such as heat and transport. As part of the project outputs, four network models were developed and disseminated. Two of these models (Interconnected London and Interconnected Manweb) were broadly concerned with studying higher distribution voltages (11/33/132kV) rather than end-customer supply, so these were not seen as applicable to this research study – although would be relevant to any further analysis of the aggregated impact in end-use on the deeper electricity system. It is also noted that the LV part of the ‘Interconnected London’ model relates to a section of central London surrounding St James Palace which is highly atypical (in terms of both topology and demand) and unlikely to generate results which may be meaningfully extrapolated to other urban areas.

The remaining two DS2030 models concerned exemplar Urban and Rural networks, identified as being representative of electricity network topologies, and these are developed into multi-vector energy models below. The DS2030 'Urban' model is here redefined as a 'Suburban' model. The model details are taken from the project Phase 2 report [172].

Table 15 - Summary of data sources for base exemplar network definitions

Exemplar Network	Location	Base Electricity Network Definition	Base Gas Network Definition
Rural (off-gas-grid)	Settle and Helwith Bridge, West Yorkshire	DS2030	None
Suburban	North Darlington	DS2030	Northern Gas Networks GIS Portal
Urban	Sighthill, Glasgow	Inferred from visual inspection	Inferred from visual inspection

In all the below cases, the modelled year is assumed to be 2030 (in terms of implementing cost assumptions), with all prices adjusted to their 2016 equivalent. Historical climate data used to generate relevant time series is taken from 2010, chosen as it contains a particularly cold winter period for the UK [173], so can be seen as driving peak heating capacity that may be required to cover an extended period of cold temperatures, and will so drive a measure of heat 'security' to guarantee comfortable domestic temperatures within the capabilities of local network infrastructure. All capital costs are depreciated to one year based on Eq. (6.11).

7.3 Demand Modelling

In order to accurately model the energy flows in local energy systems, the energy demands of end users must be adequately captured. As the focus of the work here presented is on the provision of residential heat demand, we examine approaches to the modelling of domestic demand. Heat demand cannot be modelled in isolation as, in terms of impacts on local infrastructure, the aggregate effect of all sources of demand must be assessed.

7.3.1 Previous approaches

An evaluation of bottom-up energy demand models [174] identifies the following model types:

- Deterministic statistical disaggregation models, where measured load profiles are disaggregated to identify individual appliances;

- Statistical random models, where a random procedure for energy demands is applied to generate different scenarios;
- Probabilistic empirical models, where real collected data (such as of domestic patterns of energy use) is used to generate probability distributions of energy use;
- Time of use (ToU)-based models, where time of use surveys defining the timing when specific appliances are most likely to be used for the basis of reconstructing diversity;
- Statistical engineering models, where measured data (such as dwelling statistics) is used to adjust a load curves simulated with an engineering approach to measured load profiles.

For the purposes of this study, disaggregation by energy demand type is important as it allows different forms of energy consumption to be shifted between vectors, such as the movement of space heating demand from gas to electricity provision without affecting other load. This means that approaches which make use of appliance-specific data can be easily disaggregated to individual energy carriers.

One option that was evaluated for this work was the demand model developed by the Centre for Renewable Energy Systems Technology (the CREST Demand Model). This is an integrated domestic demand model which has been developed for low-voltage network analysis and urban energy systems [175]. It incorporates a building occupancy model, solar thermal and PV generation, a building thermal model with gas boilers and domestic hot water consumption, as well as the use of appliances and lighting. The CREST model was downloaded for evaluation towards this study, but was found to be less suitable than the model selected for two key reasons. Firstly, the model is designed to generate data for up to 24 hours (at a 1-minute resolution). This means that any attempt to model for longer periods will introduce discontinuities to the time series – although this could be amended by appropriate transition between modelled periods and handling of random seeds. Secondly, however, the thermal building model is overly simplistic compared to that used in this study, primarily due to the need to contain the entire working within a single Excel spreadsheet with VBA.

7.3.2 Demand Model Description

The model used is as described in [176] and is a bottom-up model of occupancy combined with a building thermal model, the Environmental System Performance Research program (ESP-r). A schematic of the different model components is shown in Figure 40.

Each building in the system is individually modelled. An occupant behaviour simulation program [177] creates stochastic profiles of hot water demand, occupant presence and casual gains for each building. The occupant presence and casual gains profiles (such as those shown in Figure 41) are then integrated into the building models, which are diversified by the Building Stock Modeller program (BSM [178]). Building models are implemented in the building simulation program ESP-r [179]. Occupant-linked heating control (meaning heating is only on when the building is occupied) is implemented in a separate program, obFMU [180], which co-simulates with ESP-r. The building models give space heating demand profiles, which combined with the hot water use profiles give total heat demand. Two sets of building models are used; one with assumed as-is constructions, one with improved constructions. This results in two different sets of space heating demand profiles, though hot water demand profiles remain the same in the two cases.

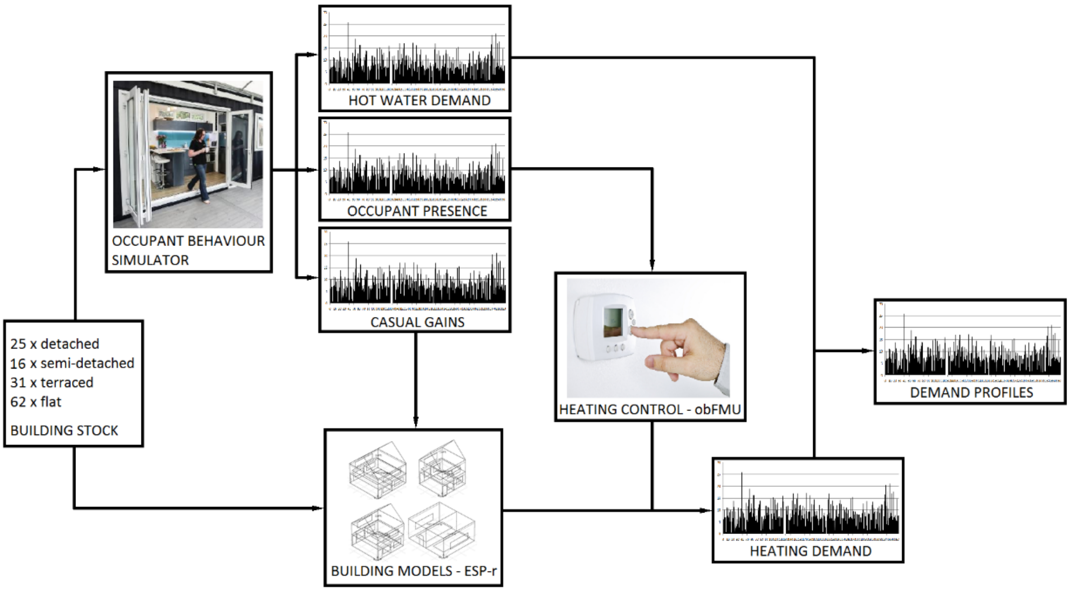

Figure 40 - Summary of demand model, as provided by Energy Systems Research Unit (ESRU) at the University of Strathclyde

ESP-r is a piece of integrated building simulation software intended to capture the dynamic behaviour of thermal building systems, and to model the underlying physical processes. This includes heat transfer, air flow, electric power and heating, ventilation and air conditioning. ESP-r utilises a finite difference approach based on a control volume heat balance, with thermal state equations describing discrete building systems [181]. ESP-r has been widely used in building energy demand studies since its inception in the 1970s. For example, in [182], ESP-r is used alongside an occupancy profile to determine the appliance demand for 2 new-build homes.

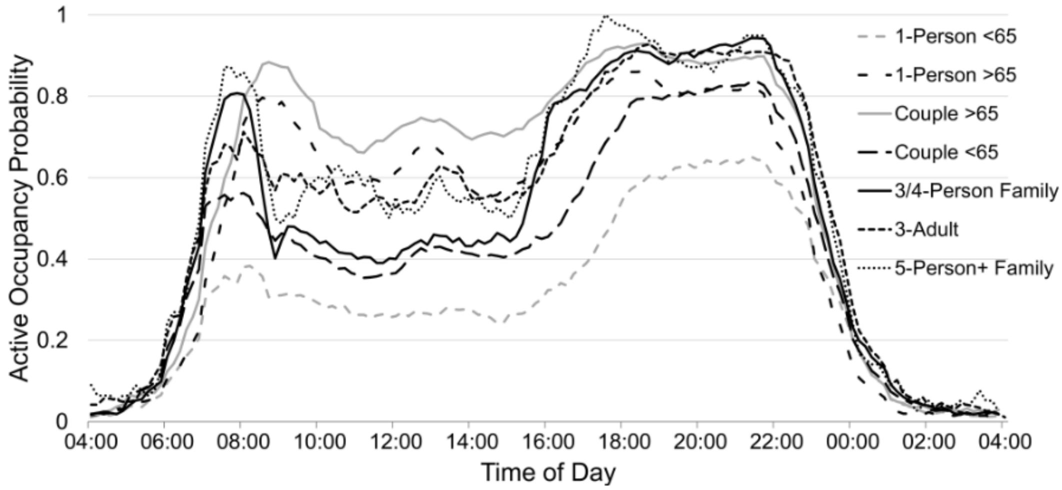

Figure 41 - Average weekday occupancy profiles for different households (reproduced from [176])

7.3.3 Example Output

Figure 42 shows a one-week time series for all 3 energy demands (space heat, hot water, non-heat electricity) for the suburban model, aggregated across different successively larger groupings (single household, single LV feeder, full model). Each has a nominal electrical transfer limit, in order to indicate the point at which – if all energy demands were supplied from electrical sources at less-than-unity efficiency – there may be an active constraint. The top trace shows the profile for a single semi-detached property, with the limit shown for typical 32A consumer box. In order to overcome this limit, there may have to be internal rewiring conducted within the household. The middle trace shows the profile for a single LV feeder (59 houses) showing the limit for smallest LV cable capacity, and the point at which cable reinforcements may be required. The bottom trace shows the profile for the secondary transformer (292 houses) showing nominal 500kVA rating. Note that the energy service demand does not necessarily equate to actual network energy demand – for example, in the case of heat pumps used to supply heat demand the Co-efficient of Performance (COP) will determine a lower actual electricity requirement. These limits are intended as conservative indicators of the points at which, under scenarios where electrification of heat demand is intended, infrastructure investment may be required.

The total modelled energy demands are shown in Table 16, indicating the total volumes of energy consumed per household (on average) for the different exemplars. The predominant difference is due to the type and size of households – further statistics on building stock and occupancy profiles is given for each model in Appendix A.

In each model, there are two sets of modelled space heat demand time series: the first relating to 'unimproved' housing stock (i.e. principally in its originally constructed form, with few improvements), and 'improved' housing stock with enhanced energy efficiency – namely loft and cavity wall insulation. As these base amounts of energy efficiency are currently targeted under UK policy (such as through the ECO – see Section 2.3.3), it is assumed that these measures will have been taken on the majority of older housing stock by 2030, and so the 'improved' values are used.

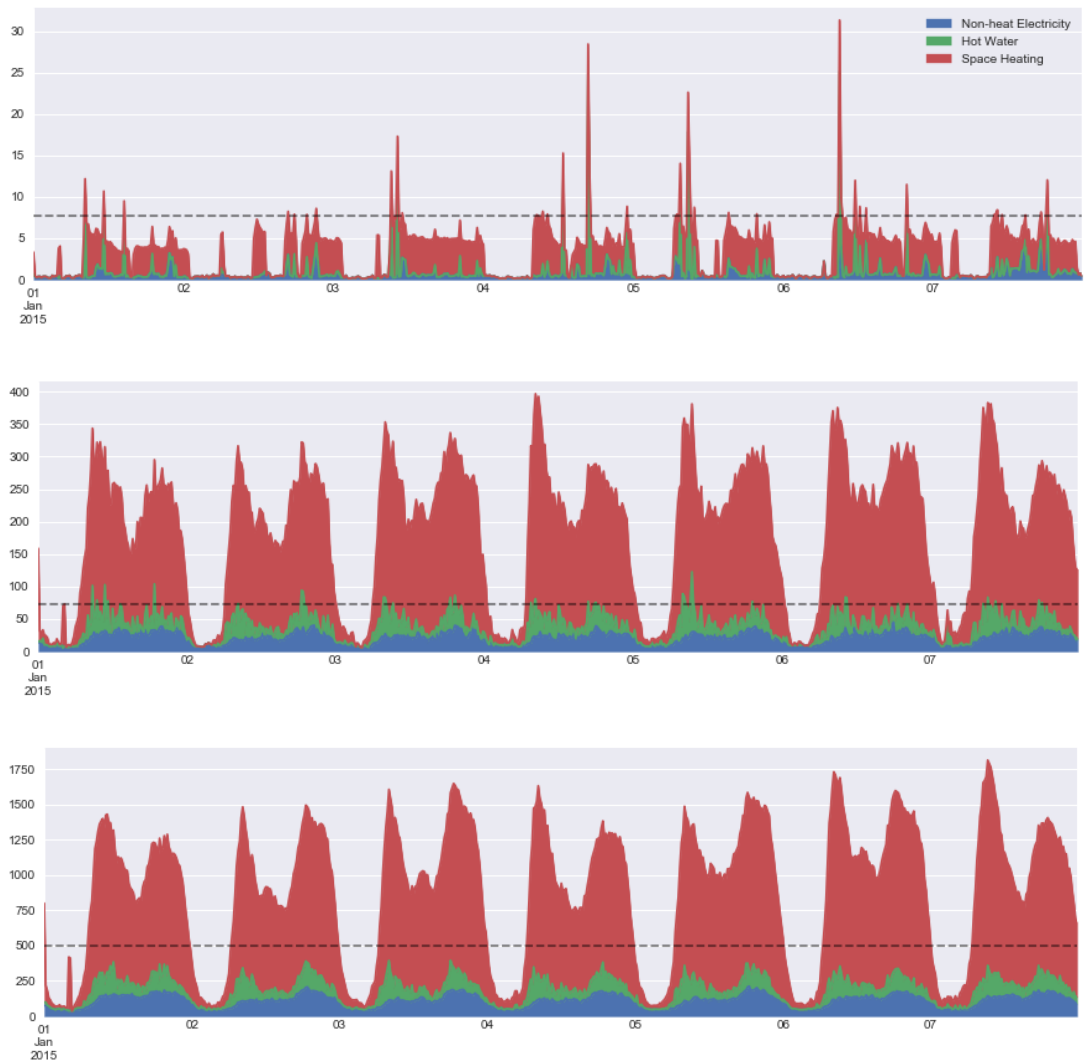

Figure 42 – Energy service demand profiles (in kW) for 1 week from exemplar suburban model at house/feeder/transformer level, indicating possible electrical transfer limits.

Table 16 - Total modelled energy demands over 1 year simulation

Model	Urban	Suburban	Rural
Space heat (unimproved)	2,002,311	2,587,044	4,614,582
Space heat (improved)	1,315,690	1,909,119	2,904,943
Hot water	517,682	619,631	704,732
Non-heat	1,056,382	999,549	1,206,129
TOTAL (improved)	2,889,755	3,528,299	4,815,804
No. households modelled	445	292	315
Mean annual energy demand (kWh)	6,494	12,083	15,288

Figure 42 shows an example of the demand outputs for the three energy service demands (space heating, hot water, non-heating) according to three distinct scales: a single household, a single LV feeder (each corresponding roughly to a street of around 80 houses) and for the entire local energy system (292 houses). The horizontal lines indicate, conservatively, the point at which – if all energy demands were met directly from electricity, that subsystem may require reinforcement. For a single house, this may correspond to an upgrade to the consumer board where the electricity connects to the household. For a feeder, this may be the limit of the capacity of the feeder cable, with addition cabling required. For the full LV subsystem, this may be the capacity of the secondary transformer. This diagram also clearly demonstrates the concept of diversity, with the variability and size of peak proportionately reduced as the number of households increases.

7.3.4 Diversity Effects

Due to the difference in timing of end use demand between households (or other consumers), peak energy consumption does not scale linearly with the number of consumers. This effect is known as diversity and is well established within the electrical sector. Diversity factors (defined in eq.(7.1) below [183]) are routinely used to size electrical networks based on assumptions around this scaling.

$$Diversity\ factor = \frac{Sum\ of\ individual\ maximum\ demands}{Simultaneous\ maximum\ demand\ for\ all\ consumers} \tag{7.1}$$

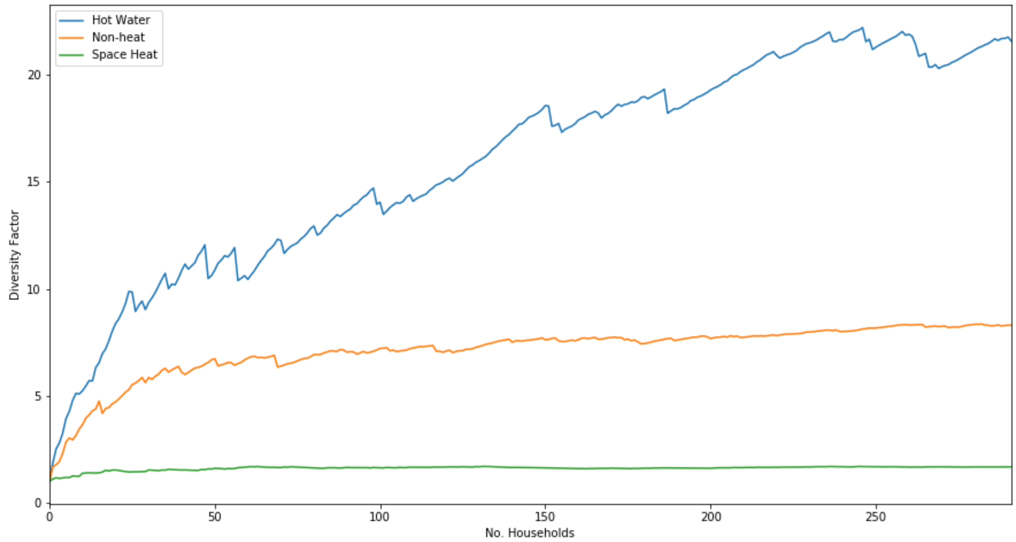

Figure 43 - Increasing diversity factors for each energy demand vector as number of households increases (Suburban model). Houses are ordered randomly.

The effect of diversity can be clearly seen in Figure 43, where the width of the demand peaks widens and the peak height is proportionally reduced, as the number of individual demands is increased. Figure 43 shows the diversity factor for each of the three modelled energy demand vectors as the number of households increases within the suburban model. For the full simulation of 292 houses, the diversity factors are given in Table 17.

Table 17 - Diversity factors for different demand vectors in suburban model

Demand vector	Diversity factor (n=292)
Space heat	1.67
Non-heat	8.29
Hot water	21.58

The primary implication of these values is to demonstrate that the diversity effects known and expected within electrical appliance demand are not reproduced within heat-based demand vectors and, in particular, space heating does not benefit from diversity effects at scale. This is because within a given area of housing, there is likely to be a highly similar housing stock, as well as a similar demographic profile. The households will also be undergoing near identical ambient temperature changes. This means that the desired temperature profile is likely to be similar for houses in a local area, and the house stock will respond in a similar manner to changes in temperature. This increases the probability (in comparison to general electrical appliance use) that different households in the same area will demand energy for space heating at the same time. This is also a result of the fact that space heating demand will generally take place over a longer period in each house than for non-heat appliances, which may only be in use for a matter of minutes. The implications of this are discussed further in Chapter 10.

7.3.5 Integration with the Optimisation Model

The inputs for the demand model are:

- The housing stock within each area, taken from publically-available mapping data and aerial surveys, at a house-by-house level;
- Housing census data to generate a set of typical occupants for each household (detailed for each model in Appendix A);
- Temperature data from a local Met Office station to each model covering 2010.

The above described demand model is used to simulate energy demand on a per-household basis for each of the energy systems in question, disaggregated into the three energy service demands: space heating, hot water and non-heating. The resolution used is 15 minutes, over a single year of simulation, driven by locally measured climate data for 2010 (chosen as a year with a significant winter peak in heating demand). Each of these are created as a demand technology (see Section 6.3.1) with a time-variant characteristic.

7.4 Renewable Generation Modelling

Using the methodology described in section 4, wind power time series can be generated to represent the injections from local wind power systems within a specified local energy system. In each model, an extant local wind farm with a recorded operational history is selected, and a statistical simulation model derived based on metered yield and the known model of wind turbine. The specific wind farm selected is discussed within each model description below.

Similarly, solar irradiance data from the same reanalysis dataset used in the wind simulation model (MERRA 2) can be used to generate locational solar power time series (either as electricity output from a PV system, or as heat energy into a solar thermal water system), following the methodology given in [140] and previously applied to MERRA data in [184]. The power output of a PV panel is a function of the in-plane irradiance and the ambient temperature, as defined by panel-specific efficiency curves.

For a given solar panel installation, the plane azimuth angle α is given by:

$$\alpha = \cos^{-1}\left(\sin(h) \times \cos(t) + \cos(h) \times \sin(t) + \cos\left(a_p - a_s\right)\right) \tag{7.2}$$

where h is the sun altitude, a_p is the panel azimuth, t is the panel tilt, and a_s is the sun azimuth angle. The direct and diffuse plane irradiance ($I_{dir,p}$ and $I_{dif,p}$) can then be computed from the global irradiance ($I_{dir,h}$ and $I_{dif,h}$) by

$$I_{dir,p} = \frac{I_{dir,h} \times \cos(\alpha)}{\cos\left(\frac{\pi}{2} - a_s\right)} \tag{7.3}$$

$$I_{dif,p} = I_{dif,h} \times \frac{1 + \cos(t)}{2} + a \times \left(I_{dir,h} + I_{dif,h}\right) \times \frac{1 - \cos(t)}{2} \tag{7.4}$$

where $a = 0.3$ is the assumed surface albedo.

The power output is calculated from the in-plane irradiance using the temperature-dependent panel efficiency curves given in [140] (as fitted against metered data from a survey of values across Europe), with examples shown in Figure 31. A further efficiency of 0.9 is applied based on the comparison to metered UK PV output in [184], although it is acknowledged in that work that this may be conservative as the value is derived from older PV systems, and newer inverters may operate at higher efficiencies.

7.5 Suburban Model

The Suburban model follows 292 households located across 5 streets in the north of Darlington (latitude 54.551, longitude -1.549). The housing stock is a mixture of semi-detached (260 households) and terraced (31 households) with a single detached property. The layout of the suburban network is shown in Figure 44, indicating that this is a highly typical suburban layout for the UK, with 1930s housing stock. This combination of street layout, housing density and network topology can be seen to be useful as a representative case for a large section of the UK population.

Figure 44 - Suburban exemplar network layout, showing 292 properties as a mixture of semi-detached, detached and terraced housing. The secondary 500 kVA transformer is located at the centre and supplies the four electricity feeders, with each property colour coded to indicate the feeder on which it is located: Green = LV Feeder A, Red = LV Feeder B, Blue = LV Feeder C, Yellow = LV Feeder D. Dashed lines indicate low pressure gas pipework. (Underlying map © OpenStreetMap contributors, licenced under the Open Data Commons Open Database License https://www.openstreetmap.org/copyright [185])

7.5.1 Electricity Network

Distribution Transformer NPG No. 235536 has a nameplate capacity of 500kVA. There are 4 LV feeders - A, B, C and D - as indicated in Figure 44, with 59, 66, 84 and 83 consumers respectively. The full LV network diagram is reproduced in Appendix A.1. The transformer ends of the LV feeders are composed of 0.3 PILC Al cable, with a rated current of 280A. At 400V this equates to a nominal power limit of 112kV, assuming load is balanced across all three phases. In total there are 2508m of LV feeder cable across the 4 feeders.

7.5.2 Gas Network

The low-pressure gas network, managed by Northern Power Grid, is a combination of old 4" cast iron pipework and modern polyethylene replacement – an indicative section of map is given in Appendix A.1. This network is not seen as having any active constraint with relation to the supply of gas at any residential demand level.

7.5.3 Energy Model Configuration

The suburban energy system is represented by the configuration of nodes and transmission links indicated in Figure 45. This includes the

Each of the demand nodes (*DarlingtonA, B, C, D*) is an aggregation of the individual household demands connected to each LV feeder, and in all models each has 6 associated demand technologies:

- *demand_space_heat*: the time-variant demand for space heating;
- *demand_space_heat_unmet*: an additional supply vector which may be used (at high cost) to supply *demand_space_heat* in the condition the model does not otherwise solve;
- *demand_hot_water*: the time-variant demand for hot water;
- *demand_hot_water_unmet*;
- *demand_power*; the time-variant demand for non-heat related electrical devices;
- *demand_power_unmet*;

The *ElecTransGrid* and *GasTransGrid* nodes represent the electricity and gas transmission grids respectively, available to supply electricity and gas at fixed, time-invariant prices as established in Table 7 in Section 5.2.5. The price is chosen to be static as, while the wholesale price of electricity on the transmission network will be dynamic (representing the current demand level, supply curve and renewable energy output), domestic consumers will predominantly have single price tariffs – however it is acknowledged that inclusion of dynamic fuel pricing would allow further investigation of the possible interactions between local energy consumers and the system-wide state through Demand Side Management (DSM). This is discussed further in Section 10.5.

