Pathways for decarbonising heat

Report for National Grid

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Version History

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Background

Almost half of the UK's current final energy consumption is used to provide heat-related services in buildings and industry. Over two-thirds of this heat demand is currently provided by natural gas, with electricity and coal dominant in the remainder. With the direct and indirect (electricity) reliance on fossil fuels a transformation in the way heat is provided will be required in order to meet the UK's carbon budgets and longer-term 2050 greenhouse gas (GHG) emission target . In the nearer term, heat from renewable sources is also expected to play a key role in meeting the UK's Renewable Energy Directive (RED) target.

Previous studies have shown that the UK can adapt to a low carbon economy in a way that reduces risks associated with security of supply and yet remain affordable to UK customers. Such studies place a high reliance on decarbonising electricity and making greater use of this for heat and transport. However, there remain concerns about the costs of additional electricity generation and network infrastructure to manage the swings (both seasonal and within day) and peak requirements associated with electrifying heat; which are currently far greater than those seen for electricity.

National Grid commissioned Redpoint Energy (a business of Baringa Partners) to explore *cost-optimal* future pathways for decarbonising heat across all sectors to 2050, which address these issues explicitly and which are consistent with both the GHG and RED targets.

Approach

The analytical approach for this study is based around Redpoint's Energy System Optimisation Model (*RESOM*). This is a least-cost optimisation framework which builds upon the energy system model developed by Redpoint as part of an earlier project for the Department of Energy and Climate Change (DECC) and the Committee on Climate Change (CCC) on Appropriate Uses of Bioenergy (AUB)[1]. Data has been compiled from the most recent available public sources, in particular; from DECC, CCC, and Department for Transport (DfT) as well as from National Grid's analysis of domestic heating and network costs.

RESOM is driven by the aim of minimising the total costs of the energy system (capital, operating, resource, etc) to 2050. The model effectively decides what technologies to build and how to operate them to meet future energy service demands[2], whilst ensuring all other constraints (such as the GHG target) are satisfied.

The solution for heating is generated as part of the cost-optimal solution for the energy system as a whole; including transport, electricity and other conversions. The optimisation effectively allows all trade-offs in technologies and energy vectors, in all periods on the pathway to 2050 to be *resolved simultaneously.*

[1] Redpoint (2012) Assessment of the appropriate uses of bioenergy feedstocks in the UK energy markethttp://www.decc.gov.uk/assets/decc/11/meeting-energy-demand/bio-energy/5128-assessment-of-the-appropriate-uses-of-bioenergy-fe.pdf

[2] To better explore seasonal, diurnal and peak demands for heat and electricity RESOM models five characteristic days within each year (winter, spring, summer, autumn, and a 1-in-20 winter peak day), and 4-hourly time periods within each of these days

Scenarios

To explore future pathways for decarbonising heat we have focused on the relative importance of affordability versus UK abatement action in driving the long-term energy system solution. Two core scenarios were created in discussion with National Grid:

- *Abatement Cost Cap (ACC)* – whereby the UK can purchase international emissions credits to meet its GHG targets, which acts as a cap on marginal abatement costs
- *All UK Action (AUKA)* – the UK effectively has to meet the GHG emission target from abatement action only within the UK

The core scenarios broadly reflect 'central assumptions' on factors such as fuel prices and energy service demands from recent Government studies. An extended set of sensitivities was then undertaken to explore how robust key elements of the core solutions are to potential changes. These explored different: fuel prices; technology costs; demands; bioenergy availability; the absence of low carbon options (nuclear, CCS, hydrogen), and restrictions on use of gas in buildings.

Key findings

Cost of the energy system

The overall costs of meeting the 2050 GHG target are likely to be in the range of 1-2% of Government's projected GDP, which is consistent with a number of earlier studies. However, this is dependent on the successful commercialisation and large-scale deployment of a number of key existing *and* developing technologies including the large-scale use of CCS (both in power generation and in conversion processes such as hydrogen), wind, nuclear generation and the mass deployment of heat pumps.

The overall costs of the energy system are driven strongly by the end-point in 2050, given that costs of abatement increase disproportionately as the target tightens in later years. Early planning to position the system to meet this end point could offer significant long-term cost savings.

Decarbonising building heat and tackling swings in demand

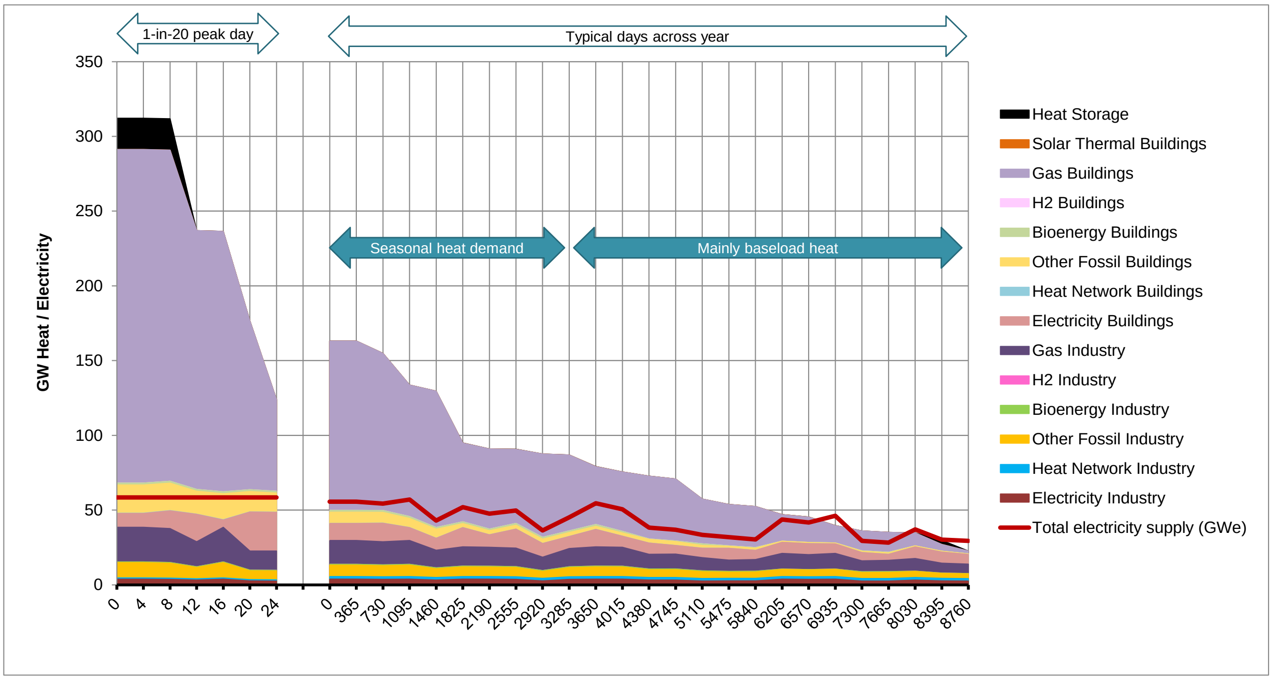
Electrification of heat in buildings, facilitated primarily by heat pumps, is a critical component of decarbonising heat and meeting the 2050 target. This re-emphasises the need for widespread and early decarbonisation of the electricity system, which is important to facilitate long-term decarbonisation of other sectors such as transport and heat. Under all scenarios examined, both peak and annual electricity demand rise rapidly from the 2030s onwards, requiring timely reinforcement.

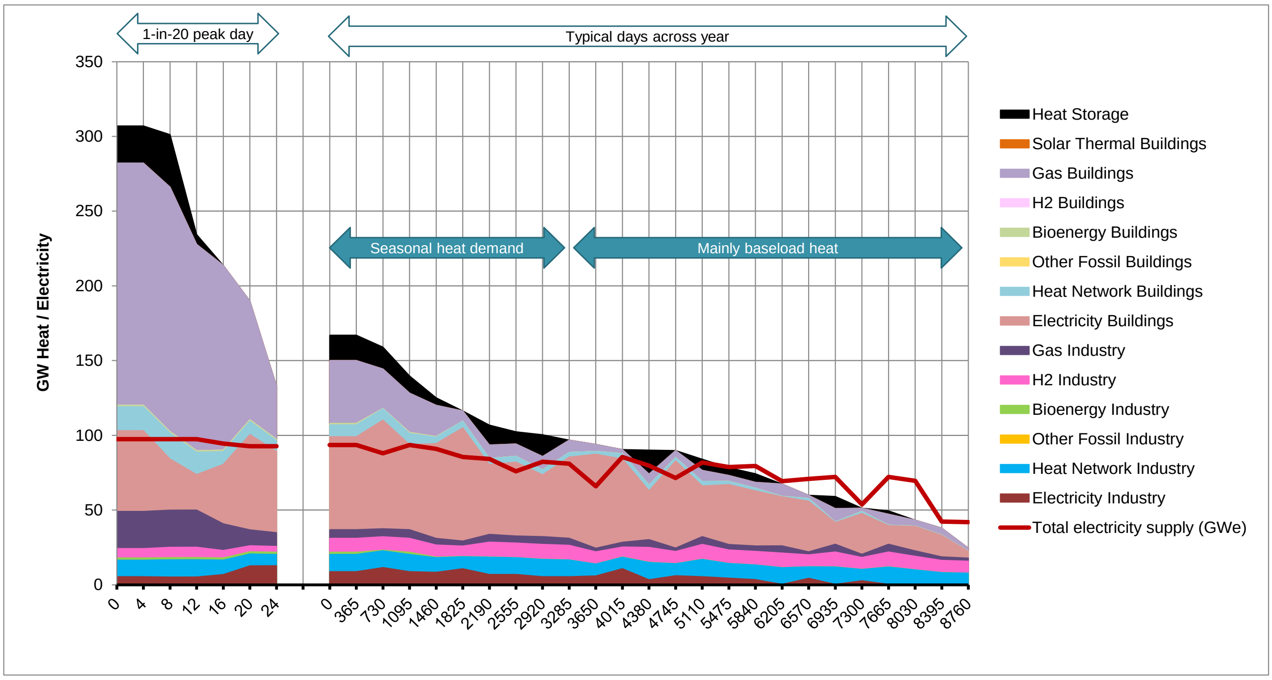
Energy efficiency has a crucial role to play, both in terms of reducing annual and peak demand, although there is a limit to what is likely to be cost-effective for the most expensive options even under very high carbon prices. Even with extensive improvements in efficiency, heat demand is likely to remain significant by 2050 along with sizeable seasonal and diurnal swings in demand, particularly in winter. These will need to be managed carefully to avoid excessive costs of electricity generation and network reinforcement if heat is provided from electric options.

One potentially cost-effective way of tackling these swings is via hybrid electric / gas heating and heat storage strategies. A low risk way to achieve this is by maintaining, significantly reduced, flows of gas in buildings for use in dual-fuel gas / heat pumps devices as illustrated in the figures below. This is more important for domestic buildings than those in the service sector, given the overall scale and shape of demand in the former.

An alternative to retaining gas to manage peak demand is to make more extensive use of heat networks, however, their use in the core scenarios was focused more in industry than buildings. In sensitivities where gas is forced out of buildings by 2050 the costs for home heat and power rise approximately by 10% - 15%, attributed to the wider use of heat networks and additional biomass and electricity for seasonal heating.

Total heat supply duration curves by energy vector – modelled 2011/2012 (top) and AUKA scenario 2050 (bottom)





Note: Duration curve time periods are normalised to the total heat demand across all sectors.

Decarbonising industrial heat

Heat for industry is subject to far less seasonal variation than buildings and can be split into three broad groups. Low temperature space heat requirements are similar to service sector buildings and are primarily decarbonised via a mix of electric ground- and air-source- heat pumps.

Low temperature process heat is provided primarily via localised heat networks (ie reflecting industrial clusters), which expand organically over time. High temperature industrial process heat has fewer abatement options[3]. Whilst gas use declines to 2050, a significant level still remains across all the scenarios. Direct use of bioliquids is not generally a preferred route for what is a relatively scarce bioenergy resource, but significant use is made of hydrogen by 2050 in a number of scenarios.

Long term role of gas

Total gas use declines significantly to 2050 in a number of sectors, particularly buildings and to a lesser extent industry. However, there is still potentially a large scale albeit different role by 2050 enabled by a combination of CCS and hydrogen production. The continued use of gas is not reliant on widespread biomethane use as bioenergy resources can be used for abatement elsewhere in the energy system, particularly in conjunction with CCS, providing 'headroom' for greater remaining emissions in other sectors.

The long-term role for direct gas in buildings shift towards winter seasonal top-up and peaking, particularly for domestic buildings, to help manage seasonal and diurnal swings in heat demand. Direct gas use in industry is retained primarily for high temperature industrial process heat where there are fewer abatement alternatives.

Gas use in dedicated power and CHP shifts strongly towards the latter, in the form of large scale CCGT CHP with CCS, with the heat used predominantly for lower temperature process heating in industrial clusters. The use of gas in hydrogen production (via steam methane reforming with CCS) is also potentially significant as the hydrogen is then used to help decarbonise specific parts of industry and transport, however this use is sensitive to gas prices.

Evolution of the system to 2050 and infrastructure planning

Finally, the evolution of the energy system is characterised by a number of key transition points, such as the rapid growth in electricity demand and roll-out of CCS from the 2030s onwards, followed by wide-scale hydrogen use in the 2040s.

All of these transitions need to be facilitated by the appropriate supporting infrastructure; electricity network reinforcements, CO_2 transport and storage, and a hydrogen distribution network. Given how rapid these transitions can become, it is important that the foundations for the supporting infrastructure are laid sufficiently early. Existing infrastructure that is cost-effective to maintain, particularly the gas network, can be retained to provide optionality (for example repurposing to hydrogen) and greater long-term flexibility for the energy system as a whole.

[3] Novel high temperature electrical routes are another potential option, but have not been included due to data uncertainty

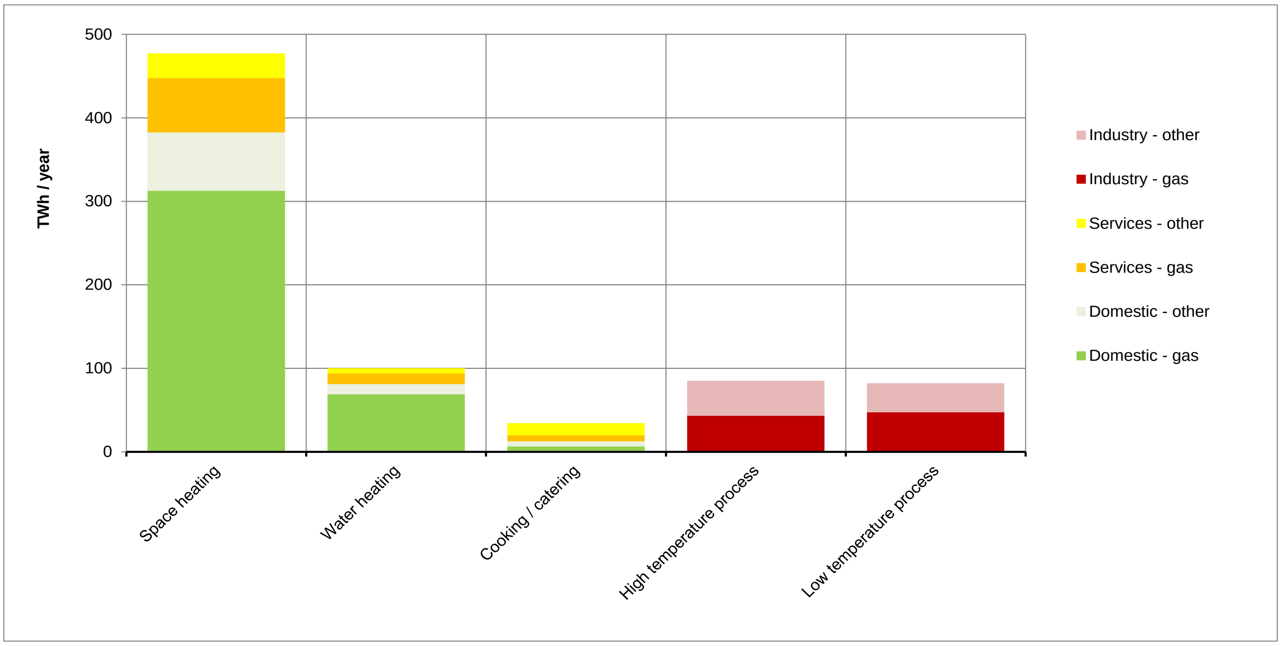
1 Introduction

1.1 Background

Almost half of the UK's current final energy consumption is used to provide heat-related services in buildings and industry, with over two-thirds of this currently provided by natural gas (see Figure 1 below).

As highlighted by the Department of Energy and Climate Change's (DECC) recent heat strategy[4]; meeting the UK's carbon budgets and longer-term 2050 greenhouse gas (GHG) emission target will require a fundamental transformation in the way heat is provided. In the nearer term, heat from renewable sources is also expected to play a key role in meeting the UK's Renewable Energy Directive target[5].

Figure 1 Use of heat across the UK economy (2010)



Source: DECC Energy Consumption in the UK statistics

The evolution of today's energy system to one that is consistent with UK climate change targets may have a significant impact on the UK's electricity and gas network infrastructure. National Grid owns and operates gas and electricity transmission networks and 4 (of the 8) local gas distribution networks serving nearly 11 million customers in Great Britain. Accordingly, National Grid along with other electricity and gas network utilities have an interest in the potential developments that influence the utilisation and on-going investment in maintaining and operating such infrastructure.

Previous studies have shown that the UK can adapt to a low carbon economy in a way that reduces risks associated with security of supply and yet remain affordable to UK customers. Such studies place a high

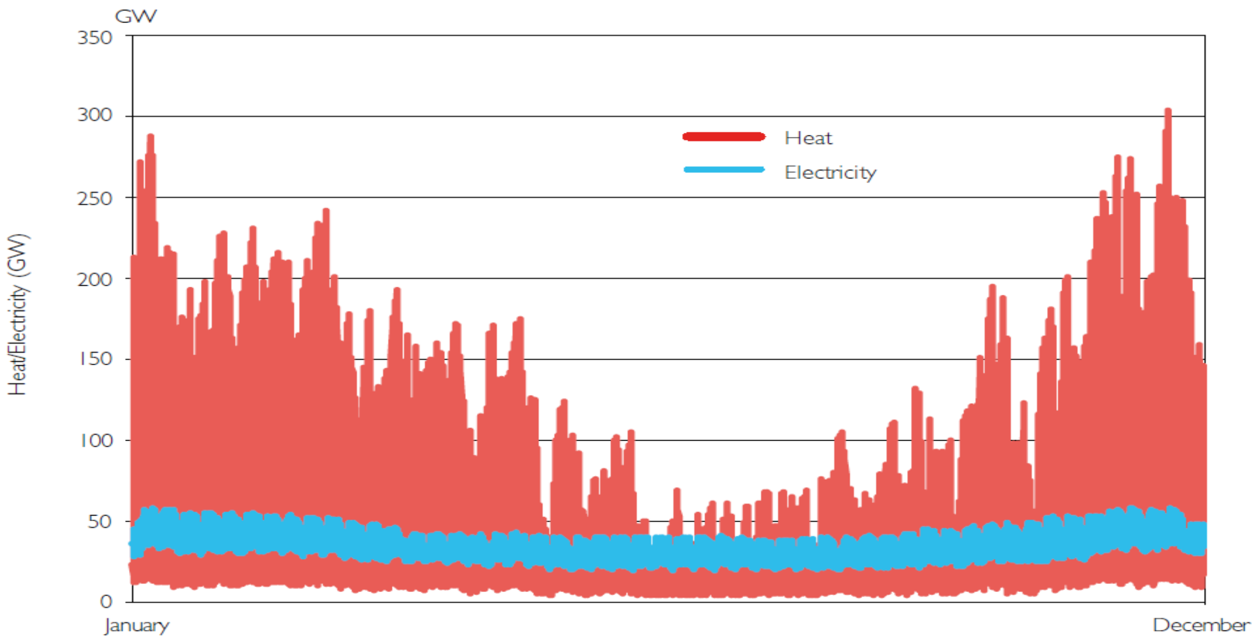
[4] DECC (2012) The Future of Heating: A strategic framework for low carbon heat in the UKhttp://www.decc.gov.uk/assets/decc/11/meeting-energy-demand/heat/4805-future-heating-strategic-framework.pdf

[5] To provide 15% of final energy consumption from renewables by 2020

reliance on decarbonising electricity and making greater use of electricity for heat and transport. Whilst this report covers the entire energy and transport sectors it was commissioned specifically to focus on heat and the role of various energy vectors (electricity, gas, heat, hydrogen) in supporting the UK climate change targets.

