Imperial College London

Whole Energy System Modelling for Heat Decarbonisation

Project team

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Contents

Abbreviations

ATR	Auto Thermal Reformer
BECCS	Bioenergy plant with Carbon Capture and Storage
BEIS	Department for Business, Energy & Industrial Strategy
CCGT	Combined Cycle Gas Turbine
CCUS	Carbon Capture, Utilisation and Storage
CHP	Combined Heat and Power
DG	Distributed generation
DH	District heating
EE	Element Energy
ELEC	Electrification scenario
GHG	Greenhouse gas
H2	Hydrogen scenario
HHP	Hybrid Heat Pump
HHP-H2	Hybrid Heat Pump with hydrogen boiler scenario
HHP-NG	Hybrid Heat Pump with natural-gas boiler scenario
HP	Heat pump
IHES	Integrated Hydrogen and Electricity System
IWES	Integrated whole energy system model
LDZ	Local Distribution Zones
NG	Natural gas
NIC	Network Innovation Competition
OCGT	Open Cycle Gas Turbine
P2G	Power to Gas
PEM	Proton Exchange Membrane
PV	Photovoltaics
RES	Renewable Energy Sources
RH	Resistive heating
SMR	Steam Methane Reformer
SOE	Solid Oxide Electrolyser
UKTM	UK TIMES model is an energy system model of the UK that has been developed by UCL and the UK Department of Business, Energy and Industrial Strategy.

Extended Executive Summary

Context and objective of the studies

The heat sector (heat in buildings and industrial processes) accounts for more than half of the UK's energy consumption and contributes to around a third of its total carbon emissions[1]. Achieving the UK's long-term climate targets will require decarbonising electricity, transport and heat in a coordinated manner with a clear strategy for delivering the optimal energy portfolio.

In this context, the report presents the key results and the findings of analyses and studies focusing on understanding and quantifying the long-term cost drivers for decarbonising the heat sector. This modelling and analysis of heat decarbonisation scenarios was supported by the Department for Business, Energy and Industrial Strategy (BEIS). The specific objectives of the research are to provide:

- Strategic insights into the economic performance of alternative heat decarbonisation scenarios by assessing the role and value of emerging low-carbon and flexibility technologies with consideration given to their future cost and availability uncertainties;
- Understanding system implications of different heat decarbonisation scenarios by analysing the system capacity and operational characteristics of electricity, natural gas and hydrogen technologies and their associated infrastructure requirements considering optimal energy vector interactions using a holistic approach to minimise the overall energy system cost to meet the UK net-zero energy system in 2050;
- Fundamental quantitative evidence to inform technical, economic and policy decision-making regarding the transition to a resilient and low-carbon heat energy future.

A spectrum of studies has been carried out using a set of data and assumptions provided by BEIS for work undertaken as part of its 6th Carbon Budget analysis. The work investigates the key cost performance and the energy system requirements for different heat decarbonisation strategies.

Modelling uses Imperial College's Integrated Whole Energy System model (IWES), which incorporates detailed modelling of the electricity, heating and hydrogen systems from the supply side, energy network to end-users, and energy storage with their associated technologies and infrastructure. The model also optimises carbon capture technologies for bioenergy processes, power generation, hydrogen production, direct air capture, and carbon storage. This enables IWES to capture the complex interactions across those energy vectors to minimise the overall system investment and operating costs focusing on the year 2050 with net-zero emissions.

Four illustrative core "scenarios" are investigated and comprise:

- Hydrogen (H2) – this assumes UK-wide repurposing of the natural gas distribution network to hydrogen with the conversion of natural gas appliances for heating to operate on hydrogen.

[1] BEIS, "Clean Growth – Transforming Heating", December 2018

- Electricity (ELEC) – this assumes UK-wide deployment of air-source heat pumps for building heating and the decommissioning of most of the natural gas network.
- Hybrid heat pumps with natural gas (HHP-NG) – this scenario is a variant of ELEC with hybrid air-source heat pumps and natural gas boilers for hybrid operation in dwellings connected to the gas grid. The natural gas network is maintained.
- Hybrid heat pumps with hydrogen (HHP-H2) – this scenario is a variant of H2 with hybrid air-source heat pumps and hydrogen boilers.

All scenarios assume that off-gas grid buildings deploy heat pumps and that 17% of the domestic and 24% of non-domestic heat demand in urban areas is supplied through district heating systems in all scenarios.

The scenarios presented are illustrative and represent maximal deployments of different on-gas-grid technologies (which may not be realistic) in order to test the impact on the system costs, security of supply, energy balancing capability and emissions aspects.

The focus is on the year 2050 and the delivery of the UK's legislated requirement of net-zero GHG emission target, so the analysis does not consider the trajectories or pathways, interim targets and associated decisions to get to this point. A critical feature of all the scenarios is the capability to offset other UK "hard-to-decarbonise" sectors such as agriculture, aviation, shipping, waste, parts of industry, and residual emissions from the energy sector. It is important to note that the model does not optimise carbon offsetting action outside the energy sector. Net-zero is achieved in the modelling by the large-scale deployment of bioenergy (within limits dictated by the likely availability of sustainable biomass) and direct air capture plant with carbon capture and storage (BECCS and DACCS). The negative carbon emission associated with these technologies is used to offset the residual emissions from the sectors listed above.

Strong interactions between electricity, hydrogen, and heat energy systems are demonstrated and illustrate the need for integrating the heat decarbonisation strategy with those in the electricity and transport sectors. IWES enables a holistic evaluation to simulate and determine the optimal energy systems. Various scenarios are used in the sensitivity studies to identify the system and cost implications of having different assumptions and test the robustness of the scenarios under future uncertainty.

Key findings

These are as follows:

Feasibility of net-zero 2050 emission target and scenarios' cost characteristics

Based on the assumptions and modelling framework, all heat decarbonisation scenarios can reach net-zero emissions at comparable 2050 total annual costs (±2.3% difference), as shown in Figure E- 1. These costs are annuitised total energy system costs in 2050 and comprise capital and financing costs (Capex) and operating costs (Opex) expressed in 2018 price levels. Capex includes financing costs[2].

Capital expenditure (Capex) dominates the cost structure in all scenarios, as more than 80% of the cost is Capex-related. Hence the results are sensitive to the uncertainty in Capex and financing costs. Electricity operating expenditure (Opex) accounts for around 5% or less of the total scenario costs since low marginal cost renewable sources supply most electricity production in this modelling. In contrast, gas (natural gas and hydrogen) Opex is more significant, i.e. 15% of all costs for the H2 scenario and between 6% and 10% for the other scenarios.

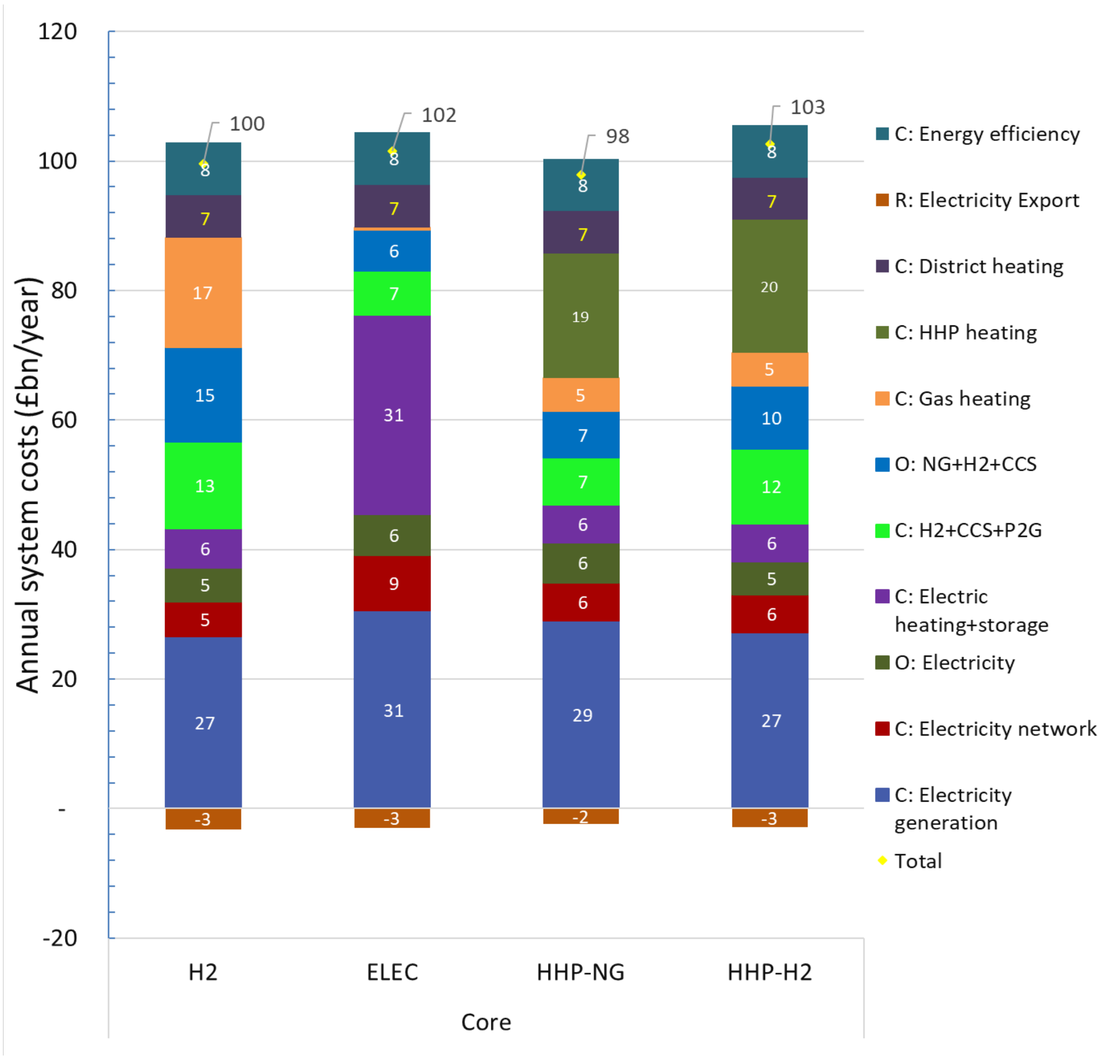

Figure E- 1 Annual system costs of different heat decarbonisation scenarios[3]

Although the total costs are comparable, the underpinning energy infrastructure and operation across different scenarios can differ significantly, as shown in Table E- 1. The

[2] Different ways of accounting for annuitised costs, particularly whether to include the payment for historical components in the system, can lead to differences between models such as the Dynamic Dispatch Model (DDM) used by BEIS and the IWES model. The latter uses an annuitisation function assuming constant payment over the economic lifetime of the asset with a fixed hurdle rate.

[3] Symbol "C:" is used for Capex and "O: "for Opex. The cost structure is explained in Table 2-1, page 28.

variance in the cost-optimal energy system design linked to different heat decarbonisation scenarios emphasises the importance of developing appropriate heat decarbonisation policies, regulatory and market arrangements to guide the transition process and the convergence of the future energy system development.

Table E- 1 Cost composition of different scenarios

Capex and Opex of	H2	ELEC	HHP-NG	HHP-H2
Electricity infrastructure	34%	42%	39%	34%
Hydrogen infrastructure and CCUS	28%	13%	15%	21%
Heating infrastructure	38%	45%	46%	45%

Given the similarity of the cost performance between different scenarios (±2% difference), it can be expected that the ranking between these scenarios will be sensitive to changes in the assumptions used in the modelling. This is confirmed in the sensitivity studies, which are summarised as follows:

- All scenarios' cost is highest where the system has very low flexibility, with ELEC the most affected scenario.
- Low gas prices will bring H2, HHP-NG and HHP-H2 scenarios to the minimum cost. In this case, the H2 scenario may become the least-cost scenario.
- The minimum cost for ELEC is found when the core scenario is combined with HP's COP improvement. The ELEC scenario also has lower costs if we assume significant spare thermal capacity in the electricity distribution networks. Network utilisation data from DNOs suggests that the level of spare capacity or 'headroom' on the network could be as high as 50-60%. However, the precise amounts can vary significantly from network to network and are highly uncertain at the Low Voltage level due to a lack of data.
- In most cases, the HHP-NG is the least-cost solution. However, it requires some conditions to be met, for example:
  (i) Deployment of smart home or building energy system management to ensure optimal usage of the gas boilers from the whole-system perspective
  (ii) A sufficient capacity of DACCS technologies are available at a reasonable cost,
  (iii) Gas distribution can be operated at a low utilisation factor (<10%), and
  (iv) Methane losses can be suppressed.

  Nevertheless, the key learning point observed in the studies is that most of the heat demand is supplied by heat pumps while a small volume of gas is used during the peak of heat demand to mitigate a substantial increase in electricity peak demand.

Critical role of CCUS, BECCS and DACCS

The model demonstrates that CCUS technologies can capture between 122 and 189 $MtCO_2$/year across all scenarios. Most of the carbon captured comes from methane reforming processes (producing hydrogen), power generation, and DACCS. Within this modelling, BECCS and DACCS technologies play a critical role in achieving the UK's net-zero GHG emission target due to their negative emission capability. These technologies are needed to offset GHG emissions from sectors other than heat and energy, though this is partially due to the scenarios' setup rather than insight from the IWES modelling. IWES does not optimise decarbonisation outside of the energy sector, and for this study, IWES relies on the cost optimisation results of the interim BEIS Sixth Carbon Budget analysis using the UK TIMES model (UKTM) for this insight. Other models might be better suited for exploring these trade-offs in more detail.

A related finding within the heat sector is that BECCS and DACCS can facilitate the transition to decarbonising heat by allowing lower-cost but higher-carbon content technologies subject to infrequent use, e.g. gas-fired CCGT/OCGT or unabated gas boilers, in order to minimise the overall system cost. However, such an approach's viability remains uncertain and depends on significant emissions removal technologies development and other sectors' outcomes.