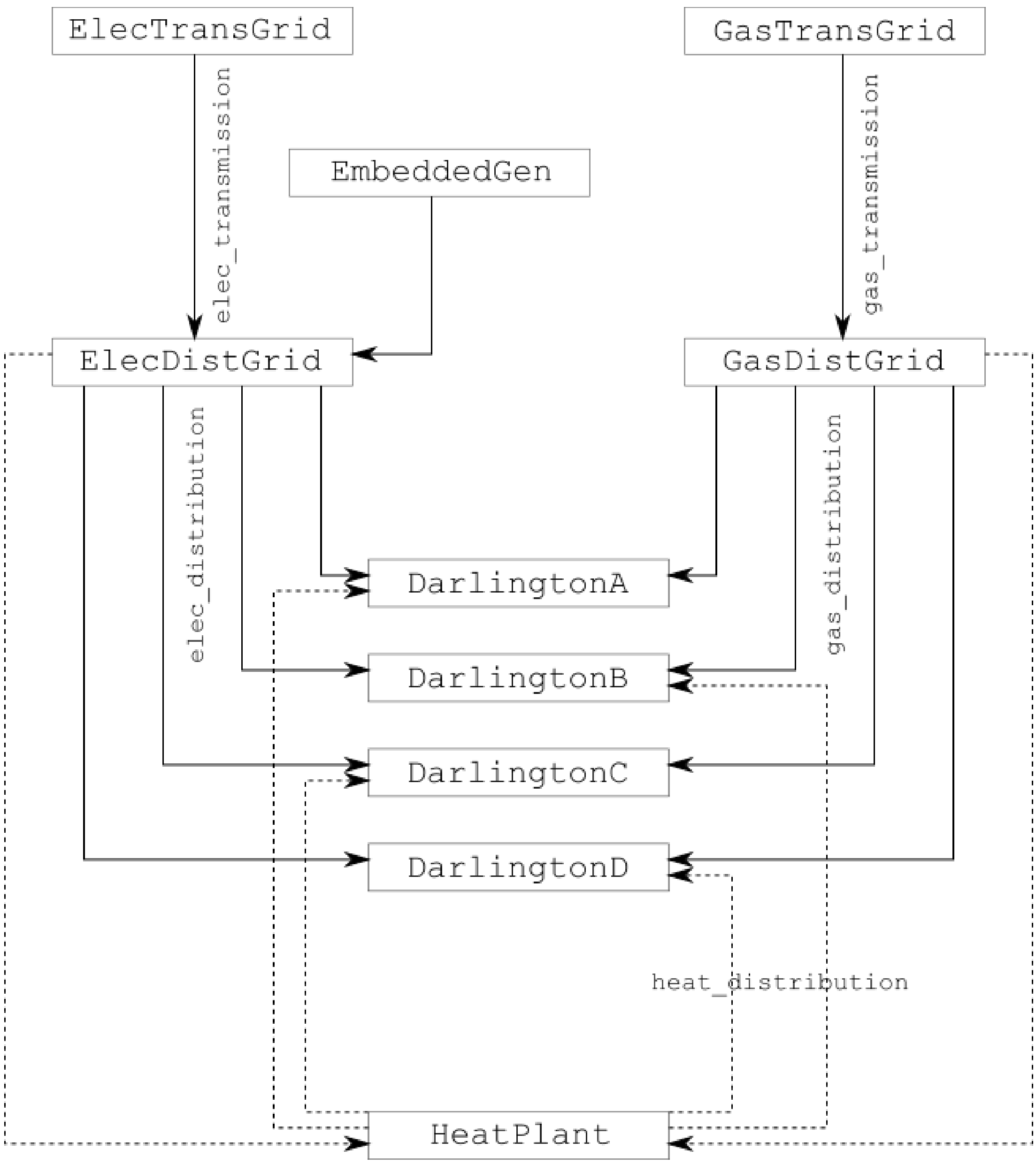

Figure 45 - Suburban energy model topology, indicating existing electrical and gas grids, alongside notional district heating system connected to either gas or distribution grid.

The *EmbeddedGen* node represents local (primarily renewable) generation which may exist behind a distribution constraint. This is connected losslessly into the local distribution grid, in order to represent volumes of energy which may be available at particular times and would otherwise be curtailed due to a shortage of network capacity to export to the transmission network. This is discussion further in the relevant scenarios below.

The non-LV distribution network is not explicitly modelled – however, the constraint imposed on the LV network by the 500 kVA LV transformer is considered as the binding capacity on the level of electricity which may be imported from the transmission grid. As 500kVA is the nameplate rating of the transformer under continuous rating, this is not seen as an appropriate hard constraint value – operation of secondary transformers above their nameplate rating during peak periods is viewed as permissible normal operation with minimal impact on the transformer lifetime providing the duration of the peak is short. The actual constraint will depend on the transformer oil temperature and peak duration, which is outside the scope of this model. For this reason, it is determined that a hard constraint of 10% above nameplate capacity (i.e. a maximum throughput of 550kW) is appropriate to represent the daily peak level a network operator would consider allowable for long-term operation. A 7% LV distribution loss is applied as typical for UK networks [186]. As described above, a feeder limit of 112kW is applied representing the current rating of the transformer end of the LV cable.

For the low-pressure gas distribution network, the pipework is already appropriately sized to allow all space heat and hot water demand to be delivered by the network. Any changes towards carbon emissions reduction (e.g. use of non-gaseous fuels, improved housing or boiler efficiencies, etc.) would serve only to decrease the necessary low-pressure capacity. For this reason, a capacity constraint is not applied to the low-pressure network between the *GasDistGrid* and each of the 4 demand nodes. As discussed in Section 5.2, the use of alternative gases in the low pressure network is also not considered to have a capacity restriction, but will carry a separate capital cost where there is a need to retrofit demand-side equipment such as fuel-specific burners. Similarly, any separate plant burning gas for a district heating network (e.g. CHP) will not be constrained by the low-pressure network but will instead have a distinct capital cost associated with connecting to the higher-pressure distribution network. Addition of case-specific additional constraints and costs are described in the appropriate scenarios below. As the target year is 2030, it is assumed that all low-pressure pipework has been replaced with modern polyethylene or similar, and that low-pressure gas losses are negligible.

7.5.4 Base Technologies

Under the base scenario, all space heat and hot water demand is met from condensing gas boilers. A trace of space heat demand against gas boiler heat generation, across all households, is shown in Figure 46.

However, it is noted that in reality, under a gas-only heating scenario, each household is likely to install an individual domestic condensing boiler, with a typical size (for the housing types in question) of 24kW, and this is introduced as a modelling constraint in scenarios where condensing gas boilers are in operation.

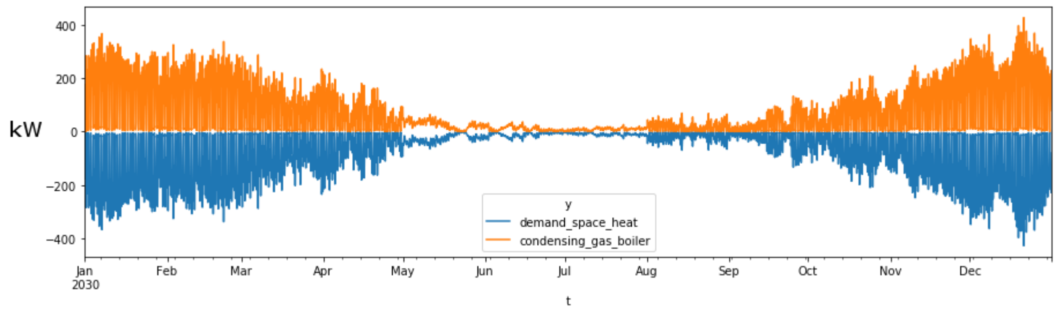

Figure 46 - Space heat demand (-ve supply) and condensing gas boiler generation (+ve supply) in kW across the whole year, Suburban Base Scenario, all households

7.5.5 Heat Pump Modelling

The first low-carbon scenario to be tested incorporates heat pumps into the end energy demand. As the coefficient of performance (COP, discussed in Section 5.4.2) varies with the difference between the return temperature and ambient temperature, the ambient temperature data used to drive the demand model (measured at Bingley) was additionally used to construct a time-variant series of COP across the simulated year. Based on the performance shown in Figure 33 for air-to-air heat pumps and the previously mentioned field data on average COPs, a heuristic for COP related to ambient temperature $t_{amb}$was derived as a quadratic function, given in Eq. (7.5):

$$COP = 0.0008x^2 + 0.0718x + 2.192 \tag{7.5}$$

For other forms of heat pump, the same generated COP time series is scaled between the minimum and maximum COP values given in Table 9. The exception is for ground-source heat pumps, where instead the thermal buffering effect of the ground is compensated for by a) averaging the COP over each month, and interpolating the high-resolution between these monthly data points; and b) time-shifting the series backwards by one month, following the seasonal variance shown in Figure 35. The maximum and minimum temperatures measured were +24.9 and -10.5 Celsius respectively. It should be noted that based on the heuristic used, the minimum described COP is not reached, and the actual modelled minima and maxima are listed for each heat pump technology are given in Table 18. The trace for the full year is shown in Figure 47, and equates to the annual average COP for each technology.

Table 18 - COP ranges from modelled data for each heat pump technology

	Air-to-air heat pump	Ground-source heat pump	High temperature heat pump	Hybrid heat pump	Gas heat pump
Min	1.53	3.22	3.11	2.89	1.17
Average	2.80	4.09	3.39	3.00	1.18
Peak	4.48	5.22	3.75	3.13	1.19

Figure 47 – Average daily COP for different heat pump technologies generated from temperatures at Bingley. AS = air-source, GS = ground source, HT = high temperature air-source, HYB = hybrid, G = gas.

7.5.6 Residual Wind Energy

If the local energy system exists in the same area of distribution network as embedded generation, and (as is increasingly the case) the distribution network has little firm capacity to offer such generators, then there may be a volume of curtailed energy available on the distribution lower-voltage side of the constraint. For example, if there are a number of wind farms connected into the distribution network at 33kV, and the 33kV network is congested at times of peak output, then a proportion of that energy may be curtailed, such as through Active Network Management (ANM).

The proportion of wind energy within a distribution network which may be curtailed at a particular time will be a function of the output of the wind generators and the aggregate demand on the distribution network – for example, if a wind farm is producing at full output during peak demand hours, then it is likely that this output will be absorbed by normal peak demand. If, however, this output occurs during minimum demand hours (such as the early hours of the morning) then this energy is more likely to be curtailed and lost, in the absence of any resource (e.g. storage) which may be redispatched to capitalise on this energy.

To represent this relationship, we can say that at a point of minimum electrical demand, there will be a maximum level of local generation which may be exported from wind generators (in sum meeting local demand subject to security constraints and the export capacity of the distribution network to the transmission network at the Grid Supply Point). Similarly, when the wind generation is at maximum (i.e. during high wind conditions when all local wind generators are at rated output) there will be a minimum level of local demand above which all this generation may be absorbed without curtailment. This relationship is illustrated in Figure 48, with an approximating linear function between the two points and an expected volume of energy which might be curtailed in the absence of any dispatchable demand. This volume of energy then represents a zero-marginal cost opportunity which may be available to local demand (such as thermal storage) which is capable of taking advantage.

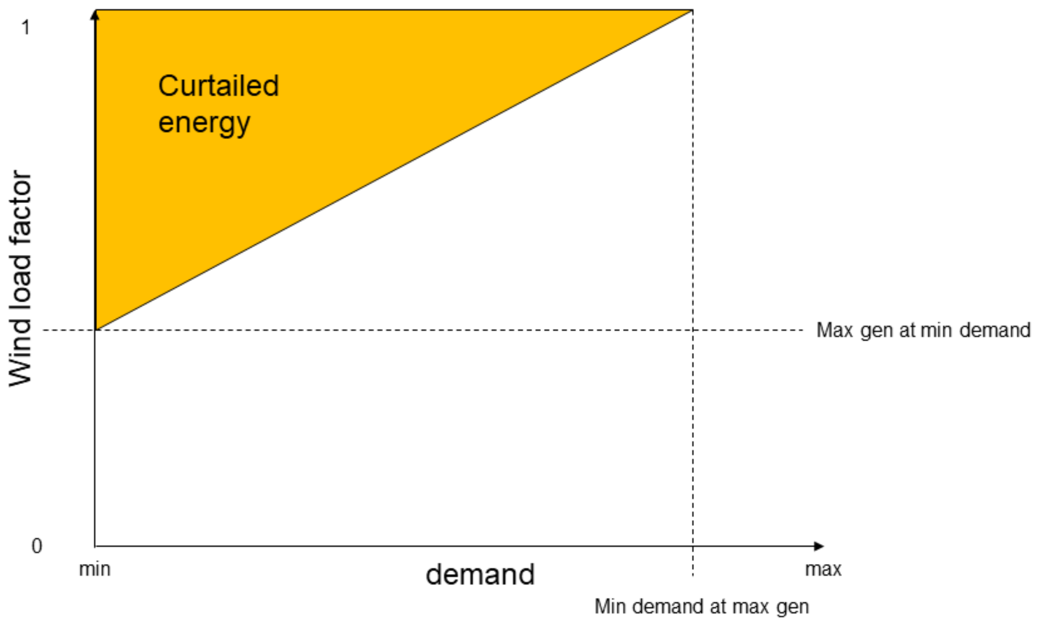

Figure 48 - Illustration of potential for curtailed energy from an embedded generator (e.g. distribution-connected wind farm)

Hence for a value of wind output e_{prod} (as a proportion of maximum possible output) and a local level of energy demand e_{demand} (as a proportion of maximum demand), with a critical value of maximum permissible wind output at minimum demand e_{MGMD} and a minimum demand level required to allow the maximum possible wind output (i.e. zero curtailment) e_{MDMG}, the proportion of residual wind energy, assuming a linear relationship as above, is given by Eq. (7.6):

$$e_{residual} = max\left\{e_{prod} - \frac{1 - e_{MGMD}}{e_{MDMG}} e_{prod} - e_{MGMD}, 0\right\} \tag{7.6}$$

In order to simulate the time-variant availability of this curtailed energy, the methodology presented in Chapter 4 was used to simulate the output for an extant 20MW wind farm within the same distribution area – EON's Butterwick Moor Wind Farm, consisting of 10 RePower MM82 wind turbines [187]. The output was simulated from the commissioning date of 2009 through to 2016 and compared to the ROC registered output for the same period to validate and scale the output (see Section 4.3.4). The values for 2010 were then normalised to a load factor, and the same conducted for the non-heat electrical demand for the local energy model (taken as a proxy for aggregate electrical demand across the distribution network). Selecting values of $Max\ gen\ at\ min\ demand = 0.4$ and $Min\ demand\ at\ max\ gen = 0.9$ equated to a total energy constraint of 10% of the total site output for 2010. The timing and magnitude of this available energy is shown in Figure 49.

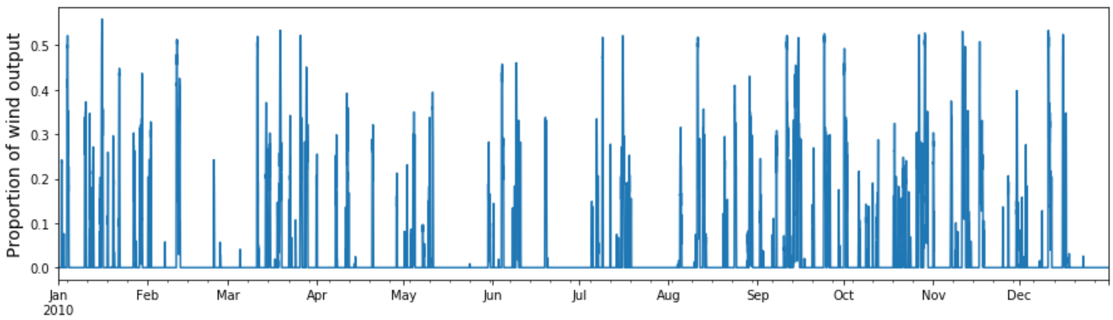

Figure 49 - Timing and size (in proportion of wind farm output) of residual wind energy from Butterwick Moor wind farm across 2010

The distribution of these volumes of energy across different hours of the day is shown in Figure 50. As the diurnal distribution of wind speeds is relatively weak (see Figure 23) compared to the diurnal distribution of demand, this curve most closely relates to inverse demand on the network. This broadly indicates that any controllable system seeking to make use of potentially low-cost energy (such as through a time-of-use tariff) will predominantly be dispatched during the late night/early morning demand minimum and, to a lesser degree, around mid-day.

The modelled values of residual energy are fed into the model at the 'EmbeddedGen' node – that is, with regards to the local energy system, use of such energy is subject to the LV network constraints.

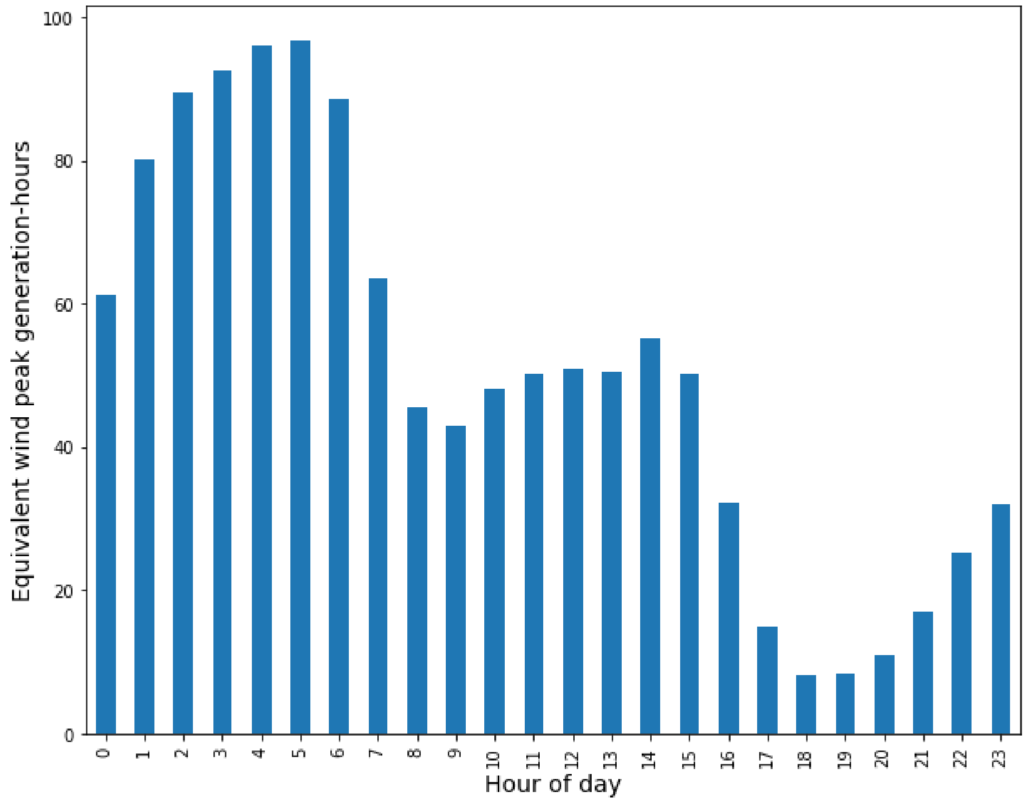

Figure 50 - Diurnal distribution of residual wind energy, in equivalent of hours of peak wind generation capacity

7.5.7 Photovoltaic and Thermal Solar Generation

In order to simulate output from domestic photovoltaics, PV systems are assumed to be installed on the south west-facing aspect of the houses, with a typical roof pitch of 40° and an azimuth of 198° (based on visual inspection of housing). Using the MERRA 2 dataset for 2010 and the methodology described in section 5.3.1, this gives an annual capacity factor before conversion losses of 12.9% (in comparison to DECC's Feed-in Tariff model which assumes a national value of 9.7% after losses and considering the distribution of panel orientations [188]). The seasonal and diurnal trends for the simulated energy time series are shown in Figure 51 and Figure 52 respectively.

The average suitable roof area is taken from [189] as 18m^2 (2.2kW of panel capacity), used to limit the total capacity of available solar generation in the model. PV and thermal output is modelled identically, with output carriers of electricity and hot water respectively.

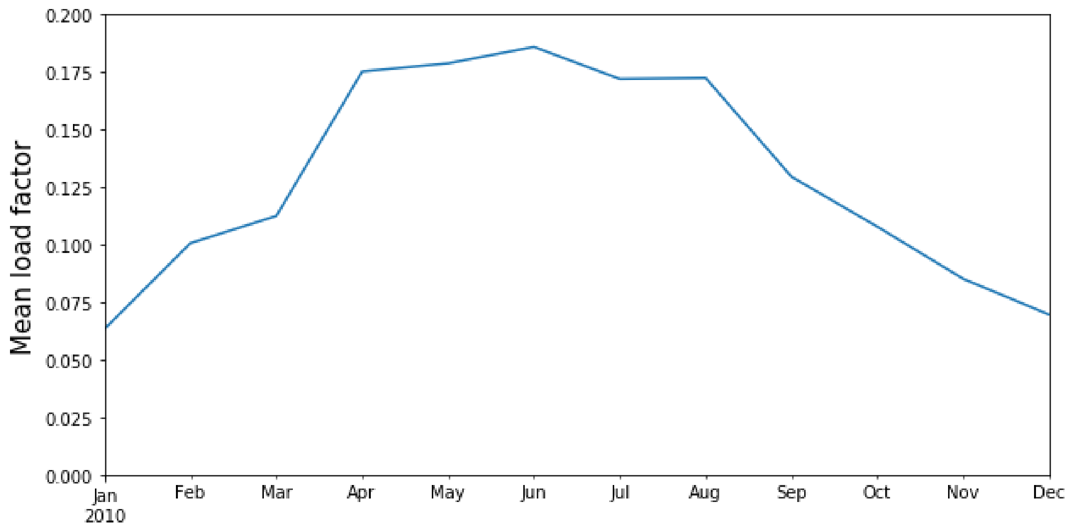

Figure 51 - Mean PV load factor by month, suburban model

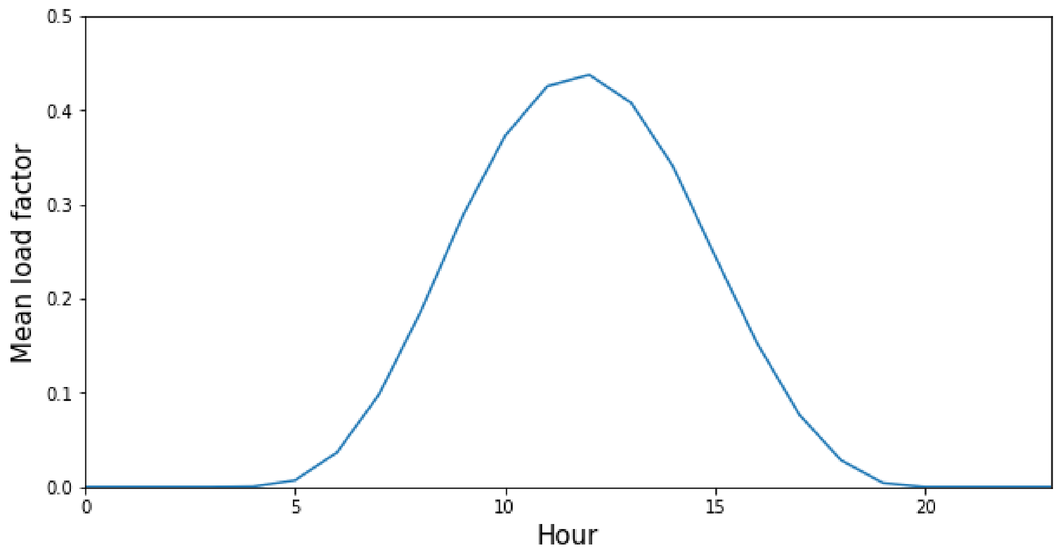

Figure 52 - Mean PV load factor by hour of day, suburban model

7.5.8 Thermal Storage

Where hot water tanks are used (in order to buffer the highly peaking nature of hot water demand in comparison to heat demand) these are sized around 200 litres, and assuming a storage temperature of 90°C[5], is equivalent to an energy store of 16.3kWh when compared to an ambient temperature of 20°C. The costs of such tanks included installation are assumed to be £500 in 2016 prices [190]. No constraints are applied to the rate at which the tank may be filled or emptied, as it is assumed that this is appropriately constrained by the power capacity of the heating system, and by the rate of consumption by householders.

7.5.9 District Heating

As reviewed in Section 5.4.3, there are a wide variety of district heating systems, with varying economic justifications according to the total demand, land footprint and spatial character of the area to be supplied. In order to model a conceptual district heating scheme, a common configuration, as described in e.g. [191], is applied, consisting of the following elements:

- An Open Cycle Gas Turbine (OCGT) CHP plant, located at the site of the LV transformer, simultaneously producing high temperature water and electricity;
- A tank-based high temperature hot water store, located in proximity to the CHP plant (i.e. is considered lossless in terms of transfer, but has a diurnal return efficiency of 95%);
- Heat pipes extending along the same topology (and having the same notional lengths) as the electrical LV network;
- An electrical connection between the CHP plant and the existing LV feeder network;
- A Hydraulic Interface Unit (HIU) in each household sized to meet peak hot water and space heat demand (with no other storage or heat technologies installed in any houses).

The CHP plant and thermal store are optimally sized to meet all heat demand (with no permissible shortfall) at the lowest combined cost. As part of the cost calculation, the CHP plant may export excess electricity (produced when heat is being generated but electrical demand is low) to the transmission grid, in return for income based on the assumed per-unit price of electricity. All costs and efficiencies of technologies are as discussed in Section 5.4.

No costs are assumed for the utilisation of the LV network by the CHP plant, and consumers may also source electricity from the distribution network as normal during periods where it is more economic to do so than to operate the CHP plant in the absence of heat demand. Thus, it is expected that consumers utilise cheaper electricity when the CHP plant is online to meet heat demand, but source grid-side electricity during other periods.

[5] See for example [207] which indicates a target temperature of 70°C and that 100°C should not be permitted from a safety point of view. In case 90°C is chosen as a maximum that would maximise the store energy capacity while also keeping within safe limits subject to typical control system envelope.

7.5.10 Network reinforcement

In order to determine the per-unit cost of LV network reinforcement, Ofgem's DPCR4 review was used to allocate the independently-assessed cost of each item of network equipment. Data at this granularity has not been made available in subsequent Price Control periods, but due to the established nature of the equipment in use costs are assumed to have remained relatively constant. The cost is divided by the additional capacity provided by each item of installed equipment to determine the costs associated with the addition of capacity to each LV feeder and to the transformer. Deeper network reinforcements are not modelled, due to the complexity of dividing up combined costs of multiple LV systems, and it is assumed that changes to the one LV system has a nominal impact on higher voltages (see Section 10.5.4 for further discussion). The costs are introduced to the model as £/kW options of upgrading the transfer capacity between the distribution network and each demand node (cable and link costs), and the total instantaneous capacity summed across all 4 nodes (transformer cost). Due to the lack of available data, it is not possible to define cost scenarios for reinforcement.

Table 19 - Costs of new suburban LV network components [139] – prices adjusted to 2016 equivalent

Component	Cost	Unit	Amount in model	Additional capacity (kVA)	Cost/kW capacity
6.6kV/11kV Ground-mounted transformer	£15,645	unit	1	500	£31.29
LV mains PIL cable	£87,612	km	2.507	448	£490.28
LV Link box	£1,639	unit	4	448	£14.63
				Total	**£536.20**

7.5.11 Modelled Scenarios

In order to evaluate a set of credible future heat scenarios, proportions of end-use technologies were set according to each scenario listed below, along with options around storage, renewable generation, gas decarbonisation, and network reinforcement. The default optimisation is for least emissions, which will preferentially dispatch the lowest-carbon options to meet demand, leaving extant technologies (such as gas boilers) for in-filling peaks where other constraints are binding. A nominal (10^{-6} $kgCO_2/kW$) emissions cost is applied to all technologies on a per-unit-capacity basis, in order to ensure the model solution only contains utilised capacity, but this value is ignored in later emissions calculations.