The focus on heat is important given the overall scale of current heat demand, which is more than twice that of electricity, and the high level of fossil energy consumption currently associated with it. Heat also has a number of complex challenges associated with it. In particular, National Grid's own analysis has illustrated concerns about the costs of additional electricity generation and network infrastructure to manage the swings (both seasonal and within day) and peak requirements associated with electrifying heat; which are currently much greater than those seen for electricity, as illustrated in Figure 2.

Figure 2 Illustration of half-hourly heat and electricity demand



Source: Imperial College for DECC (2012) The Future of Heating: A strategic framework for low carbon heat in the UK.
Notes: Illustration only for 2010 based on half-hourly electricity demand and an estimate of heat demand using a proxy of natural gas consumption, based on data from National Grid.

Furthermore, heat demands cover a range of different end-users (across industry, domestic and non-domestic buildings) and different geographic locations (eg urban versus rural versus off-grid). These end-users also have very different demand types (eg high temperature industrial heat versus domestic cooking), scales and shapes of demand, and potential for future demand reduction.

All of these factors lead to a complex mix of choices for heat supply, energy efficiency, network infrastructure and storage technology options, which evolve over time as new technologies become available, and are subject to various other barriers and constraints (eg supply chain restrictions or slow adoption by consumers). These choices also have significant implications for the wider UK energy system in terms of the cost for consumers and theoverall cost of meetings the UK's environmental targets; in particular, with respect to the electricity system and the prioritisation of scarce resources such as sustainable bioenergy.

This complexity and the need to consider the wider energy system holistically is a key reason why this study has focused on the use of least-cost optimisation to provide an internally consistent, meaningful and well-understood framework to explore future decarbonisation pathways. It provides a way to better understand how we can meet our environmental targets, whilst satisfying concerns around energy security, and meeting future energy service demands in a way that is least cost for society (and hence indirectly for consumers) as a whole.

Secondly, least-cost optimisation was used given the need to explore pathways over the long-term to 2050, which is beyond the time horizon of most existing policies, particularly incentive schemes. However, our long-term emission targets are specified in an absolute sense (ie an 80% reduction in GHG emissions by 2050 compared to 1990 levels); hence optimisation provides a way to understand how we can, from a technology-orientated perspective, best meet these long-term goals. The wider policy framework can then be adapted to try to ensure that these targets are met in the most effective way possible.

1.2 Objectives of the study

National Grid commissioned Redpoint Energy (a business of Baringa Partners) to explore future pathways for decarbonising heat across all sectors to 2050, and in particular to:

- Explore these from a *least cost-optimisation* perspective, within the context of the full energy system, to better understand the potential trade-offs across the system as a whole on a consistent basis
- Ensure these pathways are consistent with the UK's GHG and renewable energy targets
- Examine the role of key energy carriers/vectors such as electricity, gas, heat networks and hydrogen and key technologies such as heat pumps and hydrogen boilers amongst others
- Ensure that the impact and knock-on effects of the significant within year variation in demand for heat are sufficiently understood

2 Key issues associated with supplying heat

2.1 Introduction

To assess potential decarbonisation pathways for heating a number of important issues must be considered, which we have attempted to capture in our analysis in as robust a manner as possible (see section 3).

2.2 Wider energy system interactions

Given the scale and variety of UK heat demands across different parts of the energy system it quickly becomes difficult to assess appropriate pathways without a consistent understanding of the wider system implications. By considering the full energy system in a holistic manner it is possible to explore these trade-offs directly, both in terms of costs and GHG emissions, and the optimal way to meet the RED targets.

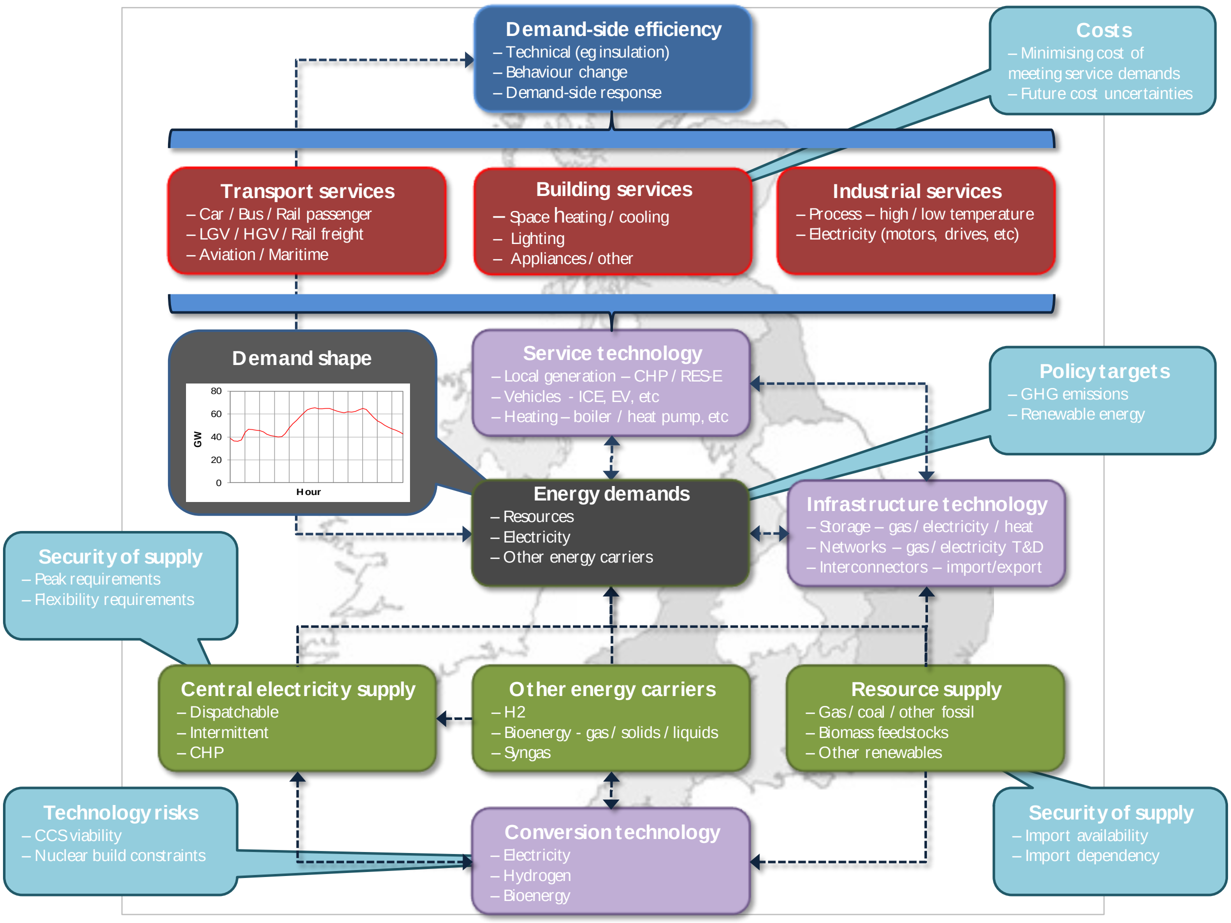
An example of this is the cost of demand side efficiency versus the costs of additional heat supply, and the knock-on implications in areas such as centralised electricity generation and network reinforcement.

Bioenergy is another case in point. Given its value in reducing emissions, coupled with limited availability, this means its use in the energy system should be prioritised to where it is most effective. Energy-system modelling to support DECC's bioenergy strategy and CCC's bioenergy review has highlighted[6] a key use of bioenergy in conjunction with carbon capture and storage (CCS) applications to help generate net negative emissions across the system as a whole. This may then mean that certain heating options such as small to medium scale direct biomass boilers are a far less attractive use of the resource.

An overview of some of the key issues and interactions across the energy system is illustrated in Figure 3.

[6] Redpoint (2012) Assessment of the appropriate uses of bioenergy feedstocks in the UK energy markethttp://www.decc.gov.uk/assets/decc/11/meeting-energy-demand/bio-energy/5128-assessment-of-the-appropriate-uses-of-bioenergy-fe.pdf

Figure 3 High level overview of key energy system interactions



2.3 Segmenting heat and the building stock

Whilst it is important to consider wider energy system interactions it is also critical that any analysis contains a sufficiently detailed representation of heating, in terms of different:

- Sectors – industry, services, domestic
- Locations – such as urban, rural, off gas-grid
- Building types / age – such as a large pre-war detached house or new-build flat, *and*
- Service demand types – high and low temperature process heat, hot water, space heat, cooking

The factors in this segmentation will have different implications for technology choices and costs. For example:

- Certain technologies cannot supply particular service demands, such as limitations on the role of electricity for high temperature process heat or the use of ground source heat pumps in high density housing
- The shape and scale of demands in different building types has implications for the operation and costs of different heating technologies, such as heat pumps and the impact on peak demands or the ability to interact with heat storage, *and*

- The location of demand which may, for example, have implications for the cost of heat networks

If the optimal choices for heating are made at a detailed level of segmentation, whilst still considering the wider system interactions, they are more likely to generate a more realistic heating solution at the system level.

2.4 Seasonal and within day shape of heat demand

As illustrated in Section 1.1the within year and day variability of heat demand is substantial greater than the current variability in electricity demand. Electrifying large portions of heating would add substantially to peak generation and network requirements, even if supplied by heat pumps with a high Coefficient of Performance (COP[7]). The impact is even more significant when considering *peak heating* requirements during extremely cold (eg 1-in-20) winters and the potential drop in heat pump COP at these times.

By providing sufficiently detailed within year and day resolution of both heat and electricity supply / demand balancing a more accurate assessment of the role of key technologies can be undertaken. For example, the relative roles of peaking electricity plant and storage, versus heat storage at the building side to help smooth the underlying demand for electricity.

2.5 Technology options

Within any assessment of heating pathways sufficient breadth of technology options and energy vectors is required to ensure an understanding of the potential trade-offs. For example, at a daily level it is important to consider not only electricity storage but also heat storage, both at the building level or on a larger scale. Similarly, the potentially significant long-term role for heat networks means it is important to consider a range of heat supply options through dedicated boilers and combined heat and power (CHP), to 'waste heat' from large scale power generation.An overview of the key heat supply technology options is provided in Table 1.

Table 1 Overview of key heat supply technology options

Type	Description
Electric heat pumps	Air-source and ground-source variants using ambient heat energy due to generate efficiencies >100%. Used primarily to produce low temperature building heat for hot water / space heating Large-scale (and potentially higher temperature) variants are being researched, but have not been included in this study.
Electric resistive heating	Traditional electric heating for buildings and lower temperature industrial process heat Novel electrical technologies for high temperature process heat are currently being researched, but have not been included in this study
Gas boilers	Standard existing technology providing range of building and industrial low and higher temperature process heat demands
Gas heat pumps	Variant on air source heat pump using gas as a fuel input rather than

[7] Which can also vary significantly across the year for Air Source Heat Pumps (ASHPs)

	electricity These have efficiencies broadly in the range 130%-160%, but significantly lower than electric heat pumps Gas heat pumps are currently used at larger scale in service sector building and development is currently being undertaken on domestic-scale equivalents
Bioenergy boilers	Covers a range of solid biomass and bioliquid boilers, both providing a range of building and lower temperature industrial process heat Bioliquid boilers are also well suited for higher temperature industrial process heat.
Solar thermal	Used to provide hot water for domestic and service sector buildings
Conventional fossil boilers	Standard existing coal and oil boilers providing range of building and industrial low and higher temperature process heat demands
Hydrogen boilers	Low carbon equivalent of gas boiler providing range of building and industrial low and higher temperature process heat demands Already used in a number of industrial applications
Micro CHP	Domestic building scale micro-Combined Heat and Power, providing space heat, hot water and some building electricity A range of possible variants exist including gas-fired micro-CHP and hydrogen based fuel-cell CHP
Heat network supply options	A range of sources are available to feed into heat networks
- Dedicated district heat boiler	This covers dedicated gas and bioenergy boilers
- Dedicated CHP	This covers the range of dedicated CHP running on different fuel sources such as gas, dedicated biomass or AD (anaerobic digestion)
- Waste heat from large thermal power stations or conversion processes	Large-scale thermal power stations (including nuclear, CCGT, coal, biomass) produce low-grade waste heat as part of their overall thermodynamic cycle. This is normally released to the environment, but can be upgraded (at minimal electrical efficiency penalty – ie high z-factor) and used as an input to heat networks

2.6 Behaviour and consumer issues

Consumer / end-user behaviour can affect potential heating choices in a number of ways, for example, changes in demand at different price levels[8] or the speed of acceptance of new technologies.

Whilst behaviour and consumer issues are not a focus of this particular study[9], some of these are accounted for or explored indirectly, via constraints in the analytical approach (eg limits on the build rate of new technologies) or via sensitivities (eg low demand scenarios).

[8] As modelled by the MARKAL-ED model used by DECC for their Carbon Plan

[9] National Grid, as part of the Energy Networks Association, is currently working on parallel study examining these issues. Some of the outputs from the ENA project could then be fed back as refined inputs to the analytical approach for this study.

3 Overview of modelling approach

3.1 Background

The analytical approach for this study is based around Redpoint's Energy System Optimisation Model (RESOM). This is a least cost optimisation framework, similar in a number of respects to the basic MARKAL/TIMES framework[10] or the ETI's Energy System Modelling Environment (ESME)[11] model.

RESOM builds upon the energy system model developed by Redpoint as part of the project for DECC and the CCC on Appropriate Uses of Bioenergy (AUB).The background to the model is discussed in detail in the accompanying report6.

To ensure that all future energy service demands and other constraints are met, the model effectively decides:

- what resources to use,
- what technologies to build and when, *and*
- how to operate this stock of technologies over time for all the main energy sectors; heating, transport, electricity and other conversions.

Other constraints include the GHG emissions and RED targets[12], resource availability limits, energy balances, and build rate constraints.

To assess optimal pathways for heating, RESOM is driven by the aim of minimising the total discounted energy system costs (capital, operating, resource/fuel, etc) over the modelled time horizon; currently 5-year periods to 2050.

The solution for heating is then generated as part of the cost-optimal solution for the system as a whole. The process of the optimisation effectively allows all possible trade-offs of technologies, their utilisation, and use of resources, over all time periods on the pathway to 2050 to be *resolved simultaneously.*

Conceptually, the model is focused on optimising a complex set of technology and energy choices under a given set of assumptions, across the entire energy system, from a societal resource cost perspective. It is also designed to aid scenario analysis, particularly over the medium and long term, rather than trying to establish near term projections. This is fundamentally different from other modelling approaches such as macro-economic/econometric or agent based models, which explore price based impacts more closely and the impact, for example, on investor behaviour in the near term.

As a result, the model for this study has a relatively abstract representation of existing policy. It is focused on meeting both the absolute GHG and RED targets in an optimal manner, and not the likely impact of

[10] http://www.decc.gov.uk/assets/decc/11/cutting-emissions/carbon-budgets/2290-pathways-to-2050-key-results.pdf

[11] http://www.eti.co.uk/technology_strategy/energy_systems_modelling_environment/

[12] Including the various RED accounting rules within the optimisation.

incentive policies or subsidies such as the Renewable Heat Incentive (RHI) or Renewables Obligation (RO) on deployment of renewables[13], or the Green Deal in the uptake of energy efficiency measures.

3.2 Key model updates for this study

As part of this study a number of significant enhancements have been made to the model to assess better the pathways for decarbonising heat. These are summarised briefly below and outlined in more detail in Appendix A:

- Fully resolved within year seasonal and diurnal timeslices have been added, to capture swing of heating across the year and within the day and the interaction with the electricity system
- Endogenous seasonal (gas and hydrogen) and diurnal (electricity and heat) storage has been added (whereby RESOM decides the quantity of storage to build and how to operate it within year)
- The segmentation of heat demands has been revised to better reflect the possible trade-offs
- A number of new heat technologies have been added
- A number of new security of supply constraints have been added in relation to electricity and gas, to reflect issues that are not directly captured within RESOM's temporal resolution (even with the additional disaggregation within year), *and*
- A new partial foresight optimisation mode, the model can now optimise with perfect foresight, fully myopically or with a user defined level of foresight, to explore the impact of infrastructure lock-in.

3.3 Key data updates

In addition to the core public data sources used in the previous Redpoint (2012) AUB6 study a number of additional sources of information were reviewed as outlined in Table 2.

[13] Although it could, for example, be used to gain a high-level understanding of how such support schemes could distort deployment relative to an 'optimal' solution

Table 2 Additional data sources

Area	Source
Long-term heat decarbonisation, heat networks	Element Energy (2012) Options for decarbonising heat in buildings 2030-2050 report for CCC[14]
Domestic building energy demands and retrofit options	National Grid (2010 / 2011)– Beywatch and IFI3 – various studies eg: – Impact of Future Energy Systems on Energy Networks – Electric Heat Pump Analysis & Validation – Heat data load by House Type datasheets
Gas Heat Pumps	Gas Terra (2010) Gas Heat Pumps KiwaGasTec direct input
Hydrogen	KiwaGasTec direct input AEA (2012) Potential for post 2030 emissions reduction from industry – report for CCC[15]
Various within year demand shapes / technology profiles and networks data	Redpoint (2010) Gas Future Scenarios report for Energy Networks Association[16]

As part of this project we also commissioned Ecofys to undertake a review of technology parameters for a number of technologies that were considered highly uncertain in the earlier AUB work, with a focus on gasification-related technologies such as bio-synthetic natural gas (SNG) production, both with and without CCS.

3.3.1 Adjustments to domestic heat technology costs

A particular issue for a number of, primarily domestic-scale, heating technologies is that the total cost per dwelling is driven more by the overall fixed cost of the installation than the actual kW capacity.

For example, the physical underlying cost of a gas boiler varies relatively little whether it is rated at 10kW or 20kW maximum output, whereas the total installation cost is broadly the same. Similar issues apply for a range of other technologies such as district heating.

This can be problematic for any Linear Program (LP) optimisation model, where the £/kW unit cost specified for a given technology (installed in a given time period) remains the same regardless of how much capacity is installed. As the typical heat demand varies significantly across the different building types this can lead to an inaccurate reflection of typical costs per building.

For example a new build, well insulated flat may have a maximum heat demand of a few kWs whereas an inefficient detached house may have a maximum demand of the order of 20kW+. The real cost of a gas

[14] http://hmccc.s3.amazonaws.com/IA&S/Element%20Energy%20-%20Decarbonising%20heat%20to%202050%20-%20Report.pdf

[15] http://hmccc.s3.amazonaws.com/IA&S/AEA%20-%20Potential%20for%20post-2030%20emissions%20reduction%20from%20industry%20-%20Report.pdf

[16] http://www.energynetworks.org/modx/assets/files/news/publications/ena_gas_future_scenarios_report.pdf

boiler installation in both cases will be quite similar, whereas an LP with a fixed £/kW will lead to an implied installation cost potentially an order of magnitude smaller.

To adjust for this problem, as far as is practical with the scope of an LP, we have defined a minimum total installation size per building where the base £/kW still holds, for example 10kW for gas, biomass, and other boilers. Where the building type within a given heat segment (after basic efficiency measures such as loft and cavity wall insulation have been installed) has a lower maximum demand, the £/kW is then scaled up leading to a higher £/kW unit cost. In this way, heat segments with low demands such as new flats will not see the equivalent of an unrealistically low cost per dwelling.

A more accurate way to account for this issue would be to change the basic model formulation to a Mixed Integer Program (MIP). This would allow us to specify a choice of discrete packages of heating-related technologies for each building heat segment, with the costs specified directly on a 'per building basis' (discussed further in Appendix B) but has a severe impact on model performance.