Therefore, the assumptions related to the volume of bioenergy and emissions that can be offset through BECCS and DACCS is critical to the overall energy planning. According to the assumptions used in the modelling for the 2050 scenario, bioenergy with CCUS can offset about 65 $MtCO_2e$/year. Given that the modelled systems emit around 80 $MtCO_2e$/year, the remaining emissions (up to 15 $MtCO_2e$/year) need to be nullified using DACCS or other offsetting action. The potential available capacity of DACCS in 2050 is still highly uncertain, so the modelling is making a significant assumption that there will be sufficient DACCS capacity to offset any additional emissions from different heat decarbonisation approaches. If less DACCS capacity was available, this might make some scenarios infeasible or significantly change their costs.

While there is a significant effort to minimise methane's loss due to its commercial value and the associated environmental concerns, some methane (or biomethane) is inevitably released into the air during its production, transportation, and final consumption. This results in increased carbon emissions between 1.5 $MtCO_2$/year in ELEC and 3.3 $MtCO_2$/year in the HHP-NG scenario. The emissions from methane leakage will also need to be compensated by BECCS and DACCS.

Strong multi-energy system interactions

The substantial changes in the energy infrastructure led by different heat decarbonisation scenarios provide evidence that coordinated energy system optimisation minimises the overall cost. This needs to happen across all energy vectors and incorporate short-term operations with long-term investment. For example, modelling has demonstrated:

- Strong interactions across different system components, especially power, heat, and gas (natural gas, hydrogen) and multiple forms of energy storage
- Multi-energy vector optimisation brings substantial cost savings. For example, the modelling reveals the importance of the portfolio optimisation of BECCS for hydrogen and electricity production due to limited bioenergy resources, the optimal operation of hybrid heating systems, the selection of heating technologies for DACCS and the hydrogen production mix (gas reforming, electrolysers, and BECCS).
- BECCS, which is needed to provide negative emissions, reduces the need for other firm low-carbon generation technologies, such as nuclear.

The findings highlight the need for a holistic and integrated decarbonisation strategy for electricity and heat sectors, thereby reducing the risk of suboptimal systems with higher overall costs.

Efficiency and flexibility of heating appliances

In these studies, heat pumps are the most energy-efficient heating appliance with a modelled coefficient of performance (COP) ranging between 200% and 450%[4] depending on ambient temperature, while natural gas or hydrogen boilers' efficiency is assumed at around 90%. Air-source heat pump performance (heat output and COP) is adversely affected by air temperature; during low COP and high heat demand, hybrid heat pumps' boilers provide additional heat supply. However, heat pumps supply most of the hybrid system's heat demand.

Smart operation of electric and hybrid heating is crucial to improving efficiency and reducing the power system capacity requirement. The heating system should be designed to supply the local heat demand and provide balancing services to improve the overall energy system's flexibility and reduce system costs. Thermal energy storage (both at district heating and building level) can provide flexibility by storing heat produced by heat pumps when electricity costs are low, e.g. during high wind output or low-demand periods.

Hybrid heating systems can also provide significant flexibility by optimising the operation of natural gas or hydrogen boilers and electric heating. IWES considers the cost of offsetting emissions from peaking plants or heating appliances operating on natural gas and infrastructure savings from reducing power system infrastructure costs simultaneously.

Electricity system

The modelling results show that more than 70% of the total electricity generation comes from wind power and between 17% - 25% from nuclear, solar PV, and biomass with CCUS. The remainder comes from hydrogen and natural gas plants with and without CCUS – unabated gas plants are operated very infrequently. Results indicate that gas plants (hydrogen and natural gas combined cycle and open cycle plants), hydro including pumped hydro and battery energy storage systems, are primarily utilised to support system balancing, supplemented by demand-response technologies.

IWES optimises the mix and location to minimise system costs, considering the temporal and spatial diversity of resources. Wind farms tend to be located in the north of Great Britain, whilst solar PV generation is more often located in the south, where their respective utilisation factors are higher.

As expected, the ELEC scenario has the highest peak demand and electricity consumption. In all scenarios, hydrogen-fired power generation's role is to support short-term balancing and strengthen the sector-coupling between hydrogen and electricity systems by converting hydrogen to electricity. Hydrogen can be produced via electrolysers using renewable energy

[4] BEIS, "Evidence Gathering – Low Carbon Heating Technologies – Domestic High Domestic High Temperature, Hybrid and Gas Driven Heat Pumps: Summary Report", Nov 2016 supplemented with Ecodan test data and assumption on the future improvement of HP COP.

(e.g. "green" hydrogen) to reduce curtailment; hydrogen can be stored and converted back to electricity if needed or used directly to supply hydrogen demand from other sectors. By having an energy system with two-way energy conversion between electricity and hydrogen (albeit with conversion losses[5]), the hydrogen energy storage system's flexibility can also benefit the electricity system. These solutions rely on having a viable hydrogen market and hydrogen to power technologies.

Due to the UK's low-cost wind resource, electricity production is competitive compared to generation in Europe. As a result, the model suggests between 40-60TWh net export of electricity to Europe annually. The estimated revenue[6] from electricity export is between 2.4 and 3.2 £bn/year. The interconnection with Europe allows electricity to be imported, providing support during periods of low wind or peak demand, and the modelling demonstrates the value of robust interconnected systems, which bring benefits to both systems.

In interpreting the results, it is important to bear in mind that as a cost optimising model, IWES will only present one result as “cost-optimal”, whereas a wide range of alternative systems could be very similar though only marginally higher in costs. Further sensitivity analysis could be used to explore this. BEIS modelling of the power sector using the Dynamic Dispatch Model[7] looking at several thousand unique low-carbon deployment mixes suggests that a broad range of generation mixes have similar costs.

Hydrogen system

Hydrogen has zero carbon emissions at the point of consumption. However, the modelling suggests that if hydrogen is to be used at scale, then most will come from natural gas supplied to autothermal reformation with carbon capture and storage (ATR+CCS), with the remainder produced from bioenergy with CCUS (BECCS) and electrolysers. Therefore, the role of CCUS in hydrogen production is essential to minimise the emissions, although some remaining residual emissions from the capture process will require offsetting.

As hydrogen demand for heating is seasonal, storage is needed to optimise the utilisation and minimise the hydrogen production capacity. The need for hydrogen storage in ELEC and HHP-NG is relatively small because most of the hydrogen demand comes from industrial sectors with a flat temporal profile and only a small proportion from power generation. In contrast, in H2 and HHP-H2, a substantial amount of hydrogen is required for heating, and therefore, it requires around 2.6 – 3.6 TWh of hydrogen storage. Larger storage capacity may be required to support hydrogen system balancing if the operation of ATR+CCUS is inflexible.

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[5] Energy conversion efficiency of ATR+CCS is 89% and electrolyser (Proton Exchange Membrane) is 82% (see Appendix A for more details).

[6] The revenue of electricity export is estimated based on the volume of net-energy export multiplies by the average cost of electricity production.

[7] BEIS (2020). Modelling 2050: Electricity System Analysis. Link: www.gov.uk/government/publications/modelling-2050-electricity-system-analysis

Impact of energy system flexibility

Improving energy system flexibility by enabling load shifting and providing ancillary services through demand-side response, energy storage, and cross-vector alignment is essential when heavily dependent on variable renewable energy sources. As might be expected, the value of flexibility[8] is highest in the ELEC scenario, reaching up to around £11bn/year. The value of flexibility is lower in other scenarios, although still significant (at least £5.3bn/year). This is because electricity balancing and storage are considerably more challenging in ELEC than in gas systems with their inherent energy storage. It is, however, important to emphasise that the IWES optimises the interaction between different energy vectors, which provides significant inherent flexibility.

While distributed flexibility reduces distribution capacity requirements, sufficient distribution network capacity will need to be provided to harness the flexibility and use it to balance the national energy system. Flexibility benefits the local and national systems; therefore, the future distribution network planning approach should consider this aspect. In this study, a conservative assumption assuming no headroom is used to evaluate the impact of heat decarbonisation on the electricity distribution networks and therefore, the distribution network cost is higher than if network headroom is considered.

Lower flexibility from demand response and energy storage leads to higher Opex and Capex of electricity and hydrogen infrastructure due to increased peak demand. It also reduces the system ability to integrate variable renewable energy sources.

Further research and energy system modelling

As suggested by the external reviewer[9], more work is required to better understand the potential energy mix to transform heating by 2050. While providing useful insight into the impact of different factors, the long-term cost drivers for different scenarios in the present studies may not be sufficiently robust; therefore, greater sensitivity analysis is extremely important. Some research areas warrant further investigation to provide an in-depth understanding of the transition towards low carbon heat and ensure optimal integration of heat and electricity decarbonisation strategies. A list of potential topics to be further explored is as follows:

- BECCS and DACCS
  The modelling has evidenced the critical importance of these technologies. Further research is required to understand the volume of bioenergy and DACCS technologies required in 2050.

- Buildings
  The UK housing stock has a highly variable energy efficiency performance with nearly 50% built before WW2. Heat performance in terms of heat demand profiles and the

[8] Flexibility is valued by comparing scenarios with realistic levels of flexibility against a counterfactual scenario with no flexibility at all.
[9] Please see the excerpt of the external review report from Prof. Tony Roskilli in Appendix B.

impact of improvements in energy efficiency performance is not well understood, and further research is needed. In particular, further work can focus on

- modelling different types of buildings (detached, semi-detached, terraced, purpose-built apartments),
- assessing the impact of energy efficiency levels across different building segments,
- on and off-gas grid urban/rural typologies,
- suitability of different heating technologies to different housing archetypes,
- integration of heating and cooling,
- the role of thermal storage, and
- analyse heat demand diversity, both local and regional, and its impact on national peak heat demand.

- Transition Pathway

  Modelling has focussed on a snapshot year, i.e. 2050, with little attention to the transition pathway and how interactions with decisions and interim targets might impact the feasibility and cost of 2050 scenarios. As identified, many uncertainties remain. Identifying the transition pathway with robust least-worst regret heat decarbonisation strategies would be valuable. This should include analysis of parallel scenarios to improve the understanding of various uncertainties before decisions have to be taken on the scenario forward. This would include identifying the required related policies and understanding the regional aspect of how low-carbon technology is deployed whilst considering a full range of technologies and system uncertainties explicitly. These types of studies can be used to provide evidence and support the development of a holistic strategic energy decarbonisation roadmap.

- Resilience

  The future energy system will have very different features and characteristics compared to today. In particular, its resilience to high impact events such as extreme weather conditions, e.g. exceptional cold spells, periods of low wind, heat waves, shortage of gas supply, and long-term variability of renewable sources. This is likely to affect system design (specifically around infrastructure on generation and storage portfolio) and related costs. It also warrants careful consideration in terms of engineering, consumers' needs and requirements.

- Interconnectors

  The power sector modelling makes effective use of interconnectors to provide flexibility and lower system costs. Modelling assumes that these can be operated optimally to export surplus generation and import at the time of shortfall. Further work could be done to increase the evidence base around future interconnector operation and the impacts of different assumptions.

- Storage

  The modelling only considers battery and pumped hydro storage as part of the power system. The operation of storage between the gas and electricity systems is also linked to other technology assumptions (e.g., a link between the flexibility of methane reformers and the scale and operation of hydrogen storage). Further work could look at a wider range of storage technologies in power as well as understanding the sensitivity of their use to other aspects of the energy system.

- Emerging technologies

  Renewables have transformed today's energy system both in terms of cost and performance, and the advent of intelligent technologies is expected to continue this transformation. This evolution is likely to continue with Active Building technologies, co-optimisation of energy for cooling and heating, and long-term thermal energy storage technologies. These technologies should be monitored and investigated.

  Other technologies that attract interest are underground hydrogen storage, a combination of fuel-cell micro-CHP and electric heating, and nuclear waste heat applications to provide a heat source for DACCS or district heating.

- Green hydrogen imports

  Investigation in greater detail the potential of green hydrogen imports and understand its implication on the hydrogen production infrastructure in the UK – this should consider solar PV costs, electrolysers, water production, marine transport, storage (ammonia versus liquid H2) and various locations (e.g. North Africa, Middle East, South Africa, Australia).

Chapter 1. Introduction and model setup

1.1 Context

Heat in buildings and the industrial sector accounts for more than half of the UK's energy consumption and contributes to around a third of the total carbon emissions[10]. Achieving the UK's long-term climate targets will require integrated decarbonisation of electricity, transport and heat sectors. Defining heat decarbonisation scenarios parallel with electricity and transport decarbonisation will require a clear strategy for delivering the optimal portfolio of low-carbon electricity, gas and heat options based on an in-depth understanding of their techno-economic-environmental characteristics and their integration with the broader energy system. The decarbonisation strategy will have to be supported by low-carbon technologies like renewables, nuclear power, bioenergy, carbon capture, utilisation, and storage (CCUS), direct air carbon capture and storage (DACCS). It also requires optimal coordination across multi-energy vectors, energy storage, and demand flexibility in parallel with improving system flexibility using innovative technologies.

1.2 Key objectives

This project focuses on understanding and quantifying the impact of long-term cost drivers of decarbonising heat in buildings. The specific objectives of the project are to provide:

- Strategic insights into the economic performance of alternative heat decarbonisation scenarios by assessing the role and value of emerging low-carbon and flexibility technologies with consideration given to their future cost and availability uncertainties;
- Understanding system implications of different heat decarbonisation scenarios by analysing the system capacity and operational characteristics of electricity, natural gas and hydrogen technologies and their associated infrastructure requirements considering optimal energy vector interactions using a holistic approach to minimise the overall energy system cost to meet the UK net-zero energy system in 2050;
- The required fundamental quantitative evidence to inform technical, economic and policy decision-making regarding the transition to a resilient and low-carbon heat energy future.