The technology sizings on a per-household basis correspond to those used in the UK TIMES model.

Heating Technology Selection

- Base: All households have a 24kW condensing gas boiler.
- GHP: All households have a 24kW gas heat pump.
- AAHP: All households have an 8kW air source to air heat pump and a 24kW condensing gas boiler. The heat pump is dispatched in preference to the gas boiler up to the constraint level of the electricity network, with the gas boiler used to in-fill peaks.
- GSHP: All households are fitted with a 200 litre hot water tank (which may supply domestic hot water but not heating demand) and a ground-source heat pump, which is optimally sized to meet all demand.
- HTHP: All households are fitted with a 200 litre hot water tank (which may supply domestic hot water but not heating demand) and a high temperature air-source heat pump, which is optimally sized to meet all demand.
- HYBHP: All households are fitted with a 200 litre hot water tank (which may supply domestic hot water but not heating demand) and a hybrid air-source heat pump combined with gas boiler unit, which is optimally sized to meet all demand.
- *_IMM: All households may add immersion hot water systems, used in cases where air-to-air heat pumps are only for space heating requirements and there is no condensing boiler.
- *_district: All households are supplied via a district CHP scheme sized to that network alone, comprising an OCGT, thermal store, and per-household HIUs.

Storage Options:

- Base: no storage is included.
- *_store: thermal storage is included and optimally sized.

Renewable Technology Options:

- Base: No renewable technology is included in the model.
- *_PV: Each household is fitted with up to 2.2kW of solar panels (as based on average roof area and constraints given in [189]) , in addition to each of the heat technologies defined above.

- *_ST: Each household is fitted with up to 2.2kW of solar thermal panels which may be used to either meet space heating or hot water demands, in addition to each of the heat technologies defined above.
- *_wind: The distribution network contains the residual wind volumes of zero-cost electrical power as defined in Section 7.5.6 above.

Network Reinforcement Options:

- Base: The network only consists of extant LV feeder and secondary transformer capacity.
- *_reinforce: The electrical distribution network capacity can be reinforced to meet peak electricity requirements. In the above heat technology scenarios where there is peak in-filling by gas condensing boilers, these are removed and the network reinforced to the point where heat pumps may meet all heat demand.

Alternative Gas Options:

- Base: The gas transmission network is solely supplied from natural gas, with associated emissions.
- *_bio: The gas transmission network is supplied from biogas rather than natural gas, and has lower associated emissions.
- *_hyd: The gas transmission network is supplied from hydrogen rather than natural gas, and has lower associated emissions. Condensing gas boilers in the heating technology selection are replaced with hydrogen boilers incorporating switchover costs.

Cost Cases:

- Low: Minimum costs/maximum efficiencies/minimum emissions.
- Central: Central estimate costs/efficiencies/emissions.
- High: High costs/minimum efficiencies/maximum emissions.

The above options are combined combinatorically and labelled, on top of the model, according to the series of options above, excluding labels for base options. For example, *suburban_AAHP_PV_wind_reinforce_central* is the scenario for the suburban model containing air-to-air heat pumps, photovoltaic panels and residual wind, alongside model freedom to reinforce the network as far as possible to reduce emissions, with in-filling by condensing gas boilers burning natural gas, using the central estimates on costs, efficiencies and emissions. Due to the high dimensionality of the permissible scenario combinations, only specific combinations are selected to assess key areas of interest, as described in the next Chapter.

7.6 Rural Model

The rural model is based around the village of Helwith Bridge close to Settle in the Yorkshire Dales (latitude: 54.121, longitude: -2.290). 63 customer properties are distributed between 10 individual settlements, as shown in Figure 53. Details of the breakdown of properties by location are given in Appendix A.2. It is noted that, unlike the suburban case, there is a far wider variation in the nature of rural local systems, and while this example is unlikely to be representative of many in terms of housing density and overall layout, analysis of such a case provides insight into the cost and infrastructure differences in a wider, weaker network than under the suburban case.

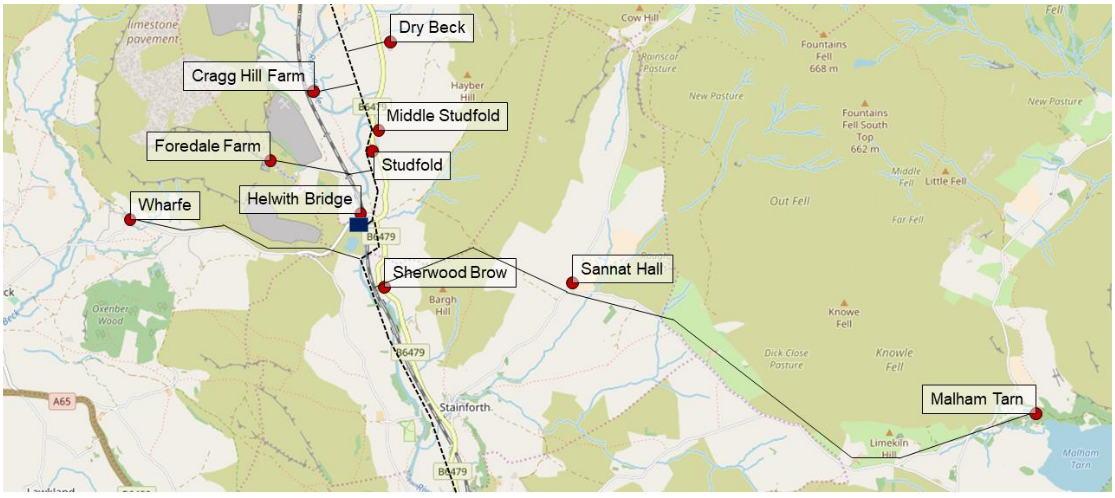

Figure 53 - Map of rural model location (Underlying map © OpenStreetMap contributors, licenced under the Open Data Commons Open Database License https://www.openstreetmap.org/copyright [185])

7.6.1 Electricity Network

The LV network is served by transformer ENWL 644799 at Helwith Bridge, with a rated capacity of 100kVA. As with the suburban model, a hard rating of 110kW is used to allow for thermal buffering in the transformer during peak demand. The customer properties are all served by overhead line, combining 4 core 95mm^2 and 3 core 185mm^2 cables, with a maximum rating of 192A and 291A respectively [192], equating to an equivalent maximum energy throughput at 400V of 76.8kW and 116.4kW. The division of cable sizes is not known, but it is assumed that the higher 3 core limit applies to the 4 settlements located along the LV feeder following the B6479 road, and the lower 4 core limit applies the 6 settlements lying along spurs from this feeder.

7.6.2 Gas Network

None of the given locations are currently supplied by the gas network. The nearest network is found approximately 3km south-west of Helwith Bridge, where the high-pressure main follows the A65. The nearest low-pressure network is located approximately 5km to the south at Settle. The high dispersal of the demand locations means that the costs of infill, due to the small number of properties, will be prohibitively expensive on a per-household basis, and gas-based scenarios are not investigated.

7.6.3 Energy Model Configuration

The topology of the rural model is shown in Figure 54. The LV backbone shown in Figure 53 is selected to represent the interface point to the distribution grid, and the cable lengths are allotted to each node link such that the total cable length in the model corresponds to the total length in the real-world network, ensuring that per-distance costs are correctly allocated. Two locations are further linked indirectly.

7.6.4 Base Scenario

Under the base scenario, heating is assumed to be supplied from oil condensing boilers, fuelled by heating oil. Each household has an individual boiler, sized at 25/30/35kW for 2/3/4 bedroom houses, and a 200 litre hot water tank.

7.6.5 Renewable generation

The residual wind output and PV outputs are modelled in a similar manner to the suburban model. The wind farm used to calculate residual wind time series is Lambrigg, consisting of 5 x 1.3MW Nordex N60 turbines, and located approximately 35km to the North-West of the model location (within the same MERRA grid square). The PV sizes are calculated on a per-location basis, using typical roof areas by house type and the values given in [189]. A random mixture of roof orientations is used distributed 180 degrees around due south in order to reflect the diversity of the housing stock.

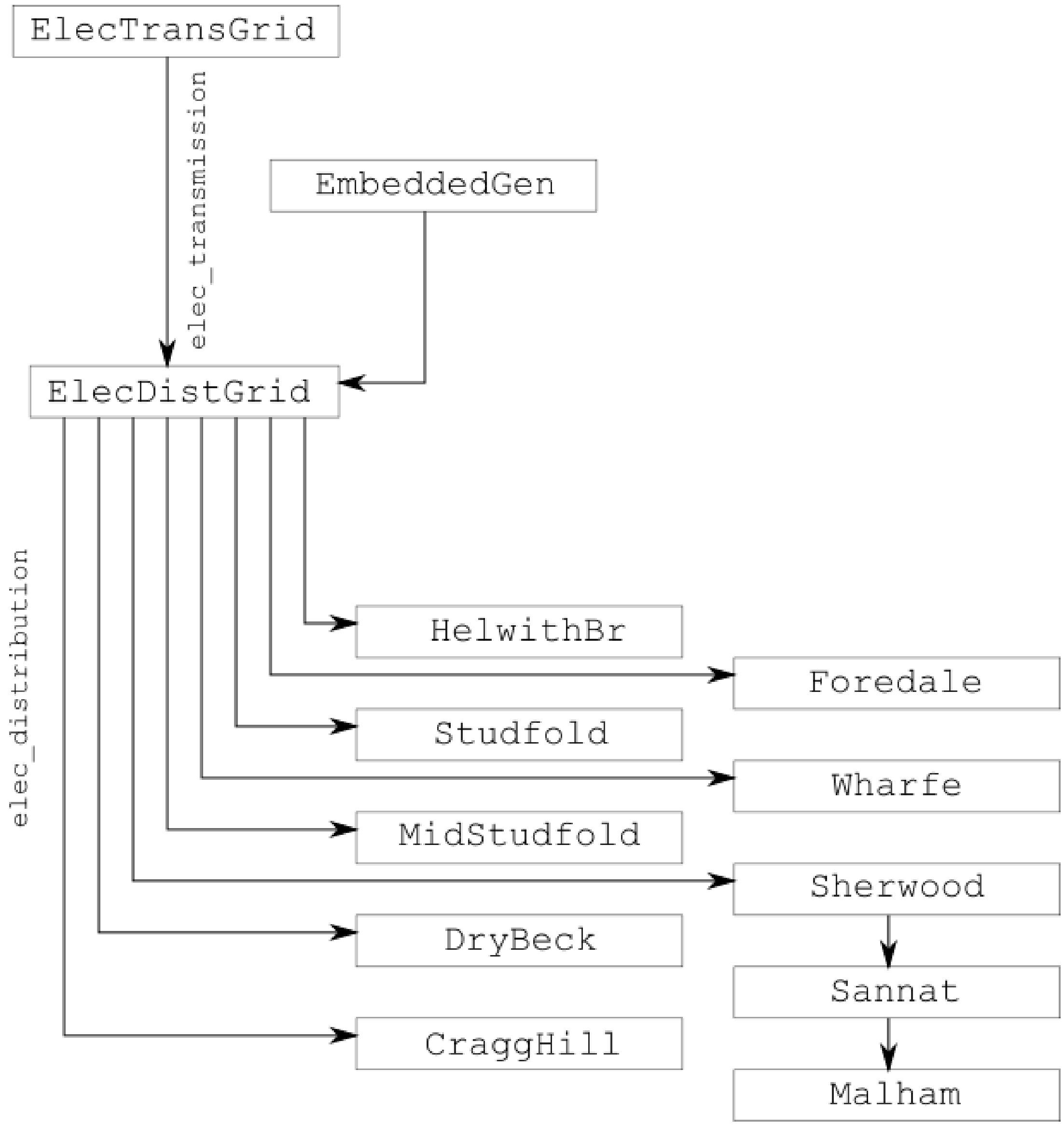

Figure 54 - Rural energy model topology

7.6.6 Modelled Scenarios

Due to the spatial diversity and low density of the model, options involving the implementation of a gas network are not modelled, nor a heat network. Instead the analyses focus on domestic scale technologies, including:

- Incorporation of solar panels and/or residual wind power;
- Electrical heat pumps (air-to-air, ground-to-water, high temperature);
- Reinforcement of the overhead electrical lines.

The line reinforcement cost is calculated from a per-unit-distance basis, with a pole-mounted transformer unit cost applied at the LV/MV interface, according to the costs given in Table 20.

Table 20 - Costs of new rural LV network components [139] – prices adjusted to 2016 equivalent

Component	Cost	Unit	Amount in model	Additional capacity (kVA)	Cost/kW capacity
6.6kV/11kV Pole-mounted transformer	£4,470	unit	1	100	£44.70
LV mains covered conductor	£40,975	km	13.41	696	£789.48
LV Link box	£2,442	unit	9	696	£31.58

The methodologies used are as per the suburban model.

District heating is not investigated due to the extremely high costs of heat pipe provision at the scale shown.

7.7 Urban Model

In this section, the Urban model is described. As the field of Urban Energy Systems Analysis is itself varied and complex (see Section 3.6), rather than attempt to characterise all urban systems within one archetype, instead a single option is selected which attempts to characterise the impacts of high-density residential zones, representing the extreme case. In reality, many urban households will occur somewhere on a continuum between high-density tower block housing and the suburban characterisation, and hence these models are chosen to 'book end' the variety of housing types seen in conurbations.

7.7.1 Overview

The urban model is based around two tower blocks in Sighthill, in the north of Glasgow: Croftbank St and Edgefauld Rd (latitude: 55.883, longitude: -4.225). These represent fairly typical UK high-density housing, with each block comprising 26 floors of 4 flats, totalling 208 properties. Both blocks date from the 1960s and were improved in 2008. As shown in Figure 55, the blocks are typical of urban construction with modern cladding.

7.7.2 Electricity Network

Figure 56 shows the local LV network from the 500kVA secondary transformer, with each of the blocks allocated to an individual feeder. For the purposes of this model, the remaining two feeders are not modelled, and the blocks are assumed to have a total of 50% of the transformer capacity allocated to their use.

7.7.3 Gas Network

Data was not made available for the gas network from the local DNO – however, the topology is assumed to conform to the electricity LV network shown above. Due to the very small length of low pressure gas network per household, this is not considered to have any significant impact on the model.

7.7.4 Energy Model Configuration

Figure 57 shows the model topology. This is broadly similar to the suburban case, with extant gas and electricity networks and a notional heat plant.

7.7.5 Scenarios

The urban model broadly carries a similar demand characterisation to the suburban model, albeit with scaled to a lower peak due to the relatively smaller size of the properties and lower occupancies. The higher density nature of the housing also means the thermal properties differ, and are generally more energy efficient. PV is not modelled due to the unavailability of roof space, and due to the urban location little opportunity is made to capitalise on residual wind power.

The base case of gas condensing boilers is defined in the same manner as for the suburban case, with the alternative scenarios modelled being the use of alternative gas sources, and the installation of a gas-powered CHP utilising either natural gas, biomethane or hydrogen.

Electrical reinforcement costs are assumed to be equivalent to the suburban case (based on the fact that similar cabling types are likely to be used) but a significant difference is that the per-household cable lengths are much shorter – approximately 3m, as opposed to 9m in the suburban model. Similarly the proposed heat network is assumed to have a similar length and cost reduction, which will have a more significant impact on total costs for the implementation of e.g. district CHP. As the tower blocks are surrounded by a significant area of empty land, it is assumed that there are no planning restrictions on the creation of a district heating scheme. Each tower block also includes a large utility space at ground level which could house containerised CHP.

Figure 55 - External view of tower block at Croftbank St, with Edgefauld Rd visible in the background

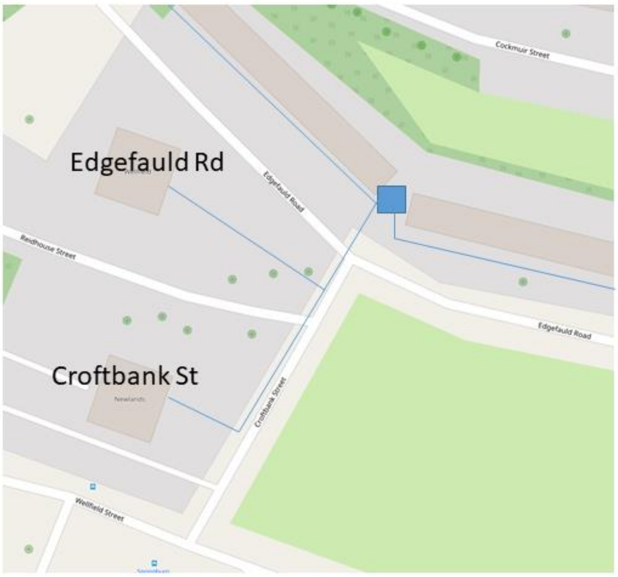

Figure 56 - Layout of urban model LV network, showing location of 500kVA transformer and 4 feeders (Underlying map © OpenStreetMap contributors, licenced under the Open Data Commons Open Database License https://www.openstreetmap.org/copyright [185])

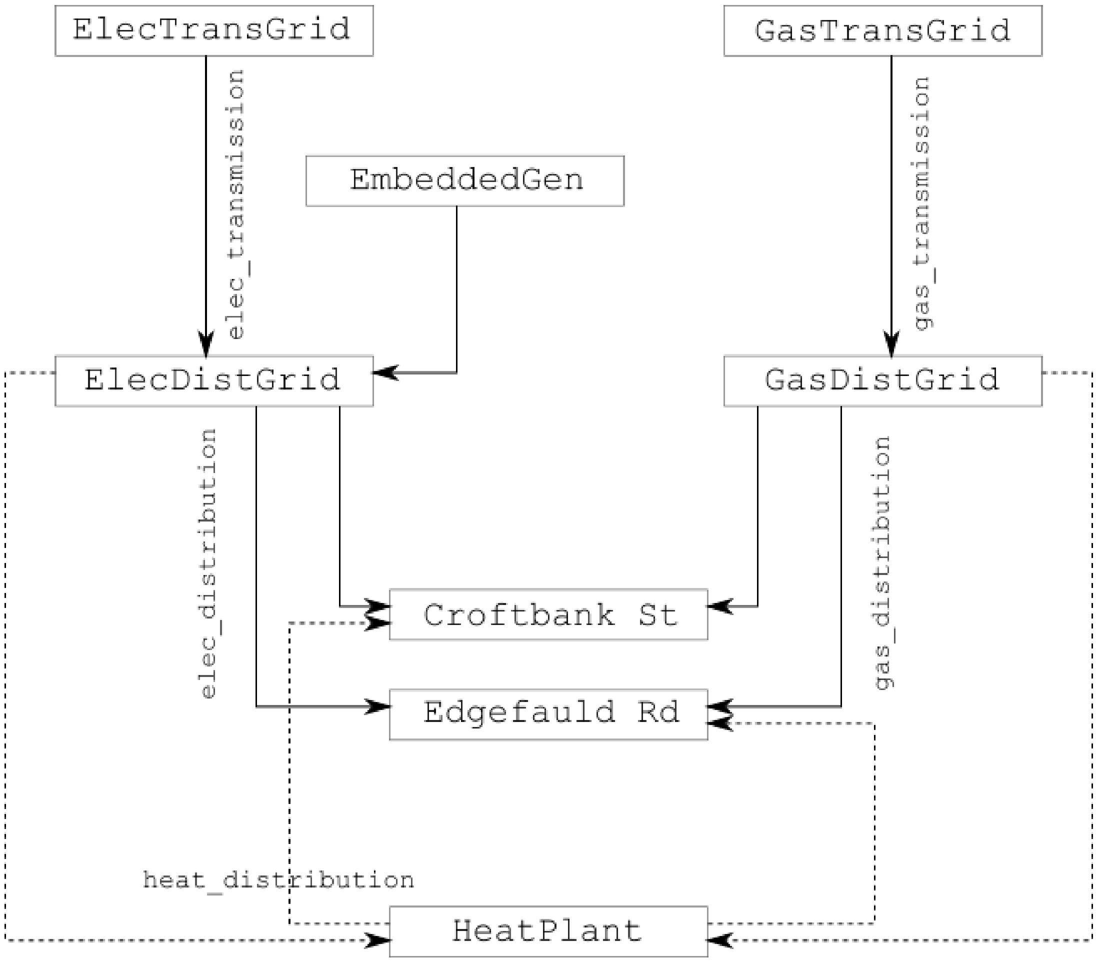

Figure 57 - Urban energy model topology

7.8 Discount Rate Selection

A variety of discount rates are used in energy systems models. These can be divided into two sets of values: *social* discount rates which represent the entire society and its awareness of environmental principles and economic growth, and *financial* discount rates which characterise the private investments which do not have a duty to consider social concerns such as welfare or sustainability [193]. In a normal financial appraisal, it is the latter that would be appropriate, but within energy systems analysing decarbonisation, a social discount rate may be more appropriate to represent true opportunity costs in a society seeking to reduce emissions. The UK Treasury Green Book [194] recommends the use of a the 'social time preference rate' (STPR) - the rate at which society values the present compared to the future – to give a standardised discount rate of 3.5%. This value is also used in UK TIMES to 2040 and 3.0% thereafter. For this reason, a social discount rate of 3.5% is also selected for the purpose of this study.

7.9 Sensitivity Analysis

For the purposes of conducting sensitivity analysis, for any numerical value with a relatively high degree of uncertainty, or large potential impact, 3 values are defined, relating to 'low', 'central' and 'high' costs respectively. The mapping of non-cost parameters to each of these is allocated in terms of cost impact; for example, the 3 values used for condensing boiler efficiency would be allocated in reverse, with the highest efficiency value mapping to the 'low' cost scenario. Values used are given in Chapter 5. These primarily relate to a) technology capital costs, evaluating the spread in cost reduction forecast for each technology according to current-day estimates; b) grid-side fuel costs (i.e. projected wholesale electricity and gas prices); and c) the emissions intensity of transmission-level electricity. The latter is of particular interest for scenarios where decarbonisation is reliant on electrification of end-use demands as an alternative to fossil fuels – if the electricity generated itself comes from fossil fuels, then little reduction in emissions intensity is actually achieved.

The sensitivity analyses are not combinatorial for different technology and fuel cost assumptions (both for monetary and emissions cost classes). That is, when a scenario which is at the minimum of its cost range is compared to other scenarios, *all* technologies and fuel costs, across all scenarios, are at the minimum of their cost ranges. Where figures are derived from the differences between scenarios (such as deriving the abatement cost of a technology compared to the base scenario), the case where the technology in question has minimum costs will only be compared to the base case which also has minimum costs, whereas the lowest abatement cost would be generated by contrasting the minimum cost of one technology to the maximum of another. This assumption is clearly valid for the case of fuel costs and emissions assumptions, as these will be extraneous to the technology choices – it would be logically inconsistent to compare the levelised cost of one technology using one set of extraneous assumptions to another using a different set. However, the additional assumption is made that cost reductions in technologies will be comparable across all low-carbon technologies, as opposed to being random and independent between technologies, and this has potential impact on the range of results presented.

8 Results of Exemplar Models

8.1 Overview

In this chapter, the results of the models and scenarios set out in the previous chapter are presented and discussed. The aim of this section is to derive for each particular technology selection for domestic heat provision (from those described in Chapter 5), applied to each local exemplar network (as described in Chapter 7) where viable, the Emissions Intensity (EI), Cost of Delivered Energy (DCOE) and Abatement Cost (AC) for supplying all demands (using the framework described in Chapter 6).

By comparing the three metrics for different technology selections, it is then possible to compare the potential value future trajectories for heat provision may have towards energy system decarbonisation, and to balance the costs and opportunities in network reinforcement, creation of new infrastructure, and the displacement of current carbon-intensive heating fuels.

The ordering used in this chapter is for each exemplar model to be interpreted in turn, examining multiple scenarios, before the combined results are compared in order to determine the implications for disaggregation of a Whole System model. The underlying cost assumptions between each model are identical (but adjusted for specific model spatial parameters such as distances between nodes), meaning that the results of each may be compared directly.

8.2 Suburban Model

As the model involving the most complete set of technology options, the suburban model is examined first in detail.

8.2.1 Base Case

The capacity and cost totals, for different gas price projections (see Section 5.4.1), are shown in Table 21. In total, the cost minimal solution sees 1986kW of condensing gas boiler capacity installed across the 4 feeders to meet peak heating and hot water demand, equating to an average of 6.8kW of boiler capacity per household.

For the case where each household has an individual condensing boiler with a capacity of 24kW, with a total installed capacity of 7008kW across all households, leads to the alternative results seen in Table 22 - the use of per-household sizing of boiler capacity negates any diversity effects and leads to (at a system level) significant overcapacity at substantial consumer cost.

Table 21 - Suburban Base Case, gas condensing boilers sized to aggregate feeder demand, total costs

Scenario	Base Low Gas	Base Central Gas	Base High Gas
Gas Price (p/kWh)	1.2969	2.1161	2.4574
Condensing Gas Boiler Capacity (kW)	1986	1986	1986
Total Fixed Costs	£ 50,974	£ 50,974	£ 50,974
Fuel Variable Costs	£ 104,691	£ 132,937	£ 144,705
Total Variable Costs	£ 104,691	£ 132,937	£ 144,705
Total Cost	£ 155,665	£ 183,911	£ 195,679
Average Annual Cost per household	**£ 533.10**	**£ 629.83**	**£ 670.13**

Table 22 - Suburban Base Case with individual 24kW condensing boilers, total Costs

Scenario	Base Low Gas	Base Central Gas	Base High Gas
Gas Price (p/kWh)	1.2969	2.1161	2.4574
Condensing Gas Boiler Capacity (kW)	7008	7008	7008
Total Fixed Costs	£ 179,846	£ 179,846	£ 179,846
Fuel Variable Costs	£ 104,691	£ 132,937	£ 144,705
Total Variable Costs	£ 104,691	£ 132,937	£ 144,705
Total Cost	£ 284,536	£ 312,783	£ 324,551
Average Annual Cost per household	**£ 974.44**	**£ 1,071.17**	**£ 1,111.48**

8.2.2 Heat Pumps

An example dispatch of an air-to-air heat pump across a 5 day period is shown in Figure 58. The heat pump is dispatched in preference to the condensing gas boiler, up to the limit of the local network net of non-heat electrical demand. The condensing gas boiler is then dispatched to in-fill at the morning and evening space heat demand peaks. The same dispatch is shown for the whole year in Figure 59, illustrating the relatively low utilisation of the condensing boiler outside of the winter season, with a correspondingly low annual load factor.