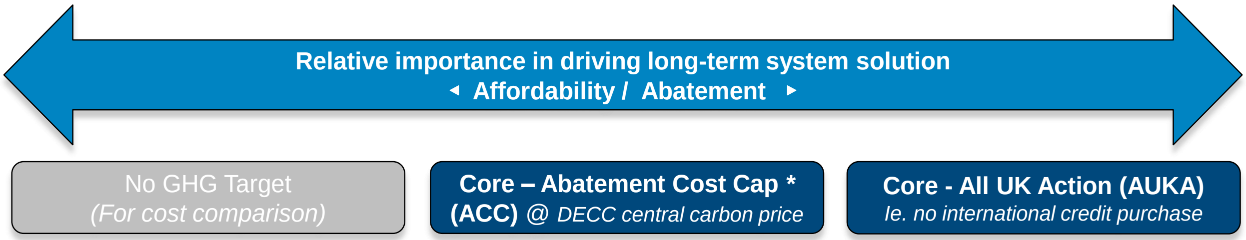
4 Scenarios

4.1 Core scenarios

To explore long-term pathways for decarbonising heat we have focused on the relative importance of affordability versus UK abatement action in driving the long-term energy system solution. As part of this, a reference scenario with no GHG target and two core scenarios and were created in discussion with National Grid along with a number of sensitivities described in (Section 4.2):

1) No GHG target –used as a baseline to compare energy system costs
2) **Abatement Cost Cap(ACC)** – whereby the UK can purchase international emissions credits to meet its targets with the price of these set at DECC's central scenario for the non-traded sector[17], which reaches over £200/tCO2 by 2050; this effectively acts as a cap on marginal abatement costs
3) **All UK Action (AUKA)** – the UK effectively has to meet the GHG emission target from abatement action only within the UK

Figure 4 Core scenarios



Aside from the option for credit purchase in the ACC scenario, the core scenarios are comprised of the same underlying assumptions:

- An emissions target path reflecting the current carbon budgets and a linear path to the 2050 target thereafter. The pathway is shown by the net emissions in the chart in Section 5.2.1 with allowed CO_2 emissions in 2050 of 63 MtCO2e/year.[18] This effectively represents a reduction of ~89% in CO_2 emission covered by the model in 2050 versus 1990 levels
- The overall RED target for 2020 of 15% renewables in final energy consumption and the transport sub-target of 10% renewables in final energy consumption for road transport. Intermediate Renewable Transport Fuel Obligation (RTFO) targets are also included

[17] http://www.decc.gov.uk/en/content/cms/emissions/valuation/valuation.aspx

[18] Allowed CO_2 emissions in 2050 are 63 $MtCO_2e$/year, which reflects the full UK 2050 target of 160 $MtCO_2e$/year, including a hypothetical UK share of international aviation and shipping emissions, minus 55 Mt for non-CO_2 GHGs (assuming a 70% reduction vs 1990 levels). Further adjustments of 42 $MtCO_2$ have been made to account for the current absence in the model of process and non-energy emissions and abatement from industrial CCS.

- The base energy service demands are broadly consistent with the "Level 2s - ambitious but reasonable" from the March 2011 version of DECC's 2050 pathway calculator[19]:
  - For the domestic sector this relates to building comfort levels as RESOM contains endogenous options for energy efficiency improvements, which broadly reflect the range of Levels 1 to 4 in the DECC calculator
  - For industry it maps to level "B2 – growth at current trends and moderate improvement in efficiency and process emissions"
- Fossil fuel prices are taken from DECC's central scenario from the October 2011 Updated Energy Projections (UEP)
- Bioenergy resources are consistent with the more conservative "core lower resource scenario" from the previous AUB study6, the "core higher resource scenario" is tested as part of the sensitivities
- A global social discount rate of 3.5% has been applied, *and*
- The core scenarios were run with perfect foresight and in LP (linear program) mode.

4.1.1 Key data constraints

A number of minimum / maximum constraints are imposed as part of the core scenarios, these are broadly consistent with the previous Redpoint (2012) AUB study6 and include:

- Maximum build quantities by 2050:
  - 39 GW nuclear – (the maximum use of waste heat from nuclear is capped at 6% of output – as this is broadly equivalent to the current proportion of heat demand within 30km of new nuclear sites from the DECC heat map[20])
  - 34 GW onshore wind, 130 GW offshore wind
  - Maximum domestic energy efficiency improvements capped at 90% of technical potential to reflect hard to treat homes
  - Waste heat network capacity capped at 40% of heat demand from CCC (2012) study (see Table 2)District Heat Constrained Scenario
  - Various other maximum build quantity constraints as per the Redpoint (2012) AUB study6 – eg near term deployment of Anaerobic Digestion (AD) plant and renewable heat to 2020
  - Electricity storage constrained to maximum of approximately 70 GWh of storage volume and just under 14 GW of power output
  - Heat storage constrained to an equivalent of a typical 200 litre tank in the largest domestic building type (ie detached) and scaled accordingly by average floor area for other domestic and service sector buildings.
- Maximum build rates:

[19] http://www.decc.gov.uk/en/content/cms/tackling/2050/2050.aspx

[20] http://ceo.decc.gov.uk/nationalheatmap/

  - A group build rate across all CCS technologies, effectively capping the maximum CCS deployment in 2030 to 15 GW and 70 GW by 2050
  - A similar group constraint for all hydrogen production technologies, with similar values
  - Domestic efficiency measures are restricted to the maximum implied build rates in CCC (2012) study on Options for decarbonising heat in buildings 2030-2050 mentioned in Table 2
  - Various other maximum build rate constraints on power, transport and heating as per the Redpoint (2012) AUB study6
- Minimum load factors are applied to a number of new technologies to avoid excessively rapid transitions in technology deployment over time (since a private company would not invest if levels of operation did not generate a sufficient return)
  - 50% for large conversion plant (eg hydrogen, biofuels, etc) and power generation
  - 2% for peaking plant (to reflect emissions not covered due to the more limited diurnal temporal granularity in RESOM)
  - 10% for a range of flexible heating technologies
- Minimum build quantities for a range of electricity technologies to 2025 to calibrate better nearer term deployment given recent policy changes; including:
  - 5 GW gas peaking plant
  - 6 GW onshore wind / 10 GW offshore wind
- Electricity interconnector capacity is set according to National Grid's Gone Green (2011) scenario rising to 10 GW by 2050; it only contributes to the peak reserve margin constraint, net flows are assumed to be zero

A summary of where these constraints are binding in the core scenarios is outlined in Section 5.2.5.

4.2 Sensitivities

It is important to emphasise that there is no such thing as a robust *projection* to 2050. The approach taken in this study has been to construct our best central *scenario* and test the robustness of key aspects of the solution via multiple sensitivities, to help draw out insights into the possible pathways for heating. The following sensitivities have been undertaken on both the core AUKA and ACC scenarios.

Table 3 Sensitivities undertaken on both core AUKA and ACC scenarios

#	Name	Rationale	Notes
4-7	High and low gas prices	Understand sensitivity of long-term uses of gas to price changes	Using DECC's October 2011 UEP high / low ranges
8-9	No peak day	Understand differences in system designed for a typical winter versus 1-in-20 peak winter day	
10-11	No gas in buildings	Explore impact of key element of DECC heat strategy	Linear decline in the maximum quantity of gas which can be used in domestic and service sector buildings from

			around 2030 to zero by 2050
12-13	No decline in electric heat pump costs	Understand sensitivity of key electrical heat decarbonisation technology to its cost	
14-15	Low heat network costs	Understand sensitivity in cost of key heat decarbonisation infrastructure compared to cost of heat supply source	50 per cent lower
16-17	Lower domestic demand	Understand extent to which lower demand levels make it easier to electrify heat	Comfort levels set broadly in line with the DECC Pathways calculator Level 3 (Level 2 in the core scenario). Efficiency improvements for the domestic sector are still endogenous to the model.
18-19	Capped LDN peak electricity demand	Explore situation where progress on network reinforcement is minimal	Capped at 60 GW
20-21	Higher bioenergy availability and lower bio-SNG costs	Understand change in role of biomethane under more favourable bioenergy conditions	Consistent with the "core higher resource scenario" in the AUB study (see footnote 4). Bio-SNG costs 25 per cent lower.

Additional sensitivities have also been run against the core AUKA scenario as set out below.

Table 4 Additional sensitivities undertaken on core AUKA

#	Name	Rationale	Notes
22	No new nuclear build	Impact on energy system and heat pathway after removing a major source of low carbon energy.	
23	No CCS options available (of any type including retrofits)		Note that the GHG target for 2050 is also adjusted downwards to account for the lack of emissions reduction from industrial CCS, which is outside the scope of the model
24	No hydrogen production options		
25	High hydrogen costs	Understand sensitivity of long-term hydrogen use to cost of production and distribution	50 per cent higher production and network costs
26	High nuclear waste heat accessibility	Understand impact of substantial additional low cost heat supply on role of heat networks	Maximum of 25% of all 'waste heat' from nuclear accessible as opposed to 6% in the core scenarios (based on the percentage of current demand within a radius of 30km from the new build sites)
27	No gas in *new* buildings from 2020	Explore impact of potential policy change on long term heating pathways, whilst still allowing gas to	Both domestic and service sector buildings

		be maintained in existing buildings	
28	Peak day gas use dependent on some seasonal use	Explore the impact of gas boiler capacity not being allowed / likely for peak day use only – ie forcing the requirement that gas use on the peak day must be accompanied by seasonal winter use as part of a dual-fuel device	Overall use on the peak day is limited to a multiplier of two on typical winter day
29	Repurposing of gas network for H2	Understand sensitivity of long-term hydrogen use to cost of distribution and potential for re-use of existing infrastructure	Effectively providing a cheaper distribution network option than the dedicated hydrogen LDN technology, but restricting the maximum flow of gas as a result of its use,ie assuming geographically self-contained sections of the gas grid are 100% repurposed over time
30	Fully myopic and partial foresight runs	To understand the impact of infrastructure lock-in and potential planning horizon on pathways compared to a perfect foresight solution	
31	Max nuclear 75 GW	To explore the impact of a nuclear dominated low carbon future	
32	Max nuclear 75 GW & no gas buildings		
33	Max nuclear 75 GW and no CCS		

5 Key results

5.1 Structure of results

The results in this section present both the core scenarios (focused primarily on the AUKA core scenario where the UK meets the GHG target by domestic abatement only) and sensitivities together, and are structured as follows:

- An overview of the key elements of the energy system (emissions and key energy vectors), and sector outside of heating (such as transport) is provided first, to help provide context for the heat pathways
- An overview of heat supply across all sectors
- A breakdown of heat supply by sector– domestic, services and industry, *and*
- Breakdown of energy system costs.

Caveats

It is important to note that technology-orientated energy system optimisation models such as RESOM, ESME or MARKAL/TIMES provide an 'idealised engineering' view of the future. They are well suited to the medium to longer term where policy is uncertain and constraints can be added to reflect real world issues such as supply chain limits for new technologies.

However, as we are modelling long term policy objectives rather than current policy instruments there is a need to provide some additional calibration of results in the early periods to reflect expected deployment with the optimisation given increasing freedom in later stages. For example, we have used Redpoint's analysis of investor behaviour in response to current and proposed policy incentives[21] to estimate a lower bound deployment of a small number of power generation technologies over the next 15 years[22].In practice, these constraints are often not binding or the installed capacity exceeds them over the medium to long-term, beyond the period of calibration.

Optimisation models can also sometimes lead to sizeable switches in results due to small changes in costs. This is mitigated by, for example, the use of build rate constraints (to try to account for technical restrictions on the rate of new infrastructure deployment) and minimum load factors (eg to try to mimic the likely minimum level of utilisation that a private investor would require to generate a return on their investment), which reduce the speed of switching.

Finally, much of the longer-term input data is inherently uncertain, in particular assumptions on future technology and energy costs. This study has focused on the use of the best available central data estimates from public studies from DECC, CCC, etc, as its starting point and has used a range of sensitivities to test how robust the core scenarios are to changes in input assumptions.

[21] For example, see Appendix A in Redpoint (2011) Modelling the Impact of Transmission Charging Options, for a description of the underlying modelling approach http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Modelling%20the%20impact%20of%20transmission%20charging%20options.pdf

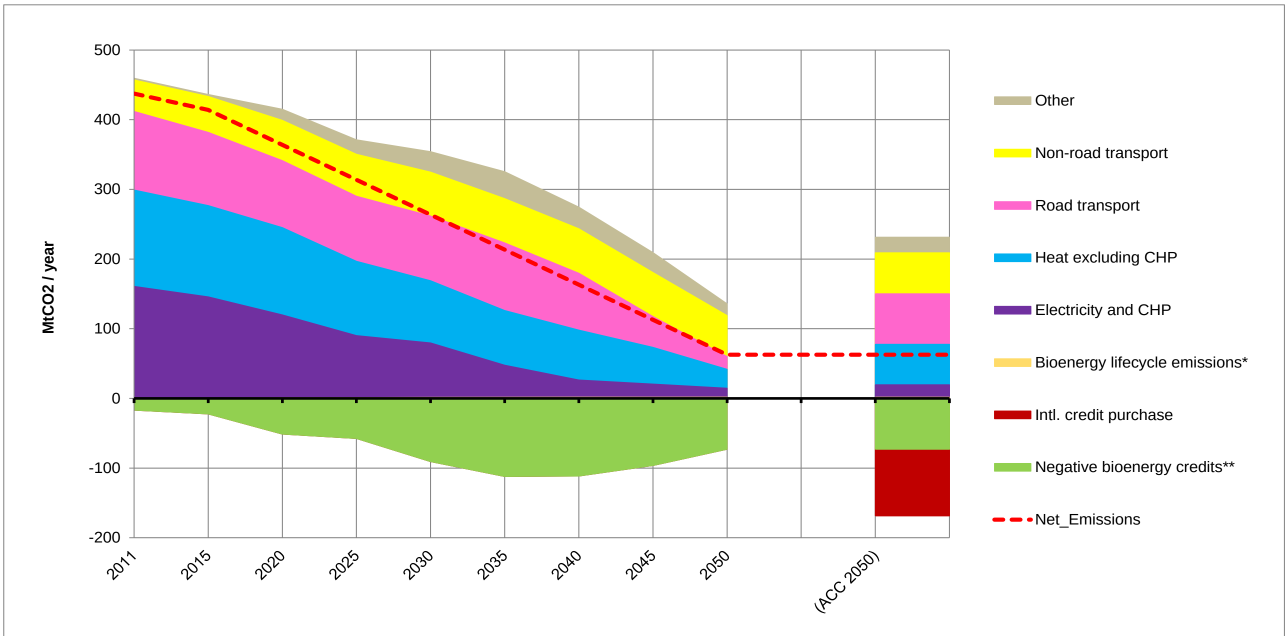
[22] Key lower bounds include 10 GW offshore wind, 6 GW onshore wind, 30 GW CCGT (in total including existing capacity), 5 GW OCGT, by 2025/2030

5.2 Overall energy system

5.2.1 Emissions

The emissions target (as shown by the net emissions in Figure 5) reflects both the UK carbon budgets (currently set out to 2027) and the 80% reduction required by 2050. With adjustments for the scope of emissions covered by the model this reflects an 89% reduction in energy system CO_2 under the AUKA scenario compared to 1990 levels.

Figure 5 Annual GHG emissions (AUKA and ACC 2050)



Notes: Negative emissions from bioenergy reflect those 'absorbed' during growth. Positive emissions from bioenergy combustion and processing are accounted for above the line and contribute to emissions in the specific sectors. Where bioenergy is combined with CCS, fewer positive emissions are (re-)released and net negative emissions are generated overall. The 'Other' category reflects emissions associated with conversion processes such as biofuel production or hydrogen production.

Under the core AUKA scenario significant emissions reductions are seen across all sectors, with electricity effectively decarbonised, by the late 2030s[23]. Compared to the ACC scenario where international credits can be purchased, the AUKA scenario has further abatement in transport and heat, in part facilitated by the expansion of bio-produced hydrogen and greater use of electric vehicles in these sectors. However, heating is not completely decarbonised as gas is retained to help manage seasonal swings in buildings and provide a more cost-effective route for high temperature industrial heat production, for which there are fewer alternatives.

The shadow price of carbon under the core AUKA scenario rises to over £450/tCO_2 by 2050. In contrast, with the cost of carbon capped at just over £200/tCO_2 in the core ACC scenario, extensive use is made of international credits to help meet the overall target.

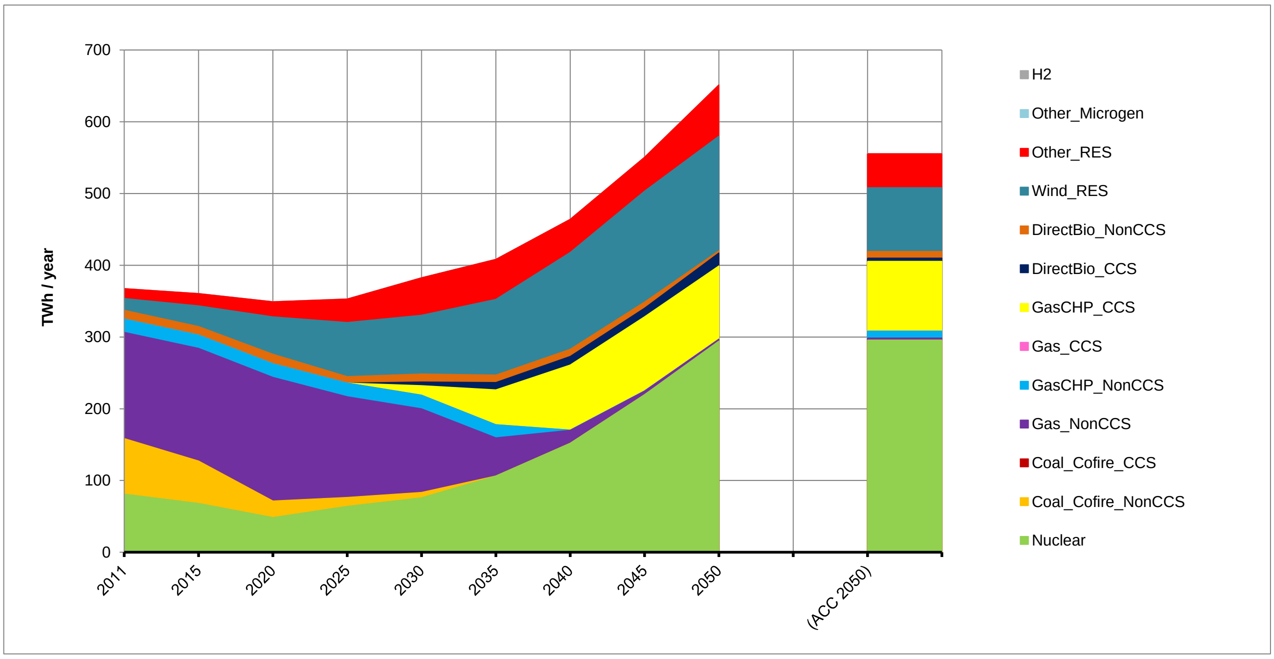
[23] NB Negative bioenergy credits need to be allocated to the sectors in which the bioenergy is used to offset the positive emissions, with the majority going to road freight transport and industrial heat, facilitated by large-scale bio-hydrogen production, by 2050 (see section 5.2.4).

However, it is important to note that the shadow price of carbon rises gradually to 2045 (just over £200/tCO_2 in the core AUKA scenario). It is the incremental reduction in emissions from 2045 to 2050 that disproportionately affects the cost of abatement and effectively doubles the shadow price. Hence in the default perfect foresight runs[24], the end point GHG target in 2050 is a strong driver of the system design for the pathway as a whole.

5.2.2 Electricity

A key of theme across virtually all scenarios, including both of the core scenarios, is the role of electrification in facilitating decarbonisation. Electricity is effectively decarbonised via a combination of nuclear, renewables and CCS with a significant rise in both annual and peak demands from the 2030s onwards, even with efforts to manage the rise in peak demand from load switching technologies associated with electrified heating and transport. Electrification in these sectors is higher under the core AUKA scenario than the ACC scenario, leading to a correspondingly higher electricity demand. Significant use is also made of gas with CCS from around 2030, focused primarily on large scale CCGT CHP combined with CCS. The heat produced from CCGT CHP is predominantly used for industry.

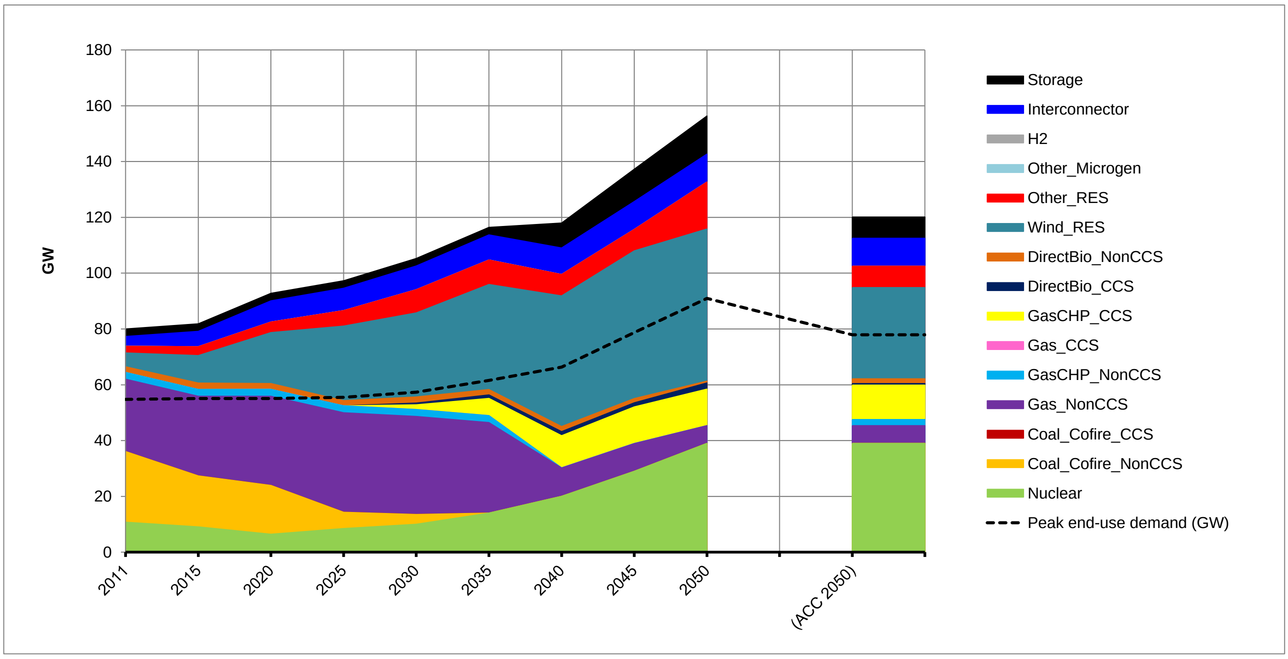
Figure 6 Annual electricity supply (AUKA and ACC 2050)



Nuclear reaches its maximum installed capacity (of 39 GW by 2050) in all scenarios where it is allowed (as well as 75 GW in the high nuclear sensitivities 31-33), as shown for the two core scenarios in Figure 7. There is also extensive use of wind across the scenarios, supported by non-CCS gas, storage and other controllable plant to provide sufficient backup.