[10] BEIS, "Clean Growth – Transforming Heating", December 2018

1.3 Modelling framework

To study the interaction between multi-energy vectors and analyse the impacts of alternative heat decarbonisation scenarios on the UK energy infrastructure in 2050, a set of scenarios were simulated and optimised using the Integrated Whole-Energy System (IWES) model developed by Imperial. The IWES model incorporates detailed modelling of the electricity system and heating options, including district heating, heat network, heat pumps (air/ground source, hybrid), and hydrogen infrastructure. IWES models the complex interactions across those energy vectors, as shown in Figure 1-1.

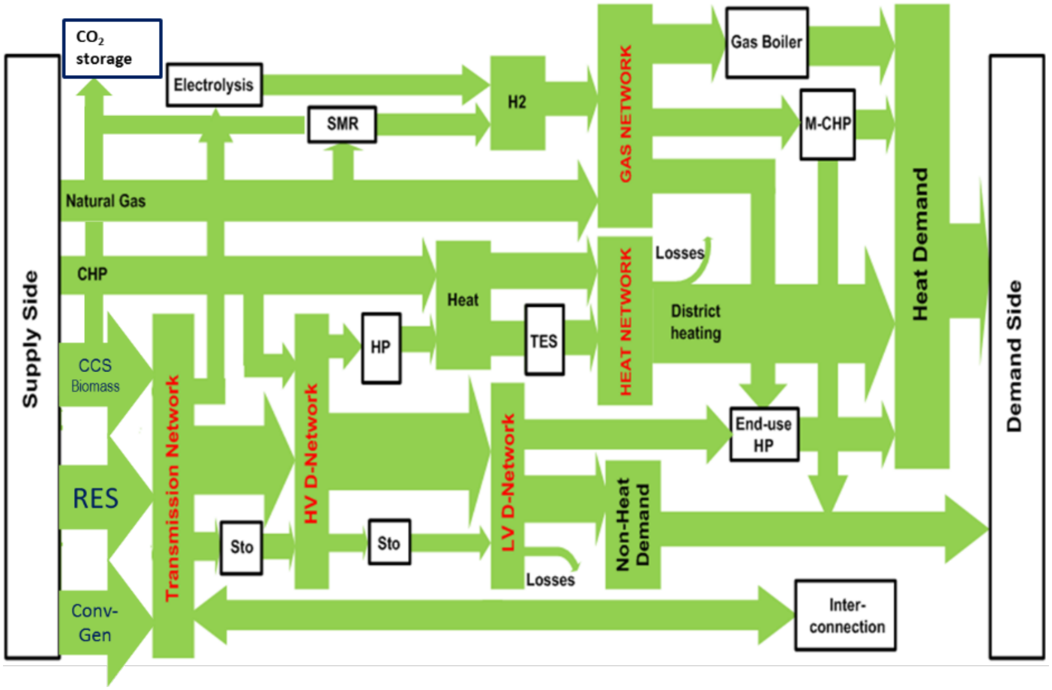

Figure 1-1 Interaction between gas, heat, and electricity systems

In IWES, the short-term operation and long-term investment decisions of the multi-energy system are optimised simultaneously to minimise the overall system costs by maximising synergies in system expansion planning and operation within agreed constraints such as a specified carbon target. The model covers local district and national/international level energy infrastructure details, including energy-flow interactions with mainland Europe via interconnectors, as illustrated in Figure 1-2. This functionality is essential since those aspects are complexly intertwined and need to be analysed simultaneously in the whole-energy system context.

The GB energy system is divided into 14 regions following the distribution network areas to provide sufficient spatial granularity to capture the regional characteristics. Each region has two (or more) different representative district characteristics (e.g. urban and rural systems). IWES also considers the interactions between the GB energy system, Ireland, and continental Europe and cross-border energy exchange and sharing capacity and flexibility.

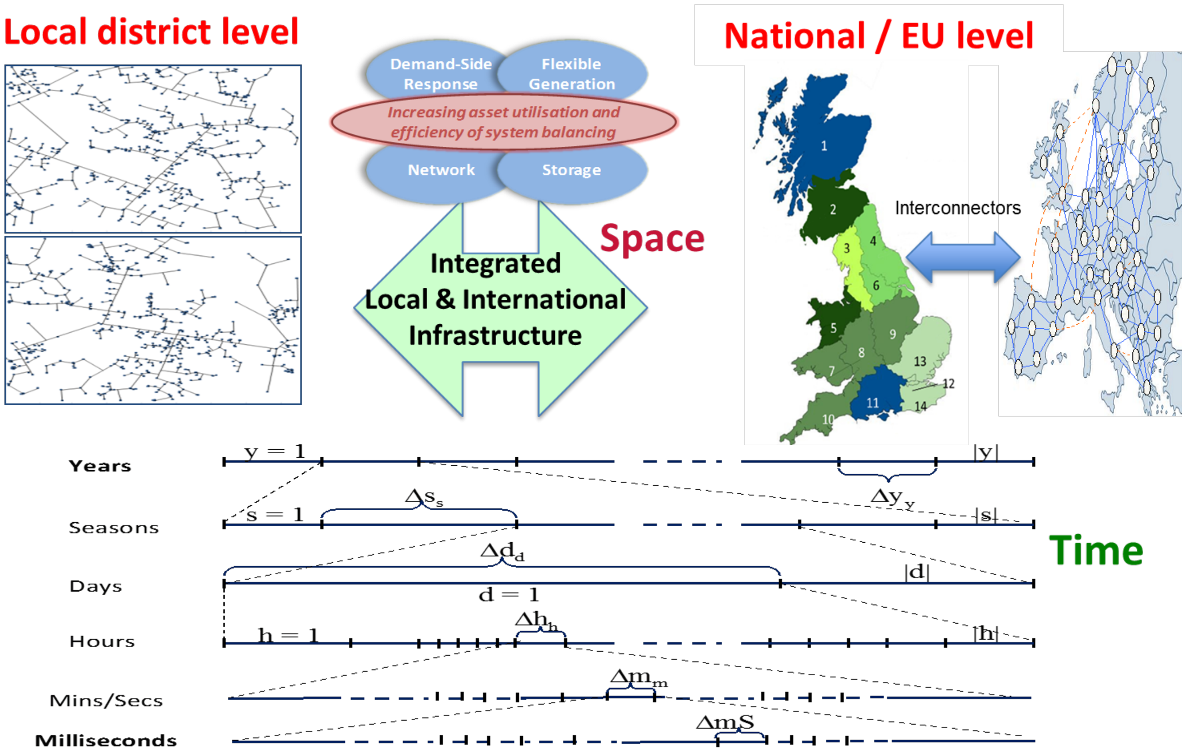

Figure 1-2 Coordinated decisions across various timeframes and location interactions in the integrated modelling of low-carbon systems

IWES optimises the energy supply portfolio, transmission and distribution infrastructure, and energy storage simultaneously to capture system components' interactions. For example, a more extensive distribution capacity may be needed to enable end-users flexibility to follow renewable output. IWES also optimises the technical needs for real-time supply and demand balancing, including frequency regulation and balancing reserve (seconds and minutes time-scale) while considering critically essential changes in the system inertia (which is vital for zero-carbon energy system) while reflecting on the dynamic parameters and technical limitations of the selected portfolio of energy sources and flexibility technologies. The benefits of system flexibility provision can be analysed across various energy vectors.

In the context of this study, IWES is used to optimise the 2050 energy system with net-zero emissions. Hourly operating snapshots across one year represent the dynamic changes in demand and generation output following renewable energy sources availability. To speed up the computation time, allowing the model to process a higher number of studies within the project timeframe, the model considers 12 representative weeks, i.e. three weeks per season. The results are very similar to the 52-weeks model, while the computation time reduces by 70% - 80%.

1.3.1 Key information provided by IWES

The key outputs of the IWES model include:

- Optimised energy infrastructure, including the costs, and capacity for various technologies for

    - Power generation, transmission and distribution networks, interconnectors, and electricity storage
    - Hydrogen production, transmission, storage
    - Building heating sources and district heating system, thermal energy storage
    - Carbon storage, network and DACCS
- Emissions and generation/production by technology source, including electricity, heat and hydrogen production processes;
- System operating costs related to fuel costs;
- Other household related costs (e.g. heat pump capital costs and the conversion cost from natural gas appliances to hydrogen).

1.3.2 Modelling limitations

The model also has some limitations, such as:

- It focuses only on a snapshot year, i.e. 2050, so the transition to 2050 is not analysed. The impact of this approach is not clear and warrants further investigation to understand how greater consideration of trajectories, pathways, interim targets and decisions would impact the cost and feasibility of 2050 scenarios.
- As the model is cost optimising within constraints, alternative energy systems (e.g. technology mix in the power sector) have similar costs but are not selected as these are only marginally higher.
- It only directly models CO_2 emissions. Emissions from other GHGs are considered off-model and considered as part of the overall target.
- The modelling makes a general assumption that for any extra residual emissions associated with heating, hydrogen production, unabated gas in the power sector to meet peak requirements or combustion of natural gas in a hybrid system, that the model can propose to build a sufficient amount of DACCS capacity to offset the emissions. It is worth noting this major assumption given that DACCS is not a developed technology, so its costs and potential capacity are highly uncertain. This assumption also implies that all the scenarios will meet the emissions target by deploying more or less DACCS with an associated cost.
- The model solves a deterministic optimisation problem. The solution is system and scenario-specific and may not be optimal under different circumstances. The impact of different assumptions or parameters is to be studied through sensitivity studies.
- It is formulated as a large-scale linear optimisation problem and simplifies energy system non-linear properties.
- It is assumed that the existing natural gas transmission and storage are sufficient for the production of blue hydrogen and hydrogen for power generation, and there is no specific modelling of natural gas storage requirements and associated costs
- The model does not optimise investment in energy efficiency measures. The impact of changing heat demand is studied through sensitivity analysis, though the insights are limited as the model does not currently consider a detailed description of diversity within the building stock.
- The model optimises the aggregated scheduling of millions of heating appliances and does not concern itself with specific individual building requirements, for example,

between new and old buildings. However, aggregated heat demand profiles are derived from a national gas heating demand profile considering different building types.

- The model optimises the hourly energy profiles that depend on the flexibility level assumed but retains the inputted annual or daily volume of energy demand across all sectors. Annual hydrogen and electricity demand for industrial processes and transport sectors are given as input data and not optimised. A higher synergy level could be achieved if those sectors' decarbonisation is optimised simultaneously. Industrial CCUS is not modelled, given the assumptions.

1.4 Core scenarios and the key assumptions

This section outlines the key characteristics of the core scenarios of this analysis. Other assumptions can be found in Appendix A.

1.4.1 Annual energy demand and heat decarbonisation scenarios

Some parameters were optimised using the cost optimisation results of the interim BEIS Sixth Carbon Budget analysis using the UK TIMES model (UKTM) and used as input data for the IWES modelling runs. These include the demand for electricity and heat demand for domestic and non-domestic customers, electricity and hydrogen demand for industry and transport, energy and the cost of producing hydrogen or biomethane from landfill gas, a renewable fraction of wastes and biogas resources.

Figure 1-3 shows the mapping of annual energy demands between those pulled out of the interim BEIS Sixth Carbon Budget analysis considered in the UKTM and those provided to IWES as inputs and are not optimised by the optimisation model. The annual energy demand at the point of use consists of circa 460 TWh of electricity load[11], 290 TWh of hydrogen demand for transport and industry processes (excluding hydrogen needed for power generation, which IWES optimises) and 390 TWh of heat demand (met with electricity or gas, depending on the heat decarbonisation scenario). Non-heat electricity demand has the following sectors as its source: industrial, domestic appliances, non-domestic appliances, transport, cooking[12] and cooling, and agriculture. Hydrogen demand comes from similar sources (industry, transport and shipping, and agriculture). Heat energy demand is divided into several categories: demand from domestic and non-domestic space and water heating. The UKTM modelled heat demand assumes deployment of energy efficiency measures, i.e. measures which save 18% of domestic heat demand and 50% for non-domestic heat demand (compared to a counterfactual where no energy efficiency measures are deployed). The volume of annual energy demand in each category used in the study is shown in Figure 1-4.

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[11] Around 8% electricity losses are added in the model to account transmission and distribution losses.

[12] It is assumed that all cooking appliances will be electric; the conversion cost is not included in the analysis.

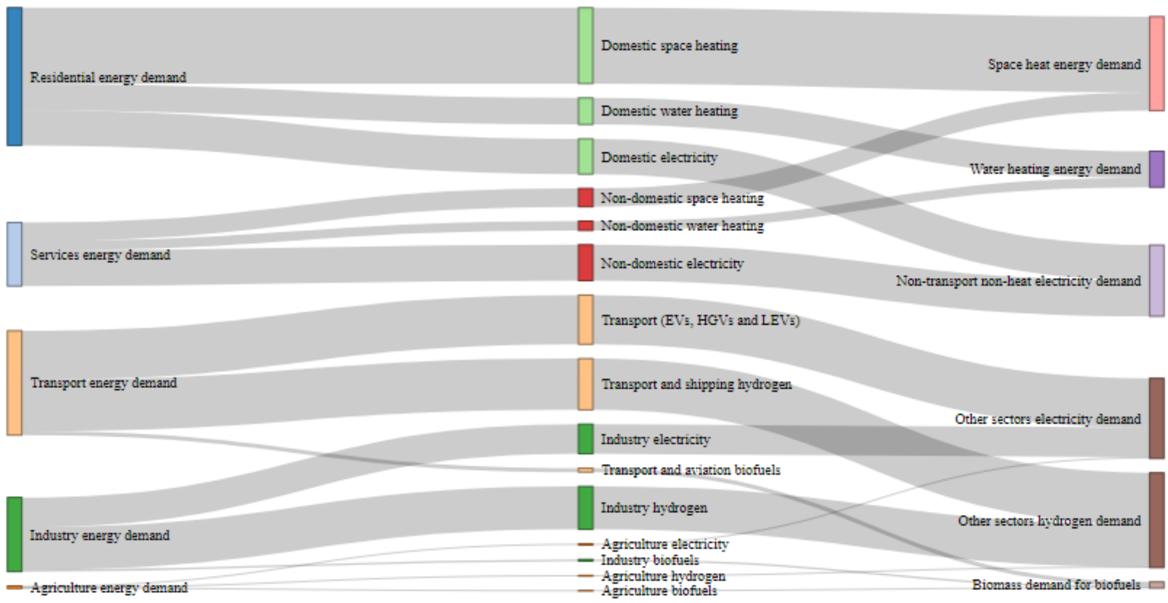

Figure 1-3 Mapping UK TIMES detailed demand for IWES

The energy system infrastructure and operation in IWES are optimised to meet the annual energy demand and net-zero emissions requirements. It is assumed that the UK is energy positive at the annual level (total annual demand is greater or equal to annual production) while allowing short-term energy/power exchanges with interconnected countries. The study also assumes that hydrogen production in the UK should be sufficient to meet the hydrogen demand.