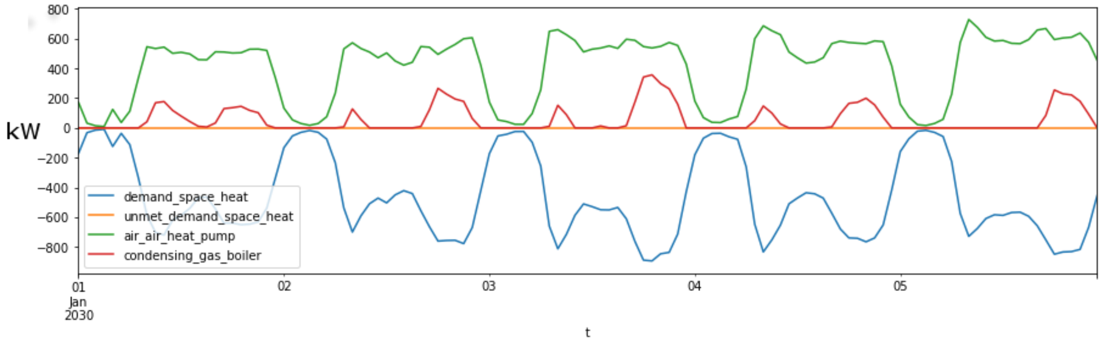

Figure 58 - Example dispatch across 5 days of air-to-air heat pump meeting space heat demand alongside condensing gas boiler for peak infilling

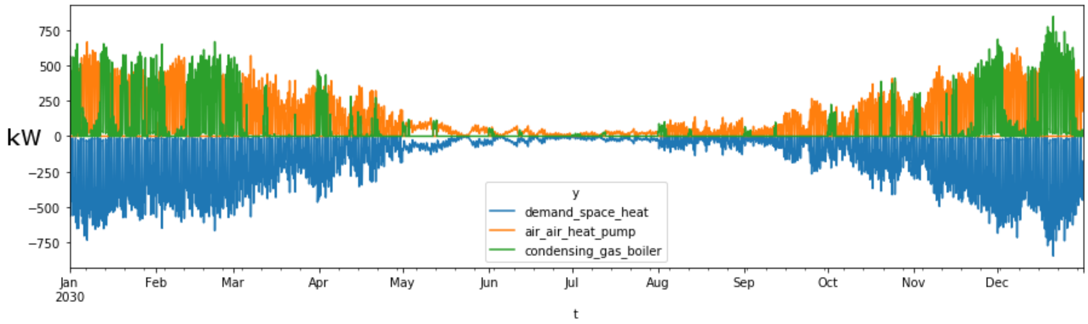

Figure 59 - Example dispatch of condensing boiler to infill across modelled year with air-to-air heat pumps, suburban model

For the different heat pump technologies, Table 23 and Figure 60 show the Delivered Cost of Energy, and Table 24 and Figure 61 show the Energy Intensity, with Table 25 and Figure 62 showing the final Abatement Cost for each heat pump technology against the base scenario involving gas condensing boilers.

The use of air-to-air source heat pumps marginally increases the DCOE against the use of condensing boilers only – this is because the heat pumps are unable to supply all demand, and in the case modelled this requires backup by gas boilers. As this results in an increase in fixed costs, the overall DCOE increases. The total impact will vary according to the capacity of technologies required in support – for example, if the constraint is not active with respect to space heating demand only, then a lower DCOE may be achieved if hot water demand is met through immersion heating, with no further peak infilling necessary. However, in the case given, this would be insufficient to meet all demand as the COP for air-to-air heat pumps is lower than for the high-temperature and ground source variants, so some support for space heating is also required.

However, the results show that electric heat pump technologies which may completely replace the gas boiler, and have a high COP, may lead to an overall reduced DCOE and reduced EI, leading to a negative abatement cost. This matches with the findings in Marginal Abatement Curves such as the UK McKinsey Curve [195] which lists domestic heat pumps as a potentially negative abatement cost technology. However, where electric heat pumps are in use, the EI values depend heavily on the emissions intensity of grid electricity, and the negative abatement cost will only be achieved if installation of heat pumps is matched by a progressive decarbonisation of electricity generation.

The gas heat pump makes only marginal gains by essentially improving the efficiency of burning gas – making a small reduction in variable costs and emissions efficiency. However, this also entails a significant increase in fixed costs, with a relatively unknown, high cost technology replacing a mature well-understood one. This means that the Abatement Cost for gas heat pumps is extremely high, around £31/kgCO_2, and not comparable to other heat pump technologies.

Note that the uncertainty bands for the abatement costs may be misleading – this is because the scenarios are defined jointly for electricity emissions intensity and electricity cost - i.e. the lowest emissions scenario is also the lowest cost scenario, which may not be the case if lower carbon transmission-connected generation is more expensive than higher intensity options. In subsequent abatement cost calculations, these are excluded. It is also noted that erroneous abatement costs may result when the formula is applied to scenarios which do not actively reduce emissions – a scenario with an increased Emissions Intensity but reduced Cost of Energy will appear to have a negative abatement cost, despite having zero abatement opportunity. This means that abatement costs must be interpreted alongside the capacity of abatement that option potentially carries.

Table 23 – Energy Intensity ($kgCO_2/kWhe$) by heat pump scenario, suburban model

	Cost case		
Scenario	**low**	**central**	**high**
base	0.1689	0.1951	0.2234
AAHP	0.0903	0.1327	0.1786
GHP	0.1407	0.1653	0.1921
GSHP	0.0645	0.1123	0.1637
HTHP	0.0524	0.0957	0.1426
HYBHP	0.0433	0.0680	0.0948

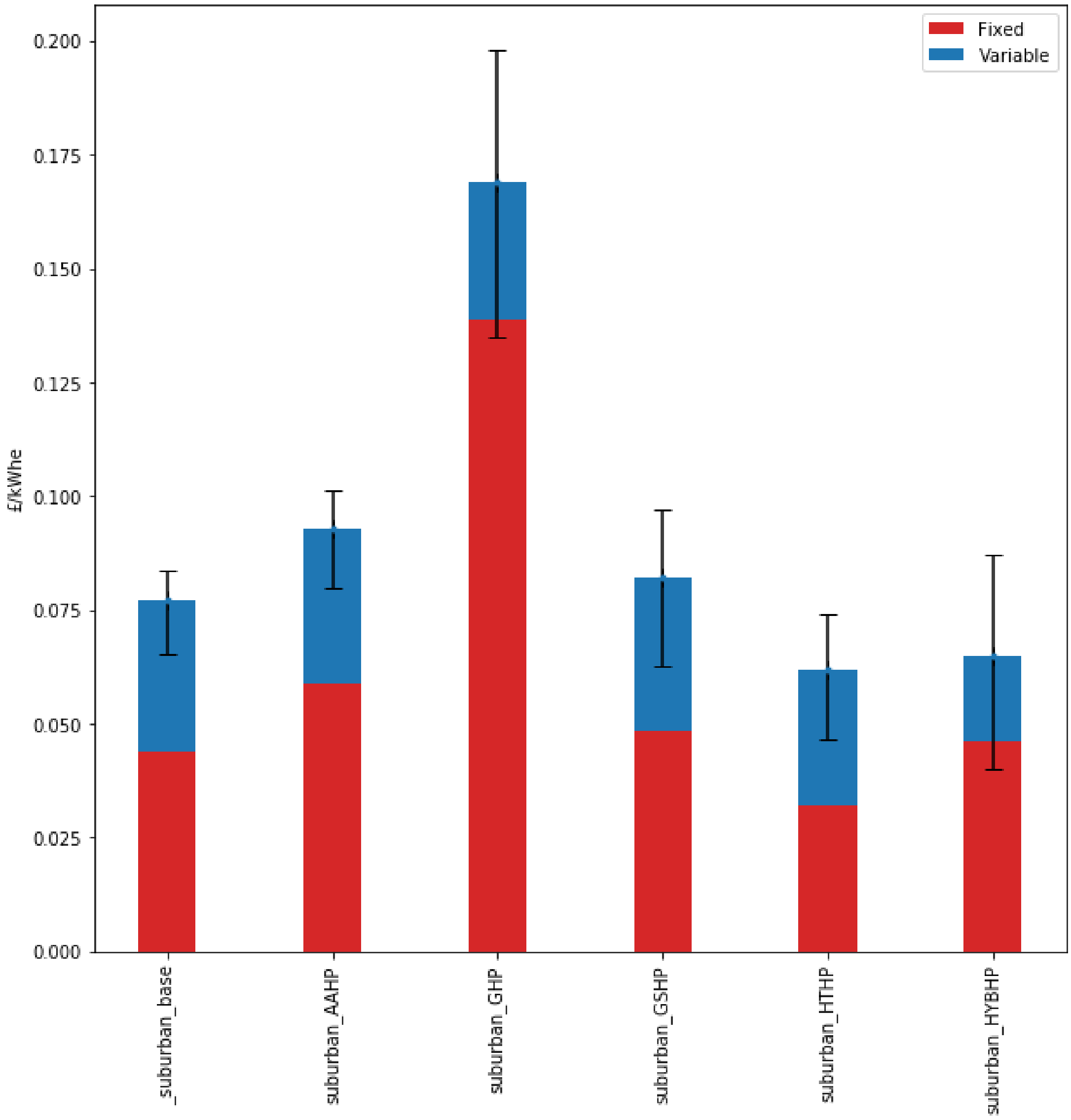

Figure 60 - Delivered Cost of Energy for different heat pump technology scenarios, suburban model. The total cost for the central scenario is shown, subdivided into fixed and variable costs, with the total cost range across the three cost scenarios shown.

Table 24 – Emissions Intensity ($kgCO_2/kWhe$) by heat pump scenario, suburban model

	Cost case		
Scenario	**low**	**central**	**high**
base	0.1689	0.1951	0.2234
AAHP	0.0903	0.1327	0.1786
GHP	0.1407	0.1653	0.1921
GSHP	0.0645	0.1123	0.1637
HTHP	0.0524	0.0957	0.1426
HYBHP	0.0433	0.0680	0.0948

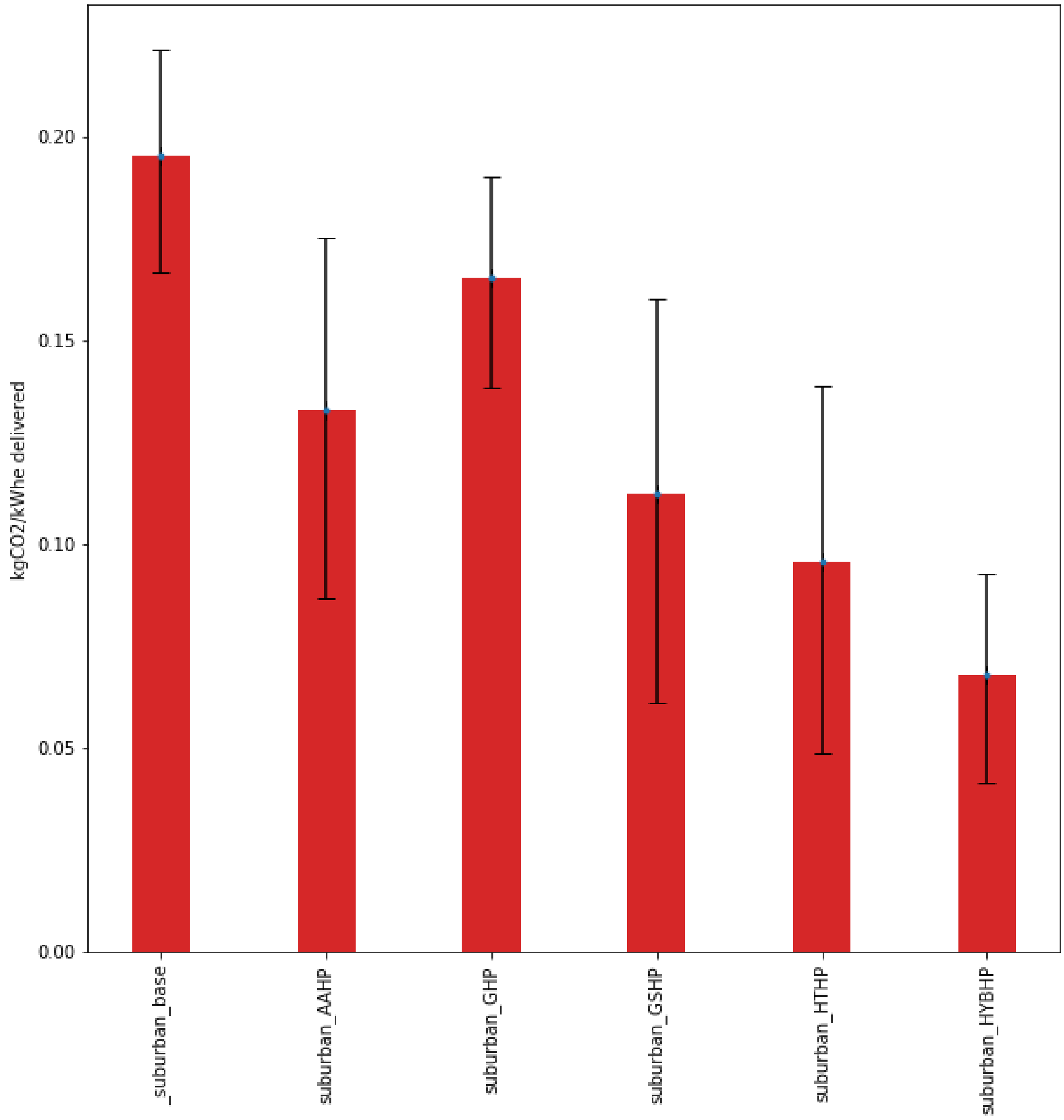

Figure 61 - Emissions Intensity for different heat pump technology scenarios, suburban model.

Table 25 - Abatement Costs (£/kgCO2) by heat pump technology compared to base scenario, suburban model

	Cost case		
Scenario	**low**	**central**	**high**
AAHP	0.2476	0.3934	0.1837
GHP	3.0801	3.6554	2.4630
GSHP	0.0614	0.2262	-0.0258
HTHP	-0.1535	-0.1176	-0.1596
HYBHP	-0.0979	0.0274	-0.2010

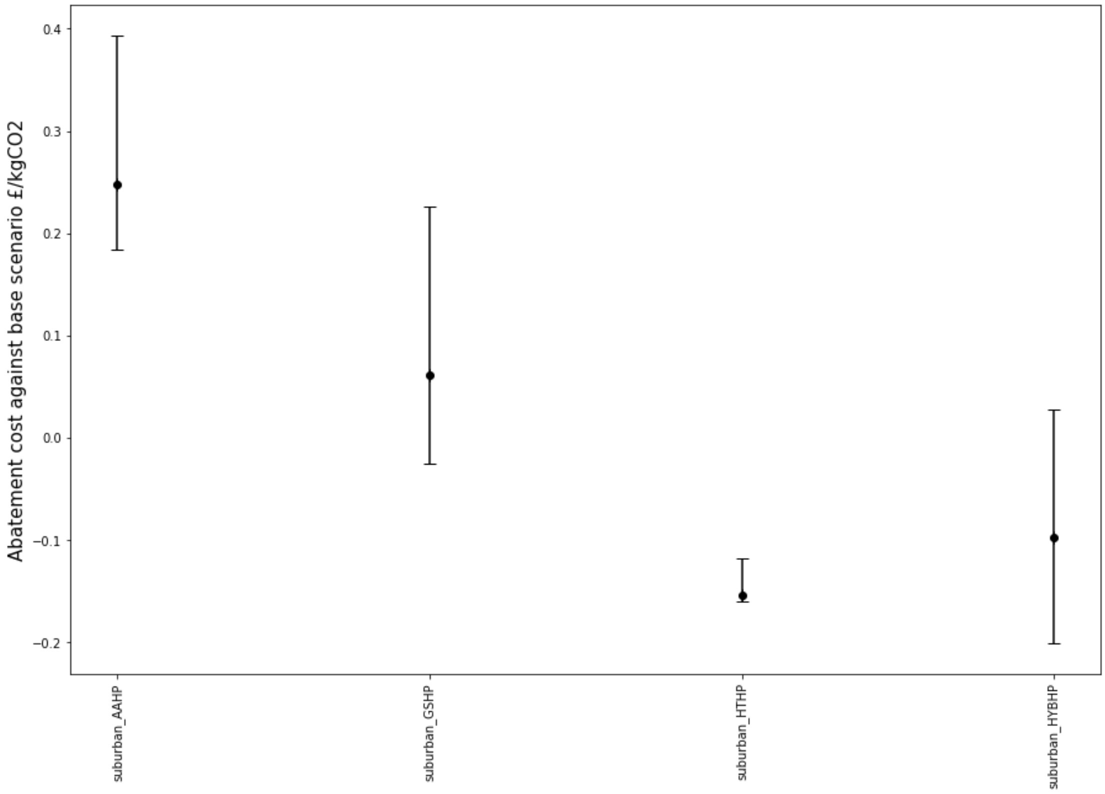

Figure 62 - Abatement costs for different heat pump scenarios, suburban case. Gas heat pumps are excluded with a figure of around 3.7 £/kgCO$_2$.

8.2.3 Incorporation of Local Renewables and Network Reinforcement

In order to illustrate the opportunity for utilising local renewables, in the form of photovoltaics and embedded wind power, additional scenarios were run for the case involving high-temperature heat pumps (as this represented the lowest abatement cost in the existing scenarios, due to the high COP values attained and the applicability to both space heating and hot water provision). In the previous case, the heat pump capacity is limited by the capacity of the LV network and secondary transformer. Additional scenarios are defined, with the heat pump capacity as a decision variable, for the following cases:

- With or without PV panels (up to the limit of the roof area as defined in Section 7.5.7) added;
- either alone or alongside embedded residual wind (as defined in Section 7.5.6).
- with or without LV network reinforcement to double the existing capacity (using the cost values defined in Section 7.5.9).

This creates 8 combinations: with/without PV; with/without residual wind; with/without network reinforcement. In order to include these variant scenarios within the model formulation, each was added as a distinct technology with capacities set to fixed values.

Figure 64 and Figure 66 show the different DCOE and EI values derived for the different scenarios, alongside the installed capacities of heat pumps and condensing gas boilers under an emissions minimisation objective. Under the base high-temperature heat pump scenario, the electrical network constraint only restricts utilisation for a small amount of time in the year, so the volume of condensing gas boiler capacity required is relatively low. Releasing this constraint via reinforcement increases the fixed costs by replacing this gas boiler capacity with significantly more expensive heat pump capacity, with a relatively low utilisation rate (seen in the minimal decrease in EI). Variable costs are very slightly reduced due to the gains in COP over burning gas at a sub-unity efficiency.

Addition of PV capacity has a marked impact on both the DCOE and EI, in permitting significantly more heat pump capacity to be installed and utilised. Due to the presence of a hot water storage tank, the heat pump capacity is maximised to take advantage of the mid-day peak in solar PV output, alongside relatively higher COP values due to higher temperatures. Again this causes a large increase in fixed costs, with a large reduction in EI due to the sourcing of zero-emissions electricity to power the heat pumps. In combination with network reinforcement the heat pump capacity is further increased to take greater advantage of the timing of this zero-emissions electricity by utilising the hot water store. Similar effects occur under the provision of residual wind – the zero-emissions electricity made available equals a significant opportunity in the least-emissions model, and so heat pump capacity is sized to take as much advantage as possible of this opportunity in combination with the hot water storage. As the residual wind energy is external to the LV distribution network, the extent to which this can be utilised is, unlike the PV, dependent on additional transformer and LV feeder capacity.

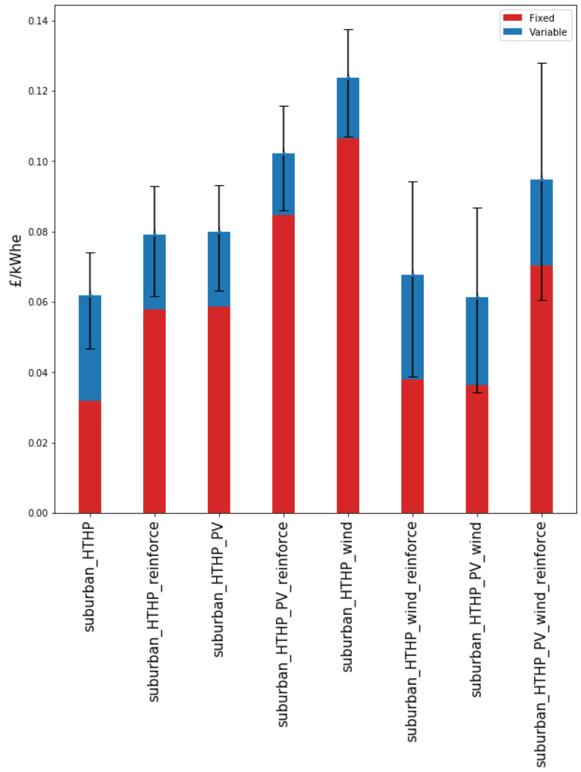

Figure 63 - DCOEs for renewables and reinforcement options, based on high-temperature heat pump usage

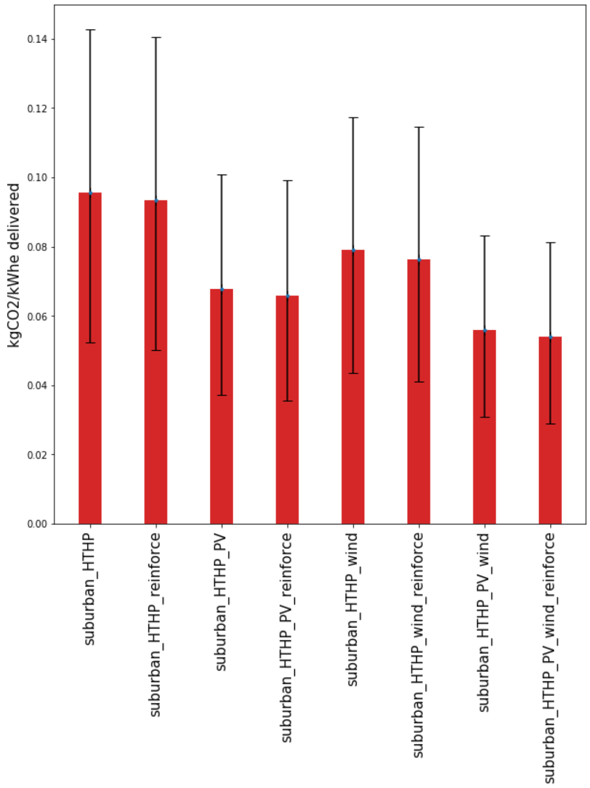

Figure 64 - EIs for renewables and reinforcement options, based on high-temperature heat pump usage

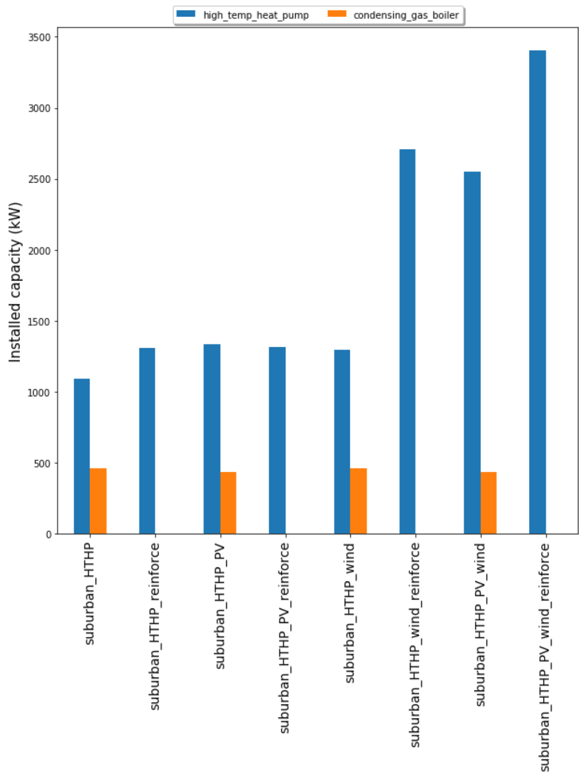

Figure 65 - Installed capacities (for decision variable technologies) by technology, suburban model, high-temperature heat pump scenarios

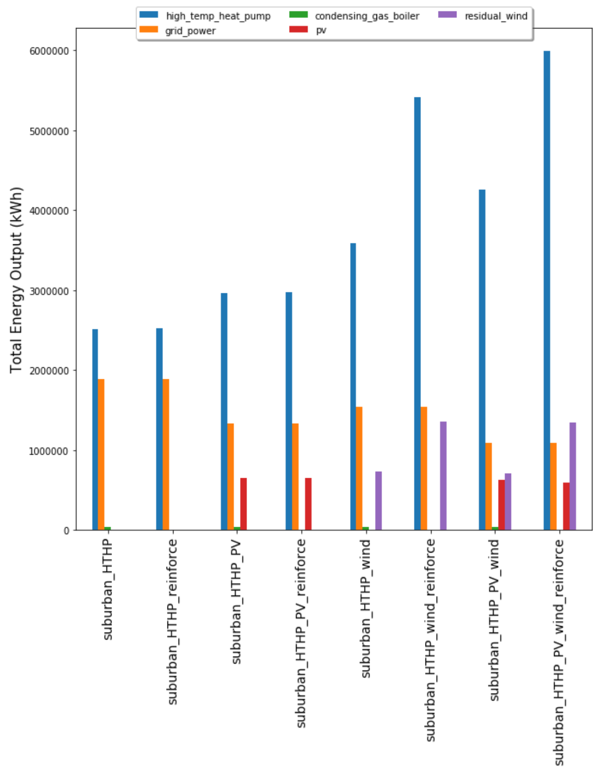

Figure 66 - Energy production by technology, suburban model, high-temperature heat pump scenarios

8.2.4 Thermal Storage

In order to investigate the potential impact of a generic thermal storage technology, a space heat store of increasing size was added to the scenario including air-to-air heat pumps. The technology was idealised, with the ability to fully charge and discharge within 30 minutes, and with a per-hour storage loss rate of 10%, and an each-way efficiency of 95%. The main impact is that this permits the heat pumps to operate during periods of low demand, with the stored heat then contributing to meeting peak space heat demand when the network transfer constraint might otherwise prevent the heat pumps from meeting demand, and requiring in-filling by gas.

Figure 67 illustrates the dispatch of thermal stores across the suburban network under the objective of emissions minimisation – as the per-unit emissions associated with electricity are lower than for gas, utilisation of heat pumps is maximised up to the net constraint of the LV network, with gas in-filling to meet morning and evening peaks.