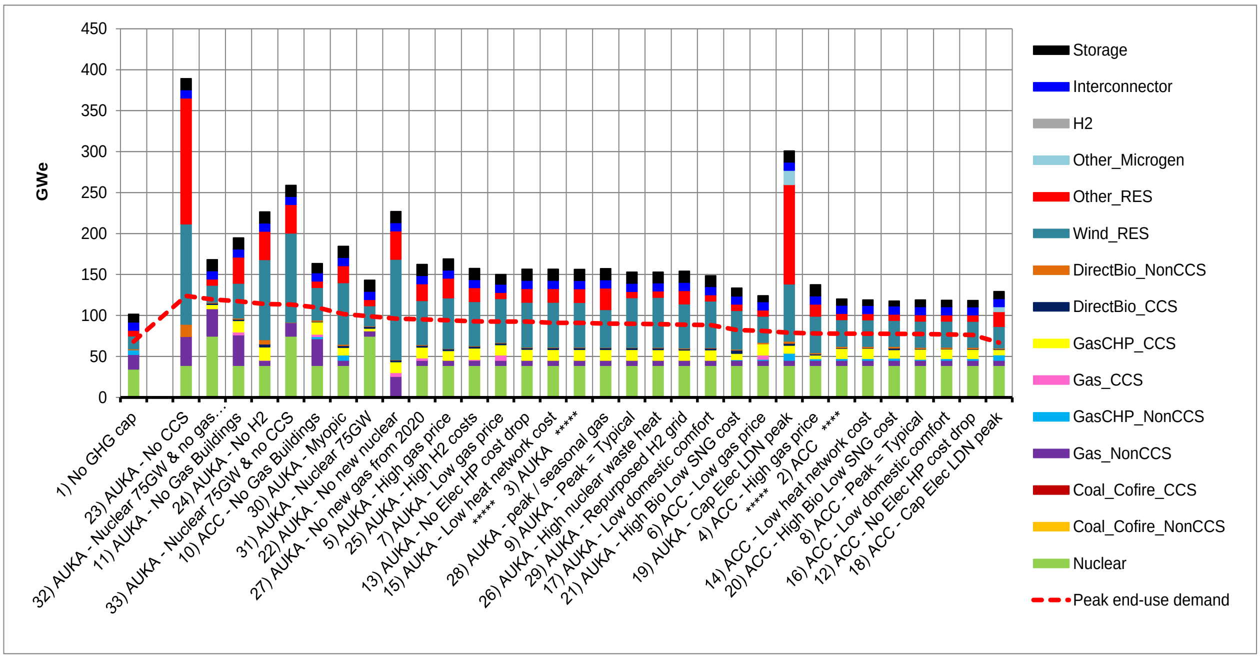
[24] Which are used for all sensitivities bar 30) Myopic

Figure 7 Installed generation GWe and peak demand (AUKA and ACC 2050)



Note: For CHP plant this is maximum GWe output from the operating modes and not the full thermal capacity.

Figure 8 Installed generationGWe and peak electricity demand (All cases 2050)



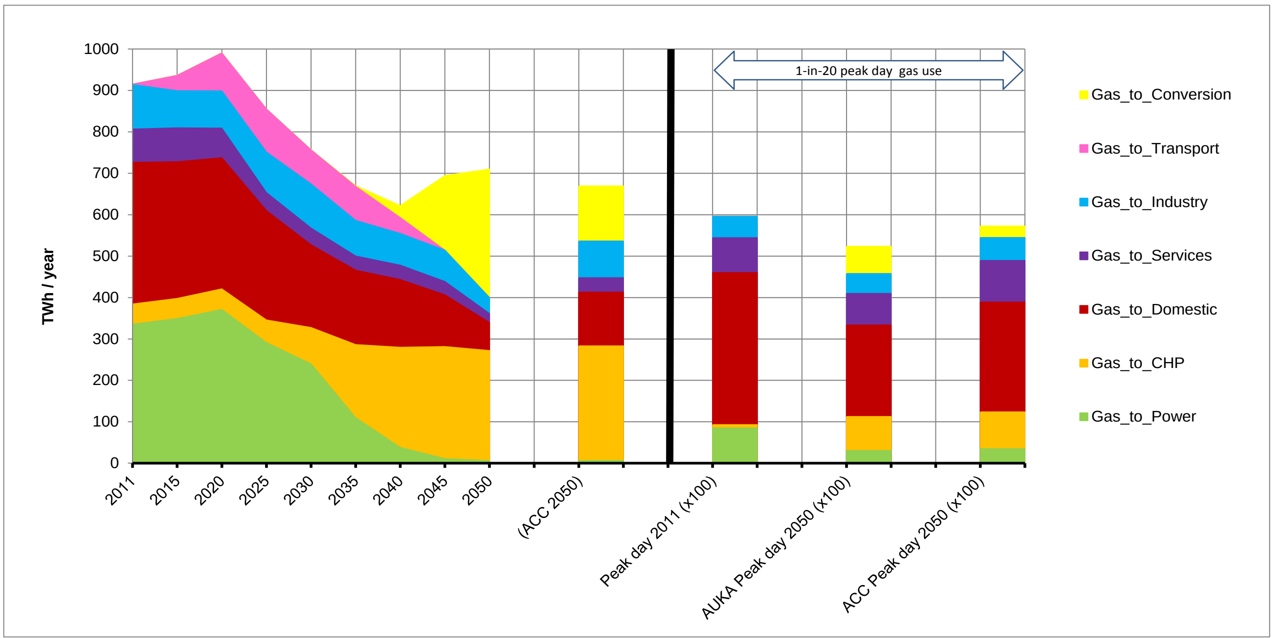
Notes: Ordered from left to right by highest to lowest peak demand

In general, there is more extensive use of electricity as it becomes more difficult to meet the emissions target to help facilitate wider decarbonisation across the energy system. This leads to correspondingly higher annual and peak demand (as shown in Figure 8).

5.2.3 Gas

Total gas use declines significantly in a number of sectors under the core scenarios, particularly buildings, but is there still potentially a large scale role by 2050 enabled by CCS and hydrogen production. Gas use in power and CHP shifts primarily towards the latter, in the form of large scale CHP with CCS, with the heat used for industrial clusters.

Figure 9 Annual and peak day gas use (AUKA and ACC 2050)



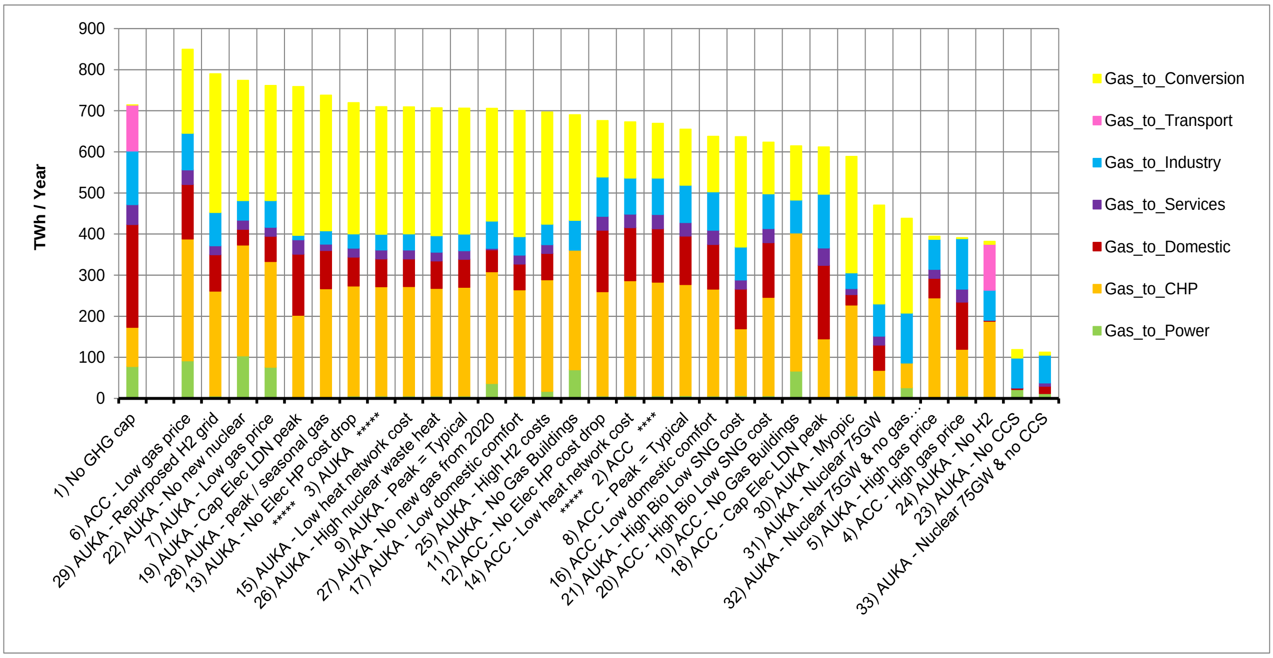
Notes: Gas can include natural gas and gas from bio and non-bio-derived alternatives, however, in the core scenarios there is <15 TWh / year of biomethane and < 5 TWh / year of blended hydrogen by 2050.

Annual use of gas in buildings declines by over 50%, but is retained in some segments to help manage both seasonal swing and peak day heating requirements; with a less significant drop seen in peak day use. Direct gas is retained in industry largely for high-temperature industrial processes, with lower temperature requirements provided indirectly via gas CHP + CCS. There is also a transitional use of gas in road freight transport to provide cost-effective abatement in the medium term, before a longer term transition to hydrogen (see Section 5.2.5).

The results also highlight a significant late stage role for gas seen in hydrogen production (the majority of gas to conversion) via Steam Methane Reforming (SMR) with CCS. The hydrogen is then used indirectly to help decarbonise road freight transport and some high temperature industrial process heat requirements. However, as seen in Figure 10, use of gas in hydrogen production (which accounts for almost all of the 'gas to conversion' category) is sensitive to long-term gas prices, with wider hydrogen production (outside of that produced from bioenergy) shifting to alternatives such as coal gasification with CCS.

The range of sensitivities in Figure 10 also highlights the relatively consistent, albeit significantly reduced, long-term role for gas in buildings and industry (compared to the consumption for 2011/12 shown in Figure 9), and the significantly expanded role in CHP with CCS as opposed to pure electricity generation. However, the no-CCS sensitivity highlights the extent to which this is dependent on the availability of CCS across the system. This is not just in terms of helping to directly abate gas-related emissions, but by also providing headroom for increased emissions across the energy system due to the creation of negative overall emissions from bioenergy and CCS use.

Figure 10 Annual gas use in 2050 (All cases)



Notes: Ordered from left to right by declining total gas use

5.2.4 Biomethane and bio-hydrogen

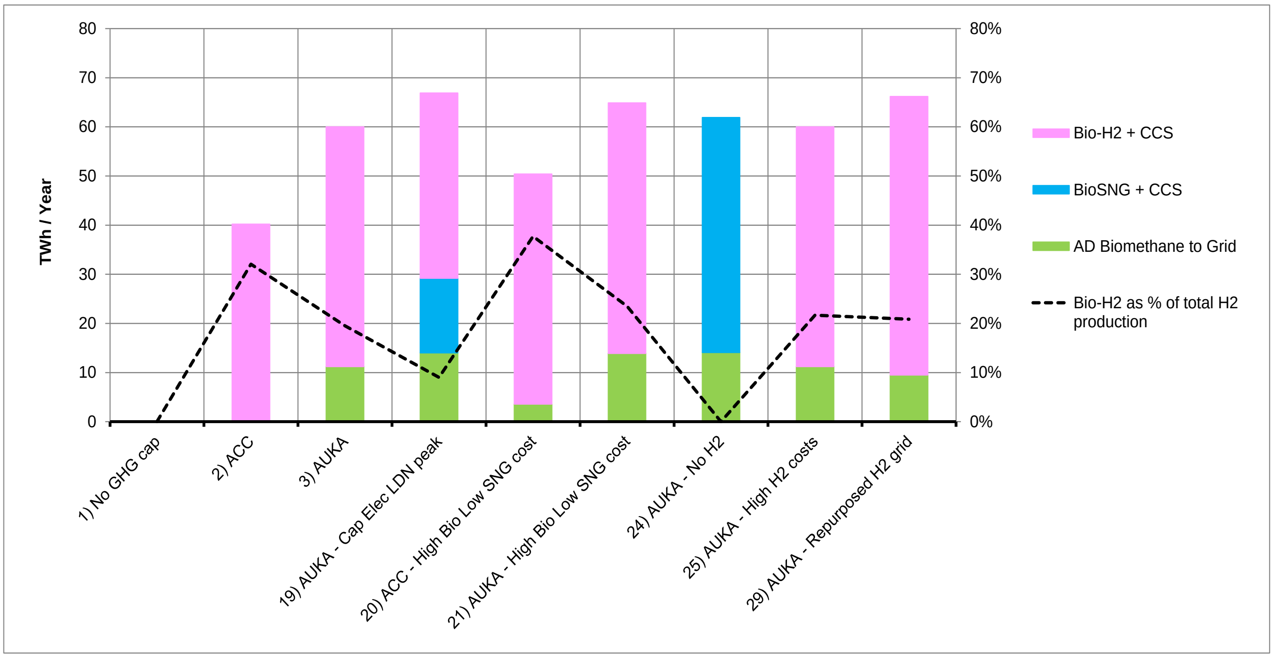
Natural gas and hydrogen in RESOM can be produced from a range of different sources, but are blended into a single carrier ie gas use in the previous can include natural gas, bio-derived sources and other non-bio-derived sources.

As shown in Figure 11 there is significant long-term use of bioenergy for hydrogen production via CCS routes across virtually all scenarios where this option is available, and given that relatively conservative assumptions have been made (consistent with the Redpoint (2012) AUB study6) on the maximum availability of 'sustainable' bioenergy.

The other sizeable long-term use of bioenergy is for large-scale syngas CHP with CCS which helps indirectly to facilitate heat decarbonisation, along with a range of smaller uses such as anaerobic digestion (AD) for biomethane grid injection. There is significant use of bioenergy in bioliquids for road and non-transport (See section 5.2.5), but this tends to be transitional, with bioenergy diverted to hydrogen and CHP CCS routes over the longer term.

Aside from a relatively small, but consistent input of biomethane from AD (using waste resources) the majority of gas within the network is natural gas, along with a small amount of hydrogen blending, capped at 3% by energy content to avoid the need for any transition of existing appliances. Large-scale deployment of bio-SNG for grid injection is only really seen where hydrogen production is not an option. This is in part due to the high shadow price of carbon by 2050 and the ability of the hydrogen + CCS route to remove carbon more effectively in the conversion process. By contrast, the bio-SNG + CCS process removes less carbon in a single step and is reliant on a CCS further down the energy chain at the point the gas is finally used, to provide a comparable level of abatement. This is difficult given the inability to direct individual molecules of gas to specific end-uses and to apply CCS to smaller scale end-uses.

Figure 11 Production of biomethane and hydrogen (Selected cases 2050)



5.2.5 Transport

Trends in transport can be split broadly into car passenger transport, non-car road transport (predominantly LGVs and HGVs) and non-road transport (aviation and shipping) as shown in the figures below for the core AUKA scenario and ACC in 2050.

Car transport shows a gradual decline in fossil fuel usage, with a late stage expansion of electric vehicles[25]. There is a transitional use of bioenergy for passenger cars, driven primarily by the need to meet the RED road target in the near term, but a combination of cheaper electric vehicles and more cost-effective abatement opportunities for bioenergy mean it is subsequently diverted away from car transport.

The use of electric vehicles has somewhat more significant implications for peak than annual electricity demand. Even with assumptions around off-peak load shifting for vehicle charging, there is still approximately 10-15 GW of demand occurring around the time of the overall system peak, rising to 20 GW if significant load shifting does not occur. Given the substantial cost of additional peak generation and network reinforcements this has implications for peak electricity demand from heating, which is then added on top of that from transport. This is particularly important with regard to the early evening peak in winter, when high demand for heating may coincide with demand for electric vehicle charging as people return from work.

[25] NB given the efficiency of electric cars they are delivering proportionally more vkm than illustrated by the fuel splits in Figure 12

Figure 12 **Car transport final energy consumption (AUKA and ACC 2050)**

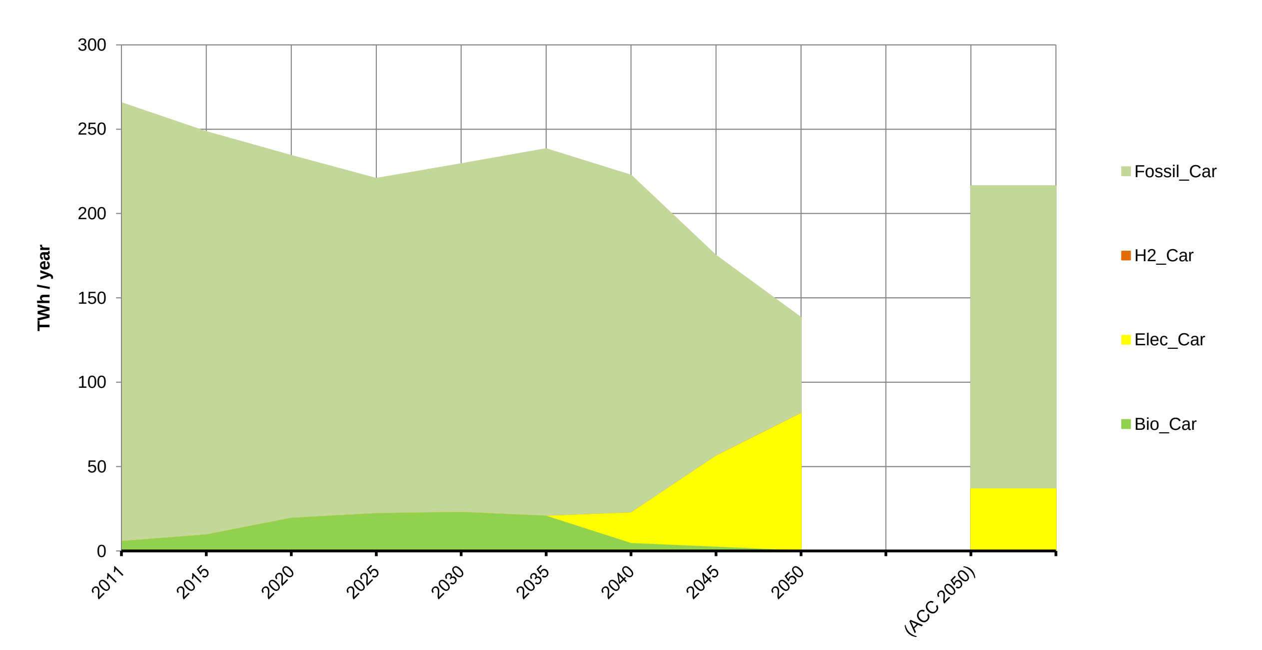
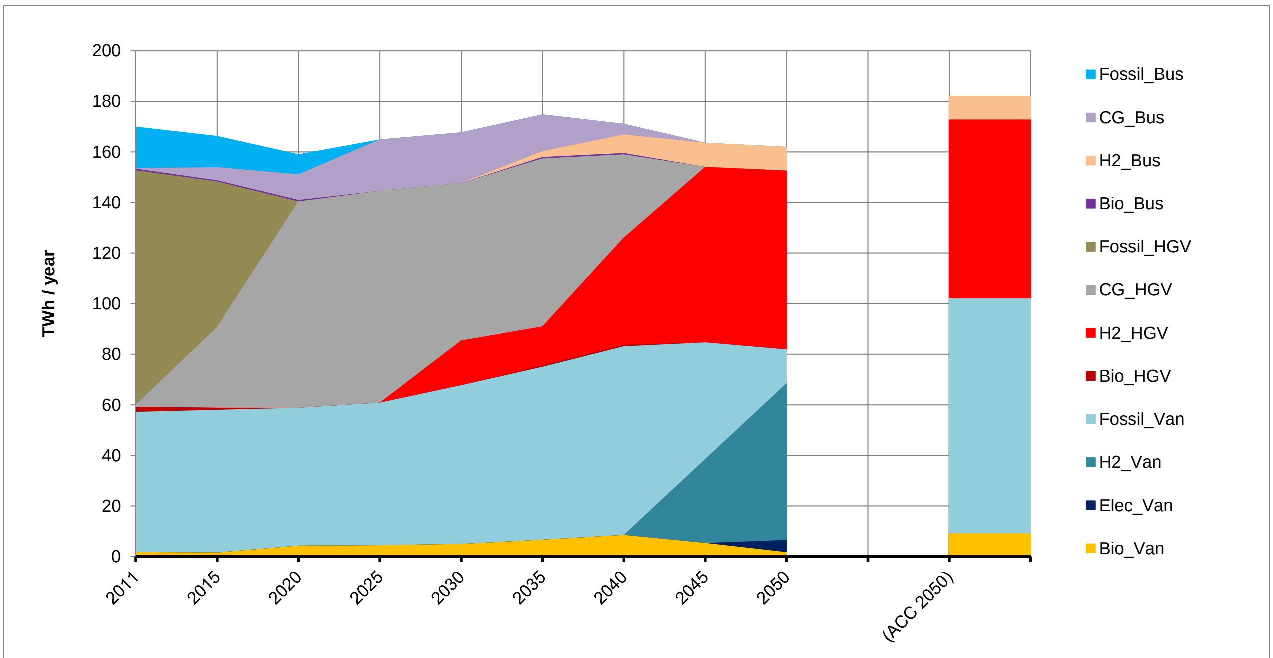