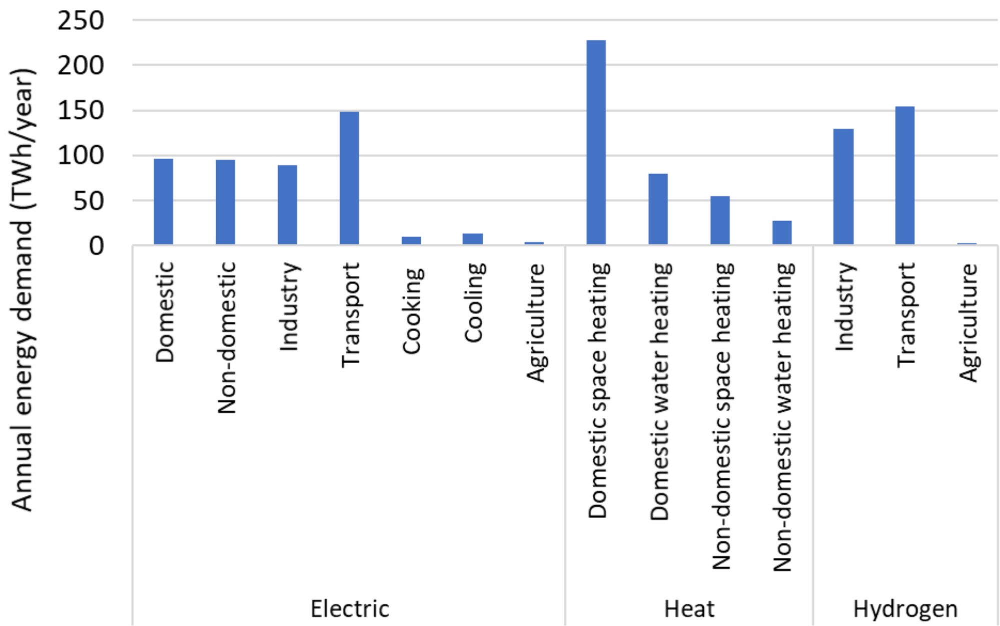

Figure 1-4 Annual energy demand at the point of use

1.4.2 Heat decarbonisation scenarios

Particularly for heat decarbonisation, the study considers four core scenarios:

- **Hydrogen scenario [H2]**
  The core Hydrogen scenario is based on installing hydrogen boilers at on-gas grid consumer premises to decarbonise heat demand.
- **Electrification scenario [ELEC]**
  In the Electrification scenario, heat demand is met by electric heat pumps (HPs) with domestic thermal storage.
- **Hybrid scenario with natural gas boilers (HHP-NG)**
  The HHP-NG scenario combines electric HPs and gas boilers fuelled by natural gas and biomethane in on-gas grid properties.
- **Hybrid scenario with hydrogen boilers (HHP-H2)**
  This is similar to HHP-NG, but heat pumps are combined with hydrogen boilers in on-gas grid buildings.

The core scenarios are deliberately simplified in terms of the heating appliances mixes; the scenarios are designed to look at the envelope of deployment of different technologies to understand system impacts. In all scenarios, the off-gas grid consumers' heat demand is supplied by air source heat pumps with 2 kWh capacity of flexible thermal storage. It is assumed that about 10% of domestic and 20% non-domestic heat demand is off the gas grid. Furthermore, 17% of the domestic and 24% of non-domestic heat demand in urban areas is supplied through district heating systems in all scenarios[13]. It is assumed that large scale water-source heat pumps (WSHPs) with thermal storage[14] would supply district heating networks. The COP of these WSHPs is assumed to be constant at 3. IWES also optimised heat storage of district heating networks. Flexible thermal storage allows heat pump electricity load to be shifted to improve its efficiency and support system balancing at the local and national levels. All cooking demand is assumed to be electric.

1.4.3 Temperature scenarios

Temperature scenarios are used to determine daily space heat demand and the operating efficiency (i.e. coefficient of performance) of air source heat pumps. The core scenario (Central) uses historical daily-mean temperature data from the Met Office[15] with a few consecutive days of low temperatures to simulate very cold weather. Since air-source heat pumps' performance in terms of efficiency and maximum heat output is sensitive to air temperature, which can vary by several degrees within a short period, a set of hourly temperature profiles were derived based on Met Office provided data and used in the study. The methodology adopted was based on "flexing" normalised hourly profiles for each season to align with the temperature scenario daily mean.

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[13] This assumption is based on a specific model run (with best assumptions available to date) and not a consolidated view of the heat networks potential.

[14] The size of thermal storage for district heating is equivalent to 20 kWh per dwelling.

[15] See www.metoffice.gov.uk/hadobs/hadcet/data/download.html

1.4.4 System flexibility

The study assumes a significant level of system flexibility within the core scenarios. This is defined as follows:

- 10% of industrial and commercial's electricity demand can be shifted within 24 hours; it represents the percentage of demand that can be reduced and shifted to other periods.
- 40% of electric vehicles' electricity demand can be shifted within a 24-hour period;
- 20% of appliances' electricity demand can be shifted within a 24-hour period.

Demand response can provide load-shifting capability and balancing services, including frequency response in the form of interruptible load.

The model also assumes that electrolysers and DACCS can also provide flexibility by ramping up or down in response to the level of available low-carbon energy, e.g. from PV or wind. This improves system balancing and reduces the associated operating costs.

Storage can also provide balancing services and an opportunity for energy arbitrage. The study also considers using various energy storage technologies, including electrical bulk storage (e.g. pumped-hydro energy storage), distributed storage (e.g. batteries), thermal storage in residential and district heating, and hydrogen storage. Sufficient thermal storage capacity allows heat pump load to be shifted to maximise the COP, benefit from temporal low electricity prices, manage system constraints and provide balancing if needed. Thermal storage also typically costs less than heating appliances and also displaces the need for electricity storage.

1.4.5 Hard-to-decarbonise residual emissions

For "hard-to-decarbonise" sectors[16], their residual emissions were included in the analysis alongside their hydrogen and electricity demand. These are fed as input data to IWES. The residual emissions of around 72 $MtCO_2$/year in 2050 reflect the difficulty of decarbonising these sectors[17].

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[16] These include aviation, shipping, waste, agriculture, land use, forestry, F-gases, other fuels used in transport, rail demand, and some industrial processes.

[17] Source: Interim BEIS Sixth Carbon Budget analysis using the UK TIMES model

Chapter 2. Costs and system characteristics of the core heat decarbonisation scenarios

This chapter presents the results of the core heat decarbonisation scenarios: H2, ELEC, HHP-NG, and HHP-H2. The discussion focuses on the following topics:

- Source of emissions and the critical role of DACCS and BECCS
- Volume of carbon sequestration
- Annual system investment and operation costs of different scenarios
- Heat delivered by various appliances
- Electricity distribution peak flows
- Electricity demand
- Electricity production
- Energy exchange with Europe
- Optimal portfolio of power generation technologies
- Electricity supply and demand balance
- Offshore and onshore transmission
- Hydrogen demand and hydrogen production output
- Hydrogen and biomethane production capacity
- Supply and demand of natural gas and biomethane
- Cost comparison of various sources of methane
- Hydrogen storage
- Hydrogen transmission
- Direct Air Carbon Capture and Storage

2.1 Source of emissions and the critical role of DACCS and BECCS

The largest emissions in 2050 are expected from "hard-to-decarbonise" sectors, i.e. around 72 $MtCO_2$/year in 2050. These emissions are presented as the "Others" category in Figure 2-1 below.

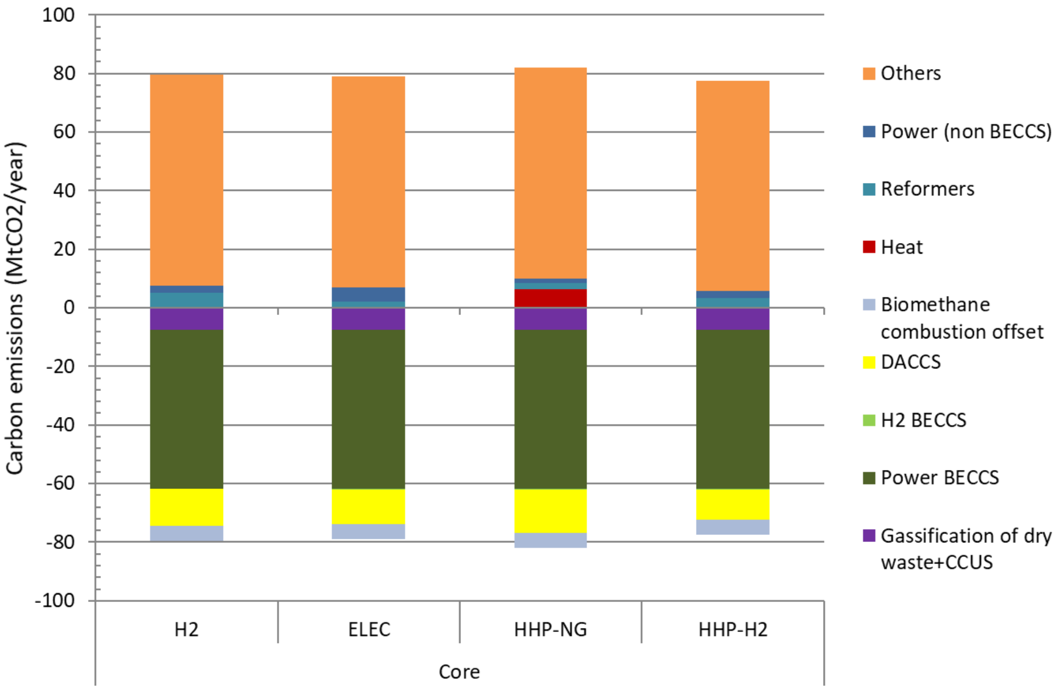

Figure 2-1 Source of emissions and the role of DACCS and BECCS

The modelled heat and energy systems' annual positive emissions are less than 8 $MtCO_2$/year (depending on the scenario), with total positive emissions from all sectors coming to less than 80 $MtCO_2$/year. Residual emissions from methane reformers are up to 5.2 $MtCO_2$/year, and natural gas heating in the HHP-NG scenario, equal to 6.4 $MtCO_2$/year.

The modelling results suggest that a small volume of emissions from energy and heat sectors could be cost-optimal, allowing the use of low-cost but not carbon-free resources. However, this result is subject to uncertainty, given the lack of confidence in the costs and feasibility of deploying carbon removal technologies at scale. Across all scenarios, the total emissions in ELEC are the lowest, while the emissions from HHP-NG are the highest due to emissions from natural gas use in heating.

These positive emissions are offset within the model by the negative emissions from bioenergy with CCUS (BECCS) and direct air carbon capture and storage (DACCS). Total emissions from electricity generation (power BECCS + power non-BECCS) are negative between -49 and -53 $MtCO_2$/year (depending on the scenario), driven by the negative emissions from power BECCS (around -54 $MtCO_2$/year) and deployment of other low-carbon technologies (RES, nuclear, hydrogen-based power generation, and gas CCUS). Residual emissions from power generation non-BECCS are between 2.3 and 4.8 $MtCO_2$/year.

There are several BECCS technologies considered in the studies:

1. H2 BECCS which produces hydrogen from solid biomass[18] through gasification processes with CCUS

[18] The costs of pellets used for H2 BECCS were based on BECCS to power due to limitations in evidence. In future work, they should be updated to reflect the specific costs of biomass pellets for use in H2 BECCS processes.

2. Biomethane BECCS produces biomethane from solid biomass through gasification with CCUS – but this technology is not selected by model for these core scenarios as, given the assumptions used in the study, it is less competitive than other technologies
3. Power BECCS which generates electricity from solid biomass – the negative emissions from power BECCS are included in the emissions from the electricity sector
4. Biomethane from a renewable fraction of wastes through gasification with CCUS, landfill gas and other biogas resources – the amounts of biomethane from these technologies are included in IWES as input based on cost optimisation results of the interim BEIS Sixth Carbon Budget analysis using UK TIMES model (UKTM)

This analysis suggests that, in a cost-optimal system, BECCS and DACCS would play a role in compensating the emissions allowing low emissions from electricity, heat, and hydrogen processes to minimise the overall system costs. For example, having DACCS and BECCS can allow the use of low-cost but not necessarily low-carbon technologies such as gas boilers in hybrid heating systems to reduce the overall system costs. However, this result is subject to significant uncertainty given that the degree of confidence in the assumptions costs of utilising DACCS and BECCS at scale is lower than for more established technologies (such as the heating appliances modelled).