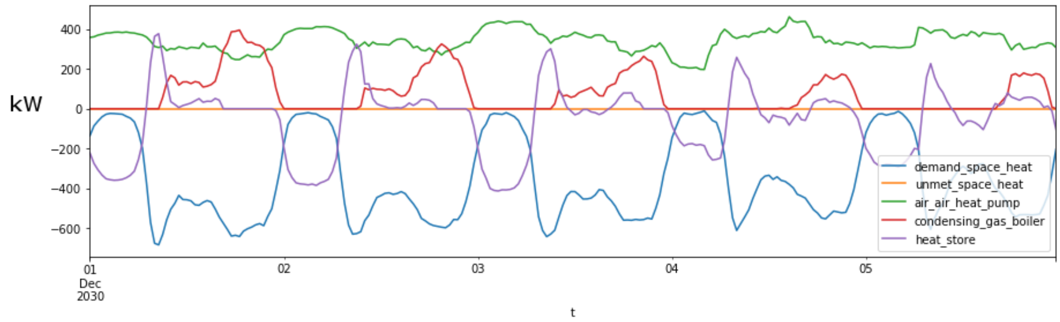

Figure 67 - 5 day winter period showing dispatch of thermal store under minimum emissions objective, maximising utilisation of heat pump

In Figure 68, the diminishing returns (in terms of gains in utilisation) for heat pumps with increasing heat storage installation is shown. This indicates that where there is a binding constraints, there are significant gains in heat pump utilisation to be made for a relatively modest volume of space heating storage, but that this benefit rapidly reduces beyond the point at which it is required on a daily basis, to a point where all gas in-filling is redundant. However, the model currently has a time-invariant cost of electricity – if the owner of the household were exposed to the wholesale electricity price, or was offering a service to someone who was exposed to time-variant prices (such as a Distribution System Operator seeking to locally balance a network), then there may be further gains made by being able to charge the thermal store during periods of cheaper energy.

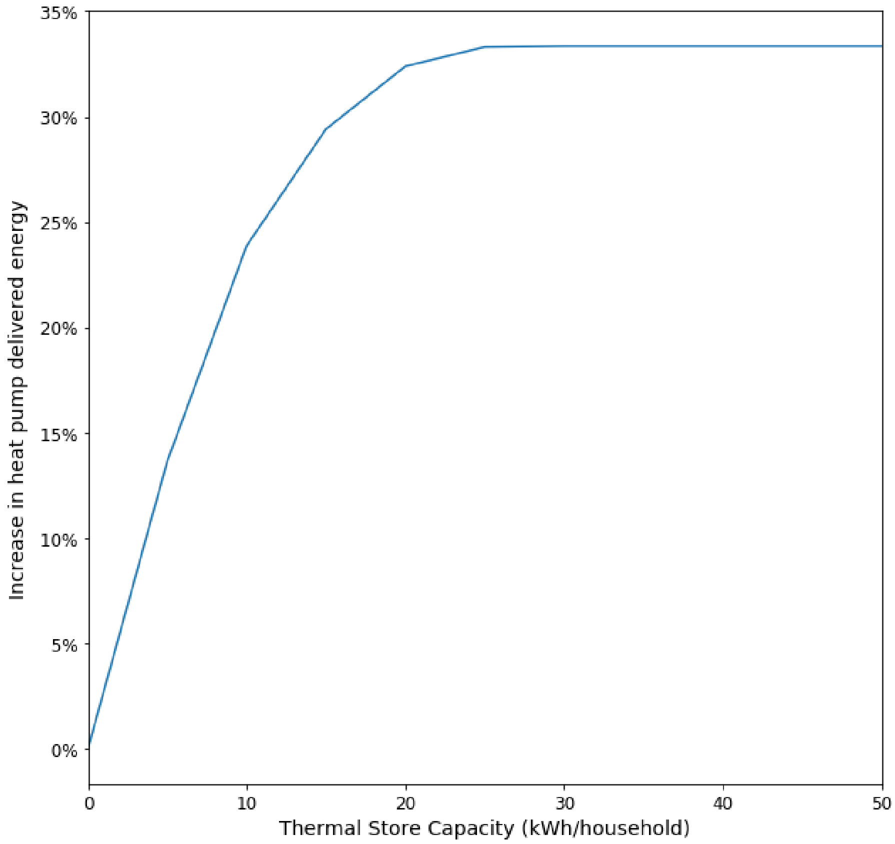

Figure 68 - Decreasing returns in heat pump utilisation from thermal store capacity

8.2.5 Alternative Gases

In order to assess the range of abatement costs for different alternative gases (biomethane and hydrogen), the gas condensing boiler scenario was re-run with the costs and emission intensities of those gases as given in Table 4. The resulting DCOE and EI values are given in Figure 69 and Figure 70. This shows that the goal of decarbonising heat provision through the reduction of the emissions intensity of the gas grid is successful, albeit at significant cost. It is also noted that the uncertainty ranges are extremely high, due to the wide range in cost and emissions estimates for different gas grid decarbonisation scenarios, as listed in Section 5.2.5. This makes the abatement potential of gas grid decarbonisation very difficult to determine in comparison to other options. However, the local implementation costs of switchover to hydrogen in low-pressure networks (assuming iron mains replacement has taken places) means that there is little difference in total capital cost between different local options, and the main variant is the per-unit fuel cost. It is also noted that under some assumptions, the emissions intensity of alternative gases may be higher than for natural gas, dependent on the mechanism of gas production.

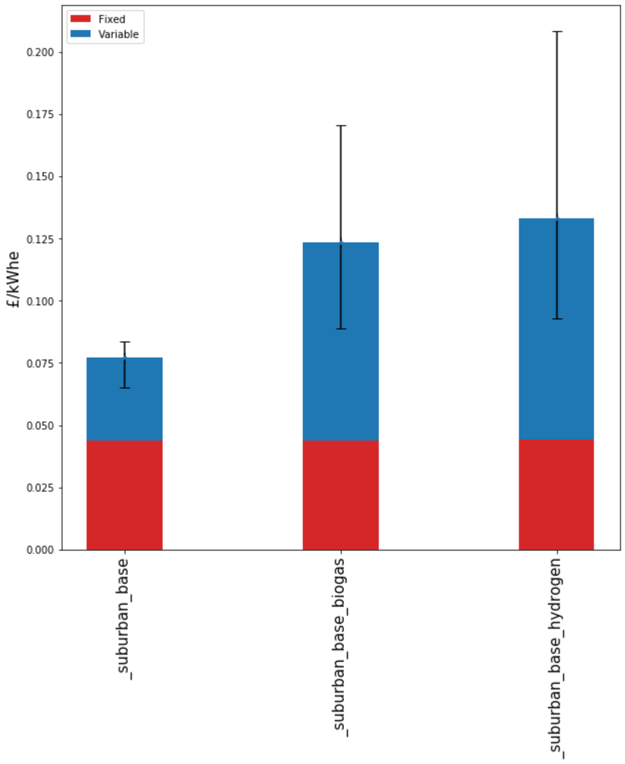

Figure 69 - DCOE for natural gas, biomethane and hydrogen, suburban model, using gas condensing boilers (incorporating household conversion costs for hydrogen)

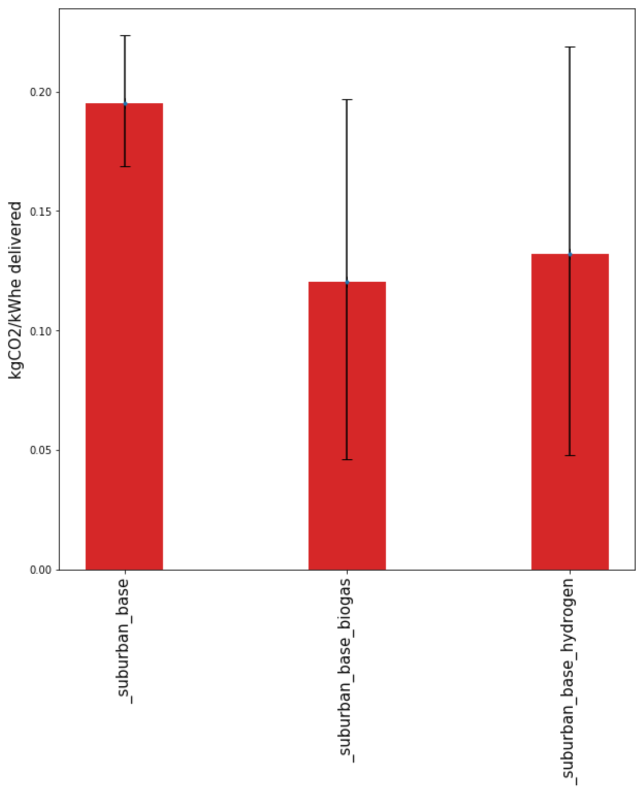

Figure 70 - EIs for natural gas, biomethane and hydrogen, suburban model, using gas condensing boilers (incorporating household conversion costs for hydrogen)

8.2.6 District Heating

The DCOEs and EIs for the 3 forms of district CHP are given in Figure 71 and Figure 72. The implementation of a CHP system leads to an increase in fixed costs due to the cost of heat pipes. There is also a significant impact due to the losses in heat storage and transport, meaning that the volume of energy consumed per unit heat delivered is much greater than for individual condensing boilers, as well as small-scale OCGT having a lower thermal efficiency. This means that the variable costs are significantly higher than for the base scenario, and where combined with the higher projected costs of alternative gases, leads to a potentially very high cost of energy. As with the previous section, these values are subject to a high degree of uncertainty due to the wide range of costs and emissions intensities for different sources of alternative gases.

The reduced emissions intensity (under some scenarios) of alternative gases means that even when the reduced efficiency of the district heating system is taken into account, the overall emissions intensity of heat delivery may be reduced, providing abatement potential, but at a likely high cost, providing perhaps limited potential to contribute to national emissions abatement. Alternatively, this points towards a strong need to improve the efficiency of district heating systems as much as possible, which can be achieved in a number of ways:

- Increased scale, with larger stores and heat pipe throughput reducing per-unit losses;
- Higher efficiency CHP plant, such as through heat recapture or e.g. Stirling Engines;
- Priority application to higher density locations with lower network distances;
- Integration with non-gas fuel sources, such as waste heat, biomass or agricultural/industrial waste.

This supports the idea that district heating cannot be applied in a ‘one size fits all’ manner, and must be closely designed to the needs and opportunities of a particular local system. The results presented here should not be taken to suggest that district heat cannot contribute to national decarbonisation, nor the reduction in the cost of heating. This is shown in other markets such as Denmark where its use is more common, but with cost reduction primarily achieved in a commercial manner through the creation of municipal energy companies which may source fuels at a lower cost than the assumed averaged grid price used here.

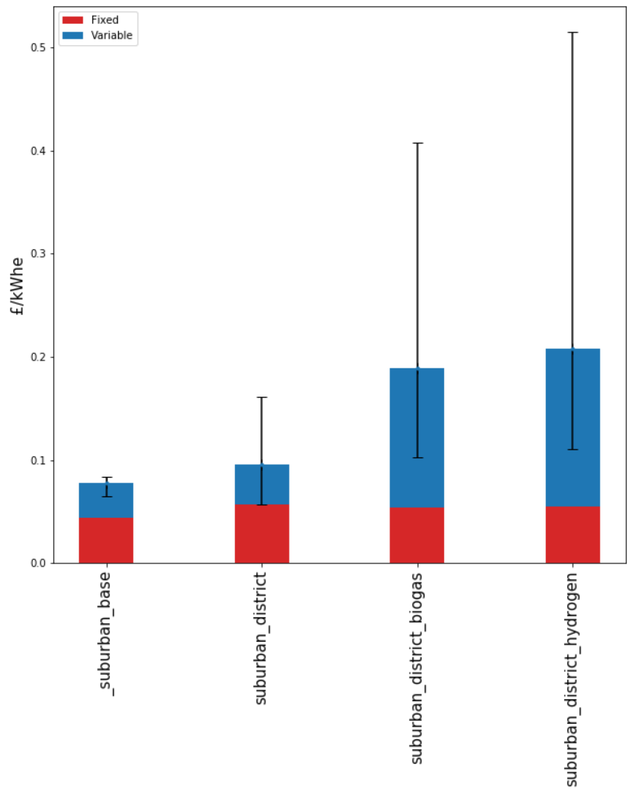

Figure 71 - DCOEs for district CHP using natural gas, biomethane and hydrogen, suburban model

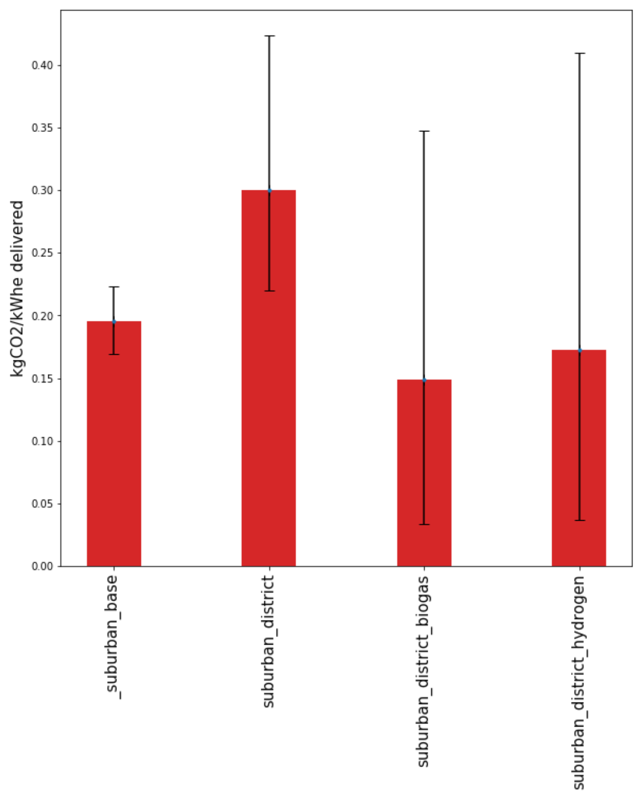

Figure 72 - EIs for district CHP using natural gas, biomethane and hydrogen, suburban model

8.2.7 Abatement Costs

Using the central cost scenarios, the final abatement costs for different scenarios are presented in Table 26.

No abatement cost is given for the district CHP case using natural gas, as this increases emissions above the base scenario. The PV/wind/reinforcement cases are only analysed where high temperature heat pumps are in use (representing the most optimistic technology from the previous heat pump analysis) and are not included for other scenarios. Similarly, use of alternative gases are only listed for condensing boiler and CHP use.

The results indicate that, within suburban systems, network costs are a strong constraint on the potential for decarbonisation. The abatement cost for high temperature heat pumps is lower for their installation in isolation than for their joint implementation with other technologies such as PV, residual wind and/or network reinforcement. However, it is noted that the abatement costs for those additional technologies are not significantly different. This means that while heat pumps in isolation represent a negative cost opportunity, the actual volume of total abatement which may be achieved will be limited by the networks, and that reinforcement of the LV system, alongside incorporation of renewables, exists as a secondary option. This might be viewed as analogous to the insight provided by a Marginal Abatement Cost Curve, where the negative abatement cost shown by heat pumps demonstrates an early priority, with the further technologies further along the investment cycle, but still capable of providing significant progress towards a total decarbonisation target. This is analysed further in Chapter 9.

Table 26 - Abatement costs for different technology scenarios, suburban model

	Scenario					Average Abatement Cost compared to Base Scenario (£/kgCO$_2$)
End Use Technology	**PV**	**Wind**	**Reinforcement**	**Biogas**	**Hydrogen**	
High Temperature Heat Pump	-	-	-	-	-	-0.154
Hybrid Heat Pump	No	No	No	-	-	-0.100
Ground-to-water Heat Pump	-	-	-	-	-	0.061
High Temperature Heat Pump	No	Yes	No	-	-	0.061
High Temperature Heat Pump	No	No	Yes	-	-	0.068
High Temperature Heat Pump	Yes	No	No	-	-	0.079
High Temperature Heat Pump	Yes	No	Yes	-	-	0.080
High Temperature Heat Pump	No	Yes	Yes	-	-	0.095
High Temperature Heat Pump	Yes	Yes	No	-	-	0.102
High Temperature Heat Pump	Yes	Yes	Yes	-	-	0.124
Air-air Heat Pump	-	-	-	-	-	0.248
Condensing Gas Boiler	-	-	-	Yes	No	0.617
Condensing Gas Boiler	-	-	-	No	Yes	0.882
District CHP	-	-	-	Yes	No	2.431
Gas Heat Pump	-	-	-	-	-	3.080
District CHP	-	-	-	No	Yes	5.811
District CHP	-	-	-	No	No	-

8.2.8 Cost-Optimal Solution

The above cases have broadly involved pre-defining proportions of end-use technologies, and dispatching based on a minimum emissions objective function, which implies a fixed merit order according to the carbon intensity of the fuel consumed: zero emissions electricity (wind/PV), low-carbon gases, grid electricity, natural gas. In cases where optimal sizing is included, this has been defined on the basis of similarly maximising the utilisation of each fuel in turn. However, this does not equate to an economic case, as this implies that capacity will be invested in even where the expected number of operating hours for the additional capacity is very small: an additional 1kW of heat pump capacity will be invested in even if it only displaces 1kWh of gas through the year.

In order to understand the impact of costs, the model was set to full planning mode (i.e. the capacities of all technologies are decision variables) and optimised to least cost across the full year dispatch, including the depreciated capital cost of each technology. This delivered one of three options, depending on the cost scenario:

- Under the ‘central’ cost scenario, high temperature heat pumps were installed alongside hot water storage and the electricity network reinforced to be able to meet peak demand without any requirement for infilling. Thermal storage was not included.
- Under the ‘low’ cost scenario, hybrid boilers were selected as able to utilise electricity at high COP values, up to the binding level of the network constraint, with gas burned to infill.
- Under the ‘high’ cost scenario, the status quo of gas condensing boilers was maintained. This is primarily due to the low uncertainty in cost compared to lower carbon selections.

Clearly, the exact choice of least cost scenario will depend highly on the relative cost of each technology, and the lack of combinatorial analysis on prices disguises this. However, this does clearly indicate that the cost-optimal solution will depend strongly on relatively unknown factors, and that the unpredictable nature of future costs dominate. Note that this does not take emissions into account as there is no emissions component to the objective – a further development to the model would be to explore an implied cost per emissions class (e.g. a carbon tax) in order to appropriately balance the dual objectives of cost and decarbonisation.

8.2.9 Impact on Energy System Actors

One implication of the difference scenarios presented is that different energy system actors will undergo differing cash flows under the proposed arrangements. In order to summarise this, the depreciated capital costs and fuel costs are aggregated by system actor responsible for each technology, and this is summarised in Figure 73 for a selected subset of scenarios previously analysed. While this is primarily a local view of cash flows (so in keeping with the rest of the analysis, does not evaluate deeper reinforcement costs), it illustrates clearly the significant differences that occur.

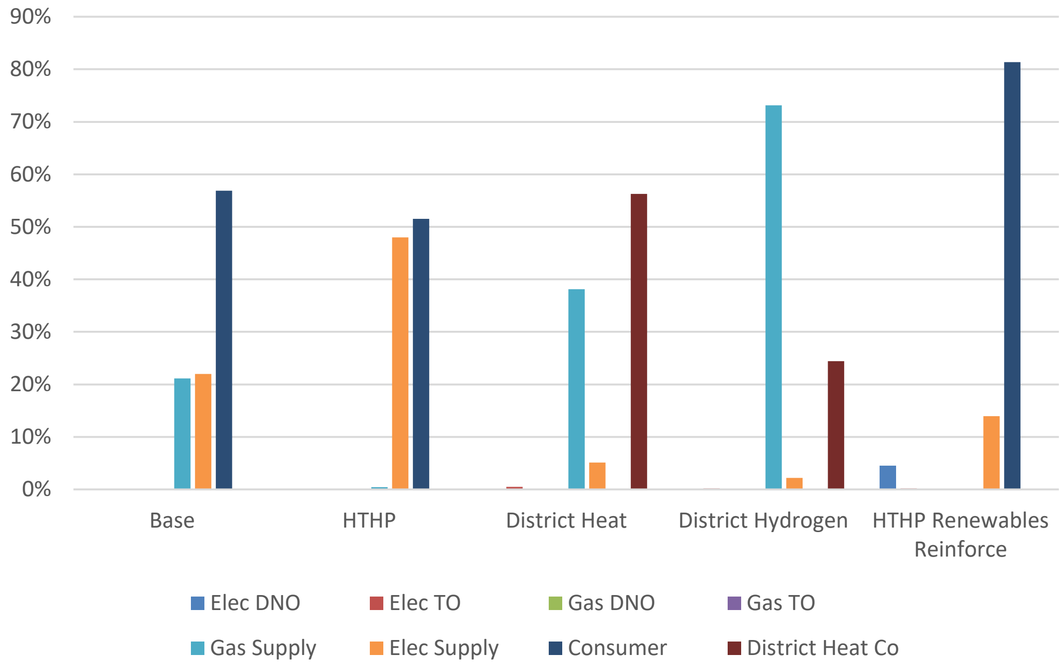

Figure 73 - Proportion of total cash flow by system actor, key scenarios, suburban model

This has several implications. Firstly, where the DCOE calculated previously represents a cost saving when accounted across the local energy system, this may represent a cost increase to particular actors. For example, the scenario where increased capacity of high-temperature heat pumps is facilitated through network reinforcement and integration with renewables requires significantly increased expenditure from consumers – in other words, householders must spend proportionally more in order to realise a lower level of emissions. This makes the case that such reductions in carbon emissions can only be realised through financial incentives to the homeowner (such as via the Renewable Heat Incentive).

Secondly, this change in cash flows means that the business case of different incumbent actors may be significantly affected. For example, the revenue of gas suppliers will significantly decline under scenarios with a high penetration of heat pumps, where electricity utilisation displaces gas. In other cases, such as district heating, entirely new actors may come into play. This represents the problem of incumbency, and the changes that must be enacted at a policy level to enable new business cases to displace existing ones. This has diverse impacts on the wider economy, with businesses and jobs being displaced. Businesses are not, however, likely to be passive bystanders to the heat transformation, and will interact with the transition through their investment and innovation behaviour [196]. Many energy businesses, particularly in the supply side, are large and influential companies and may seek to direct the transition towards policies which will benefit them – for example, gas network companies are keen to promote alternative gases as this means ongoing utilisation of their assets into the future.

8.3 Rural Model

Within the rural model, the base case of oil condensing boilers has a significantly higher cost of delivered energy than for the suburban case of gas condensing boilers, purely as a result of increased fuel cost. This means that in off-gas-grid locations, the implementation of heat pumps can lead to a proportionally greater cost saving. This is indicated by the DCOEs of the different heat pump options modelled shown in Figure 74. In keeping with the findings of the suburban model, heat pump options which may supply both space heat and hot water carry a lower DCOE than air-to-air heat pumps, which require additional hot water heating capacity to be installed alongside. This makes ground source heat pumps and high temperature heat pumps the preferred cost options, but with all cases carrying relatively high cost uncertainties.

However, due to the relatively high emissions intensity of heating fuel oil, in comparison to natural gas, the emissions savings (shown in Figure 75) of heat pumps are significant, with low-intensity electricity having the potential to make significant emissions reduction in rural systems.

Investigating the combined impact of other electrical systems – PV panels and residual wind energy – with high temperature heat pumps (again representing the heat pump technology with the greatest potential) results in the DCOEs and EIs shown in Figure 76 and Figure 77 respectively. The electrical network connections in the rural LV network are relatively low capacity compared to distribution systems in more populous areas, with a small transformer value and line ratings, accompanied by decreased diversity due to the reduced number of properties in the system. This means that the system is more highly constrained in the capacity of heat pumps it may accommodate. Again, reinforcement of the LV network and introduction of solar PV leads to further emissions reduction, but an increased cost of energy due to the additional fixed costs from further installation of heat pump capacity. Significant cost savings can be introduced by the use of residual wind, but this is primarily constrained by the capacity of the secondary transformer, and cannot be capitalised on without reinforcement or the use of PV to reduce flows through the secondary transformer by meeting demand locally.

Table 27 lists the abatement costs of different options against the base scenario of oil condensing boilers. The high cost and emissions of heating fuel oil mean that almost all options studied carry a negative abatement cost. The lowest abatement cost comes under the scenario where high temperature heat pumps are used in combination with network reinforcement, increasing the capacity of heat pumps that may be utilised and allowing maximum utilisation of residual wind energy.

In order to permit this local use of constrained wind energy, some form of Demand-Side Management (DSM) is required, as described in Section 5.6. At a technical level, this could be enacted by the Distribution Network / System Operator (DNO/DSO), dispatching local heat resources according to the monitored level of wind output on the network, or through scheduling according to a forecast of output. At a commercial level, the wind operator (or a representative thereof) could establish a local supply company providing a lower cost tariff to local residents under a form of community energy scheme. An aggregator could provide mediation for both technical and commercial services in order to minimise the technical and administrative overhead for residents.