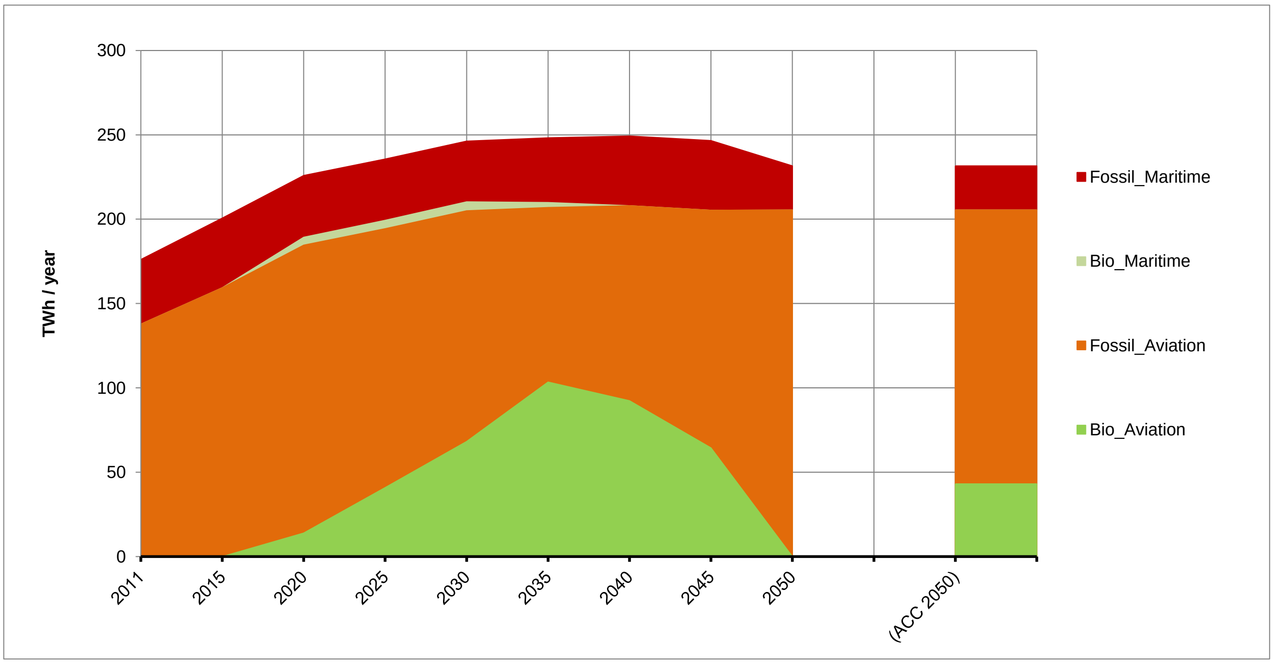
Figure 13 **Other road transport final energy consumption (AUKA and ACC 2050)**



Trends in non-car road transport can be divided into two further groups. Light Goods Vehicles (LGVs) show a similar pattern to cars, but with a late stage transition to hydrogen rather than electric vehicles. Heavy Goods Vehicles (HGVs) and buses move through two transitions: a near term transition away from diesel to compressed gas, followed by a late stage transition to hydrogen to provide further abatement, as electric vehicles are not available for these segments.

A similar pattern to bioenergy use in cars is observed in aviation. In the medium term it becomes a cost-effective use of bioenergy for emissions abatement[26], before bioenergy is diverted to other uses. However, in sensitivity 21) AUKA - with higher bioenergy availability some use in aviation is still maintained by 2050.

Figure 14 Non-road transport final energy consumption (AUKA and ACC 2050)



5.2.6 Key binding constraints

From the long-list of key data constraints described in 4.1.1 a number of the build rate and maximum build quantity constraints are binding in the core scenarios and sensitivities. These can be broadly divided into constraints binding in the near-term to 2020 and longer term constraints binding to 2050:

- Nearer term constraints, which are *binding* and broadly consistent with those used in the Redpoint (2012) AUB study6'[27] to prevent unrealistically high builds to meet the RED, and include
  - Heat pumps and biomass boilers across all sectors
  - 2nd Generation biofuels – both domestic and imported
  - AD plants of all types
  - More cost-effective forms of efficiency measures (CWI and loft insulation).
- Over the longer term to 2050, key binding constraints are:
  - Build rates for new nuclear, such that the maximum build limit is just reached by 2050, this includes the sensitivities where the maximum nuclear limit is increased to 75GW by 2050

[26] It is the only explicit option in the model, efficiency improvements are built into the exogenous air service demands

[27] Calibrated to the upper bounds of scenarios from the: DECC National Renewable Energy Action Plan; CCC (2010) Renewable Energy Review; SKM Enviros (2010) report for DECC on Analysis of characteristics and growth assumptions regarding AD, and Element Energy (2012) report for CCC on options for decarbonising heat in buildings

- Group build rate constraint on CCS technologies, which is generally binding from the mid-2030s onwards
- Maximum build quantity limits on hydro, geothermal, onshore wind and offshore wind (excluding round 3 sites) are generally reached by the 2040s onwards

Whilst some individual heating segments show build rate / quantity limits being reached before 2050 (for both direct heating stock turnover and efficiency measures) it is generally relatively unconstrained within the sector as a whole[28]. Hence the model has a 'relatively' high degree of freedom to find a least cost-solution for heating, subject to the costs and constraints within the wider energy system.

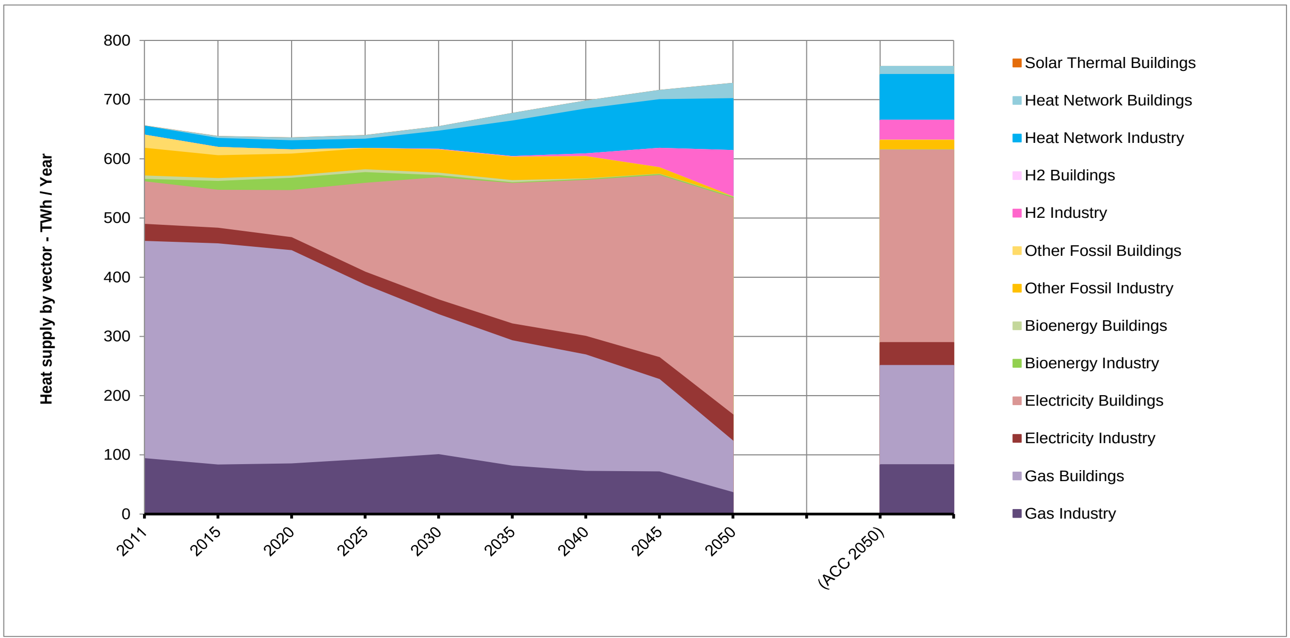
5.3 Total heat supply

5.3.1 Heat supply by vector

The overview of annual heat supply across different vectors, shown in Figure 15, highlights the significant expansion of electricity for heating, predominantly via the use of heat pumps in buildings. Gas use declines substantially under both the AUKA and ACC core scenarios, but more so in the former case where the GHG target must be met from UK abatement alone. However, a sizeable amount of gas still remains in buildings to help manage seasonal winter swings in heat demand.

Hydrogen for heating is focused almost exclusively in industrial applications rather than for buildings, and heat networks are also used primarily for providing heat to industrial clusters, with more limited provision to buildings (focused on the service sector).

Figure 15 Heat supply by vector (AUKA and ACC 2050)

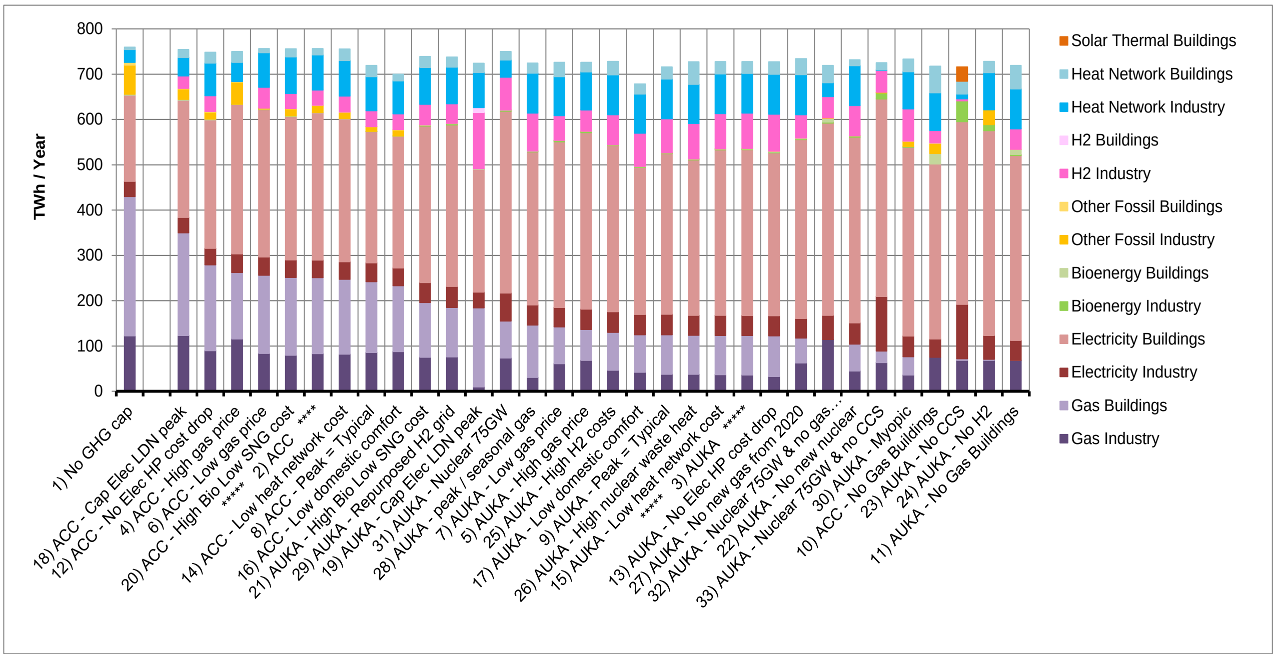


The significant expansion of electricity for building heat and the residual role of gas in both industry and buildings is relatively consistent across the set of scenarios as shown in Figure 16, with the broad

[28] Aside from more fundamental heat technology applicability issues – eg GSHPs in high-rise flats

characteristics of the pathway driven more by the overall cost of abatement rather than the relative differences in heat technology costs. For example, under the ACC scenario where the cost of abatement is effectively capped, electricity use in heat still expands significantly, but greater residual gas remains in buildings than under the core AUKA-based scenarios. However, even under 'ACC sensitivity 12) No decline in electric heat pump costs' there is not substantially more gas used than under the core ACC scenario.

Figure 16 Heat output by vector (all cases 2050)



Notes: Ordered from left to right by declining total gas-related heat output

By contrast, gas is virtually eliminated from buildings under the AUKA sensitivities where the cost of abatement is extremely high, such as 23) and 24), where neither CCS nor large scale hydrogen production are available abatement options. Whilst neither the CCS nor hydrogen options are used directly at the building level, their absence makes it more difficult to meet the overall UK target, making it more important to reduce emissions in all parts of the system.

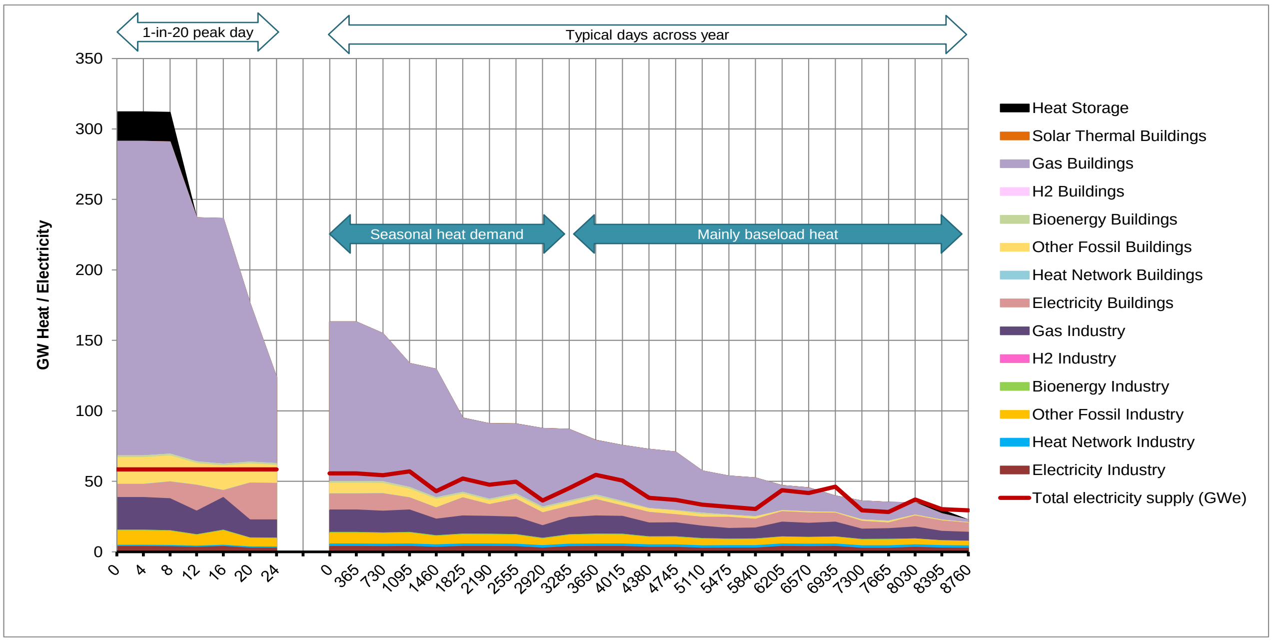
5.3.2 Duration curves

A helpful way to illustrate the role of different heat vectors within the year is via a supply duration curve. Figure 17 to Figure 19 outline the situation for all heat supply in 2011/12, 2050 under the core AUKA scenario and sensitivity 11) No gas in buildings (by 2050).

The duration curves are ordered by total heat demand across all sectors, with each individual heat supply vector (and total electricity supply) mapped to the corresponding chronological period (eg winter 00:00-4:00am, which represent 365 characteristic hours in the entire year).

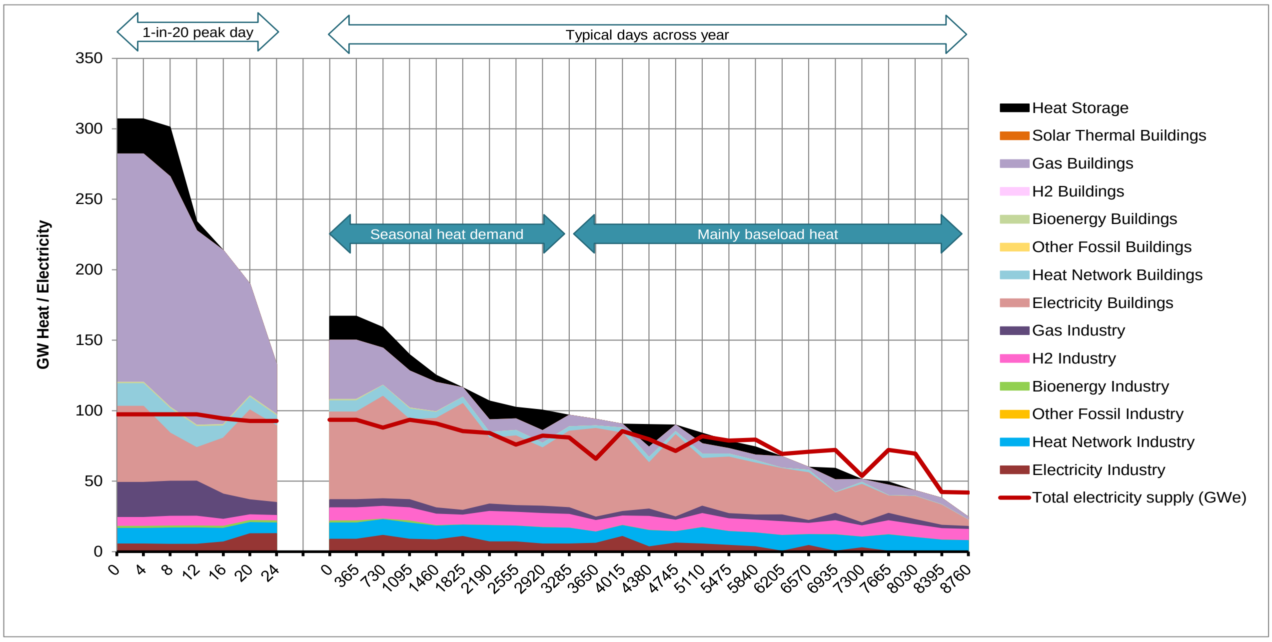
The curves illustrate the seasonal swing in heat demand relative to electricity demand across the year, particularly for the buildings sector, and the significant jump in peak heat demand moving from a typical to 1-in-20 cold winter. Despite improvements in efficiency, the overall demand for heat is, to a large extent, offset by increasing numbers of buildings and gradual industry growth, such that the seasonal and peak swings remain significant in 2050.

Figure 17 Heat supply duration by vector (2011/2012 - modelled)



Note: Duration curve time periods normalised to total heat demand

Figure 18 Heat supply duration by vector (AUKA 2050)



Note: Duration curve time periods normalised to total heat demand.