It is worth noting that the result of the natural gas hybrid scenario depends on the limited use of gas for heating, e.g. only for peak period (equating to circa 10% of on-gas grid heat demand). While the volume of natural gas usage is relatively small, its value is high since it can reduce the cost of heat pumps and the power system investment required to secure the peak demand. If used more frequently (and hence sub-optimally from an energy system perspective), these boilers would cause higher emissions than predicted. *Thus, a hybrid heating system's smart operation should be recommended to ensure the optimal coordination between electric and gas heating from the whole-system perspective***.**

Furthermore, questions arise about the realism of operating a gas grid with a low utilisation factor – that delivers only around 10% of the current amount of gas and its dynamic ability to deliver the gas volume needed during peak demand. Some preliminary studies suggest that this might not be feasible. Furthermore, natural gas storage is out of the IWES modelling scope, which might pose more limitations for the NG-HHP than other scenarios. A higher volume of emission removals in this scenario further reduces its realism due to the uncertainty of deploying carbon removal technologies at a larger scale.

2.2 Volume of carbon sequestration

There is a significant amount of carbon captured and stored in all scenarios. As demonstrated in Figure 2-2, volumes of carbon captured and stored vary between 122 and 189 $MtCO_2$/year (noting that CCUS capacity for industry is not in the modelling scope). The H2 scenario results in the highest volume of carbon captured and stored contributed from the CCUS use in gas reforming processes, power sector (including BECCS to power), DACCS, and biomethane and hydrogen production from the gasification of dry waste with CCUS. A similar composition, but with much lower volumes of carbon captured from the gas reforming process, is found in all other scenarios. The amount of carbon captured in the ELEC scenario is the lowest, i.e. 67

$MtCO_2$/year less than the carbon captured in H2, given that the ELEC scenario utilises more renewable generation than hydrogen.

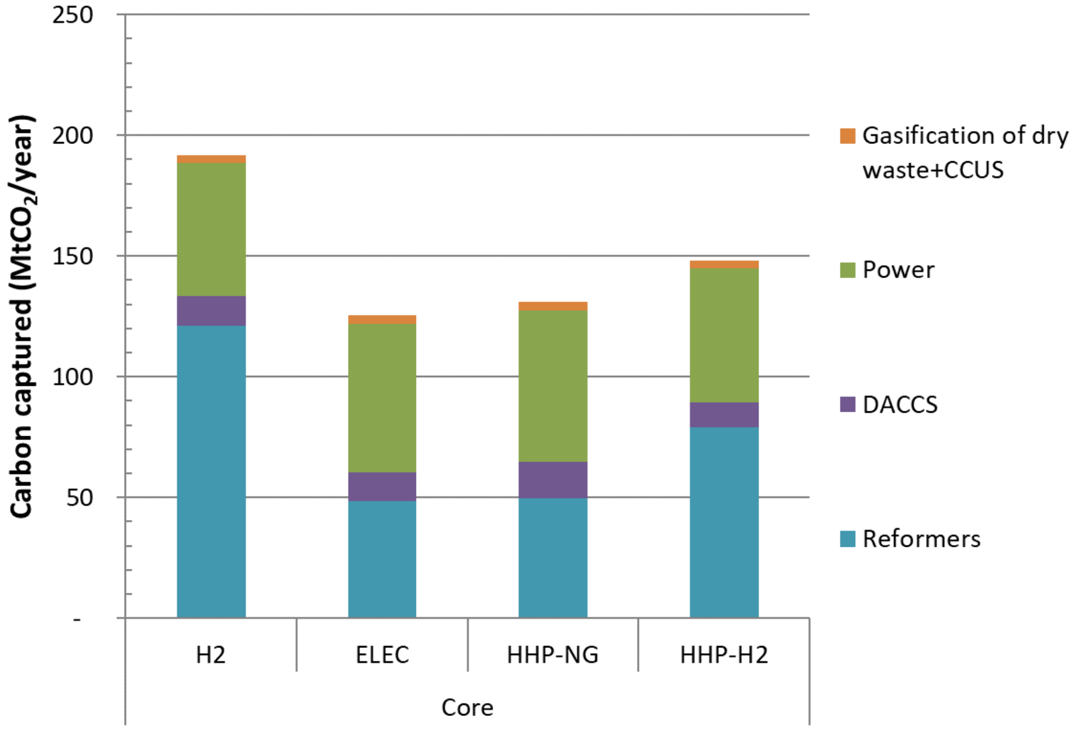

Figure 2-2 Volume of carbon sequestration

This analysis assumes that the cost of storing carbon is around £15/tCO_2, which includes the Capex and Opex of the carbon storage system (offshore). Thus, the total carbon storage cost in modelled scenarios is between 1.8 and 2.8 £bn/year – this cost does not include the CCUS network, which is discussed later in section 2.19. Given the uncertainty in the cost assumption, the results suggest that the H2 scenario will be more sensitive to any changes in the carbon storage cost assumptions, while the ELEC scenario would be the least affected. The model estimates the annual CCUS capacity required for each scenario, so it does not consider any limits to the deployment of annual CCUS capacity by 2050. If there were any capacity limits, then the H2 scenario would be most affected and ELEC the least.

2.3 Annual system investment and operation costs of different scenarios

IWES considers 31 system cost components shown in Figure 2-3 and listed in Table 2-1 to examine the impact of different heat decarbonisation strategies. The components are also grouped further into 11 higher-level cost categories to analyse the results. It is worth noting that some costs are not considered in IWES (for example, those of industry appliances or transport), making the total costs not directly comparable to those coming out of other whole systems models, such as UK TIMES.

Table 2-1 Description of the cost components

Detailed cost category	Higher-level cost mapping	Description (all capital costs are annuitized[19] and operating costs are annual)
C: Low carbon gen	C: Electricity generation	Capital cost of wind, PV, hydro, nuclear, gas CCUS, power BECCS, and H2-based generation.
C: Non low-carbon gen	C: Electricity generation	Capital cost of traditional fossil-fuel-based generation such as CCGT, OCGT and CHP
C: Transmission	C: Electricity network	Capital cost of the GB transmission network, including onshore and offshore (but not interconnection)
C: Interconnection	C: Electricity network	Capital cost of GB interconnectors
C: Distribution	C: Electricity network	Capital cost of reinforcing electricity distribution network
O: Electricity	O: Electricity	Fuel cost, no-load cost and start-up cost of power generation. The cost of hydrogen as a fuel is excluded here[20] but included in the Capex and Opex of hydrogen.
C: HP	C: Electric heating +storage	Capital cost of heat pump devices, installation cost and the annual fixed operating and maintenance cost
C: RH	C: Electric heating +storage	Capital cost of resistive heating devices, installation cost and the annual fixed operating and maintenance cost. RH is not used in this study, but it is part of the IWES model.
C: Storage	C: Electric heating +storage	Capital cost of electricity storage in the system; it includes the cost of pumped hydro and battery energy storage system
C: Heat storage	C: Electric heating +storage	Capital cost of domestic and district heating thermal energy storage
C: DACCS	C: H2+CCS+P2G	Capital cost of DACCS[21]
C: Decom. gas distribution	C: H2+CCS+P2G	this cost occurs only in the Electric scenario as most of the gas distribution network is no longer used, and therefore, it should be decommissioned. The cost is estimated at £1bn/year. A small proportion of gas distribution connected to large customers (e.g. industry) and BECCS to hydrogen is maintained.
C: ATR+Bio	C: H2+CCS+P2G	Capital cost of building ATR with CCUS and the biomass gasification with CCUS for hydrogen production

19 The annuitisation of capital cost considers hurdle rates and payment periods.

20 Because of this, the Opex for electricity in IWES can produce lower estimates than other models, notably BEIS's Dynamic Dispatch Model

21 The cost information on Direct Air Capture (DAC) is based on the 2018 report by the US National Academies titled "Negative Emissions Technologies and Reliable Sequestration: a research agenda."

Detailed cost category	Higher-level cost mapping	Description (all capital costs are annuitized[19] and operating costs are annual)
C: Electrolysis	C: H2+CCS+P2G	Capital cost of various electrolysers: Proton Exchange Membrane (PEM), Alkaline, Solid Oxide Electrolyser (SOE)
C: H2 network	C: H2+CCS+P2G	Capital cost of building a national hydrogen transmission network. It is assumed that the national gas transmission is retained.
C:H2 storage	C: H2+CCS+P2G	Capital cost of both underground and overground storage
C: CCUS network	C: H2+CCS+P2G	Capital cost of building the CCUS network
C: Carbon storage	C: H2+CCS+P2G	Cost of storing carbon captured by CCUS. It is assumed that the carbon storage cost is £15/tCO_2.
O: ATR+Bio	O: NG+H2+CCS	Fuel cost used by ATR with CCUS and BECCS to produce hydrogen[22]
O:H2 storage	O: NG+H2+CCS	Operating cost of hydrogen storage
O: NG boiler	O: NG+H2+CCS	Cost of natural gas used by the boilers
C: NG boiler	C: Gas heating	Cost of natural-gas-based boilers, installation, and the annual fixed operating and maintenance costs
C: H2 boiler	C: Gas heating	Cost of hydrogen-based boilers, installation, and the annual fixed operating and maintenance costs
C: Gas network	C: Gas heating	Cost of retaining the present gas distribution network. It is applied to the H2 and Hybrid scenarios.
C: DH (network)	C: District heating	Cost of district heating networks, including the operating and maintenance cost
C: DH (appliance)	C: District heating	Cost of household heat infrastructure needed for the district heating system, e.g. metering, heat control, and connection to the main heat network
C: DH (conversion)	C: District heating	Cost of decommissioning natural-gas appliances including replacing the gas hob and gas oven with an electric hob and oven and add the hot-water storage system
C: HHP	C: HHP heating	Capital cost of heat pump, natural gas or hydrogen boiler, control system and the fitting cost.
C: Energy efficiency	C: Energy efficiency	Capital cost of energy efficiency measures
R: Electricity Export	R: Electricity Export	Estimated revenue from electricity export (calculated based on the average electricity cost)

[22] Operating cost of electrolysers is part of the power sector costs.

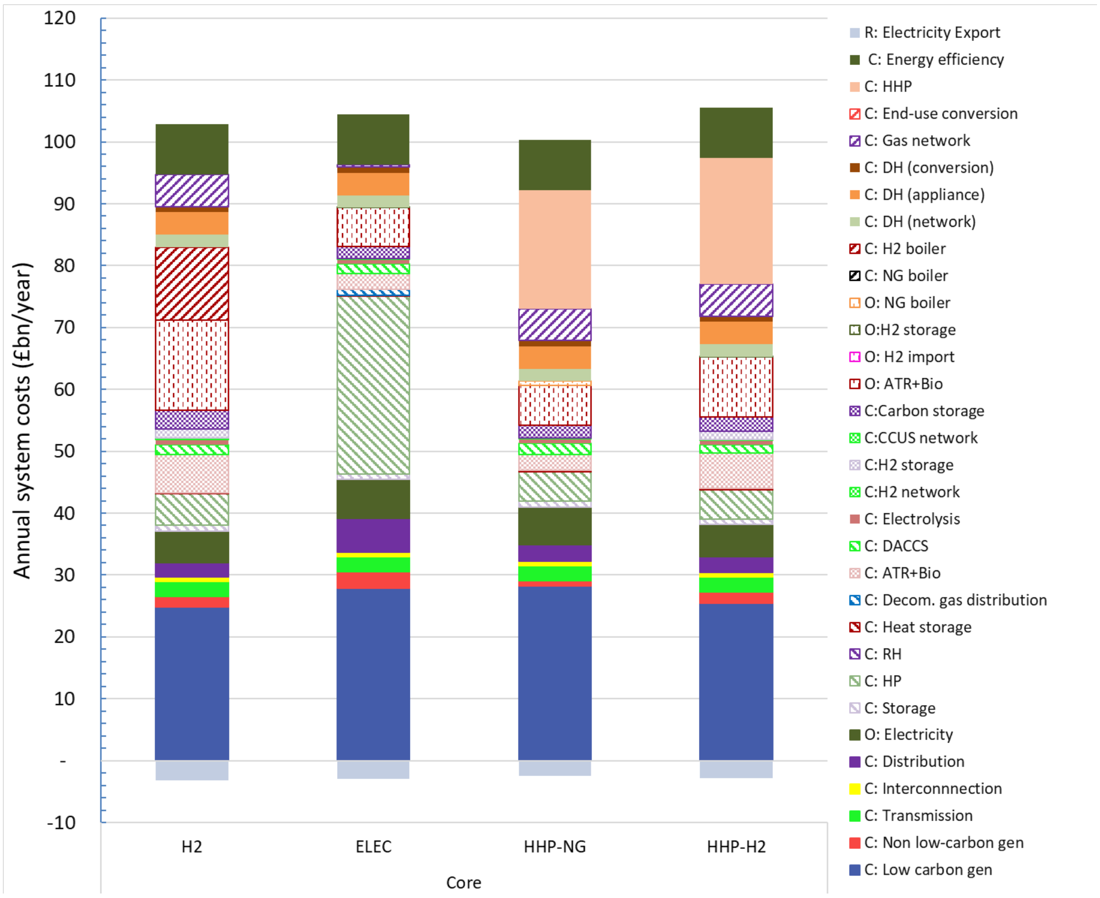

Figure 2-3 Annual system costs of different heat decarbonisation scenarios in detail[23]

Figure 2-4 below shows the distribution and total of annuitized costs in each scenario using the higher-level cost mapping. The most cost-effective scenario is HHP-NG (costing £97.9bn/year) followed by H2 (£99.6bn/year), ELEC (£101.5bn/year), and HHP-H2 (£102.7bn/year). Given the similarity of the cost performance between different scenarios (±2.3% difference), it can be expected that the ranking between these scenarios will be sensitive to changes in the assumptions used in the modelling. This is confirmed in the sensitivity studies.