Scenario				**Average Abatement Cost compared to Base Scenario (£/kgCO_2)**
End Use Technology	**PV**	**Wind**	**Reinforcement**	
High Temperature Heat Pump	-	Yes	Yes	-0.203
High Temperature Heat Pump	-	-	Yes	-0.195
High Temperature Heat Pump	-	Yes	-	-0.190
High Temperature Heat Pump	-	-	-	-0.183
High Temperature Heat Pump	Yes	-	Yes	-0.091
High Temperature Heat Pump	Yes	Yes	-	-0.086
High Temperature Heat Pump	Yes	Yes	Yes	-0.086
High Temperature Heat Pump	Yes	-	-	-0.077
Ground-to-water Heat Pump	-	-	-	-0.052
Air-air Heat Pump	-	-	-	0.054

Table 27 - Abatement costs for different technology scenarios against base scenario, rural model, central assumptions

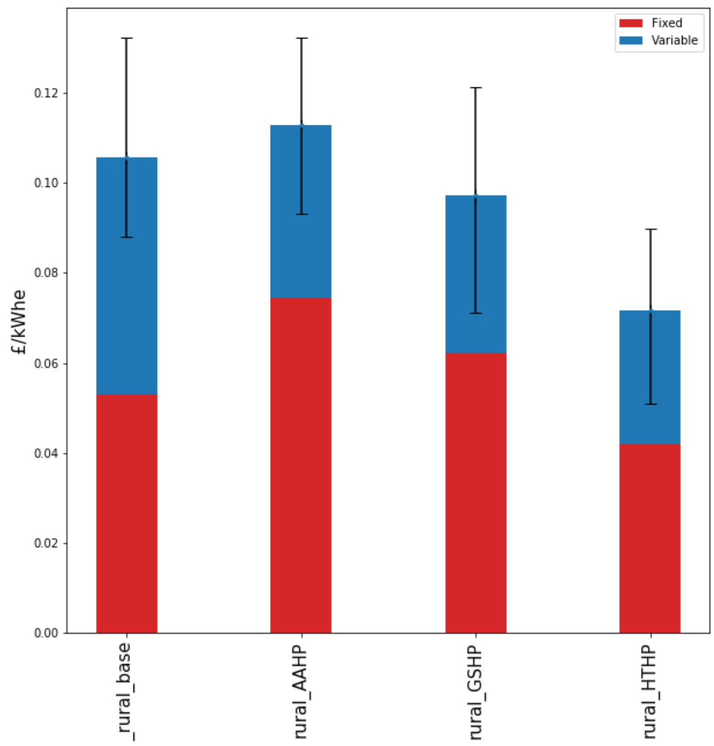

Figure 74 - DCOEs for different heat pumps against base scenario, rural model

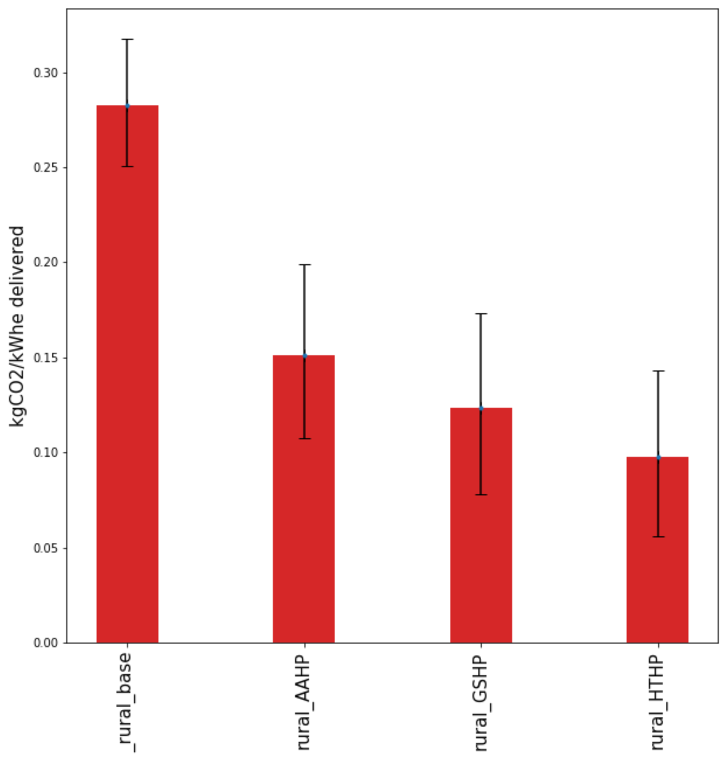

Figure 75 - EIs for different heat pumps against base scenario, rural model

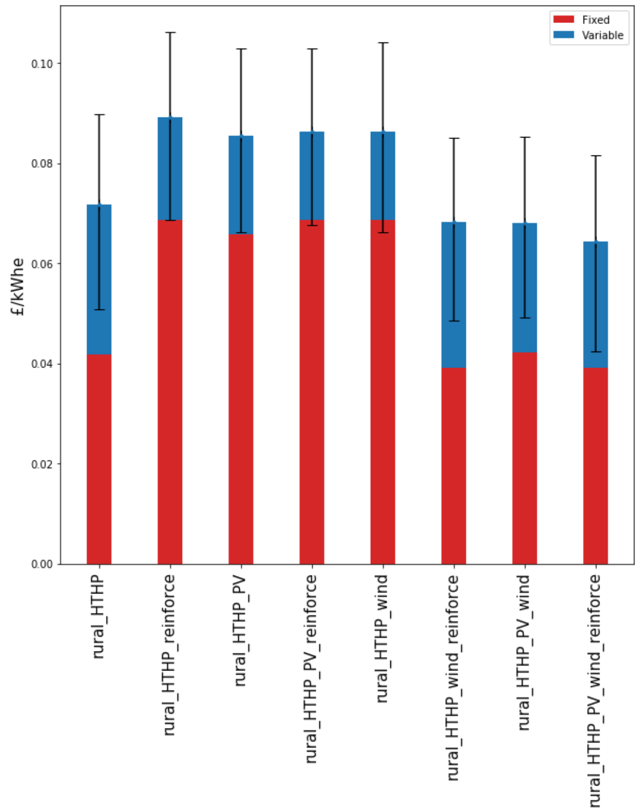

Figure 76 - DCOEs for renewable/reinforcement scenarios using high temp heat pumps, rural model

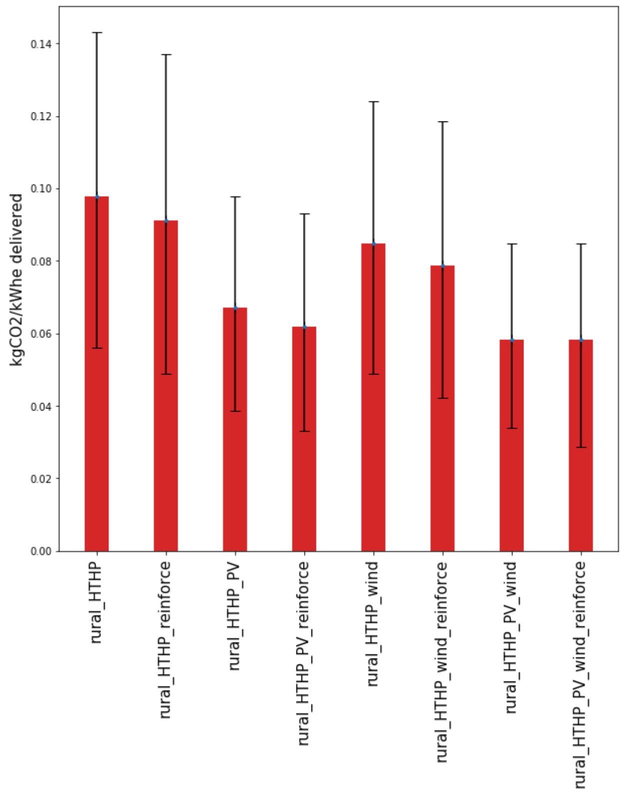

Figure 77 - EIs for renewable and reinforcement scenarios using high temp heat pumps, rural model

8.4 Urban Model

The DCOEs and EIs for the urban model scenarios are given in Figure 78 and Figure 79 respectively, including the base scenario of gas condensing boilers, alongside alternative gas options and a district CHP again including alternative gas options.

The district heat system using natural gas sees a significant reduction in delivered cost as compared to the suburban case - this is due to the lower capital costs involved in heat network investment, as a result of much lower pipe lengths. In addition, the gas boiler sizing for the urban and suburban cases is the same, which in the urban case leads to a greater overcapacity when considering reduced absolute energy consumption in the higher-density, more energy efficient, and lower occupancy urban case. However, as with the suburban case, the emissions intensity of a natural gas CHP is increased due to lower efficiency, and so this does not represent a viable decarbonisation option.

The results for displacement of natural gas with alternative gases again follows the pattern of the suburban case – increasing cost across multiple scenarios, but significantly reducing emissions, all subject to a wide range of uncertainty. This makes the case that in higher density urban locations district heating is likely to be a key decarbonisation option, but is highly dependent on decarbonisation of the gas grid, again requiring joint planning of future scenarios in both energy supply and demand.

Table 28 lists the abatement costs for the different urban scenarios against the base scenario. It is noted that none of these are negative – it is unlikely that any of the scenarios would be undertaken without significant incentives, and that the abatement values are higher than for other models. However, this again depends highly on the cost and emissions uncertainties underpinning these scenarios. One further note, in the case of district heating, is that relatively short depreciation terms are used for heat network elements, and if the expected lifetime of such elements can be better known and extended, then this would reduce the proportionate cost of capital. However, fuel costs remain the primary component of the delivered cost of energy.

It is worth highlighting the case that district heating does not necessarily equate to carbon reduction, and as demonstrated here, may have a negative emissions impact, in contrary to what is often assumed by policymakers – local provision of heat is not necessarily more environmentally-friendly.

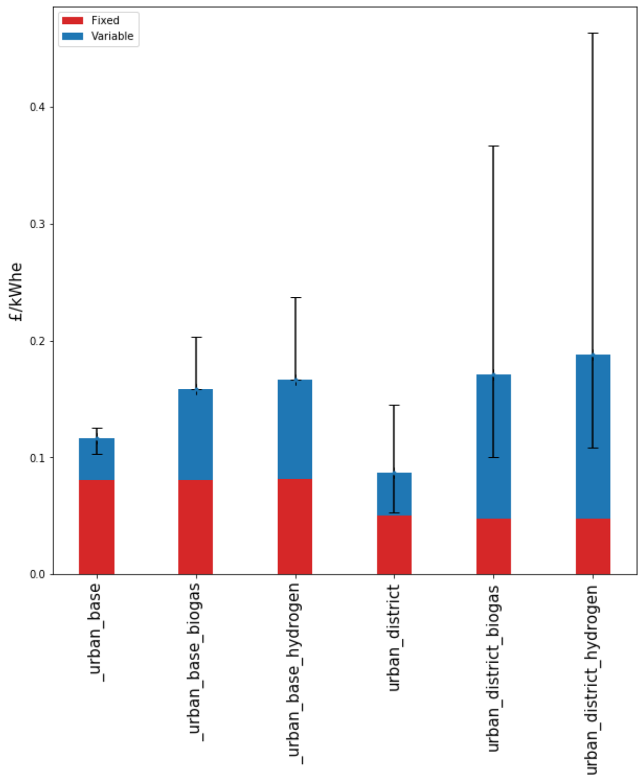

Figure 78 - DCOEs for urban scenarios including district heat and alternative gas options

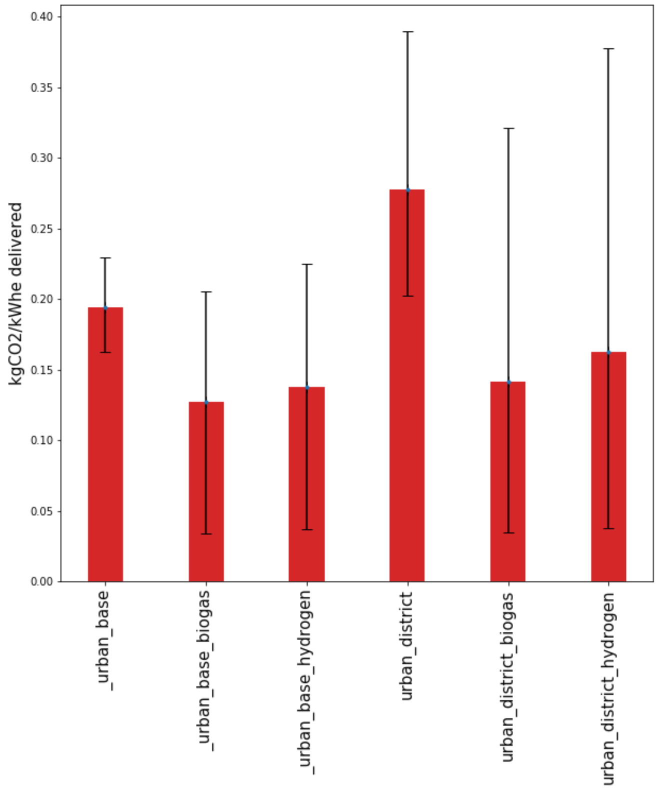

Figure 79 - EIs for urban scenarios including district heat and alternative gas options

Table 28 - Abatement costs for urban model, central assumptions

Scenario			Average Abatement Cost compared to Base Scenario (£/kgCO₂)
End Use Technology	**Biogas**	**Hydrogen**	
Gas Condensing Boiler	Yes	No	0.617
Gas Condensing Boiler	No	Yes	0.882
District Heat	No	No	-
District Heat	Yes	No	1.016
District Heat	No	Yes	2.225

Figure 80 below illustrates the import and export of electricity from the district heating scheme, showing that electricity is exported (generating revenue) during periods of peak heating demand, and during periods of low heat demand the electricity demand of the households is met by import from the distribution network. As the costs of import and revenue from export are assumed to be identical (at the unit value of electricity used throughout) the determinant will be the comparative efficiency of the CHP plant in generating heat and electricity. The exact dispatch may vary according to time-variant electricity prices, if the CHP plant is able to act within the wholesale market or through a bilateral contract with a similar pricing structure.

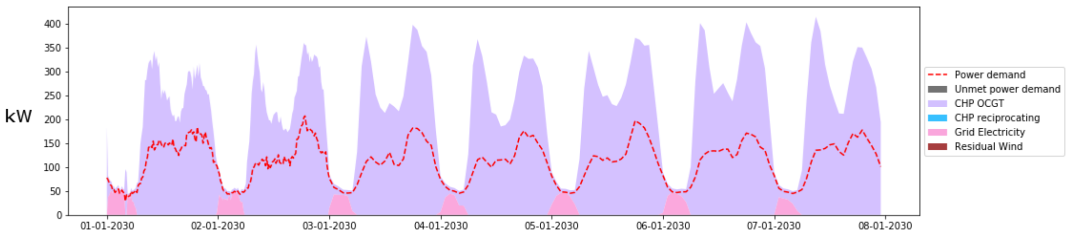

Figure 80 - electrical utilisation of urban district CHP

8.5 Combined Assessment

The above results show that the consideration of heat archetypes is valid, with the hugely differing costs of infrastructure reinforcement in local systems playing a key role in deciding the ultimate cost of carbon abatement. At the two extremes, it is clear that the density of urban systems makes communalised heat provision in the form of heat networks a key contributor to potential heat emissions abatement, whereas in rural systems more decentralised, per-household solutions which do not entail significant system alteration are more valuable. In the middle, suburban systems incentivise network reinforcement to accommodate increased penetrations of e.g. heat pumps, but this is dependent on housing density.

A key delineation has been identified, largely extant in the existing policy space, between options which look to electrification and decarbonisation of the electricity transmission grid, against options which continue to utilise the gas network (already being updated under the mains replacement programme discussed in Section 5.2) but look to alternative, lower carbon gas sources at a transmission level.

A key issue repeatedly demonstrated in the above results is the over-riding importance of uncertainty. These uncertainties include:

- Emissions intensities of grid-supplied fuels;
- Costs of grid-supplied fuels;
- Efficiencies/COPs of heat generating technologies;
- Losses in heat network components;
- Variability in demand and diversity;
- Variance in capital costs;
- Interactions with stochastic renewables.

However, these are not all implicitly exogenous variables to the future planning of the energy system, and most are within the remit of a (conceptual) system planner. For example, the emissions intensity of the future gas grid is not an independent variable against which the decision to continue gas use must be made; rather, the joint decision can be made to opt for gas technologies while simultaneously incentivising decarbonisation of gas supply systems. This implies the necessity for coordination between upstream and downstream systems, such as is proposed for electricity – based decarbonisation under the 'Three Pillars' strategy (electrification of traditionally non-electric demand, decarbonisation of electricity supply, demand reduction through efficiency) [197].

By comparing the three sets of results, it can also be seen that the highest priority options (defined by the abatement costs) are for displacing high-emissions fuels where these are currently used to supply domestic heat. In particular, the use of heating oil in rural locations has a particularly high energy intensity, and incentives should focus on delivery of this 'easy win' first and foremost. This is illustrated by the highest abatement values for all scenarios coming from the rural simulation, as shown in Table 27. While the modelling conducted here assumes that energy efficiency improvements have already been conducted, it is also noted that rural locations may have a high degree of fuel poverty and poor housing efficiencies, and that there is opportunity to target all 3 issues in combination, as is the current policy goal in Scotland [36].

9 Incorporation of Exemplar Results into UK TIMES

9.1 Overview

The UK TIMES model, previously described in Section 2.6.3, is a single-region model of the UK energy system, with no explicit spatial granularity. However, it does include network upgrade costs. In this chapter, the results of the previous sections are used to add further detail to the single-region representation, and to determine the potential impact on the least-cost pathway indicated by the TIMES framework. The implications of this impact is then further examined within the policy evaluation context for which UK TIMES has been designed, and to make recommendations for how this level of detail could be included in future iterations of such models.

9.2 Representation of the Domestic Sector in UK TIMES

The UK domestic sector is represented through a set of energy service demands, consisting of space heat, hot water, and non-heat individual appliances (such as computers, consumer electronics, cooking, cooling, lighting, refrigeration, wet appliances).

These demands are set exogenously to the model, and are disaggregated by housing type: existing houses, existing flats, and new builds (which are based on an average across both housing types). Each is divided into demand for cavity wall insulated and solid wall insulated types. The breakdown is based on household statistics for 2010 (the base year of UK TIMES). The demand is further temporally subdivided into 4 seasonal and 4 diurnal time slices, combined to give 16 time periods of energy service demand.

The values are based on 2010 figures which are projected forwards in time. The shares of technologies are assumed to be constant until 2030, and then follow household growth to 2050. Future growth is based on historic growth in demand and appliance numbers. Alternatively, the total penetration for 2050 may be set and then a linear trend is interpolated based on a standard consumption per appliance. The household breakdown is similarly projected based on population growth from Office for National Statistics (ONS) data to derive projections of future occupancy and household demographics. The dwellings are divided into existing and new categories by subtraction of the base year values.

A number of residential heat technologies are represented as processes:

- Gas boilers (condensing/non-condensing, natural gas/biomethane/hydrogen)
- Oil boilers (condensing/non-condensing)

- Electric boilers
- Biomass boilers
- Air source heat pumps
- Night storage electric heaters
- Electric resistive heaters (fitted/standalone)
- Standalone gas heaters
- Solar thermal water heating
- District heat piping
- District gas boiler
- District CHP (based on CCGT)

In addition, different forms of radiator (wet/dry/underfloor) are represented to supply heat from conversion devices. Each technology is linked to the appropriate fuel source, from which the emissions accounts are calculated. Existing technology volumes are set for the base year of 2010.

9.3 Electricity Network Representation in UK TIMES

In order to represent the costs of maintaining or expanding the UK gas and electricity transmission and distribution networks UK TIMES includes a levelised cost of network expansion at each level.

As an example, the electricity network values are summarised in Table 29. The OPEX values are taken from Ofgem's 2012 RIIO-T1 price control review [198] and 2009 Electricity Distribution Price Control Review Final Proposals [199], averaged across all TO / DNO submissions by capacity. The existing 2010 base capacity for each is based on the current peak reserve level of generation - in other words, the assessed limit of current secure transmission capacity, as opposed to the actual bulk capacity of the transmission network. The cost of new-build transmission capacity is determined by averaging the price review cost submissions over the intended new build rate.

Table 29 - Electricity network costs in UK TIMES v1.2.2

	Transmission		Distribution		Behind the meter	
Parameter	**Existing**	**New-build**	**Existing**	**New-build**	**Existing**	**New-build**
CAPEX (£m/GW)		628.26		666.10		20.04
Fixed OPEX (£m/GW)	6.34	6.34	11.73	25.59	5.74	12.52
Availability factor	100%	100%	100%	100%	100%	100%
Average efficiency	98.40%	98.40%	94.21%	94.21%	100%	100%
Activity/ capacity (PJ/GW)	31.54	31.56	31.54	31.54	31.54	31.54
Last year of investment	2010		2010		2010	
Technical Lifetime (years)	40	40	25	25	25	25
Economic Lifetime (years)		30				
2010 Stock (GW)	60.10		36.47		36.47	

9.4 Disaggregation Options

As described in Section 9.2, UK TIMES already incorporates some form of disaggregation by housing type, but solely by the household rather than its context. Additionally, the network costs are applied in flat manner to all houses based on the capacity required to meet the peak demand period (of the 16 diurnal/seasonal time slices).

There are several methods that could be used to further disaggregate or rationalise the TIMES inputs in order to appropriately capture the key differences in the archetypes proposed in this work.

Firstly, the temporal resolution could be improved. That is, an increased number of time slices (diurnal and seasonal) can be introduced. This would likely capture the peak demand in more detail, which as described above, would better indicate the peak network requirements. This would require subdivision of all time-variant parameters, with the appropriate level of data sourced to inform this time-slicing. It is noted, however, that these models are not intended to be sequential simulation-type models, and hence cannot achieve the same resolution as a detailed time-based simulation. As a result, the temporal resolution should only be amended where it is believed that the peak is not being adequately captured. As the UK TIMES model specifies a short evening peak of 3 hours, there is likely little insight to be gained by further reducing this time period, which carries a cost of significantly increased model dimensionality.

Similarly, the spatial resolution could be improved, but this is subject to the same consideration – that any improvement would be seen as a closer reflection of reality, with the ideal of a full network representation. However, this again increases the dimensionality of the problem and moves the modelling paradigm away from techno-economic optimisation towards detailed simulation. So we instead look at options which may be incorporated sympathetically into the modelling framework as it is intended to be used – modifications which characterise the results of detailed simulation modelling, but do not attempt to actually convert the TIMES-type model into an actual simulation.

Secondly, instead, the network costs could be disaggregated according to the housing type. Rather than define a single flat cost across all residential demands, the housing stock could be subdivided into the archetypes given and differing network costs applied according to the likely level of reinforcement required for that set of houses. For example, a distinct set of electricity distribution network technologies could be defined and mapped across to each set of residential households. This would assist in differentiating between, for example, the low network costs given for the urban model (where reinforcement is seen as a relatively cheap cost enabling increase of certain technologies) against the very high reinforcement costs for rural locations, acting as a key barrier to the uptake of e.g. heat pumps.

Third, manual constraints may be added which reflect realistic limitations to technology installations that are not otherwise represented in the model. This is generally the mechanism used where UK TIMES is implemented in practice for investigation of policy. For example, the permissible volume of heat pumps could be calculated according to existing and realistic levels of distribution network reinforcement, and this set as a 'hard' constraint on what may be installed. This has the handicap that it reduces the solution space of the model, and if this is enacted for multiple technologies, may 'over constrain' the model. It also means that the model may be self-reinforcing towards assumptions made by the modeller – that is, if constraints are added that reflect what the modeller assumes is permissible in their system, then this may artificially disguise potential decarbonisation measures where the barriers to implementation have the potential to be overcome.

This leads to the fourth mechanism, whereby network costs are disaggregated by technology and archetype. That is, the cost impacts of different end-use technologies are mapped across to their concordant network technologies, again by disaggregation of single network costs into multiple subsets. For example, a volume of energy demand services would be mapped across to a specific subset of the distribution network relating to (for example) the rural case, and specific averaged per-household reinforcement costs defined and applied for that case. This would implicitly contain within the model decision space the implications of selecting a particular technology taking into account its context. Of course, this requires that the archetypes chosen appropriately represent an adequate number of households around the energy system being considered. At one extreme, a single case study would be used as a basis for extrapolation to every household in the UK; at the other, every single household would be modelled individually. Somewhere between the two lies a pragmatic optimum between the value of disaggregation and the effort required in doing so. The aim of the work here has been to examine 3 key archetypes which are understood to relate to the key spatial differentials in local energy systems (as discussed in Section 7.2) as a justifiable compromise between those two tensions, with the potential for further disaggregation to be conducted in further work.

9.5 Disaggregation of Domestic Heating Infrastructure in UK TIMES

Following the fourth option described in the previous section, the outputs from the Local Exemplar models can be used to improve assumptions in a higher-level model such as UK TIMES, of which an overview is given in Section 2.6.3. The detailed single-year modelling conducted in the previous chapters results in a detailed picture of how the specific costs and values of technology options might be realised if applied to real-world systems, and this can be integrated into the TIMES model as a set of improved assumptions. A key difference is that the multi-year TIMES modelling framework attempts to meet a carbon emission reduction across multiple years, taking into account constraints around (for example) build rates and investment. The Local Exemplar model, in contrast, assumes there are no such constraints and instead attempts to consider a system once a technology has been implemented, by whatever actual commercial means. The local results may then inform the technical assumptions that have been made in the Whole System model and which constrain the technology selection.

Figure 81 shows the projected provision of heating in existing buildings under a low greenhouse gas constraint (set as specified targets within years 2030 to 2050) within the UK TIMES model. The overall reduction in energy consumption is primarily from energy efficiency improvements, but also includes demolition of housing stock. Primarily the large proportion of condensing gas boilers are gradually replaced with a variety of heat pump based solutions. It should be noted that within UK TIMES, Stirling micro-CHP engines are included as a viable technology and the solution space will converge to a high proportion of such installations due to the low assumed costs of the technology. This cost is highly uncertain, and in the eventuality the specific technology becomes higher cost than expected, the model will install an equivalent volume of heat pumps in its place. For this reason, the micro-CHP and heat pump technologies are aggregated in the figure given.

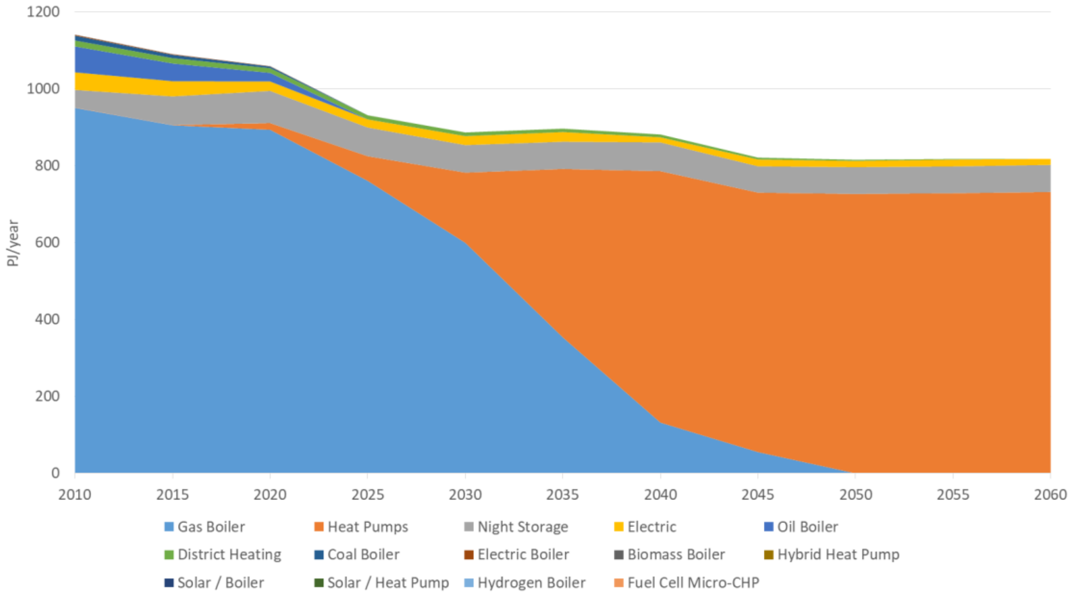

Figure 81 - Heat provision in existing residential buildings, UK TIMES solution, low GHG scenario. All included heat technologies are listed.