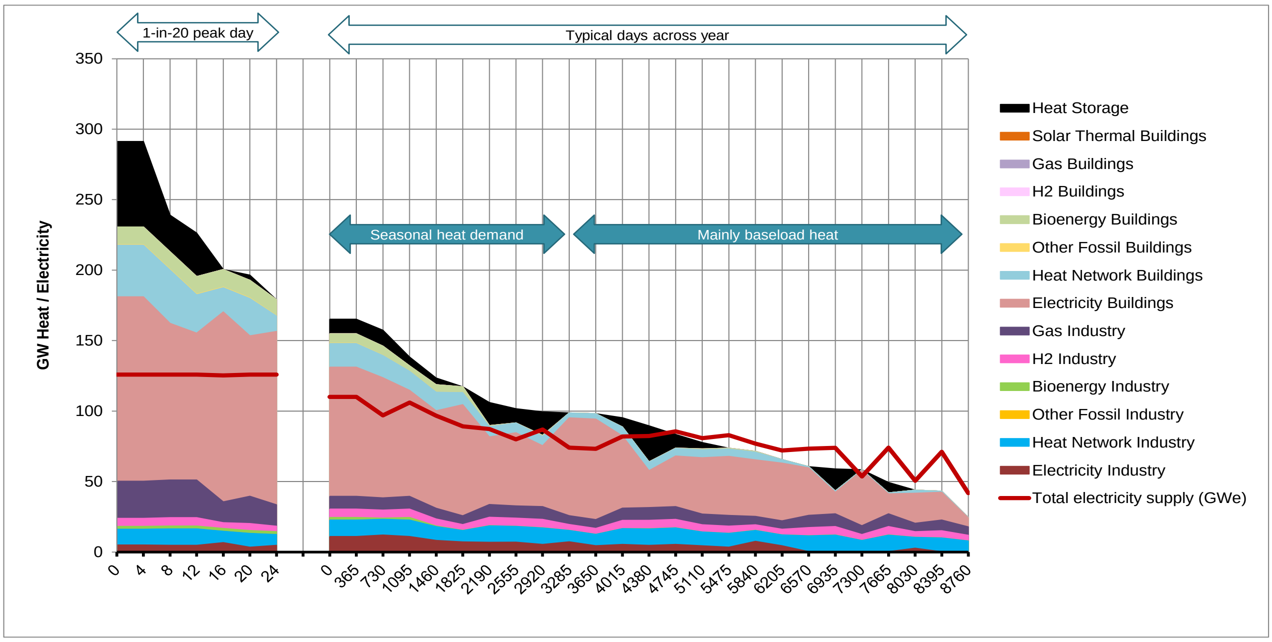
By 2050 significant amounts of electricity are being used to provide heating (largely via heat pumps), but in a baseload manner[29]. Whilst gas use is much lower on an annual basis it is concentrated in winter providing seasonal top up. Gas is predominantly used in dual-fuel devices with an electric heat pump which helps to

[29] Note that the graph show heat output by vector hence a significant portion of electricity supply is being used to run heat pumps and actual electricity demand needs to be adjusted for their COP

mitigate the scale of electricity demand growth. Similarly, extensive use is made of within-building heat storage to smooth electricity demand. However, even with these options, peak electricity demand almost doubles from 2011/12 to 2050 in the AUKA scenario from almost 60 to 100 GW, with between 15-35GW of heat-related electricity demand occurring across the peak day.

In the sensitivity (Figure 19) where gas is forced out of buildings, peak electricity demand increases further, even with greater efficiency improvements, heat storage, the use of heat networks and direct bioenergy in buildings. Unlike the core AUKA scenario, where gas is being used as part of a dual fuel device with a heat pump, heat networks are assumed to be the only heat supply source for space heat and hot water in an individual building[30]. This indicates that heat networks are used in around one fifth of buildings.

Figure 19 Heat supply duration by vector (AUKA – No gas in buildings 2050)



Note: Duration curve time periods normalised to total heat demand

5.3.3 Heat network supply

Heat network supply options in RESOM include a range of dedicated boiler and CHP options, along with ‘waste’ heat from conventional power stations, which supply heat to transmission heat networks that then feed into distribution heat networks. Heat networks also have diurnal timescale heat storage to provide a buffer between CHP / power generation and heat demand.

The majority of the heat provided into heat networks is via large scale gas or bioenergy CHP with CCS. This heat is then used in more localised heat networks providing lower temperature process heat for industry.

Some waste from power stations, particularly nuclear, is used to provide lower grade heat for networks in buildings rather than for industry process heat. For nuclear this has been constrained to around 6% of

30 Hydrogen boilers, GASHPs and micro-CHP technologies are also other technologies which are assumed to be the only space heat / hot water supply source in a given building segment, when they are being used. They are modelled as fixed profile technologies, where the profile exactly matches the shape of the heat demand, hence there is effectively no benefit incurred from interaction with other building heat technologies or heat storage.

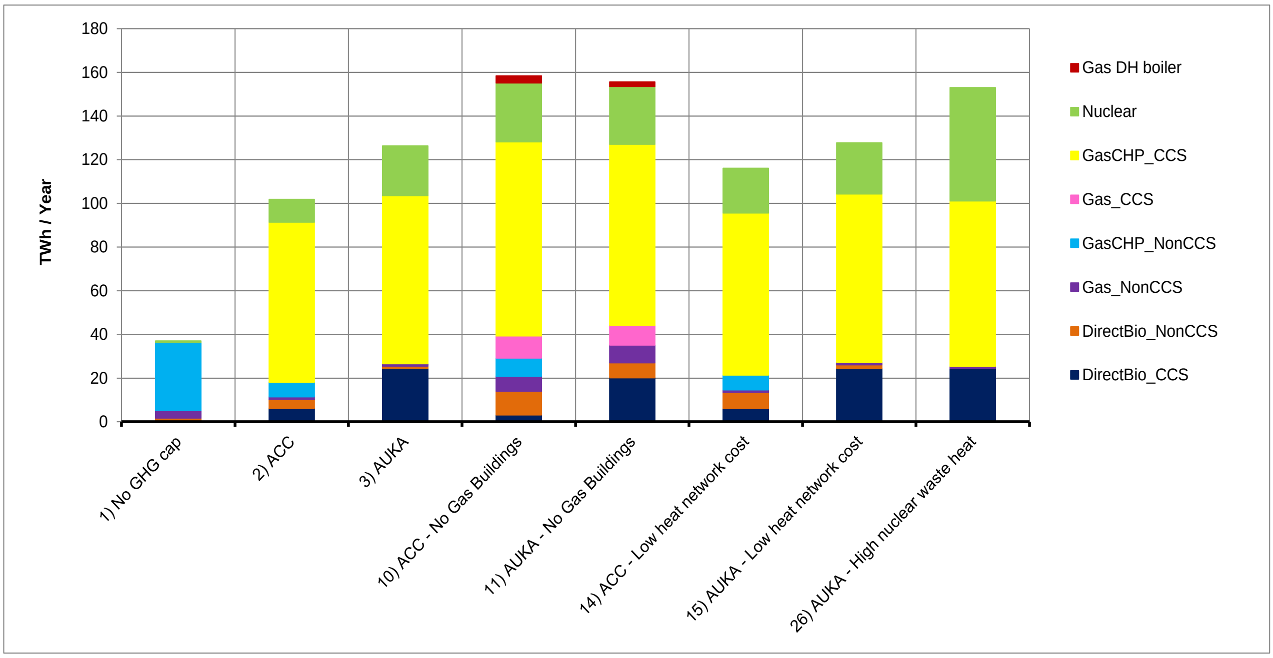
possible waste heat output reflecting the relatively low proportion of demand within a 30 km radius of the anticipated future sites.

When this share is increased to 25% of possible output, as per sensitivity 26) High nuclear waste heat accessibility, the total use of waste heat doubles (see Figure 22 in section 5.4.1). However, nuclear heat is not being used to its maximum capability in this scenario and is still only providing a relatively small share of relevant building heat demand in 2050, of over 400 TWh / year. In this sensitivity the cost effective opportunities for heat networks in the service sector begin to be saturated, with the remaining heat in this sector provided by electric heat pumps. In this situation some limited use is then made of heat networks in the domestic sector, but this tends to displace heat supply from electric heat pumps rather than residual gas.

Where heat networks are used in buildings it tends to be more cost effective within the services sector, particularly higher density, new urban buildings. Heat segments in the domestic sector tend to suffer more from the higher fixed costs of the heat networks relative to the scale of demand, particularly after significant energy efficiency improvements have been made to the buildings. They therefore tend to be more suited to higher density less efficient building segments, even if the cost of heat supply into the networks themselves is very low.

In the AUKA sensitivity 11) No gas in buildings (by 2050), greater use is then made of heat networks to help decarbonise heating and cap the rise in electricity demand, but this only represents one fifth of relevant building heat demand (ie excluding cooking) and leads to a higher overall energy system cost (see Section 5.5).

Figure 20 Supply to heat networks by technology (Selected cases 2050)



5.4 Heat by sector

5.4.1 Domestic sector

Under the cores scenarios, extensive use is made of electric heat pumps for providing space heat and hot water in the domestic sector by 2050, as shown in Figure 21 below. Gas use declines gradually until the early 2020s when it is more rapidly squeezed from the heating mix. By 2050 the role for gas in space heat and hot water has shifted from annual provision to winter top up and peaking, with a separate on-going role for cooking representing a significant share of remaining emissions, helping to avoid additional peak electrical demands.

Extensive use is made of available efficiency options, particularly more cost-effective measures such as cavity wall insulation (CWI) and loft insulation in the near term, and solid wall insulation (SWI) in the longer-term. However, by 2050 even under the AUKA scenario only around 80% of measures have been taken up as some of the more expensive options (eg enhanced glazing) are not deemed cost-effective in specific heat segments.

There is also a potential transitional role for gas heat pumps. However, when they are the only heating device in a building their long-term role depends on the balance of gas in peaking / top-up versus more general provision of heat. Due to higher capital costs they need to be able to run at a higher load factor to take advantage of their significantly higher efficiency, but as gas moves more towards a peaking role under a higher carbon price it becomes more cost-effective to use a standard gas boiler as a backup.

More flexible, hybrid versions of a gas heat pump, for example in combination with an ASHP (rather than in a dual fuel device with a gas boiler), would likely provide more scope for long-term use, and potential cost savings in an integrated package given that both heat pumps share a number of common components.

Figure 21 Domestic heat supply (AUKA and ACC 2050)

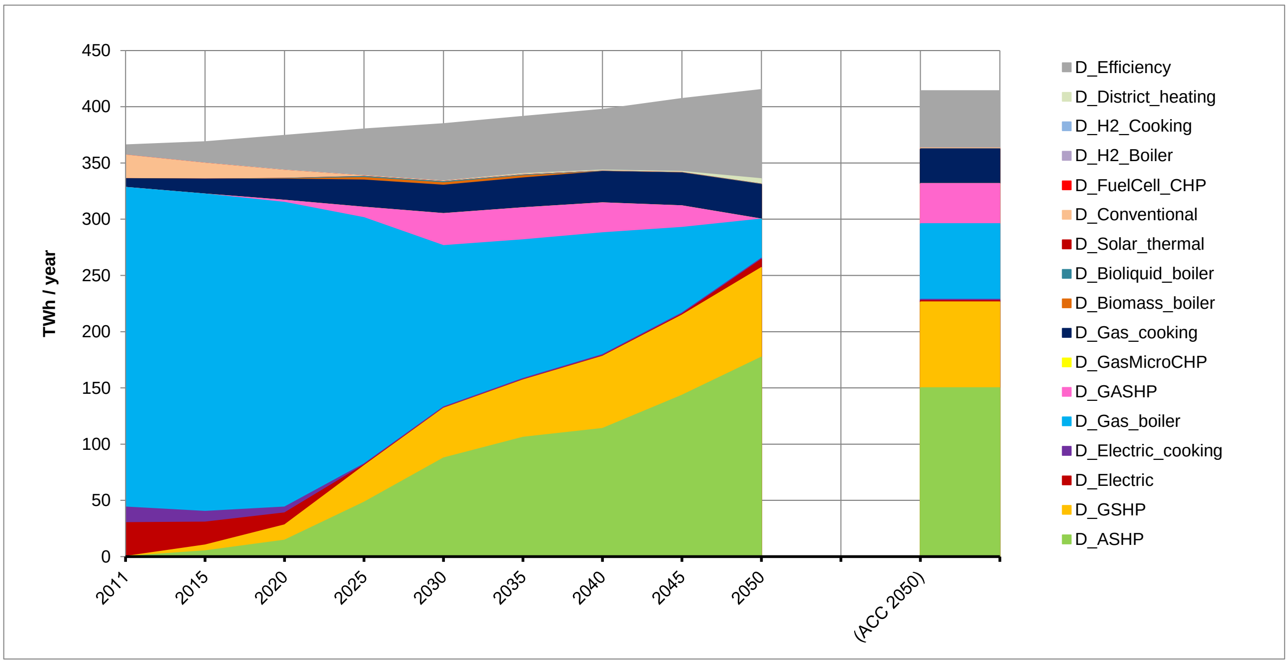
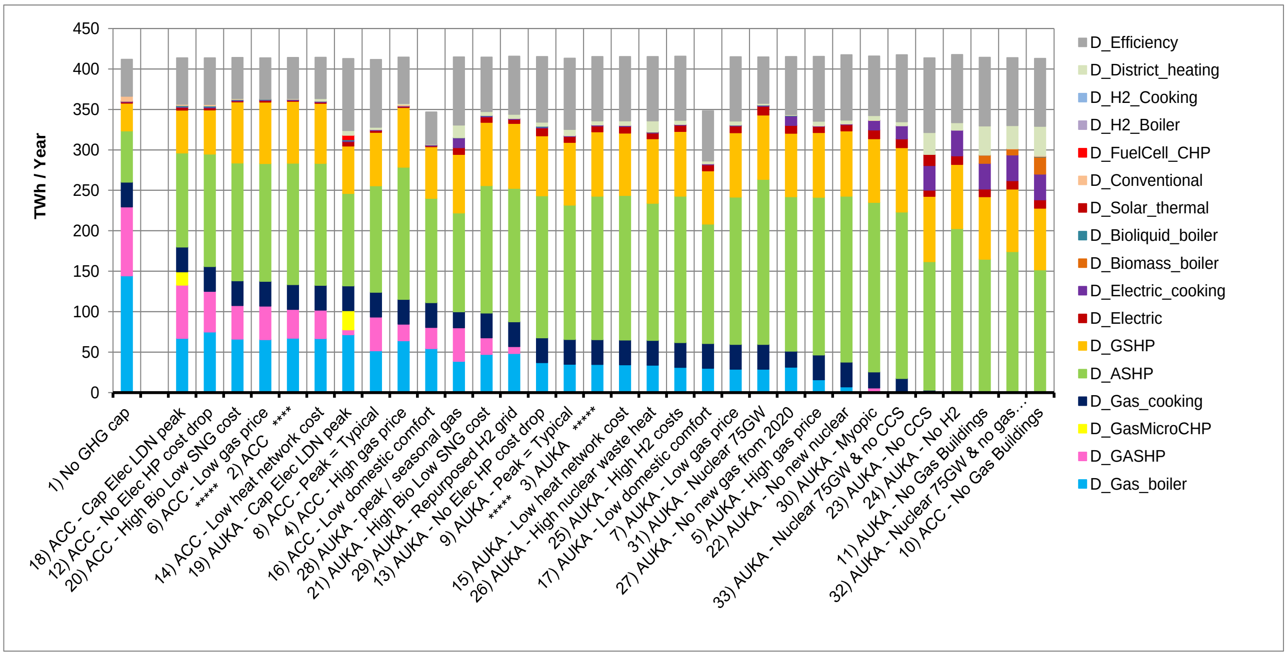


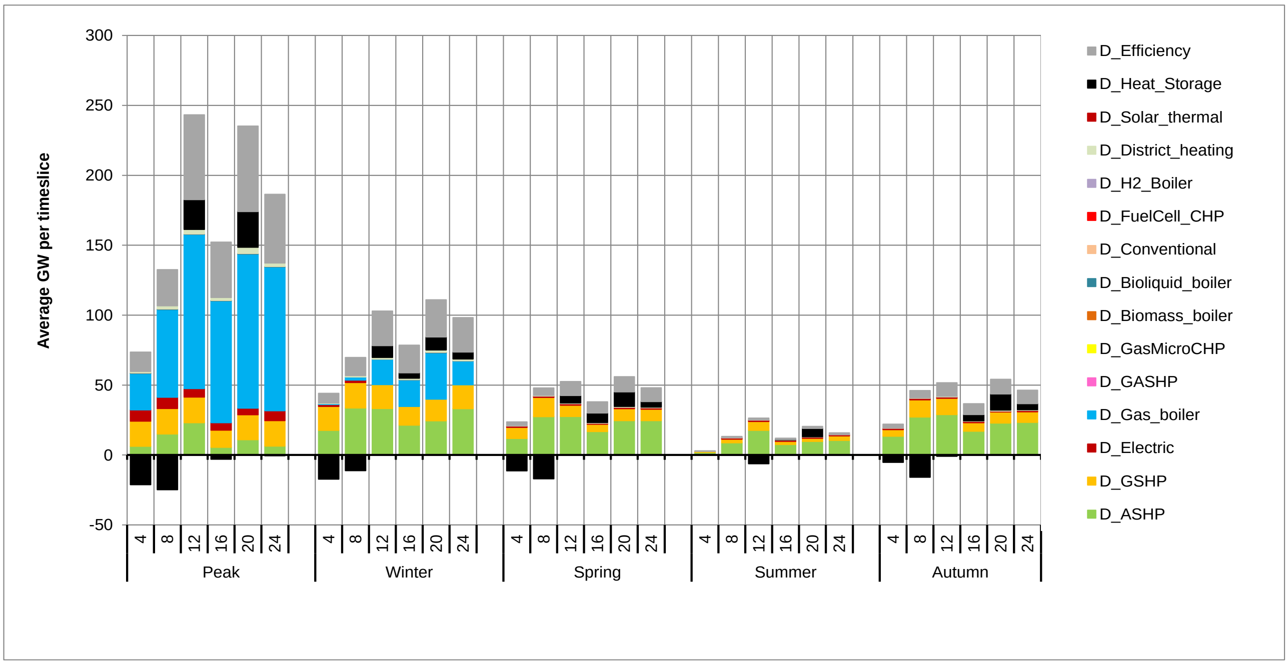
Figure 22 Domestic heat supply (All cases 2050)



Notes: Ordered from left to right by declining total gas-related heat output

Figure 23 provides an alternative within year view to the duration curves in Section 5.3.2 for the domestic sector only, and shows the chronological profile for the aggregate domestic sector in each of the characteristic days under the core AUKA scenario in 2050.

Figure 23 Aggregate domestic heat supply profile (AUKA 2050)



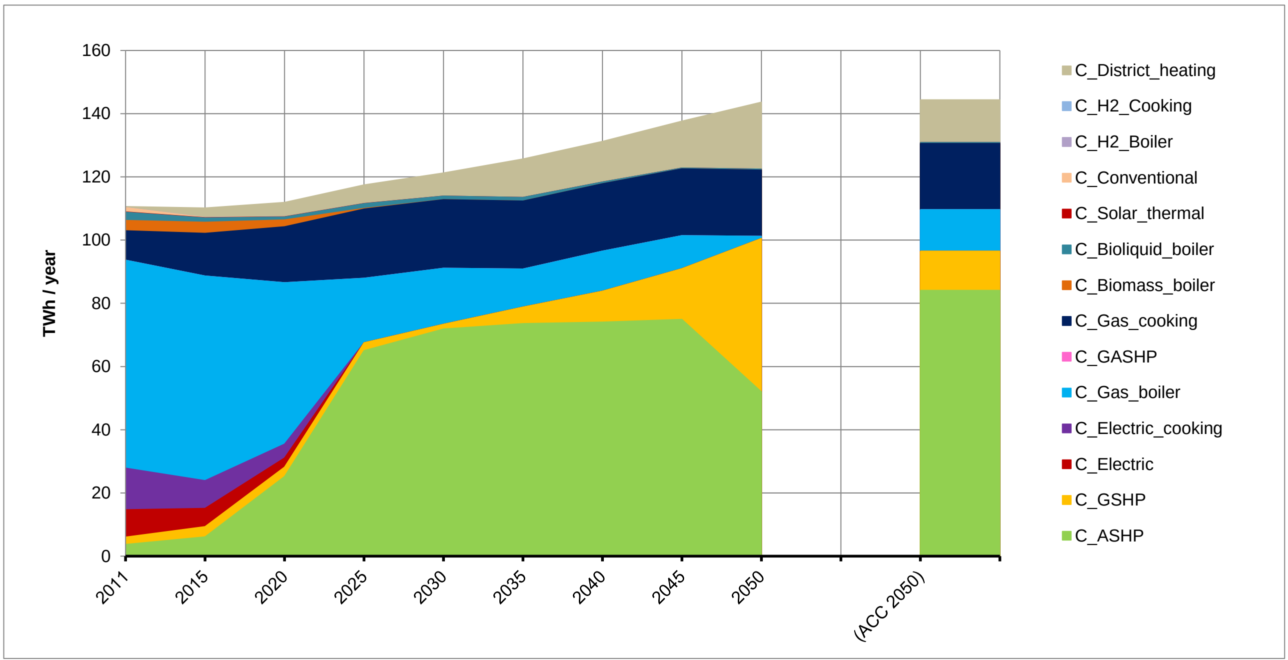
Notes: Only space heat and hot water demand, excludes cooking.