[23] Costs are associated with year 2050, presented as £2018 real value.

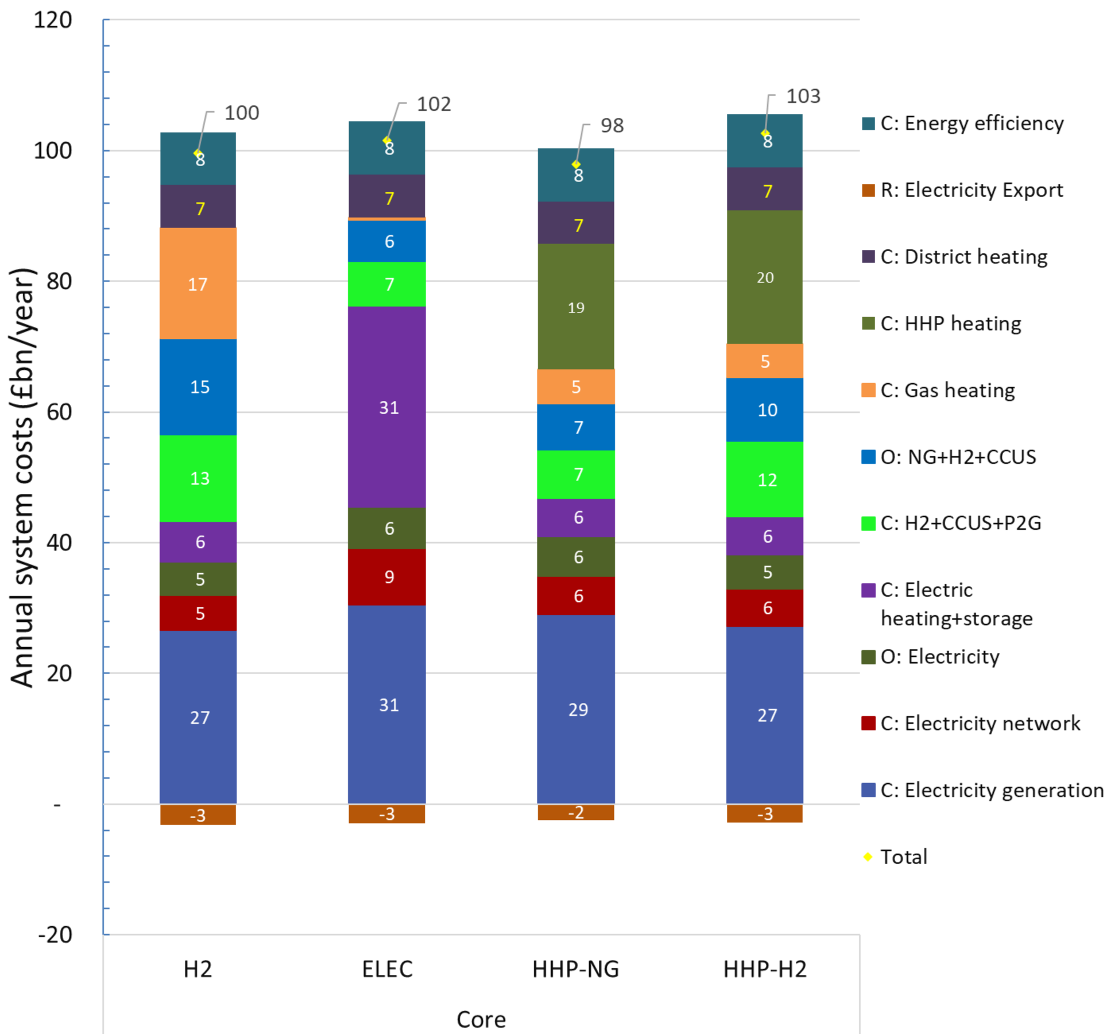

Figure 2-4 Annual system costs of different heat decarbonisation scenarios

The electricity generation Capex varies between 27 and 31 £bn/year, with a substantial investment in low-carbon generation accounting for 25 to 28 £bn/year. The remainder of the electricity generation cost comes from conventional generation, mainly gas CCGT and peaking plants. As expected, the lowest electricity generation cost can be found in H2 and the highest in ELEC as the overall electricity demand is the highest in ELEC. The electricity network cost is similar in the scenarios that use gas/hybrid heating systems. It is considerably higher in ELEC due to higher electricity peak demand – however, this is based on a very pessimistic scenario where there is modest or no spare thermal capacity in the distribution network. Data from DNOs suggests a significant degree of network headroom at the primary substation level and that LV network utilisation is highly uncertain – therefore, the distribution network reinforcement costs presented here are conservative.

The results in Figure 2-4 also indicate that the heat decarbonisation option affects both investment and operation of hydrogen and power sectors. In terms of coordinated planning, investment rollout, and operation, integrating those sectors is beneficial in all scenarios, even in ELEC and HHP-NG, where hydrogen is not used for heating but only for power, transport, and industry. As hydrogen and low-carbon generation technologies are used to decarbonise the energy system, coordination across those sectors is essential. Across all scenarios, the minimum total hydrogen Capex and Opex found in ELEC is still around £13bn/year, indicating the need for hydrogen system integration with the power sector. The role of hydrogen in the power sector will be discussed in more detail in section 2.7.

H2 has the lowest heating appliance cost, i.e. around £22bn/year, including hydrogen-based heating for on-gas-grid customers, heat pumps for off-gas-grid customers, and the cost of maintaining gas distribution networks. In comparison, the cost of heating appliances in ELEC, HHP-NG and HHP-H2 scenarios are similar, around 29 – 30 £bn/year[24]. Given that IWES does not optimise the amount of heat provided by heat networks, the cost of this is driven by an input assumption, which is around £7bn/year for all scenarios.

An off-model adjustment of HP sizing for IWES was made, based on engineering advice that HPs are in practice sized to account for space heat demand but excluding hot water demand. This adjustment is applied only to non-district heating areas (domestic and non-domestic customers).

Changing the heat pump sizing does not result in a significant cost difference. The magnitude of the difference per scenario is:

Scenario	Cost differences in £bn/year per scenario
H2	- 0.091
Elec	- 0.732
HHP-NG	- 0.076
HHP-H2	- 0.073

This change does not alter the ordering of the scenarios in terms of cost or any key conclusions. Therefore, the results of the IWES model presented in this report, do not include this off-model adjustment of HP sizing.

Overall, the results demonstrate that the system costs are dominated by Capex (infrastructure plus fixed cost), and therefore, the reduction of Capex of technologies or reduction of financing cost will have a high impact on the total system costs[25]. The Opex of electricity is relatively small (between 5.2 – 6.3 £bn/year) as the electricity generation is dominated by zero marginal cost low-carbon sources such as wind generation. The Opex of electricity generation does not include the cost of hydrogen fuel used in the power sector as this cost is already accounted for in the Capex and Opex of H2 systems. The gas Opex varies between £6.3bn/year in ELEC and £14.6 bn/year in the H2 scenario.

The differences in the energy infrastructure and Opex cost of different heat decarbonisation scenarios demonstrate the strong interactions between electricity, hydrogen, and heating systems; for example, the investment and operating strategies selected for heating will affect investment and operation of electricity and hydrogen systems. The results suggest that coordinated multi-energy vector planning and operation coordination are vital for developing

[24] The cost of hybrid appliances is not substantially higher than that of stand-alone heat pumps because the heat pump element in a hybrid system is sized as significantly smaller than in the ELEC scenario.

[25] It is important to note that in this study, zero headroom in electricity networks is assumed (different assumptions would lead to changes in the estimated network reinforcement costs). Additionally, network costs in IWES do not include the “sunk” historic components.

and optimising integrated low-carbon energy systems. Furthermore, although the total costs are comparable, the underpinning energy infrastructure and operation across different scenarios can differ significantly, as shown in Table 2-2. For example, the cost of heating infrastructure in H2 accounts for 38% of the scenario costs, while in ELEC and hybrid, around 45%. However, the cost of hydrogen and CCUS in H2 (28%) is higher than in ELEC and hybrid. It is not clear whether the system cost will be directly visible to customers, and this analysis shows that choosing the scenario based on the lowest heating cost may not necessarily be optimal from the whole-system perspective.

Table 2-2 Cost composition of different scenarios

Total Capex and Opex (as % of total system cost)	H2	ELEC	HHP-NG	HHP-H2
Electricity infrastructure	34%	42%	39%	34%
Hydrogen and CCUS infrastructure	28%	13%	15%	21%
Heating infrastructure	38%	45%	46%	45%

It is worth noting that most CCUS facilities (e.g. gas-based hydrogen production facilities, power generation with CCUS, DACCS) are assumed to be large-scale and located on the coast close to gas import terminals with access to offshore infrastructure carbon sequestration and storage. Large-scale development of CCUS plants near coast is more cost-efficient than distributed small-scale CCUS plants, as shown in the previous study for the CCC[26]. However, a national CCUS network might be needed to transport CO_2 captured from CCUS facilities such as BECCS in other GB regions to coastal CCUS facilities.

The variance in the cost-optimal energy system design linked to different heat decarbonisation scenarios also emphasises the importance of developing consistent heat decarbonisation policies and appropriate market signals to guide the transition process and the convergence of the energy system development.

Comparison with Modelling 2050 Electricity system analysis

The power sector costs shown in Figure 2-4 are lower than those reported in BEIS Modelling 2050, which were between 50 and 85 £bn/year. Some factors that may drive the differences are listed as follows:

- Different approaches and assumptions used in calculating the annual investment cost of energy infrastructure
- Differences in the deployment of nuclear and gas CCUS in the system – Capex of these technologies is high;
- Different assumptions associated with capacity factors of renewable energy sources;
- Presentation of electricity distribution network costs (only reinforcement costs are presented in this analysis)

[26] Imperial College London, "Analysis of Alternative UK Heat Decarbonisation Scenarios", a report to the Committee on Climate Change, June 2018. Available at: https://www.theccc.org.uk/wp-content/uploads/2018/06/Imperial-College-2018-Analysis-of-Alternative-UK-Heat-Decarbonisation-Scenarios.pdf

- Different levels of whole-system integration and flexibility assumptions;
- Different assumptions on the use of negative emission technologies to reduce the cost of power sector decarbonisation.

2.4 Heat delivered by various appliances

The volume of heat delivered by various appliances is shown in Figure 2-6. The results are consistent with the setup described in section 1.4.2. In HHP-NG, optimisation results in the majority of heat demand (287 TWh) being supplied by heat pumps due to its high coefficient of performance (COP) and the remaining 33 TWh of heat (peak demand) being supplied by gas boilers. With this arrangement, electricity peak demand does not increase as high as in the ELEC scenario. Consequently, hybrid scenarios require less power system capacity investment and network reinforcement than the ELEC scenario (discussed in the next section).

Figure 2-5 shows the hourly profile of heat supply from air-source heat pumps (HP), NG boiler, district heating HP, and thermal energy storage (TES) in a week (7 days), with peak demand coinciding with low wind output on day 16-18. The use of HP is much lower on days 16-18 compared to other days where wind output is high. To reduce the stress on the electricity system, the model proposes to reduce the use of HP and increase the use of NG boilers in the hybrid system. TES is also used to supply the peak demand while being charged during off-peak periods. TES can reduce the size of other heating appliances needed to meet the peak of heat demand while also reducing electricity peak demand by lowering electric heating during peak. When there is sufficient output of wind generation in the system, HPs are utilised more and NGs boiler are used only to top-up heat supply.

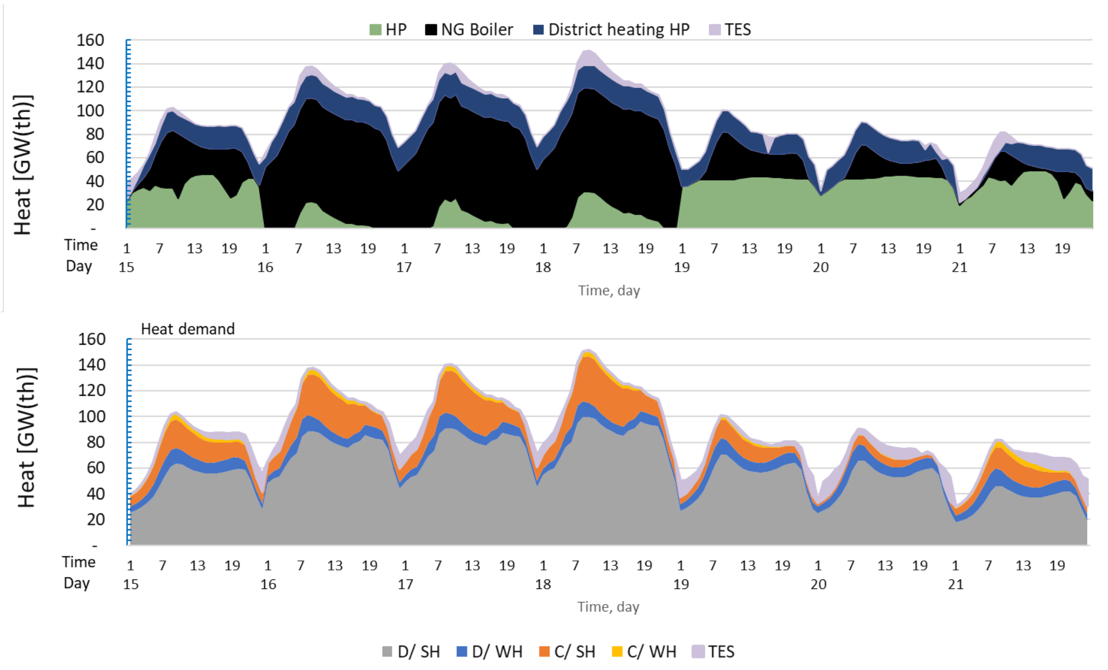

Figure 2-5 Hourly heat supply (top diagram) and demand (bottom diagram) profiles in a week with peak demand [case: core HHP-NG]

However, the use of natural gas heating increases emissions, as shown in Figure 2-1. Therefore, gas heating usage is limited by its carbon emissions which must be offset by BECCS or DACCS (as discussed in section 2.1). Nevertheless, although the volume of gas usage for heating is reduced substantially (to less than 10% of the overall heating), the value of gas and the hybrid system's flexibility is significant. In HHP-H2, the majority of heat demand is still supplied by heat pumps, but the utilisation of hydrogen boilers is higher than the use of natural gas boilers in HHP-NG as hydrogen boilers do not directly emit CO_2.