In order to apply the three existing housing archetypes analysed in this study, the urban/rural housing estimates for Scotland [200] and England and Wales [201] were analysed at a high level in order to determine the approximate proportion of the domestic population which might be characterised according to each of urban, suburban and rural classifications. This was found to be 32.6% urban, 39.3% suburban, and 28.1% rural. There is, in reality, a continuum of households at densities which might correspond to each, so the delineation is relatively arbitrary – in this case, high-density urban is separated from low-density urban conurbation and the remainder allocated to rural. It is noted that a large proportion of the rural population is to be found in the Scottish and Welsh data, and this may provide a justification for some regional disaggregation of the model to allow for the different proportions of household density in different regions, as well as the varied costs of network and energy supply. However, in this case, a single region model is still used.

Assuming that all high-density urban population conforms to the urban model (which makes the case that all high-density urban housing conforms to flats as modelled, which is a significant simplification), the CAPEX and OPEX for electricity distribution network was similarly disaggregated, alongside the CAPEX and OPEX for heat networks. For distribution networks, the costs are separated out into LV and higher voltage costs according to DPCR4 values. The costs of higher voltage reinforcement is assumed to be the same for all archetypes, with only the LV costs varying. The cost of plant providing heat supply into heat networks was not disaggregated, as this is assumed to be independent of location. Heat networks were not included as a technology option for rural locations. Again, it would be more correct to include the true cost of rural heat networks in order to avoid unnecessary constraint of the solution space, but this is not considered to be likely to affect the model solution except under extreme scenarios.

The assumed values used for disaggregated CAPEX and OPEX, along with the proportionate breakdown of energy demand values, are given in Table 30. These values are applied to existing housing stock only, in order to determine illustrative impacts. The values given are chosen to represent as closely as possible the three local archetypes presented in this work – including the definition of cable/pipe lengths, and it is accepted that these are not necessarily reflective of the true average lengths for all households that might be considered to be captured by those archetypes.

The new solution for the provision of heat in residential buildings, incorporating these disaggregated network values, is shown in Figure 82.

Table 30 - Disaggregated network costs by archetype for electricity distribution and heat networks, native TIMES units

Archetype	Urban	Suburban	Rural
Proportion of Households	32.6%	39.3%	28.1%
Proportion of Energy Demand	28.0%	36.2%	35.8%
Average households per secondary transformer	416	292	63
Average network length per household (m)	2.96	8.59	212.86
Distribution CAPEX (£m/GW)	451.2	630.2	851.7
Distribution OPEX (£m/GW/a)	15.3	24.5	32.3
Heat network CAPEX (£m/PJ)	35.5	46.7	-
Heat network OPEX (£m/PJ/a)	0.19	0.25	-

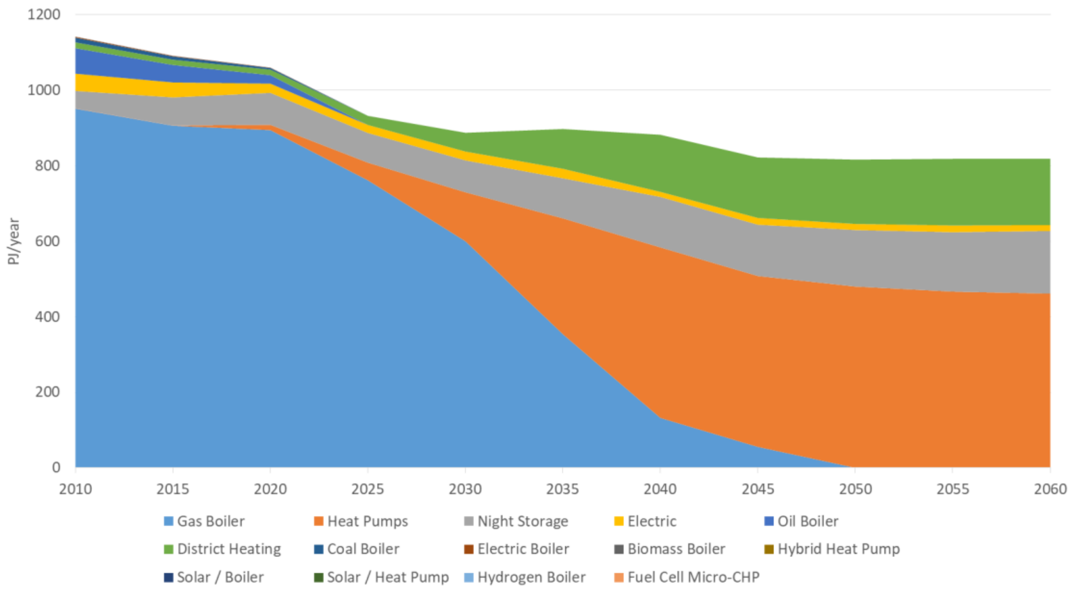

Figure 82 - Heat provision in existing buildings, UK TIMES solution, low GHG scenario, incorporating disaggregated costs of LV electrical and heat networks.

In comparison to the base solution, a far greater proportion of storage is installed in domestic premises as this has a cheaper cost of implementation than network reinforcement in rural areas. The balance between reinforcement of networks and the value of local thermal storage is dependent on the thermal losses of that storage. If the network reinforcement cost is high enough (i.e. the cable lengths per customer are particularly high) and the thermal storage round trip efficiency is low (for example, for newer second generation night storage heaters) then the cost-effective solution will be to install the storage heating as an alternative to network reinforcement. This is likely to be particularly the case in rural areas, where such conditions are likely to be met. In addition, rural locations may currently be dependent on particularly high-emissions-intensity fuels such as oil and solid fuels, and replacing these sources with electrified options. The efficiency losses, however, mean that unlike the fixed level of heat provision shown, the amount of heat *generation* is higher, and overall energy consumption is increased. As this is sourced from the electrical sector, this has a relatively low impact on emissions under the low GHG scenario modelled, as the electricity grid has also been significantly decarbonised. Under alternative scenarios, this reduced heat provision efficiency may entail an increase in emissions which would be balanced against emissions reduction costs in other sectors in order to determine a global solution. Secondly, as per the findings in Chapter 8, district heating investment is primarily driven by heat network costs, which vary greatly by housing density and location. By representing urban areas with a lower heat network costs, this moves that option to a potentially lower abatement cost than e.g. heat pump options which require reinforcement. As a result, the proportion of district heating installed is greatly increased. Again, due to the lack of spatial detail in the TIMES model, heat networks are poorly represented and are very difficult to appropriately summarise in a single region aggregate manner. Introduction of tiered heat network costs in this manner effectively introduces 'tranches' of investment which may each compare less or more favourably with other decarbonisation options.

Figure 83 illustrates the magnitude of changes in utilisation for the main heat technologies discussed above between the base and disaggregated scenario. This shows that under the base scenario heat pumps are favoured as an 'optimal' supply technology seen as applicable to all housing stock. With disaggregation applied, the volume of installed heat pumps is reduced in favour of night storage in rural areas and district heating in urban areas, as a result of the cost differential derived due to differing network costs. The disaggregated variant then represents a more complex and diverse scenario of future decarbonisation, highlighting the possible oversimplification that may be made in the base, non-disaggregated model. It is, of course, possible that this diversity may be further increased by the introduction of further disaggregation.

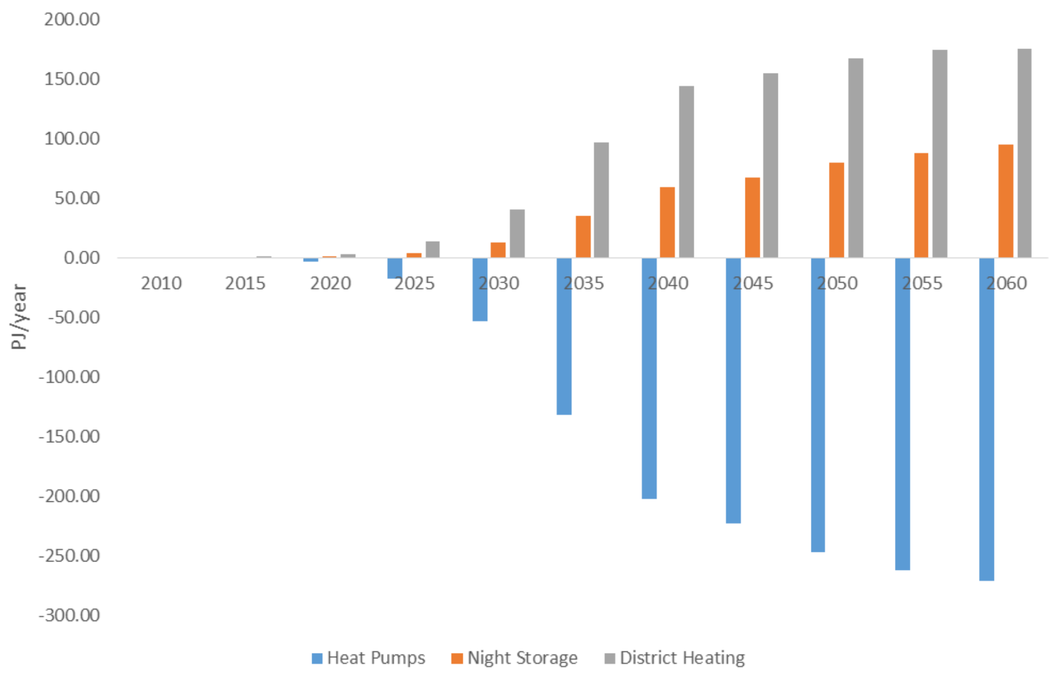

Figure 83 - Relative change in major domestic heat technologies between base and disaggregated scenarios. A positive value indicates an increase in a technology utilisation from the base scenario.

This raises, however, the idea of appropriate detail across the model. In this case, 2 specific network technologies have been disaggregated, along with the energy demands divided appropriately, while leaving the remainder of the model unchanged. This may have the unintended impact of changing the solution space merely through the introduction of increased detail. In other words, a sector which is more closely specified (in this case, residential heating) may include detail which reduces or increases investment in that sector towards decarbonisation, to the expense of / in favour of other sectors which are less well-defined. Those other sectors hence compare less or more favourably not due to their technical or economic characteristics in the real world, but simply because they contain less detail. If the network requirements of domestic heat provision are disaggregated, then it can be safely argued that the network requirements of *all* sectors should be disaggregated in this manner. It may be that for many processes there is no effective difference by archetype, and disaggregation has no impact on the solution space, but it may be the case that, for example, industrial and commercial processes – which otherwise have no connection to residential heat – should be similarly disaggregated to reflect their differing cost of decarbonisation in similar archetypes. This then keeps the model within its intended purpose – balancing the decarbonisation options across all carriers and sectors.

This specific implementation of disaggregation and re-analysis of optimisation is not intended as a fully rigorous analysis at a level of detail required to influence energy policy; it is instead intended to demonstrate the *potential* for the alteration of WSEM outputs based on disaggregation of network costs by archetype. If this methodology was to be used in a rigorous manner, further archetype analysis would be required, with a more detailed breakdown of UK housing stock according, including incorporating this methodology into the extant breakdown into existing and new-build housing stock. This would include more detailed analysis of average network lengths and costs. Such work could be undertaken through use of the existing heat maps for England and Wales [202] and Scotland [203], whereby clustering analysis could be used to identify firstly a more detailed subset of archetypes for local energy systems, followed by quantification of the number of households which fall into each category. This would also permit detailed analysis of interactions with other spatial parameters, such as determining the average nature of housing stock with network location, or for interactions with other energy uses such as transport.

What is clearly illustrated, however, is that the use of least-cost optimisation within the TIMES framework has a tendency towards solutions which have mixed applicability in the real world. The unconstrained results show a solution which entails a high volume of heat pumps which only considers a flat cost of reinforcement, whereas in reality there will be locations where this installation is more highly constrained and limited. Policy interpretations of the TIMES modelling, such as in [67], have taken this into account by applying limits to the build rates of certain technologies such as heat pumps, reflecting the time taken to gradually reinforce electrical networks across the country. This shows a high penetration of heat pumps at the long-term target point of 2050, but in the interim hybrid heat pumps are used as a bridging technology, as they may be installed with no reinforcement. This corresponds to the findings in Chapter 8, where ongoing utilisation of gas boilers accompanied by decarbonisation of the gas grid (via biomethane or hydrogen) gives a higher-cost decarbonisation option that can be achieved in a centralised manner with little local reinforcement necessary.

9.6 Exemplar Modelling and the Energy Transition

The interaction illustrated above also shows the value of combining simulation models (which examine a fixed time period) with mixed-horizon WSEMs – the former can inform specific costs and constraints around implementation scenarios, whereas the latter can examine the total trajectory across an extended period of time, and hence examine system *transition* as opposed to only examining the end point. Such transitions have existed in the past, such as the shift from coal to fluid fossil fuels in the mid-20th century, and latterly the move away from fossil fuels to renewable energy in electricity grids. Alongside techno-economic modelling this creates a need to describe the pathway from one system state to another, in order to enact enabling policy and incentives. [204] identifies 3 key pathways for the UK energy transition:

- Market Rules: whereby the market-led logic of UK energy systems is continued, with large energy firms as the dominant actors, and ongoing investment in large assets and infrastructure;
- Central Coordination: whereby the government's involvement in meeting the energy trilemma is increased, with substantial technology 'push' programs and tenders issued for particular tranches of low-carbon generation;
- Thousand Flowers: whereby energy governance is dominated by civil society, with social movements and decentralised generation/conservation movements, including the involvement of local government.

It is evident from the results presented in Section 8.2.9 that different technological trajectories imply considerably different action from present and future energy system actors, and the investment flows vary considerably between centralised actors, (new) local actors, and (perhaps previously unengaged) consumers. For example, options presented which involve decarbonisation of the gas grid will require significant central coordination in order to enact a significant switchover between input gases, and in the case of hydrogen, significant coordinated investment in gas grid changes. Similarly scenarios which utilise electrification of demand alongside reduction in the emissions intensity of grid electricity requires coordination between decentralised consumers moving to electric heat demands and grid-side generators, alongside commercial mechanisms which incentivise both actions.

This creates a further purpose for combining Whole System modelling with local exemplars in an iterative manner – the Whole System view indicates a desirable trajectory on a least cost, national basis, and specific points along that trajectory can be constructed and explored through the generation of local system models. This then gives a real-world picture of the implementation of that trajectory, and highlights any technical, cost or behavioural constraints which may oppose it. These can then be incorporated into the Whole System model in a manner similar to that shown above, in order to explore a potentially more realistic solution space, avoiding the need for 'hard' constraints which self-reinforce policy assumptions. Again, the new solution can be projected onto local exemplars, and used for discursive evaluation of energy policies alongside the techno-economic case, and the cycle repeated and updated as assumptions are improved with new information. This is particularly relevant where the inputs to techno-economic models are highly uncertain, and solutions may point towards technologies with as-yet unknown costs. If, as discussed in Section 8.2, the technical and cost uncertainties point towards the use of non-cost-optimal analyses such as Least Regret methods, then the exemplar models can similarly be used to demonstrate the viability – and economic security – of those least regret options.

Under the 'Thousand Flowers' transition involving the creation and support of local energy systems, identifying local opportunities in energy provision and conservation, case-specific exemplar models may be used to evaluate the local implementation of energy policies and to construct cost/benefit cases for specific local energy systems. These can provide a basis for discussions between local actors, providing additional scrutiny to the initial discursive case for an energy system, as a stepping stone towards the full business case evaluation. If conducted in parallel across multiple locations, this might allow local or regional government to identify priority locations for energy interventions and/or investment.0

Lastly, the behavioural aspects of energy transitions are not incorporated into TIMES-like Whole System models, other than (in some cases) including a demand elasticity component. While the local exemplar models analysed in this study also do not include considerations of end-user behaviour, with energy demands being exogenous to the model, they give an indication of the barriers to implementation that may be faced by a particular trajectory. There is potential scope to include energy demand behaviour as a part of the model, by coupling agent-based modelling of consumer demand. This has particular application to cases which include Demand-side Management (as discussed in Section 5.6) to determine the response of consumers to investment or operational signals from e.g. aggregators or other system actors.

10 Conclusion and Future Work

In this chapter, the main outcomes and learning of this work are proposed and discussed. These are divided into:

1. the methodological outcomes which relate to the structural and computational aspects of local energy system modelling, and are theoretical;
2. the technical outcomes which relate to the implementation of low carbon technologies in real local energy systems, and which are practical and within the engineering and economic spheres;
3. the political and regulatory outcomes which define the means by which the low carbon futures may be put into action by policymakers.

The incorporation of the methodology presented into the Whole System modelling process is discussed in terms of it wider applicability. Finally further work is proposed which may directly extend from here.

The methodology, in brief, involves evaluating heat technology options through their implementation in a local multi-carrier system model which represents a key system archetype. This model is run as a least-emissions optimisation with fixed levels of end-use technologies and exogenous demand. The implied requirements of network assets for different technologies is explored, along with the calculation of the emissions intensity of energy, the delivered cost per unit, and the potential abatement cost this represents against the base scenario of present-day heat provision. These insights are then used to feed back into the high-level system model and disaggregate appropriately without the need to incorporate complete levels of spatial and/or temporal detail.

10.1 Contributions

The contributions of this work are the following.

Firstly, futures for the provision of energy within local energy systems, considering domestic heat options in particular, have been assessed within the context of deep decarbonisation. This has demonstrated that carbon abatement costs for different options vary considerably, and that the increased cost to the consumer of installing local equipment may displace decarbonisation options elsewhere. It also highlights the requirement to consider the value of local low-carbon technology options against the cost of network reinforcement, such as where heating is electrified where it previously is sustained by gas or oil. This is shown in the total abatement costs for options in rural, urban and suburban local systems in Chapter 8. A key finding is the opportunity generated to match the output from constrained local renewable generation (specifically wind power) with local demand, potentially facilitated by thermal storage.

Secondly, a contribution has been made to the use of the existing Energy Hub formulation by expanding its use into the domestic heating sector and through the combination with a more sophisticated demand model (Section 7.3) and renewable generation inputs (Chapter 4 and Section 7.4). Extensions to the method include the use of time masking, and derivation of final abatement costs based on the delivered cost of energy and emission intensity, by combining the use of different cost classes in the optimisation framework.

Third, the outputs from a significant Whole System model (UK TIMES) have been downscaled to a set of local energy models in order to further evaluate their coherency and applicability to real-world systems, and the results from that modelling used to disaggregate the domestic heating sector in the Whole System model (Chapter 9). This has demonstrated that disaggregating in this manner moves the solution away from a single technology selection (heat pumps) towards a more diverse selection of technologies, including district heating in urban networks (where per customer heat network infrastructure costs are lower) and towards thermal storage in rural networks (where the per customer electrical reinforcement costs are higher). This points towards the importance of incorporating a pragmatic level of spatial detail within such models, even where the models themselves are not spatially explicit,

10.2 Assessment of the Methodology

Disaggregating WSEM outputs to spatially and temporally explicit local energy models provides a clear mechanism towards testing proposed energy futures

A TIMES-like WSEM conducts a system-wide least-cost optimisation, with aggregated volumes of technology investments as the final output, representing the total future pathway towards an emissions target. However, while these technology volumes are aggregated across all consumers, there is the implicit requirement that the identified technologies are installed at specific locations by specific system actors. As discussed in Chapter 2, these specifics are not indicated by WSEM outputs, and this means that the results are not easily converted to policy-relevant narratives which demonstrate the actual real-world cases in which the technologies must be utilised and dispatched. Existing approaches such as soft- or hard- linking sectoral models (such as security analyses of the output for power or gas sectors) provide additional rigour and demonstrate the viability of the WSEM solution in total, but still do not provide a picture of impacts and transition pathways for end consumers. The modelling work shown here (as detailed through modelling results discussion in Chapter 8) allows outputs of WSEMs to be downscaled to local energy systems which clearly exemplify the requirements that end consumers and associated energy actors (network operators, local authorities etc.) will have to fulfil to meet the end state identified by the WSEM as the least-cost pathway to emissions reduction.

Representing a technology in a WSEM by the use of a single cost and capacity disguises the discretised nature of most technology tranches

The full implementation cost of an end-use technology will vary significantly according to a number of factors – for example, the cost of retrofit vs new-build installation; the length of last-mile network requiring reinforcement; the interaction with other existing technologies. For this reason, representing the cost of installation as a single value disguises the varying fixed costs that are the reality. As demonstrated in Chapter 8, the total costs for identical technologies are very different in alternative local energy systems. This means that ideally, when incorporating the costs of a technology into a WSEM where it is not possible to include significant spatial and temporal detail, the costs should be divided into recognised tranches that represent the true costs and benefits of different system implementations. As shown in Chapter 9, this could divide end-use technologies in their costs of implementations into different system archetypes, alongside the estimated size (in number of households) for each archetype as identified from housing survey and census data.

The level of technical and economic detail implemented in a WSEM should be consistent across all sectors

The intention of a WSEM is to locate a cost-optimal trajectory which accurately balances different decarbonisation options between different sectors. Due to the highly aggregate nature of a (tractable) WSEM, it is necessary to simplify the spatial and temporal detail with which different technologies (and their supporting infrastructure) are represented. However, if this level of detail is not comparable between different sectors, then the optimum point determined by the model may simply be a reflection of this discrepancy. For example, in Chapter 9 it was shown that increasing the detail of cost assumptions for heat pump requirements (in terms of accounting for local network reinforcement) averted some investment into that technology, but this was not balanced against a similar consideration for the counterfactual of alternative gas utilisation, which may have similar impacts on local network requirements.

10.3 Technical Outcomes

The diversity effects seen in electricity are not fully replicated in heat

In Section 7.3, a bottom-up demand model is used to illustrate the aggregation of the different demand vectors (space heat, hot water, non-heat). The diversity factor for space heating provision across the 292 suburban households is calculated as 1.7, as compared to 8.3 for non-heat electricity demand. This means that traditional scaling methods for distribution network capacity sizing must be revisited under future scenarios involving the electrification of domestic space heat provision. This additionally means that the load factor of such new network will be lower than at present, with further impacts on potential Network Operator revenue under existing remuneration mechanisms.

An individualist approach to heat provision creates significant overcapacity

In extension to the previous statement, diversity effects mean that heat generation solutions operating at the local scale where losses and transport costs are relatively low can benefit significantly from the benefits of aggregation. The total capacity of condensing gas boilers required on a house-by-house basis is significantly more than under a communal solution (as shown in Section 8.2.1), with commensurate savings in capital costs and maintenance. However, the cost of heat networks vary considerably by location and have significant uncertainty (as shown in Section 8.2.6), making business cases difficult to construct, and meaning that the potential of such technologies are difficult to represent within WSEMs. An optimal approach would be to use clustering techniques to identify likely tranches of low-cost heat networks, an extension of the current approach taken in e.g. UK TIMES.

Time-shifting of heat demand has significant potential in deferring electricity system investment

The thermal buffering effect of buildings, and the relatively low per-unit-energy cost of proposed thermal storage systems, creates a significant opportunity for time-shifting of energy demand from the external network to supply building heat. This is in comparison to e.g. electrical storage, which may deliver large amounts of power but is costly in terms of energy capacity. Under scenarios which evaluate the impact of electrification of heat, such as through the increased use of heat pumps, a relatively small volume of thermal storage has the potential to avoid reinforcement in electrical distribution while removing the requirement for peak-filling by gas. This is illustrated in Section 8.2.4.

There is a strong co-dependency between local renewable generation capacity and the value of decentralised storage

Where decentralised storage (such as hot water tanks) is implemented within last-mile networks, it makes a strong contribution towards the deferral of electricity network investment. This is primarily through reduction of peak demand, which drives the capacity sizing of the local network. However, in terms of actual energy stored and delivered, this contribution is likely to be relatively low. Where additional value for storage may be derived is from bulk storage of energy available within the distribution network which, due to local congestion, cannot be delivered to the transmission system and must be curtailed or utilised locally.

The least-cost optimal solution is subject to high uncertainty due to the wide range of future technology cost estimates

As described in Section 5.4, most low-carbon heating technologies have an extremely wide range of cost predictions. This is further exacerbated by a wide range of predictions for future fuel costs, such that the end cost of delivered energy is subject to a broad range of possible values for different scenarios, as shown in Chapter 8. This also makes it difficult to compare established technologies with known costs with other less-proven technologies where there is little evidence on where the future cost may lie. This inherently undermines any least-cost optimisation method as evidence for a particular trajectory, and as demonstrated in this work, iteration through multiple cost scenarios is key to correct interpretation of modelling outputs for setting policies and incentives. This means that for system actors looking to make decisions in the near future, least regret-type analyses may be more suitable than least-cost optimisations.

10.4 Policy Implications

Under all projected gas and electricity cost scenarios, incentives will be required to realise transition to heat pumps from condensing gas boilers

The evaluation in Chapter 8 of delivered costs of energy supports the conclusion from government-commissioned modelling (e.g. [144]) that continued incentives are required to see a significant growth in heat pump installation, primarily due to the expected ongoing low cost of natural gas as a heating fuel. While the greater-than-unity efficiency of heat pumps, combined with zero-marginal cost renewables does create opportunities for cheap low-carbon heating, the merit order varies with time and so the business case for replacing condensing boilers with gas (at a domestic level) is not definitive.

New heat solutions which do not entirely displace incumbent technologies may represent a very poor cost of abatement

Most of the technologies studied, including incumbent systems, carry very high capital costs as a proportion of total costs, which is a major contributor to the delivered cost of energy, as presented in Chapter 8. This means that if a new technology does not entirely displace an incumbent source – for example, continuing to replace condensing gas boilers to infill heating demand alongside heat pumps – then the cost of abatement will carry multiple capital expenditure sources, and will so be much higher than for solutions which replace existing technologies outright. In this respect, there appears to be an opportunity for potential designs for e.g. hybrid heat pumps which successfully reduce the costs of the combined solution compared to individual heating systems.