The domestic heat supply profile again highlight the interaction of gas for seasonal and peak use in a dual fuel device with heat pumps predominantly for baseload operation. There also a key role for building heat storage to facilitate the use of heat pumps, along with energy efficiency measures to reduce the scale of peak demand as well as annual heating demands.

5.4.2 Services and industry

The services sector shows a similar pattern to the domestic sector, with a strong phase in of electric heating via heat pumps, and with the RED having a significant impact on early deployment of renewable heating[31]. However, due to the smoother overall heat demand profile and more cost-effective district heating options, gas can effectively be removed from the system under the core AUKA scenario under typical winter conditions, and is maintained as the cheapest form of cheap back-up capacity to meet the demand on a 1-in-20 peak day.

Figure 24 Services heat supply (AUKA and ACC 2050)



Within industry (Figure 25) there is a sizeable on-going role for gas in the provision of high temperature process heat to 2050, which is relatively consistent across the scenarios (as shown in Figure 10). This is supplemented to some extent by hydrogen from the late 2030s onwards.

Electrical high temperature process heat technologies are another potential option, but have not been included due to uncertainty in their cost[32]. It is unclear how significant this option would be as replacing gas and hydrogen use could add the order of 100 TWh / year and 10 GW of peak demand to an already 'stretched' electricity system.

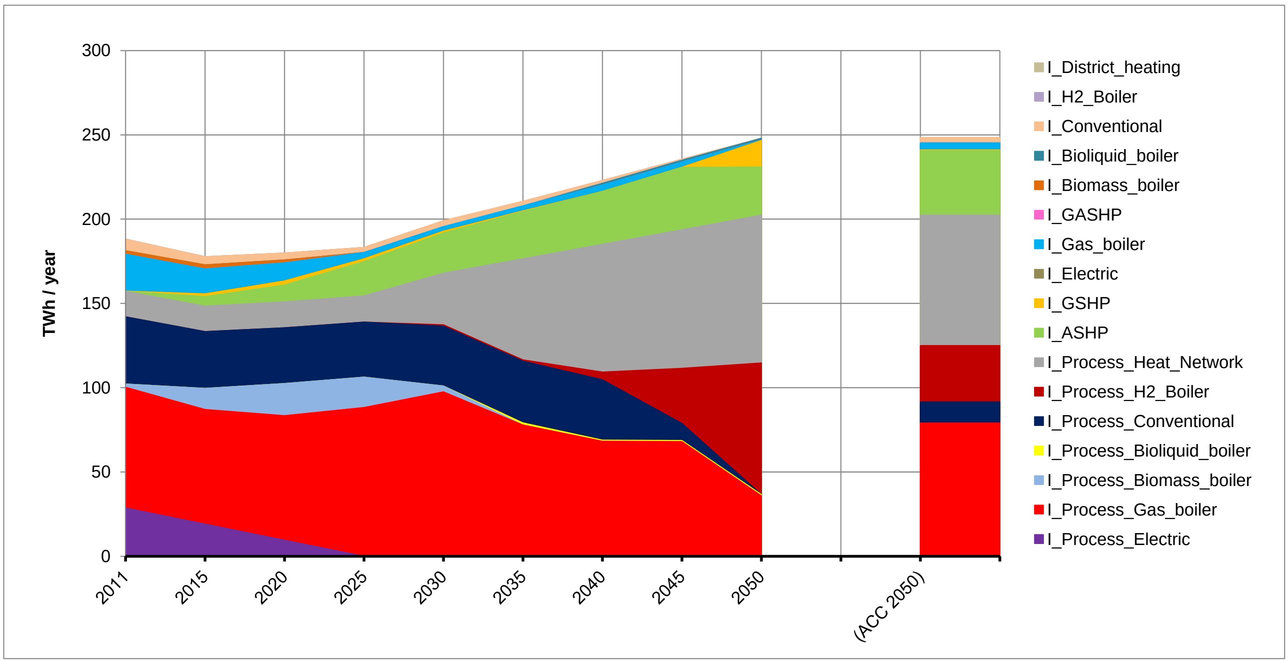
The other major change is a shift in the provision of lower temperature process heat, from direct gas boilers to indirect heat provision from CHP. As illustrated in Section 5.3.3, much of this is from large scale

[31] As noted in Section 5.2.6 a number of near term constraints are binding in the core scenarios, particularly around renewable heat to limit unrealistically high near term deployment.

[32] For example, these were considered as part of AEA (2012) Potential for post 2030 emissions reduction from industry report for the CCC, but a much lower level of confidence was ascribed to their cost data compared to hydrogen heat technologies.

gas CHP with CCS, ie shifting use of gas further back up the energy chain to allow more cost-effective implementation of CCS.

Figure 25 Industry heat supply (AUKA and ACC 2050)



5.5 Costs

This section provides a breakdown of the energy system costs in 2011/12 and in 2050 for the core scenarios and selected sensitivities. It is important to note that costs, particularly out to 2050, are highly uncertain and hence the absolute numbers should be treated with caution. They are more useful in understanding the relative differences between sectors and across the scenarios.

The overall cost of abatement *in* 2050 compared to an energy system without a GHG target from the modelling is in the range of 1-2% of 2050 GDP, broadly consistent with existing UK Government and CCC studies[33].

As highlighted in Table 5, of the total annualised energy system costs almost half are related to transport in the form of capital costs for the vehicles themselves. The next most significant set of costs are fossil fuel related, although these have declined significantly under the AUKA scenarios by 2050 (even as prices rise) as fossil fuels play a more limited role in the overall energy system.

It is interesting to note that even though the ability to use international credits can change the system solution significantly in 2050 the total costs (and hence average costs of abatement) are very similar between the ACC and AUKA scenario, with significant costs assigned to credit purchase rather than UK energy infrastructure. However, the marginal cost of abatement is very different, with implications for prices seen across the energy system.

[33] Eg analysis for the DECC (2011) Carbon Plan http://www.decc.gov.uk/en/content/cms/tackling/carbon_plan/carbon_plan.aspx

Removing gas from buildings has a significant impact on costs by 2050. The additional costs are driven by substantially higher power and electricity distribution costs due to significantly higher peak demand, as well as more expensive heat supply options.

Optimising myopically (ie with only foresight of the next 5 years) has a similar impact on overall cost. This is particularly noticeable in the power sector where costs are substantially higher due to the effective stranding of some assets. For example, non-CCS gas built in the middle of the pathway, which it is not then cost-effective to retrofit. Without the benefit of perfect foresight it is not possible to understand the disproportionate increase in the difficultly of meeting the emissions target the closer it gets to 2050. As a result there is a greater potential for stranding assets and a more expensive and hurried late stage transition to more expensive low carbon technologies, as build rate limitations then affect how quickly the cheaper low carbon options can be deployed.

A high-level estimate has also been made of household energy costs (see footnote to table for definition). This, very approximately, indicates that household costs could be at least 50% higher than current costs and double what the costs would have been in 2050 in the absence of a GHG target.

Table 5 **Breakdown of 2050 undiscounted system costs(£bn / year unless specified)**

Sector	2011/12 modelled	1) No GHG target	2) ACC	3) AUKA	10) ACC – No in gas buildings	11) AUKA – No in gas buildings	30) AUKA - Myopic
Transport	75.5	102.7	106.6	120.7	106.6	120.5	124.4
Conversion	0.1	2.3	3.7	6.8	3.6	5.8	6.9
Power - Nuclear	3.3	13.5	15.3	15.3	15.3	15.3	15.3
Power – Gasinc.CHPNon-CCS	3.8	3.3	1.3	0.8	4.1	4.0	2.2
Power – Gasinc. CHPCCS	0.0	0.0	5.3	5.6	7.2	6.9	3.8
Power - Wind	1.5	4.7	8.5	16.5	11.0	12.0	24.2
Power – Other renewables	0.4	2.8	3.1	5.9	3.1	10.7	7.2
Power - Other	10.7	0.5	1.2	1.9	1.2	1.9	2.3
Network – Electricity transmission	1.7	1.8	1.9	2.1	2.2	2.3	2.2
Network – Electricity distribution	3.4	4.3	5.2	6.6	8.0	8.7	7.8
Network – Hydrogen	0.0	0.0	0.7	1.3	0.7	1.3	1.3
Network - Gas	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Gas – LNG and storage	0.6	1.0	0.9	0.9	0.7	0.7	0.8
Storage - Electricity	0.1	0.2	0.2	0.3	0.3	0.3	0.3
Heat – Domestic efficiency	0.1	0.4	0.8	3.2	3.7	3.8	2.7
Heat – Electric heat pump	0.1	2.0	4.0	5.4	7.3	8.3	6.1
Heat - Networks	0.0	0.1	0.3	0.8	2.4	2.3	0.9
Heat – Storage	1.0	0.7	1.2	1.4	2.6	2.4	1.6
Heat – Other exc. CHP	8.4	8.6	7.1	5.7	4.7	3.2	6.2
Resource – Fossil fuel	55.7	49.0	45.5	36.0	44.8	36.0	32.9
Resource – Non fossil	0.6	1.3	1.4	1.3	2.5	4.7	2.6
Resource – Carbon credits			20.9		17.3		
Other costs	0.9	2.6	2.4	2.4	2.4	2.6	7.3
Total	**171.4**	**205.6**	**241.2**	**244.4**	**255.2**	**257.4**	**262.5**
- Increment cf. 1) No GHG	**-**	**-**	**35.6**	**38.8**	**49.6**	**51.8**	**56.9**
- As a % of 2050 GDP[34]	**-**	**-**	**1.0%**	**1.1%**	**1.4%**	**1.4%**	**1.6%**
Shadow price of carbon £ / tCO2	0	-	212*	477	212*	391	1365
£ / capita total system costs	2755	2677	3141	3183	3324	3352	3418
£ / household energy costs**	941	612	961	1107	1152	1271	1406
£ / household energy costs ** (normalised to 2011 occupancy)	941	736	1156	1331	1386	1528	1691
Total undiscounted energy system cost over full pathway 2011-2050 - £bn	-	3823	3959	3968	3995	4001	4007
- Increment cf. 1) No GHG	-	-	136	145	172	178	184

Notes: Sector costs include annualised capital and operating costs, fuel and other costs are captured in other sectors such as resource fossil fuel costs. ***** Capped at DECC central carbon price. ****** Estimate of total annualised household energy costs including: capital and operating costs of efficiency measures and building level heat supply measures; price of energy inputs for heating (eg electricity or heat network supply) based on marginal / shadow prices, and price of other electricity consumption (eg for lighting and appliances) based on marginal / shadow prices; estimate of generator and supplier margins; and VAT.

[34] Assumed to be £ 3643bn / year

6 Evolution of the energy system to 2050

Introduction

The results of the analysis have highlighted a number of key transition points for both heating and the wider energy system on the pathway to 2050. To ensure successful decarbonisation takes place there appear to be:

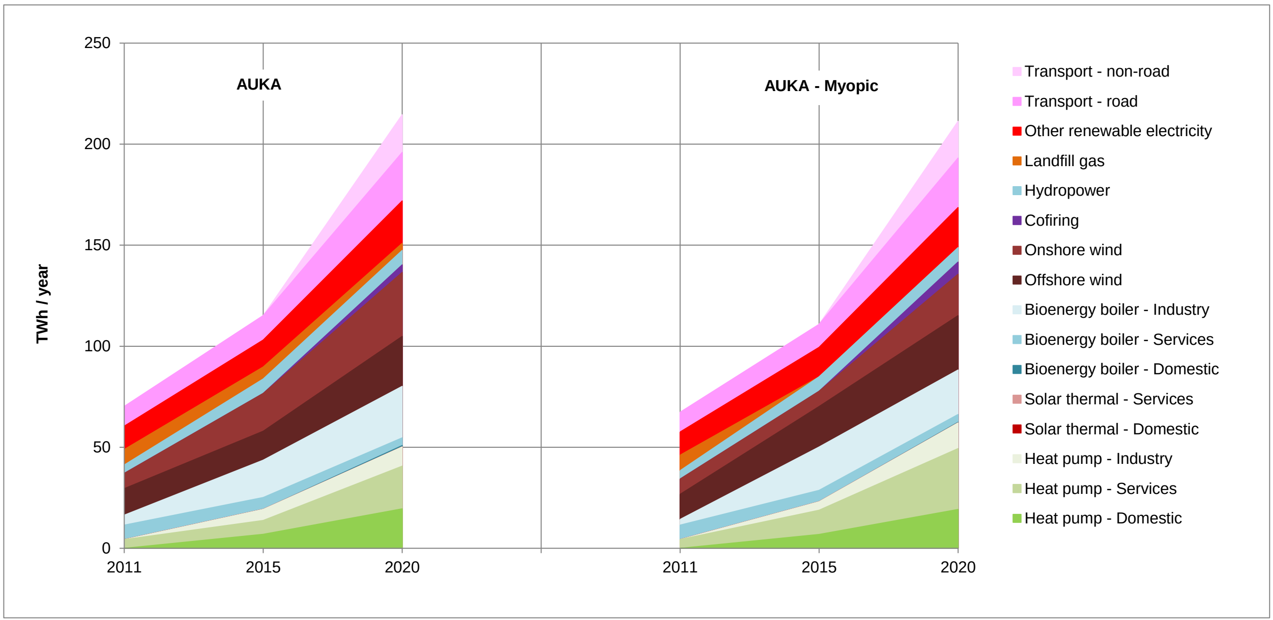
- A number of decision points where early action is necessary to ensure that these transitions are possible
- A number of low regrets options which should be pursed early on, but which may still need to be enabled by wider action across the energy system, *and*
- Uncertainty around a number of key technological building blocks of our future energy system (eg CCS, nuclear and large scale hydrogen production) and a need to ensure that early decisions do not hinder our ability to adapt should one or more of these fail or prove not to be cost effective.

The evolution of the system and the key milestones are described below on a decade by decade basis.

To 2020

To 2020 the RED is the main driver of change in the energy system and starts to accelerate the deployment of a range of renewable technologies as shown in Figure 26. For heat pumps and renewable electricity, the RED provides a useful early stimulus for technologies which continue to play a fundamental role along the entire pathway to 2050. However, in the case of bioenergy, the use in heating is largely transitional; outside of a few niche areas (eg bioliquids in off-gas grid segments), bioenergy moves to more cost-effective abatement opportunities in other parts of the energy system by the late 2030s.

Figure 26 Contribution to the RED (AUKA and AUKA myopic)



In the majority of scenarios examined, peak electricity demand does not start to rise significantly until the late-2030s onwards (in part due to the relatively late adoption of significant numbers of electric vehicles), but given the long-lead times for grid reinforcement, particularly at the distribution network level, it may be necessary to accelerate current reinforcement work in this period. In a world where CCS fails to materialise the situation is exacerbated further, with a more rapid increase in peak demand starting in the early 2030s.

A substantial rise in both annual and peak electricity demand is seen in every scenario, the uncertainty is more around the extent of this rise and timing. As a result it should be possible to identify low regrets network reinforcements which could start significantly ahead of need, to ensure that the system is able to facilitate wider decarbonisation via the electricity system in later periods.

To 2020 gas use is very similar to today's levels, with limited change to current operation of the gas networks. There is even a potential increase in overall gas flows on the distribution network to facilitate a transitional use in CNG (compressed natural gas) for freight transport. It is not until the late 2020s onwards that gas use starts to decline, particularly on the distribution network.

2020s

The 2020s are marked by a continued rapid expansion of heat pumps, particularly within the industry and services sector, with penetration even beginning to saturate by the end of the decade in the latter. Take up is slower in the domestic sector with continued steady increases seen from this point through to 2050 in the majority of scenarios. This pattern is still broadly true, even in a world without CCS as other technologies such as district heating are instead developed in later decades to avoid adding further to peak electricity demand, rather than extending the deployment of heat pumps. The only place where gas use in heating is not significantly affected is high temperature process heat.

The electricity system moves through a first stage transition with significant fossil plant (particularly coal) retiring under the Industrial Emissions Directive (IED) accompanied by a gradual expansion of wind and some new CCGT, along with the anticipated first new nuclear plants. The roles for both significant new wind and (a somewhat more limited) new build of unabated gas are fairly low regrets at this point given the role of wind by 2050, and the shift in emphasis of non-CCS gas generation from annual baseload supply through the 2020s and early 2030s through to peaking plant in later years.

Under the majority of scenarios, large scale roll-out of CCS does not start until the late 2020s or early 2030s, providing potential time for further demonstration. However, the roll-out occurs rapidly through the 2030s and beyond so there is a need to ensure the supporting infrastructure for CO_2 transport and storage is laid in the 2020s to accommodate this, if the early demonstrations are promising.

However, in a world where new nuclear fails to materialise there is added pressure to bring forward large scale deployment of CCS into the late 2020s with corresponding implications for wider infrastructure.

In a world without CCS the burden shifts heavily onto rapid deployment of nuclear and wind, with offshore wind build rates effectively at their maximum assumed level all the way through the 2020s to 2050. This in turn requires a more rapid maturing of the wind supply chain and rapid infrastructure reinforcement to accommodate offshore wind into the electricity network, along with sufficient balancing and back-up capability.

Large-scale hydrogen deployment does not begin until the 2030s, before expanding rapidly in the 2040s. There is a need to begin laying the foundations for its network infrastructure in this decade, as the majority of future hydrogen production occurs at large-scale facilities to take advantage of CCS. Whilst a significant quantity of hydrogen is ultimately used in industry which could be sited locally to the hydrogen production[35], the larger share is used in freight vehicles and vans, requiring a dedicated distribution network.

2030s

In the majority of scenarios the 2030s is period of continued, gradual penetration of heat pumps in the domestic sector. In the services sector electric heat pumps have already saturated the market to a large extent, but there is a continued gradual expansion of heat networks through to 2050. Electricity, both peak and annual now starts to rise more rapidly, requiring sufficient network reinforcement to have already been undertaken. The electricity sector experiences a rapid period of decarbonisation over this decade due to the retirement of older unabated gas plant and a continued expansion of nuclear and renewables, with nuclear being deployed at its maximum build rate. In addition, CCS deployment accelerates, with rapid growth in large-scale CHP with CCS and more gradual growth in hydrogen production with CCS which then accelerates in the 2040s as the CHP capacity starts to plateau. The availability of low carbon process heat starts to facilitate the first major shift in industry as heat networks expand rapidly, but as these are likely to be more localised and can develop relatively organically. By contrast, continued development is needed on hydrogen distribution networks in preparation for the rapid expansion in the 2040s.

In a world without nuclear the pressure to deploy CCS increases. Some deployment has already been brought forward into the 2020s, but now new deployment effectively has to be constructed through the 2030s to 2050 at its maximum build rate to be in a position to meet the 2050 target.

In a world where CCS is not available there is virtually no margin for error in the pathway at this point to meet the 2050 target. The services and domestic sector have to be largely decarbonised already via a combination of electric heat pumps, solar thermal and district heating. Non-road transport is using the bulk of available bioenergy and a rapid expansion in electric road transport is starting. All of this puts increasing pressure on the electricity system with new build new nuclear and renewables being constructed at the upper limit of what is likely to be feasible. Gas use for high temperature industrial process heating is the only part of heating which sees relatively little impact and this remains out to 2050.

It is also likely in worlds where meeting the UK target is increasingly difficult, that energy prices rise to a level that leads to a significant reduction in overall demand[36].

2040s

By the 2040s the electricity system has effectively been decarbonised in all scenarios. The last decade is categorised by a further squeezing of gas from the domestic sector (shifting it to more of a seasonal top-up role) and the large scale expansion of hydrogen(produced via bioenergy gasification and steam methane reforming, both with CCS). Hydrogen is used largely for industry and transport, with the latter assuming that the hydrogen distribution network has been developed sufficiently to accommodate this.

Heat networks play a significant role in industry by this point, but only a relatively modest role in buildings (focused primarily in the services sector) due to their high fixed infrastructure costs relative to the scale and seasonal shape of building heat demand. Where there is substantial availability of very low cost/carbon, building-grade heat supply (primarily waste heat from nuclear within reasonable proximity of a heat load) there is greater cost-effective potential for heat networks across buildings; but this is generally at the

[35] Along with large scale CHP with CCS to take advantage of the CO2 transport infrastructure

[36]Although this has not been modelled explicitly it is an area for further work as highlighted in Section Appendix B.

expense of some electric heat rather than residual gas used for heating, to help minimise peak electricity demands.