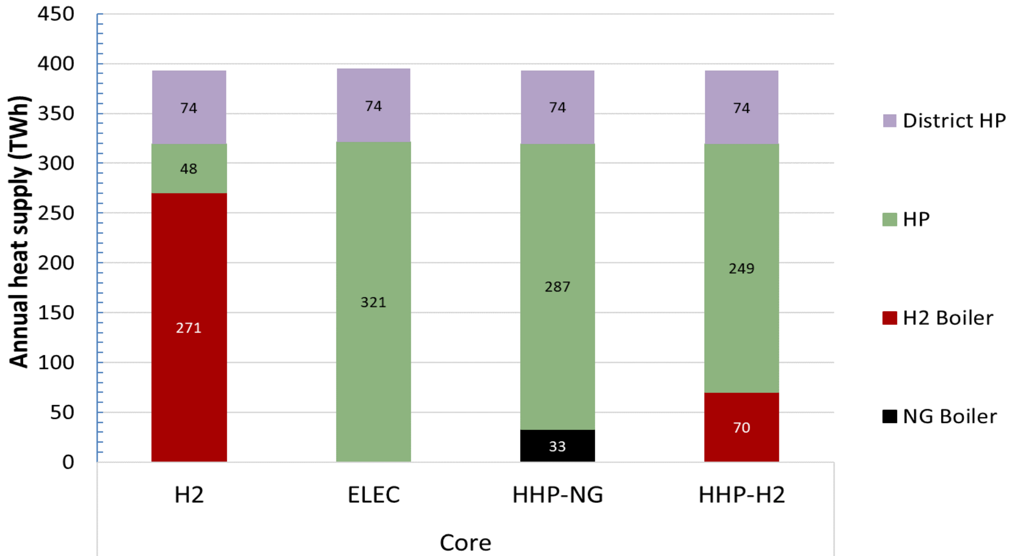

Figure 2-6 The amount of heat supplied by various heating appliances

In these studies, heat pumps are the most energy-efficient heating appliance with a modelled coefficient of performance (COP) ranging between 200% and 450%[27] depending on the ambient temperature, while natural gas or hydrogen boilers' efficiency is assumed at around 90%. Air-source heat pump performance (heat output and COP) is adversely affected by air temperature; during low COP and high heat demand, hybrid heat pumps' boilers provide additional heat supply. However, heat pumps supply most of the hybrid system's heat demand, as shown in Figure 2-6.

Given the assumptions, modelling results show that thermal storage losses are insignificant; there are around 3 TWh per year, i.e. less than 1%, particularly in the ELEC case. The energy losses are small due to high thermal storage efficiency (95%-99%) with low hourly losses (1%/h).

2.5 Electricity distribution peak

Figure 2-7 shows the electricity distribution peak. In the study, the peak flows are driven mainly by the peak of electricity demand combined with low output from distributed energy resources. In the H2 and hybrid systems, the electricity distribution peak flows do not increase significantly; the peak is between 86 and 90 GW. In ELEC, as expected, the peak is much higher;

[27] BEIS, "Evidence Gathering – Low Carbon Heating Technologies – Domestic High Domestic High Temperature, Hybrid and Gas Driven Heat Pumps: Summary Report", Nov 2016 supplemented with Ecodan test data and assumption on the future improvement of HP COP.

it is around 119 GW (33 GW more than in the H2 scenario). This drives £3.1 bn/year of additional investment in the electricity distribution in ELEC compared to other scenarios.

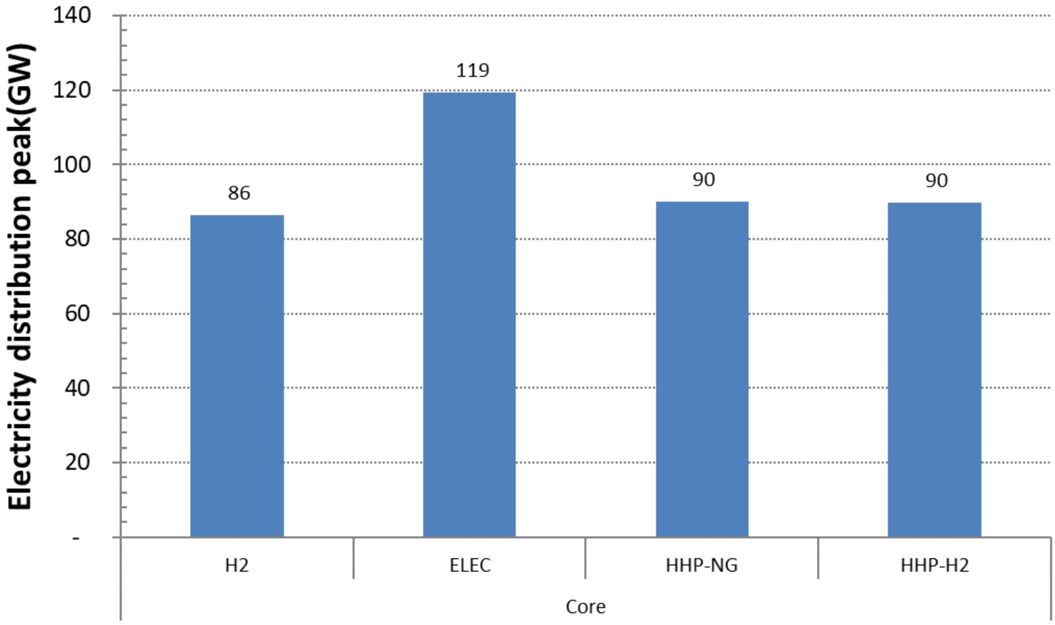

Figure 2-7 Electricity distribution peak under different scenarios

It is worth noting that even though heat pumps are used extensively in the hybrid systems, as discussed previously in section 2.4, this only adds around 4 GW capacity requirements compared to the peak in the H2 case. It is also worth noting that the flexibility, from electric vehicles and smart appliances, assumed in all scenarios, reduces the electricity peak demand by shifting the loads from peak to off-peak periods. In a system without sufficient flexibility, the electricity peak demand in ELEC would be much higher. The impact of flexibility is discussed further in section 3.1.

2.6 Electricity demand

Figure 2-8 shows the annual electricity demand in different heat decarbonisation scenarios. The model optimises the annual electricity demand related to electricity storage, hydrogen storage, gas reformers and BECCS (gasification plants), DACCS, electrolysers, and heat. In contrast, the electricity demand associated with the transport sector ("EV load"), appliances ("Smart appliance load"), and industrial and non-heat non-transport electricity load from domestic and commercial sectors ("I&C and inflexible residential") is provided by cost optimisation results of the interim BEIS Sixth Carbon Budget analysis using UK TIMES model (UKTM) and acts as an input to IWES. Therefore, the electricity load presented in the last three categories above is the same across all scenarios.

The heat-led electricity load in H2 is 40 TWh (driven by the heating load of off-gas grid customers), much less than 126 TWh in ELEC[28] . The heat-led electricity load in HHP-NG and HHP-H2 is 114 TWh and 102 TWh, respectively[29].

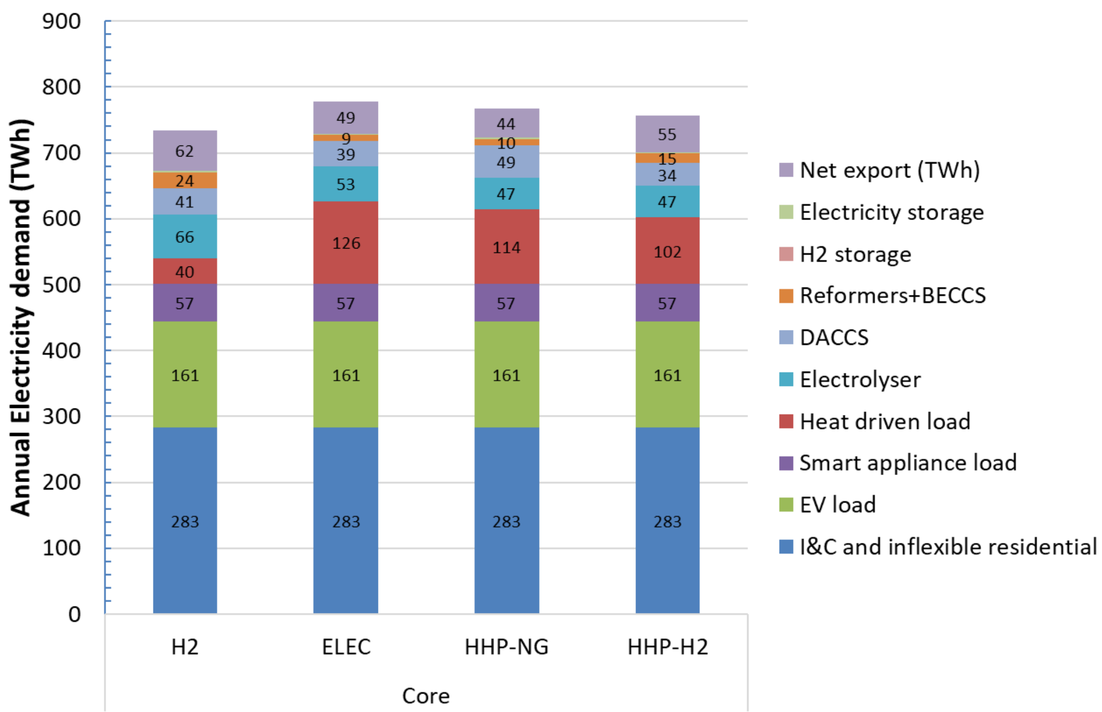

Figure 2-8 Annual electricity demand

The H2 scenario requires more hydrogen production, and therefore the load related to electrolysis (66 TWh) is the highest compared to other scenarios, which have a similar load for electrolysis, i.e. around 47-53 TWh. The demand and production of hydrogen will be discussed in more detail in section 2.12.

The electric load related to DACCS also varies across scenarios. HHP-NG has the highest electric load for DACCS due to the highest usage across different scenarios. The electricity load related to the gas reformers and BECCS for hydrogen production[30] varies between 9 and 24 TWh across all scenarios. In H2 and HHP-H2, the electricity load for reformers and BECCS for hydrogen production is higher than in the other two scenarios due to the higher hydrogen use in these two scenarios.

Another interesting finding is that the volume of electricity to charge electricity storage is relatively small. This indicates that sufficient flexibility is provided by demand response and sector-coupling flexibility, especially from the hydrogen and heating system, which supports electricity system balancing.

Overall, the annual electricity demand excluding net export to Europe (discussed later in section 2.8) varies between 672 and 729 TWh. It is a significant increase compared to the 2019

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[28] Which produces 321 TWh of heat (see Figure 2-6).
[29] This indicates that most of the heat demand is supplied by HPs (due to their high energy efficiency).
[30] Given the assumptions in the study, the use of BECCS for hydrogen production is relatively small.

electricity demand, i.e. circa 325 TWh[31]. This shows the impact of heat and transport electrification in 2050. A range of sensitivity studies on energy demand has also been analysed and discussed later in section 3.4.

It is also worth noting that although the electricity demand in ELEC and HHP-NG is very similar, the impact on the peak distribution flows is very different (as discussed in the previous section).

2.7 Electricity production

In the modelling results, renewable energy sources provide the majority of electricity production across all scenarios, as shown in Figure 2-9. The most dominant source is offshore wind, ranging between 476 and 492 TWh/year, followed by onshore wind, PV, and biomass (BECCS to power). The model assumes at least 5 GW of nuclear in the 2050 GB generation portfolio (Sizewell B and Hinkley Point C), producing around 39 TWh/year electricity. Onshore wind contributes to around 75 TWh/year and PV around 36 – 57 TWh/year.