The decarbonisation value of electrification of heat depends strongly on the carbon intensity of electricity generation

As demonstrated throughout Chapter 8, the abatement value of e.g. heat pumps varies strongly according to the value of emissions intensity allocated to electricity imported from the transmission network, even in the presence of local renewables. This corresponds to the 'three pillars' view of decarbonisation, which aims to electrify as many end demands for energy as possible, alongside reduction of electrical emissions intensity and gains in efficiency. This similarly applies to ongoing use of the gas grid to supply alternative gases, where the emissions intensity of heat provision is highly dependent on the specific sources of biomethane and/or hydrogen.

There is a clear need for mechanisms which pass through derived value from network owners to technology installers

The growth in use of electric heating technologies such as heat pumps is potentially constrained by the capacity of the local electricity network, and Distribution Network Owners may have to invest significantly in upgrading local network capacity in order to allow penetrations of such technologies to increase to the levels envisioned by long-term government policy intentions. However, this requirement to invest and upgrade may be offset by localised use of storage (such as thermal stores) or demand-side management mechanisms, as discussed in Section 5.6. As the financial benefits of this are accrued by the network owner (in terms of deferred investment), in order to realise the installation of such systems there must be a mechanism to pass through this saved cost, such as through the use of local balancing markets facilitated by a local aggregator.

Decarbonisation of domestic heat is a highly spatially heterogeneous challenge

The total costs of different heat technology implementations vary considerably between locations, either due to differing required levels of network investment, or - for communalised solutions such as district heating - very different costs of installation. This difference in cost may be due to the nature of the existing housing stock, the spatial extent of the area under consideration, or geophysical restrictions such as terrain and subsoil conditions. This means that it is difficult to reduce any particular technology implementation to a simple indicative cost, as is required by most WSEMs. As a result, heat systems must be considered on a case-by-case basis, and this supports the implementation of heat strategy at a local level, such as coordinated by Local Authorities who can gain familiarity with the specific challenges of their local area.

There is a wide variation in investment requirements for different energy system actors under different technology scenarios

Many of the scenarios presented include technologies which are installed per-household, and require investment by the homeowner. Others are communalised systems which require investment from a (commercial) third-party and cost recovery from householders. Each different scenario also has different impacts on the utilisation rates of network assets – for example, scenarios with high electrification of heat demand significantly reduce the utilisation rate of the gas distribution network. This in turn impacts the revenues of the network operators, where their cost recovery is conducted on a per-unit-energy-delivered basis. This means that, aside from the total cost of any given energy scenario, there is a diversity of investment requirements and revenue streams for different technology requirements, and this has a significant impact on both incumbents and new system actors. It may also define new responsibilities for existing system roles, such as Local Authorities and Housing Associations. When assessing policy options, and taking advice on those options, it is key that any possible biases of those providing technical advice is taken into account – for example, gas system incumbents only quoting minimum cost trajectories for conversion to hydrogen.

Realisation of Demand-Side Management

In the scenarios developed in this study, an optimal dispatch of the assets across the local network is assumed, which minimises total costs. In reality, however, at present domestic heating technologies are used and controlled either manually or via controllers informed by local variables. This means that to enact the ‘optimal’ schedule requires some form of centralised dispatch, such as by a Distribution Network Operator or local aggregator. This practice has been explored to date through mechanisms such as Active Network Management, whereby embedded generation assets are curtailed in response to network conditions, and through the incorporation of an aggregate response from demand-side participants. However, such mechanisms require coordination at a local level (to ensure sufficient consumer buy-in to make the system commercially viable) as well as having implementation and administrative costs that are not accounted for in this study.

10.5 Further Work

While intended to provide further depth to WSEM modelling of domestic heat provision, the work presented here has made various simplifications and assumptions. These are listed here in order to set the context for further development of such models within the context of the wider energy system, considering interactions previously ignored or technical parameters intentionally simplified.

10.5.1 Further Validation

As more detailed data from real-world trials becomes available, this may be used to improve multiple aspects of the modelling and to validate results. This may include:

- the use of improved field trial data from newer heat delivery technologies, both in better understanding technical parameters such as COP/efficiency, and a better prospective cost;
- the improved understanding of likely future fuel emissions intensities (such as the carbon intensity of grid electricity) based on improved understanding of investment trends and policy affecting investment;
- the use of smart meter data to improve the measure of domestic energy use and the quality of the demand model;
- distribution-level measurements (such as on primary and secondary substation transformers) to better investigate real-world diversity effects as patterns of energy demand change.

10.5.2 Supply Changes to Other Demand Vectors

Further to heat, transport has been identified as an additional sector which is poorly understood at a policy modelling level, and which has not contributed significantly to decarbonisation to date. There is, however, substantial academic literature concerning how, for example, electric vehicles interact with other elements of the electrical sector, but many of these outputs are not functionally incorporated into current Whole System analysis. This work could be further developed to the specific case of understanding the interaction of Electric Vehicles (EVs) with non-electrical sectors – for example, to determine the provision that EVs can make to reducing reliance on natural gas through providing buffering to the reduced capacity of electricity distribution systems, or to enable hydrogen utilisation by freeing network capacity for use in electrolysis. Again, investigation of this space requires deep insight into the spatial and temporal details of local energy systems, with significant simulation work required which can be aggregated for summary at a national level. This further interfaces with underlying transport demand modelling, and the UK and Scottish transport models could provide a basis to the scenarios used. The system impact of different transition scenarios to the long-term plan to remove combustion engines from the transport sector could be evaluated in order to assist setting short-term transport policy. While heat and transport are generally analysed in isolation, this work should aim to further understand the complex interactions between the two demand vectors within local energy systems – in particular, how the management of EV charging may ameliorate some of the constraints that local electrical infrastructure may undergo if the electrification of heating (such as through increased use of heat pumps and resistive heating) is increased, and how both vectors may interact with other forms of energy storage.

10.5.3 New-build vs Retrofit

The energy models proposed here all take retrofitting of low-carbon technologies to existing housing stock as the main case being examined. This is because new housing build rates in the UK are relatively slow, at around 200,000 new homes per year out of a total stock of 28 million. Hence a substantial challenge for decarbonisation over the next set of carbon budgets will be the need for substantial investment in retrofitting equipment to improve heat supply and efficiency in existing housing stock. A further step would be to combine the modelling here with similar work in new-build systems – particularly where estates are developed with the potential for heat networks to be installed at reduced costs – in order to create a more complete picture of the total housing situation in the UK. In terms of modelling this would be a simpler exercise, as there will be no vintaging required and all infrastructure capacity can be scaled as decision variables.

10.5.4 Ignored Technical Considerations

The following briefly summarises some of the technical assumptions made in the modelling process presented in this thesis which could be improved in future iterations of the methodology:

- The heat demand is modelled through a bottom-up process and treated as exogenous to the optimisation. In reality, the demand for space heat and hot water will be coupled, through a building’s thermal properties, to the rate of supply of heat. This will also be represented in, for example, the heat pump performance over time – as the COP varies with the return temperature rather than (as modelled here) the ambient temperature only.

- It is assumed that all non-heat appliances consume only electricity. This is clearly erroneous in the case of cooking, and there may be other future appliances which consume non-electrical vectors for purposes other than heat. Such electrical devices also generate heat in use (the 'heat replacement effect') and this is not accounted for.
- The degradation in efficiency over the lifetime of different technologies is not modelled. For example, it is well established that gas condensing boilers may lose around 10% efficiency over their lifetimes, and this will have a significant effect on the depreciated value over time.
- The electricity network's constraints are modelled as 'hard' limits – this may not be the case in reality. For example, the transformer and distribution electricity network will have variable limits based on temperature, and may have thermal buffering (such as the oil mass in the transformer) which permits the rated level to be exceeded for a certain time duration. While this is accounted for via a small increase in the 'hard' limit on the LV transformer, a more appropriate simulation would explicitly model the transformer and line temperatures based on the width of the demand peak. This is especially important when considering electrification of heat, where the peak demand may occur over a longer period than normally experienced for non-heat electrical demand.
- Increased building efficiency is only incorporated into the sensitivity analysis, and not as a decision variable or cost. This could, instead, be included as a decision variable with an associated cost of implementation, in order to balance the value of demand reduction against the cost of energy supply.
- Deep reinforcement of the distribution network (and the transmission network) beyond the secondary transformer is not considered. In reality, if the technologies involved were replicated across multiple LV systems, this would have a significant impact on the required network capacity at all voltage levels. However, assumptions would have to be made about the penetrations of technologies in different subsystems, and a further assessment of diversity at more aggregated levels would be required.

10.5.5 Security Constrained Optimisation

In section 3.5.1, the idea of security-constrained dispatch was discussed within the context of electricity-domain OPF problems. It is noted, however, that this has been nowhere considered within this modelling work, and that within the optimisation used it is assumed that all demands for energy must be met. Similarly, there is no assessment made of the reliability of network components or end-use technologies, with full availability assumed. As this study is conducted within last-mile networks, where little or no redundancy is typically provided for security purposes, this is seen as a valid assumption. An extension of the problem would be to include failure rates for different model components, and to quantify in monetary terms a failure to satisfy all energy service demand, in order to drive a system which also meets a particular level of reliability at least cost. There are a number of established methods in electrical OPF formulations which could be extended to the multi-carrier concept, as briefly described in Section 3.5.1.

10.5.6 Ancillary Services

This work only considers the value of systems in providing energy at a certain cost and emissions intensity. Heating systems may also be able to provide additional ancillary services which can increase their value. For example, in [205] decentralised control of heating loads is used to provide a frequency response service in a similar manner to conventional generators, which may become increasingly important as the proportion of renewable energy systems on the electricity grid increases.

10.5.7 Integration into the Whole Systems Modelling Process

The mechanism for interaction with WSEMs conducted here involves iterative soft-linking with the model, via exchanging data between the two modelling frameworks. This could, instead, become a hard-linked methodology, where the output results from the WSEM define specific scenarios which are then interpreted in various local archetypes to determine the true costs of implementation, and the marginal costs of abatement in the local cases used to inform the WSEM of cost tranches for each technology. Rigorous implementation of this method would, however, require clear confirmation that the archetypes do each cover a known proportion of the UK network and building stock.

10.6 Closing Remarks

Modelling in the Energy Systems space has a tendency towards breadth at the expense of depth – that is, in order to represent the huge variety of available technologies towards decarbonisation, simplifications must be made which disguise much of the important technological detail. However, multi-carrier modelling of energy systems provides a means of capturing the breadth – in terms of the comparable options in different sectors – while allowing a means to retain spatial and temporal detail. Any representation of future pathways must be a compromise between these different levels of detail, and it is unreasonable to insist that models intended to take a national view of decarbonisation (the level at which agreements on climate change are enacted and supported) retain equivalent depth. However, in order for the outputs of national models – the envisaged energy futures – to have a validity and robustness commensurate with their implementation in actual policy invoking millions or billions of pounds of incentives and investment, they must be demonstrably applicable to real-world scenarios.

Similarly, academic research into low carbon energy systems risks being inapplicable to the real world if it only deals in idealised systems – such as only evaluating the potential systems that may occur in specific new-build and urban locations. Most people do not live in such cases, and the majority of decarbonisation must exist within the shadow of legacy systems already ageing and at, or near, capacity.

The work conducted here illustrates the case-by-case nature of local systems which may contribute towards national decarbonisation in one particular sector. However, at a national level, these form but one part of a complex policy situation, which must evaluate three main options: replacement of end-use technologies (as presented here); decarbonisation of centralised energy supply systems, such as the electricity grid as a whole; and reduction of energy demand through efficiency improvements. Each of these cannot be assessed in isolation, and there are clear interdependencies between all three. For example, the carbon intensity of electrified heat solutions importing from the grid depends on the total volume of energy demand (in turn defined by the level of efficiency improvements) and the carbon intensity of the electricity being utilised (in turn defined by the national generation mix).

No energy system exists in total isolation, and through examination of local systems increased insight into the complex energy interactions which drive our lives is possible. In many cases this may not deliver brand new insights, but instead reinforces existing assumptions about the future of our energy systems and the policies needed to enact them. Given the high degree of uncertainty demonstrated through any such analysis of future energy provision, there is likely to be a strong ongoing need for such analysis, as we look to an unknown future subject to a wide range of extraneous impacts. This will assist policymakers, local actors and consumers alike to make confident decisions that help the country as a whole to advance towards a future with low carbon emissions across all sectors.

Appendix A: Further Description of Exemplar Models

A.1 Suburban Model

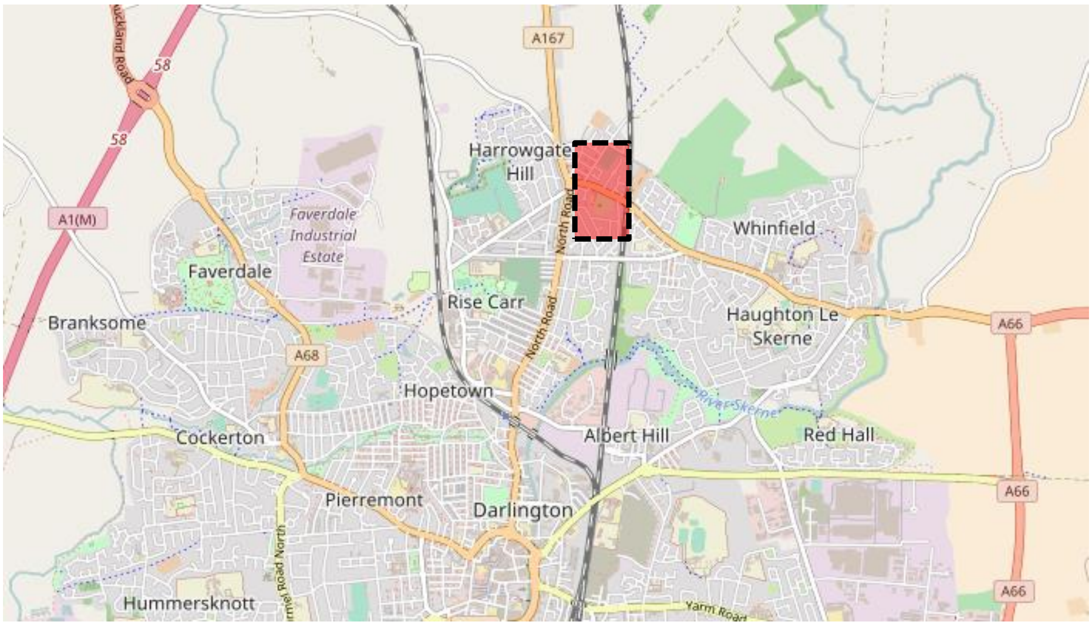

Figure 84 - Location of Suburban Model in North Darlington

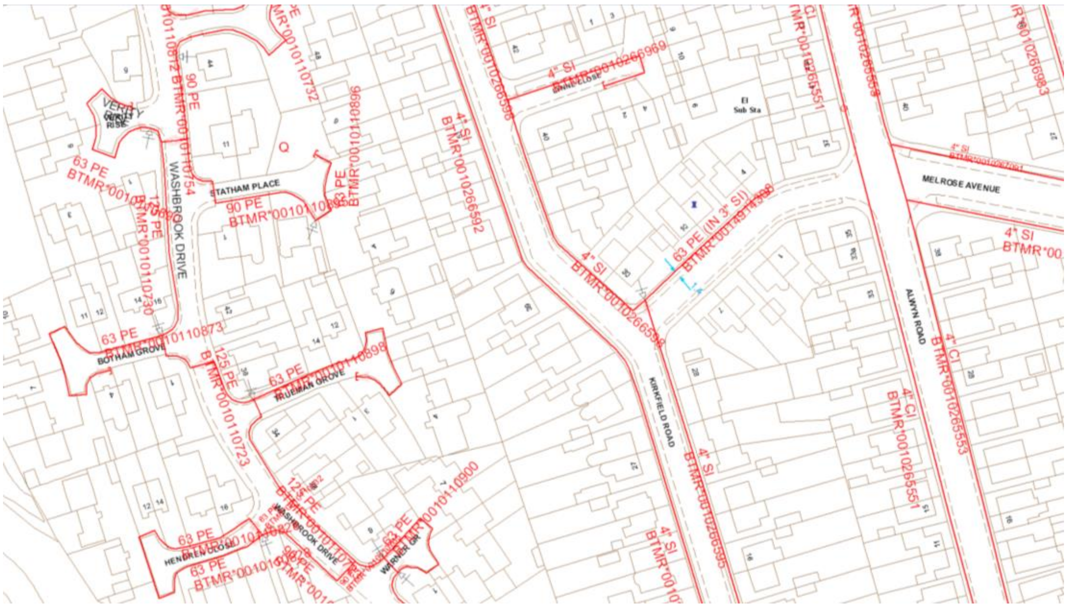

Figure 85 - Partial suburban model gas distribution network, showing mixture of legacy and new pipework, accessed from [206]

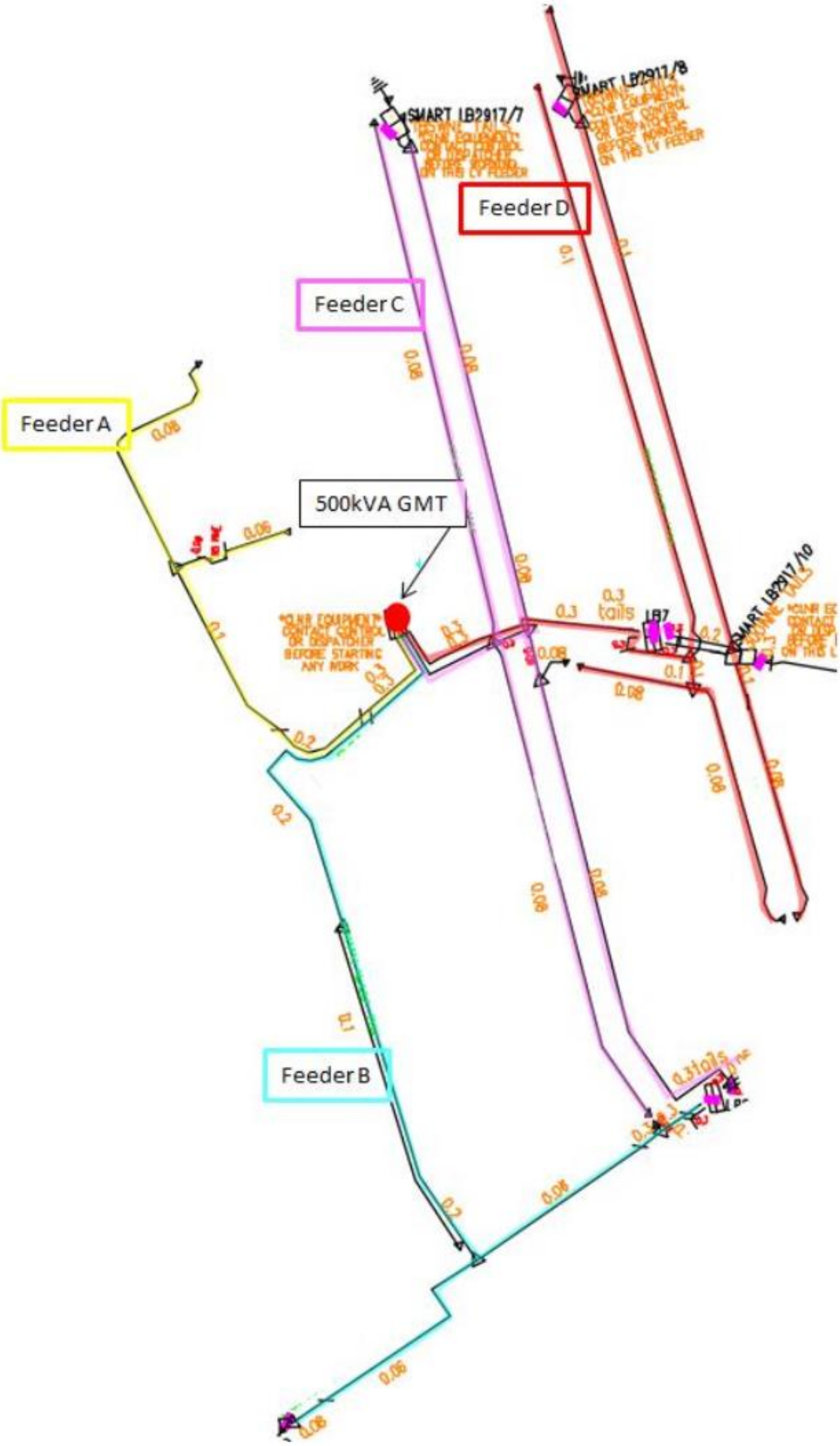

Figure 86 - Suburban model LV network diagram, reproduced from [172]

Table 31 - Housing types by LV feeder, suburban model

Housing Type	A	B	C	D	Total
Detached	1	0	0	0	1
Semi-detached	52	53	84	71	260
Terraced	6	13	0	12	31
Total	**59**	**66**	**84**	**83**	**292**

A.2 Rural Model

Table 32 - No of houses by type per location, rural model

	Housing Type		
Location	**Detached**	**Semi-detached**	**Terraced**
Helwith Bridge	4	2	4
Foredale Farm	2		8
Studfold	1	4	
Middle Studfold	3		
Cragg Hill	1		
Sherwood Brow	2		
Sannat Hall	4		
Malham Tarn	7		
Wharfe	16		
Dry Beck	5		

Table 33 - Household definitions, rural model (IMD = Index of Multiple Deprivation)

ID	Bedrooms	House Type	IMD
1	2	Detached	6
2	2	Detached	7
3	3	Detached	6
4	3	Detached	7
5	4	Detached	7
6	4	Detached	7
7	2	Semi	7
8	2	Terraced	7
9	3	Semi	7
10	3	Terraced	7
11	4	Semi	7
12	4	Terraced	7

Table 34 - Households by location, rural model

	Household Type											
Location	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Helwith Bridge		2				2					2	4
Foredale Farm				1	1			1		3		4
Studfold				1			2		2			
Middle Studfold		1				2						
Cragg Hill				1								
Sherwood Brow						2						
Sannat Hall		1				3						
Malham Tarn			2		5							
Wharfe	4		6		6							
Dry Beck			3		1							
Total	**4**	**4**	**11**	**3**	**13**	**9**	**2**	**1**	**2**	**3**	**2**	**8**

A.3 Urban Model

Table 35 - Breakdown of household occupancy used in urban demand model

ID	Bedrooms	Adults	Children	Adult occupancy	No. Households
1	1	1	0	Working age full-time	22
2	1	1	0	Working age part-time	7
3	1	1	0	Working age not working	63
4	1	1	0	Retired	28
5	2	1	0	Retired	30
6	2	2	0	Retired	4
7	2	2	0	1 full time, 1 not working	6
8	2	2	0	1 part time, 1 not working	2
9	2	2	0	Working age not working	4
10	2	2	1	1 full time 1 not working	3
11	2	2	1	1 part time, 1 not working	1
12	2	2	1	2 not working	2
13	2	2	2	1 full time 1 not working	1
14	2	2	2	2 not working	1
15	2	3	0	1 full time 2 not working	3
16	2	3	0	3 not working	2
17	2	1	1	full time	3
18	2	1	1	not working	12
19	2	1	2	full time	1
20	2	1	2	not working	5

Appendix B: Gas Network Replacement Costs

Table 36 - Proportion of gas distribution network 'at risk' by pipe diameter and DNO area [131]

	Pipe Diameter (inches)							
Network Operator	**<3**	**4 to 5**	**6 to 7**	**8 to 9**	**10 to 12**	**12 to 18**	**18 to 24**	**over 24**
EoE	0.7%	9.7%	2.9%	1.2%	1.3%	0.7%	0.3%	0.1%
Lon	0.5%	3.7%	1.9%	0.8%	0.8%	0.5%	0.3%	0.2%
NW	1.8%	5.9%	2.3%	1.1%	1.0%	0.8%	0.2%	0.1%
WM	0.6%	4.4%	1.9%	1.1%	0.7%	0.5%	0.1%	0.0%
NoE	1.6%	8.2%	3.0%	0.5%	0.6%	0.4%	0.0%	0.0%
Scot	0.9%	3.6%	1.8%	0.6%	0.5%	0.1%	0.1%	0.0%
SoE	0.7%	10.5%	4.1%	1.6%	1.2%	0.4%	0.4%	0.1%
W&W	1.0%	4.8%	2.1%	1.5%	0.6%	0.3%	0.0%	0.0%
% of network	**7.8%**	**50.9%**	**20.0%**	**8.6%**	**6.7%**	**3.8%**	**1.6%**	**0.5%**

Table 37 - Costs of gas distribution pipe replacement (2010 £ per m) [131]

	Pipe Diameter (inches)							
Network Operator	**<3**	**4 to 5**	**6 to 7**	**8 to 9**	**10 to 12**	**12 to 18**	**18 to 24**	**over 24**
EoE	62.3	68.1	95.8	177.1	247.5	358.8	501.5	618.9
Lon	76.5	83.5	117.5	217.3	303.6	440.2	615.3	759.3
NW	62.1	67.8	95.4	176.5	246.6	357.6	499.9	616.9
WM	62.8	68.5	96.4	178.4	249.2	361.4	505.1	623.4
NoE	59.8	65.3	91.9	170.0	237.5	344.4	481.3	594.0
Scot	62.5	68.2	96.0	177.6	248.1	359.8	502.8	620.5
SoE	66.4	72.5	102.0	188.8	263.7	382.4	534.5	659.6
W&W	59.3	64.7	91.0	168.4	235.3	341.2	476.9	588.5
Median	62.4	68.2	95.9	177.4	247.8	359.3	502.2	619.7
Mean	**63.8**	**69.6**	**98.0**	**181.3**	**253.3**	**367.2**	**513.3**	**633.4**

Appendix C: Heat Network Costs

Table 38 - Heat network CAPEX, [153] adjusted to 2016 prices

	Units	Cost case Low	Central	High
Network capital costs per length (main network-buried)	£/m	455.76	505.44	555.12
Network capital costs per length (internal pipe)	£/m	101.52	182.52	263.52
Substations cost per kW capacity	£/kW	17.28	37.8	57.24
Domestic HIUs cost per dwelling	£/dwelling	797.04	1161	1432.08
Heat meter cost per dwelling	£/dwelling	530.28	625.32	721.44
Thermal store cost per m3	£/m3	910.44	910.44	910.44

Table 39 - Heat network OPEX, [153] adjusted to 2016 prices – staff costs and business rates are not included in modelling

	Units	Cost case Low	Central	High
Heat network maintenance cost	£/MWh	0.324	0.648	0.972
HIUs maintenance cost	£/MWh	2.16	9.72	17.28
HIUs maintenance cost	£/MW	710.64	885.6	1122.12
Heat meter maintenance cost	£/MWh	0.108	3.672	9.72
(Average staff cost	£/MWh	0.108	18.252	37.584)
(Business rates	£/MWh	2.16	6.48	8.64)

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