In a world without large scale hydrogen production, the last decade is categorised by a continuing use of gas for HGVs, which is only transitional in other scenarios, and with greater emphasis on electric vehicles for other road transport. To meet the 2050 target gas is further squeezed from domestic and service sector buildings by additional electrification and some use of heat networks. In industry, the additional decarbonisation that was being provided by hydrogen is now provided via a number of alternative pathways. In particular, bioenergy use shifts to a combination of large-scale biomethane production (with CCS), direct bioliquid boilers and large scale biomass CHP with CCS, providing lower temperature process heat into the local heat networks, alongside the existing large-scale CCGT CHP with CCS.

7 Summary

7.1 Key messages

The analysis of optimal pathways for the decarbonisation of heating, within the context of the wider energy system, has highlighted a number of key messages.

Decarbonising building heat and tackling swings in demand

Electrification of heat in buildings, facilitated primarily by heat pumps, is a critical component of decarbonising heat and meeting the 2050 target. This also re-emphasises the need for widespread and early decarbonisation of the electricity system, which is important to facilitate long-term decarbonisation of other sectors such as transport. Under all scenarios both peak and annual electricity demand rise rapidly from the 2030s onwards.

Energy efficiency has a crucial role to play, both in terms of reducing annual and peak demand, although there is a limit to what is likely to be cost-effective for the most expensive options even under very high carbon prices. However, even with extensive improvements in efficiency, heat demand is likely to remain significant by 2050 along with sizeable seasonal and diurnal swings in demand, particularly in winter. These will need to be managed carefully to avoid excessive costs of electricity generation and network reinforcement if heat is provided from electric heat pumps. This is particularly important given the drop in the COP of ASHPs during cold winters at the point when heat demand is the highest.

One potentially cost-effective way of tackling these swings is via hybrid electric / non-electric heating and heat storage strategies. A low risk way to achieve this is by maintaining (significantly reduced) flows of gas in buildings for use in dual-fuel gas / heat pumps devices. This is more important for domestic buildings than those in the service sector, given the overall scale and shape of demand in the former.

The continued use of gas does not necessarily need to be facilitated by widespread availability of biomethane as bioenergy resources can be used more effectively for abatement elsewhere in the energy system, providing 'headroom' for greater remaining emissions in other sectors. This is particularly the case for using bioenergy with CCS to produce hydrogen, which can then be used in parts of transport and industry which have fewer abatement options.

Even with this strategy, there will likely be a significant rise in peak electricity demand from the 2030s needing substantial generation and network reinforcement. Network reinforcement, particularly at the distribution level, will need careful planning to ensure that necessary reinforcements are achieved in a timely manner.

An alternative to retaining gas to manage peak demand is to make more extensive use of heat networks. However, in the core scenarios modelled their use was relatively limited in the buildings sector. In the scenarios where gas is forced out from buildings by 2050, greater use is made of heat networks, but at materially higher overall energy system cost[37] and with the majority of heatstill provided by heat pumps.

[37]And higher transitional costs over the pathway to 2050.

Decarbonising industrial heat

Heat for industry is subject to far less seasonal variation than buildings and can be split into three broad groups:

- Low temperature space heat requirements – these are similar to service sector buildings, but form a small component (around one fifth) of total industry demand, and are primarily decarbonised via a mix of ground and AHSPs.
- Low temperature process heat – the use of more localised heat networks (ie reflecting industrial clusters) expands organically over time and by 2050 these are providing the bulk of low temperature process heat across the different scenarios examined. The provision of heat is effectively shifted further up the energy chain from direct fossil fuel boilers to large scale CHP. By 2050 this is also providing a sizeable contribution (eg 10-20%) of total electricity generation and at larger scale allows more cost-effective use of CCS.
- High temperature industrial process heat has fewer abatement options[38]. Whilst gas use declines somewhat by 2050, a significant level still remains across all the scenarios. Direct use of bioliquids is not a preferred route for relatively scarce bioenergy resource, but significant use is made of hydrogen by 2050 in a number of scenarios (produced primarily via gas SMR + CCS and biomass gasification + CCS).

Long term role of gas

Total gas use declines significantly to 2050 in a number of sectors, particularly buildings and to a lesser extent industry. However, there is still potentially a large scale, albeit different, role by 2050 enabled by CCS and hydrogen production.

The long-term role for direct gas in buildings shift towards winter seasonal top-up and peaking, particularly for domestic buildings, to help manage seasonal and diurnal swings in heat demand, whilst direct use in industry is retained primarily for high temperature industrial process heat where there are fewer abatement alternatives.

Gas use in dedicated power and CHP shifts strongly towards the latter, in the form of large scale CCGT CHP with CCS, with the heat used predominantly for lower temperature process heating in industrial clusters. The use of gas in hydrogen production (via SMR with CCS) is also potentially significant as the hydrogen is then used to help decarbonise specific parts of industry and transport. However, this use is sensitive to gas prices and disappears under the high gas price sensitivity explored.

In a world where CCS is not available it becomes significantly more difficult to meet the emissions target in 2050. As a result the role for gas is effectively reduced to high-temperature industrial process heat provision, and use in unabated peaking plant to help manage the significant quantity of intermittent renewables on the system. This raises a question about the on-going maintenance costs of the overall gas network, and whether it becomes more cost-effective to begin targeted decommissioning, particularly of the distribution network for domestic and service sector buildings.

[38]Novel high temperature electrical routes are another potential option, but have not been included due to data uncertainty (see footnote **Error! Bookmark not defined.**). It is unclear how extensively these would be used as they would also add, a not nsignificant amount, to peak and annual electricity demands.

Costs of the energy system

The analysis suggests that overall costs of the 2050 GHG target are likely to be in the range of 1-2% of GDP which is consistent with a number of earlier studies. However, this is dependent on the successful commercialisation and large-scale deployment of a number of key existing *and* developing technologies, including:

- Increased electrification of heat
- Substantial improvements in building energy efficiency
- Large-scale uses of CCS, not just in power but across the energy system, *and*
- Use of hydrogen (produced via CCS routes) in parts of the energy system with more limited abatement alternatives, such as freight transport and high-temperature process heating.

Household energy costs related to heating, as well as other electricity consumption, are likely to increase significantly compared to the situation with no emission target in place, even after accounting for the benefits of cost-effective efficiency measures.

If the UK is able to cap the cost of abatement (as per the core ACC scenario) via the purchase of international GHG credits, this will significantly reduce the marginal cost of abatement and potential energy prices seen across the system. However, the average cost of abatement is still very similar to that seen under the core AUKA scenario, with some of the underlying energy system costs shifted from energy infrastructure to credit purchase[39], effectively reducing investment within the UK.

The overall costs of the energy system are driven strongly by the end-point in 2050, given that costs of abatement increase disproportionately as the target tightens in later years. Early planning to position the system to meet this end point could offer significant long-term cost savings given the difference in costs highlighted by the 'perfect foresight' versus myopic runs for the core AUKA scenario.

Evolution of the system to 2050 and importance of infrastructure planning

Finally, the evolution of the energy system is characterised by a number of key transition points, such as the rapid growth in electricity demand and roll-out of CCS from the 2030s onwards, followed by wide-scale hydrogen use in the 2040s.

All of these transitions need to be facilitated by the appropriate supporting infrastructure; electricity network reinforcements, CO_2 transport and storage, and a hydrogen distribution network. Given how rapid these transitions become, the foundations for the supporting infrastructure need to be laid sufficiently early.

In addition, under situations where new nuclear or CCS fail to become commercially viable, increasing pressure is put on CCS deployment or electricity demand, respectively. This requires the rapid expansion in infrastructure deployment to start even earlier to ensure the system is put on a pathway that can still meet the GHG target by 2050.

[39] Although it should be noted that the DECC international credit prices are consistent with a world of strong global action on climate change, which may not be the case.

A Appendix - Key model updates

A.1 Within year timeslicing

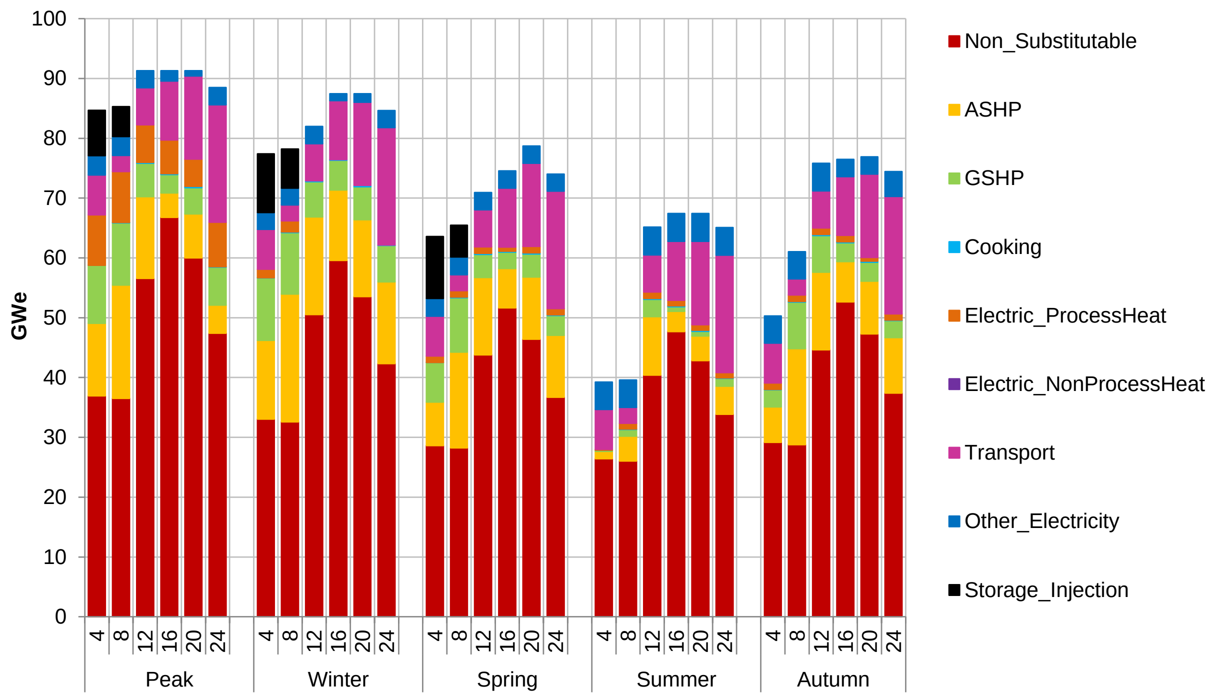
RESOM models the evolution of the energy system in 5-year steps to 2050, but within each year now also considers five characteristic days; which are modelled to account primarily for the swing in seasonal heat demand:

- Winter, Spring, Summer, Autumn – ie each characteristic day reflects one-quarter of the year, *and*
- 1-in-20 peak day – representing an extreme winter.

Each of these characteristic days are further subdivided into six diurnal timeslices representing contiguous 4-hour blocks 1-6, to help capture the variation and interaction between supply and demand for both electricity and heat within the day[40].

Hence the model needs to resolve supply / demand balances in the energy system for all possible years and all of the combined seasonal and diurnal timeslices within each year – eg 2020, winter, 00:00 to 04:00. An illustration of the within year timeslicing is provided inFigure 27.

Figure 27 Illustration of within year timeslicing – electricity demand profile in 2050



[40]Further granularity is technically possible, but there is a trade-off with model performance

A.2 Storage

Energy storage has now also been added explicitly to RESOM. The model decides how much storage to build over time, the relative technical parameters of the storage (volume and 'power rating[41]') and how to operate storage in terms of injection and withdrawal within the year. Storage is divided into two main types:

- Seasonal storage – whereby the model can choose (subject to sufficient capacity) to inject in one season and withdraw in another (both seasonal gas and hydrogen storage are included), *and*
- Diurnal storage – whereby storage operation is determined on a within day cycle. Electricity and heat storage options are included, the latter at both building level as well as larger scale attached to heat networks (to help decouple supply of heat from time of use).

Fast cycle gas storage is included separately via a security of supply constraint (see Appendix A.5) as the typical operation of such storage is across consecutive days or weeks, which is not contained within the model time horizon.

A.3 Heat segments

The original AUB model had a detailed segmentation of heat demands, but a number of adjustments have been made for this study, as follows:

- Some aggregation of the existing data has been made where there were limited, meaningful trade-offs presented to the model, for performance reasons[42]
- The generic "heat" energy service demand for the domestic and service sector segments has been disaggregated to reflect separate space heat, hot water and cooking demands
- Within year profiles have been added for all heat demands for each segment, and for each type of service demand, *and*
- The domestic sector data has effectively been replaced, drawing on more detailed information from National Grid studies[43]. The 26 characteristic building types from these studies have been aggregated into 10 for this study, and further disaggregated by location.

The new segmentation in RESOM is summarised in Table 6. The combination of sector, location and building type leads to approximately 40 heat segments in total, with some of these segments (eg domestic buildings) having a number of heat service demands.

The heat-related technologies in the model, such as air source heat pumps (ASHPs) or building heat storage, are characterised separately for each heat segment so that RESOM makes a decision to build and

[41]Ie the effective injection / withdrawal rate for electricity

[42]For example, commercial and public sector buildings have been aggregated into 'service sector buildings'; note these segments are still differentiated by location and existing / new build

[43]The Beywatch and IFI3 studies. These took domestic building survey data from a range of properties in Loughborough to create detailed (6min) simulation models of energy consumption in a range of characteristic building types and the potential impact (and cost) of retrofit measures on building energy demand.

operate the technology in the optimum way for that individual segment, whilst also considering the impact on the wider system[44].

Table 6 Heat segments

<table>
<tr><th>Sectors</th><th>Locations</th><th>Building types</th><th>Heat service demands</th></tr>
<tr><td>Domestic</td><td rowspan="3">Urban
Rural
Non-net bound</td><td>Detached – Pre-war
Detached – Post-war
Flat – Pre-war
Flat – Post-war
Other - Pre-war
Other - Post-war
Other – Post-1980
New – detached
New – flat
New - other</td><td rowspan="2">Space heat
Hot water
Cooking</td></tr>
<tr><td>Services</td><td>Existing
New Build</td></tr>
<tr><td>Industry</td><td>Existing
New Build</td><td>Space heat
Low temperature process
High temperature process</td></tr>
<tr><td>General</td><td colspan="3">Other electricity for cooling</td></tr>
</table>

A.4 New technologies

In addition to the set of technologies from the previous AUB model and the storage options mentioned above, a number of additional technologies and pathways have been added:

- Gas Heat Pumps
- MicroCHP
- Fuel cell CHP
- Hydrogen boilers/cookers for both building heat and industrial process heat
- Additional CCS retrofit options for CCGT and coal power generation
- 'Waste heat' options from large scale power stations[45] (in addition to dedicated CHP / district heat boilers) and a long distance waste heat transmission network option feeding into a variety of local heat distribution networks[46]
- Explicit domestic energy efficiency measures (disaggregated by heat segment)

[44] Rather than seeing the aggregate heat demand from all segments and ensuring the total supply of heat meets the aggregate demand profile, which may then miss some of the more subtle choices and trade-offs at the individual segment level.

[45] These are provided by an additional operating modes, which provide waste but at the loss of some electrical output (at an assumed z-factor of 8) akin to a virtual heat pump

[46] Note that this option provides low temperature heat suitable for buildings, but not for process heat, which is provided by dedicated boilers or CHP.

- Two-stage representation of gas and electricity networks to differentiate transmission from distribution infrastructure
- Liquefied Natural Gas (LNG) regasification infrastructure
- Electricity (load-shedding) demand side response, *and*
- Additional timeslice-dependent parameters where appropriate, including
  - Seasonal variation in heat pump Coefficient of Performance (COP)
  - Electric vehicles with a fixed charging profile, varying by type of vehicle, assuming a significant degree of off-peak load shifting.

There are a number of other possible pathways and technology options, which have not been included in the model due to the uncertainty in available data, for example, novel electrical technologies for providing high temperature process heat.

A.5 Security of supply constraints

Even with the addition of within day timeslices the temporal granularity of the model is still relatively limited compared to modelling approaches targeting just one part of the energy system, such as electricity dispatch models operating at an hourly resolution.

To ensure that the model is generating an appropriate solution a number of proxy constraints have been added to address particular security of supply issues:

- Peak reserve margin – to ensure that sufficient *de-rated*[47] capacity (of both generation and storage) is available to meet the likely 'true' peak demand plus a sufficient reserve margin (currently set to 15%)
- Flexibility margin[48] – to ensure that sufficient controllable plant (both generation and storage) which is not already being utilised, is available to ramp up to meet a rapid increase in demand[49], coupled with a coincident loss of some intermittent generation, for example caused by the wind dropping, *and*
- Peak day gas deliverability – to ensure sufficient deliverability of gas on a 1-in-20 peak day, combining average winter 'availability' from standard sources (interconnectors, seasonal storage, etc) and short cycle gas storage, which can be constructed at additional cost.

A.6 Partial foresight optimisation mode

The original optimisation model operates in two main modes:

- Perfect foresight, where all time periods to 2050 are optimised simultaneously to provide a full least cost-optimised pathway, *and*

[47] A probabilistic measure of how likely the plant is to be available at the point of peak demand, for example, for most dispatchable plant this would reflect 100% minus the likelihood of an unplanned outage.

[48]This is focused primarily around STORR (Short Term Operating Reserve Requirements) over a 1-4 hour period, as opposed to short timescale flexibility requirements such as frequency response.

[49] Based on the shape of diurnal demand, but requiring that the ramp up in achieved over a 2-hour as opposed to 4-hour period

- Myopic foresight, where the model optimises in 5-years steps, carrying forward the stock of technologies it has built, but with no foresight of assumptions in future years.

This latter approach is used to help explore the impact of infrastructure lock-in – ie making decisions that appear cost-effective in the near term, but which are not in the medium to longer-term and may lead to stranding of assets.

To these approaches we have added a partial-foresight mode, whereby the model still optimises in 5-year steps, but with a user specified level of foresight of future periods (eg of energy demands, fossil fuel prices). This allows the spectrum of full myopia through to perfect foresight to be explored.

B Appendix – Areas for further work

B.1 Summary

As part of this study we have identified a number of potential areas for further development of both the model and analysis:

- Data gathering and refinement is in essence an on-going process. Potential areas of focus for heating are around more novel electrical technologies for high temperature industrial process heat, however, the model may not be sensitive to their addition given the desire to avoid adding further to peak electricity demand
- National Grid is currently working, through the Energy Networks Association on a project focused on consumer behaviour and acceptance of new heat-related technologies in the domestic sector. This may lead to refinements in, for example, the data and type of build rate constraints[50] imposed within the model, to model better the likely roll-out of new heating technologies
- It would be relatively straight forward to add the functionality to represent elastic demand response, as per the MARKAL-ED model used by DECC. This would allow us to explore endogenously the response of energy service demands to changes in price, particularly around times of peak demand, and in scenarios where it is significantly more difficult to meet the emissions target, leading to higher prices and potentially more significant reductions in demand
- Adding an explicit geographical representation to the model could allow better categorisation of the costs of certain technologies, particularly heat or electricity network infrastructure costs. However, accurately costing these technologies would require a level of geographic detail that is likely to make the optimisation problem intractable (if the level of detail across the rest of the energy system is maintained), whilst modest levels of geographic detail are unlikely to offer sufficient improvements in accuracy; *and*
- Finally, as discussed in Section 3.3.1, the use of a Linear Program (LP) optimisation means that it is sometimes hard to accurately reflect the costs of different technologies where these exhibit economies of scale or where costs are largely fixed per installation rather than per unit of capacity. For example, where the costs of heating technologies or packages of efficiency measures are, in the real-world, more correctly specified on a ‘per dwelling’ basis
    - Whilst we have accounted for this as far as is practical in an LP formulation, a better representation could be specified via a Mixed Integer Program (MIP)[51]. With this, discrete choices for individual heating and / or retrofit packages could be specified and costed for individual building segments, effectively providing the cost optimisation process with a more accurate picture of heat-related costs.
    - The MIP formulation could also allow economies of scale in the deployment of particular technologies to be reflected. For example, small-scale, piecemeal retrofit of buildings or reinforcement of the electricity distribution network (at high cost per kW / building) versus large-scale coordinated action (with higher total upfront costs, but lower cost per kW).

[50] For example, RESOM has functionality to implement proportional build rate constraints, where the maximum rate of new build is a function of previously installed capacity, to provide a better proxy for the accelerating market penetration of a new technology.

[51] Albeit with severe implications for model performance

Whereas the £ / kW in an LP for the distribution network upgrade are constant regardless of the scale of installation in each time period.

- Finally, a more straightforward use of the MIP formulation[52] would be to explore the impact of lumpy investment, which is particularly relevant for larger plant (eg biofuel production or nuclear plants) whether there will only be a small number of plants installed.

[52] Already implemented in an earlier version of RESOM