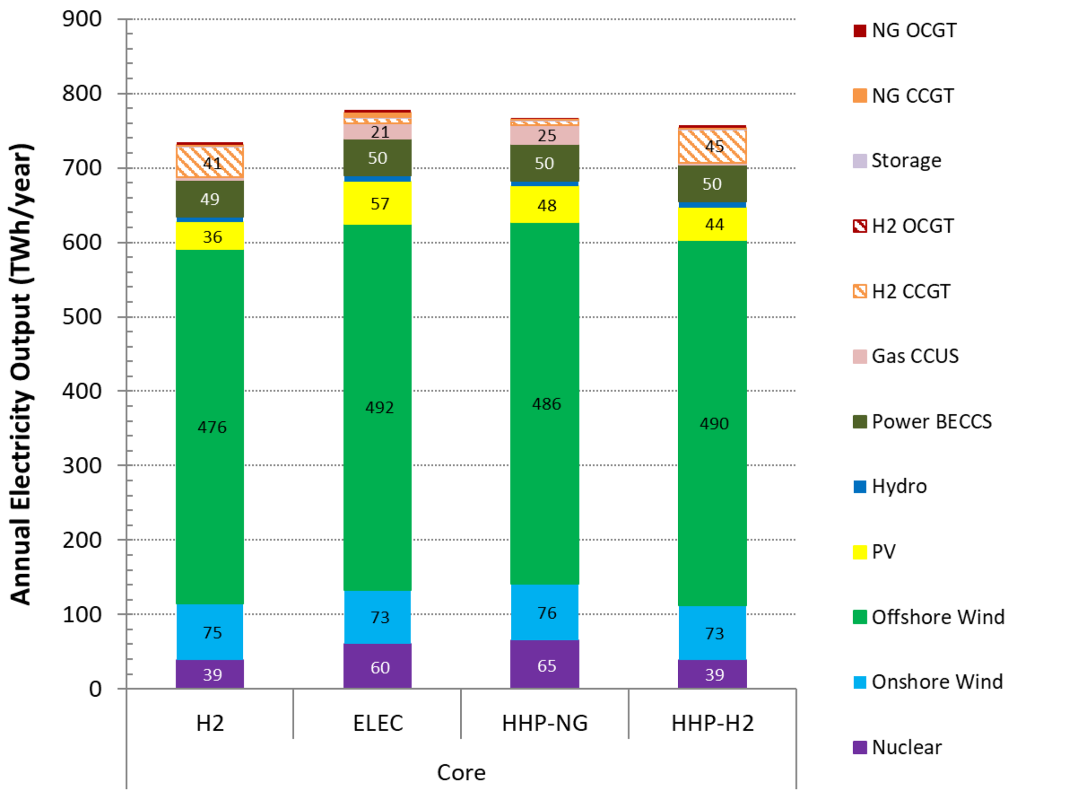

Figure 2-9 Annual electricity production

The study illustrates the importance of hydrogen as zero-carbon fuel in power generation, especially when hydrogen is also used for heating. Around 6 – 45 TWh/year of electricity comes from H2 CCGTs, which are primarily used for system balancing, providing sufficient ramping up or down capability, operating reserve and frequency regulation services. On the other hand, in ELEC and HHP-NG, the model chooses more gas CCUS than hydrogen power

[31] UK Energy Statistics, 2019

generation. The results indicate more synergy between the hydrogen and electricity sectors infrastructure (which is more substantial in the H2 and HHP-H2 scenarios). Improving the synergy across energy vectors will reduce system costs. The share of other technologies – such as gas CCUS, traditional gas CCGT and peakers (OCGT) – is relatively small, but their capacity is still needed to maintain supply security.

The electricity mixes obtained in this study are similar to the mixes reported in BEIS Modelling 2050[32] with a large share of renewables. However, the latter has a higher share of nuclear and gas CCUS, while the mixes obtained by IWES have a higher wind contribution. This may be driven by the capacity factor assumptions for wind power generation. In this study, the capacity factor for offshore and onshore wind is around 60% and 30%, respectively. When interpreting IWES results, it is important to remember that IWES is a cost optimising model, and therefore, there may be alternative solutions with similar but marginally higher costs that the model will not select. Further sensitivity analysis could be used to explore this. BEIS modelling of the power sector using the Dynamic Dispatch Model[33] looking at several thousand unique low-carbon deployment mixes suggests that a broad range of generation mixes have similar costs.

2.8 Energy exchange with Europe

When IWES is set up to allow electricity export and import to minimise the UK and European energy systems' joint cost, it chooses to allow for net exports of electricity from the UK. The study demonstrates that the annual electricity production (Figure 2-9) is greater than the electricity demand (Figure 2-8) in all scenarios. With 17.9 GW interconnection capacity, the excess electricity between 44 TWh/year in HHP-NG and 62 TWh/year in H2, as shown in Figure 2-10 is exported to Europe. The results suggest that the UK's electricity cost tends to be lower, considering the volume of available wind energy resources resulting in the net electricity export to Europe. A lower amount of electricity export is cost-optimal in scenarios with high annual electricity demand (ELEC and HHP-NG). Scenarios with a higher share of hydrogen (H2 and HHP-H2) export more electricity to Europe and import less than the other two scenarios.

The results are aligned with the findings from the BEIS research on the impact of interconnectors on decarbonisation[34]. The main findings include: (a) GB becomes a net exporter by 2050, (ii) the use of interconnectors for sharing resources (both energy and capacity) that reduces generation capacity requirements and facilitates better integration of renewables.

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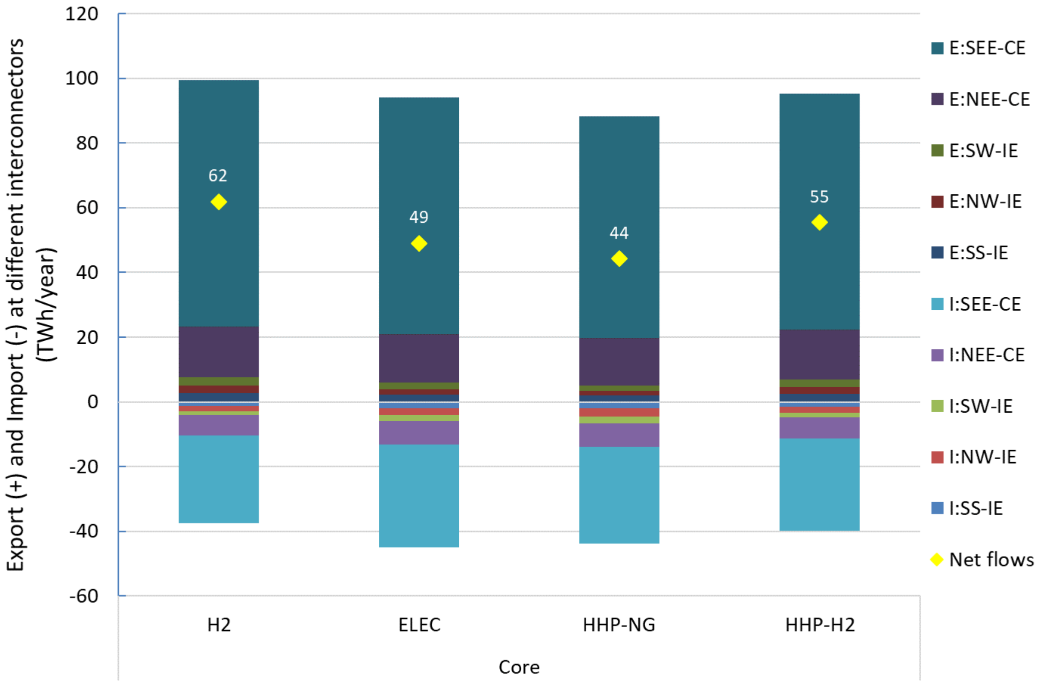
32 BEIS (2020). Modelling 2050: Electricity System Analysis. Link: www.gov.uk/government/publications/modelling-2050-electricity-system-analysis

33 DECC (2012). Dynamic Dispatch Model. Link: www.gov.uk/government/statistics/the-dynamic-dispatch-model-a-fully-integrated-power-market-model

34 Aurora Energy Research (2020). The impact of interconnectors on decarbonisation. BEIS Research Paper number 2020/056. Link: assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/943239/impact-of-interconnectors-on-decarbonisation.pdf



Legend:
E: Export, I: Import, SEE: South East England, NEE: North East England, SW: South Wales, NW: North Wales, SS: South of Scotland, IE: Ireland, CE: Continental Europe

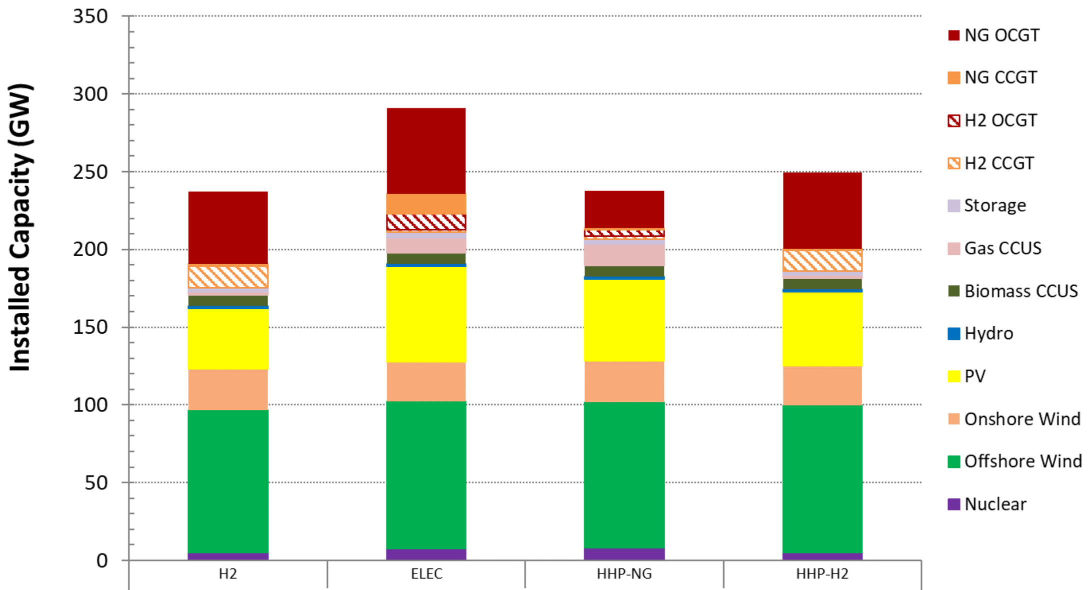
Figure 2-10 Annual electricity exchange with Europe

The regional results of IWES show that most of the electricity export will take place via the GB interconnectors in the South East of England to continental Europe (E: SEE-CE). In some periods, the GB system still needs to import power from Europe, especially during low renewable output. The revenue from net electricity export is estimated between 2.4 and 3.2 £bn/year (see the previous discussion in section 2.3). The revenue from exports is expressed as a negative cost, as shown in Figure 2-4.

2.9 Portfolio of power generation capacity

Figure 2-11 shows the portfolio of power generation capacity for each heat decarbonisation scenario proposed by IWES. It is worth noting that the results are driven by costs and other assumptions used in the study. Considering future uncertainties in the cost and technical performance of new technologies (such as CCUS, DACCS, different storage technologies etc.), further studies will be needed to determine a robust generation portfolio and corresponding development scenarios.

In H2 and HHP-H2, nuclear power is at the minimum limit, i.e. 5 GW (given the assumption used in this study). A higher nuclear capacity (8GW) is needed to provide firm low-carbon generation in ELEC and HHP-NG. Around 26 GW of onshore wind and 95 GW of offshore wind are needed across the scenarios with the highest requirement in ELEC and HHP-NG. It is cost-optimal to have more low-carbon generation capacity in ELEC and HHP-NG since the annual electrical energy demand in those two scenarios is higher. Around 39 - 62 GW of PV (combined utility-scale and residential roof-top PV) is needed. 7 GW of biomass (power BECCS) is proposed in all scenarios. Between 2- 14 GW of gas CCUS is needed across scenarios, particularly in ELEC and HHP-NG.



	H2	ELEC	HHP-NG	HHP-H2
	Core			
NG OCGT	47	55	24	49
NG CCGT	2	13	1	1
H2 OCGT	0	10	4	0
H2 CCGT	13	2	2	13
Storage	3	3	3	3
Gas CCUS	2	10	14	2
Biomass CCUS	7	7	7	7
Hydro	1	1	1	1
PV	39	62	53	48
Onshore Wind	26	25	26	26
Offshore Wind	92	95	94	94
Nuclear	5	8	8	5

Figure 2-11 Electricity generation capacity portfolio

The level of electricity storage needed is 3 GW with 16.5 GWh energy capacity. The low usage of storage (see Figure 2-8) indicates that the value of storage, in this case, is leaning towards providing system capacity and occasionally system balancing. Therefore, it competes directly with the low-cost peaking plant (OCGT) and flexibility from demand response services. Given the assumptions taken in the study, the cost of storage is higher than the cost of hydrogen or natural gas OCGT, and there is a significant level of flexibility from demand response and hydrogen sector coupling.

One of the roles of energy storage is to store low-carbon energy and generate electricity when renewable output is low to minimise the use of natural gas thermal plants and emissions. With negative emissions technologies, the emission restrictions can be temporarily relaxed since the emissions can be offset at different times. Therefore, the deployment of electricity storage is relatively modest. However, different assumptions lead to a very different capacity for electricity storage. For example, if the annual electricity storage cost is reduced (£30m per GW[35] per year), the model proposes between 41 and 82 GW of electricity storage.

The study also demonstrates that the integration of hydrogen-based power generation is needed in all scenarios, considering the synergy between electricity and hydrogen sectors.

[35] Storage duration is 2 h.

Around 2 – 13 GW of H2 CCGT and up to 10 GW of H2 OCGT are needed to provide the required energy and system balancing services. OCGT and H2 OCGT also provide the reserve capacity needed to deal with generation outages. In ELEC, the 10 GW H2 OCGTs produce only 0.06 TWh/year and are primarily used to ensure generation adequacy. While hydrogen for power is already available in the market[36], no gas-fired power station in the UK uses hydrogen yet. This technology can be an option for meeting the UK's 2050 net-zero emissions target.

The study also shows that there is still a place for conventional gas CGGT and OCGT, primarily to be used occasionally to supply electricity during extreme peak conditions. Considering that renewables' capacity value is low, a considerable capacity (24 – 55 GW) of peaking or back-up capacity is needed to meet the security requirement (modelling considers exceptionally cold days when wind output is assumed to be extremely low). The highest requirement is in the ELEC scenario, where the peak demand is the largest. However, as with residual emissions in heating, this result carries some uncertainty, given its reliance on developing widely available carbon removal technologies, whose cost is not prohibitive.

2.10 Electricity supply and demand balance during extreme weather conditions

Figure 2-12 shows hourly electricity generation and demand in the week with extreme weather conditions (low temperature less than -6°C with low wind output) in ELEC.

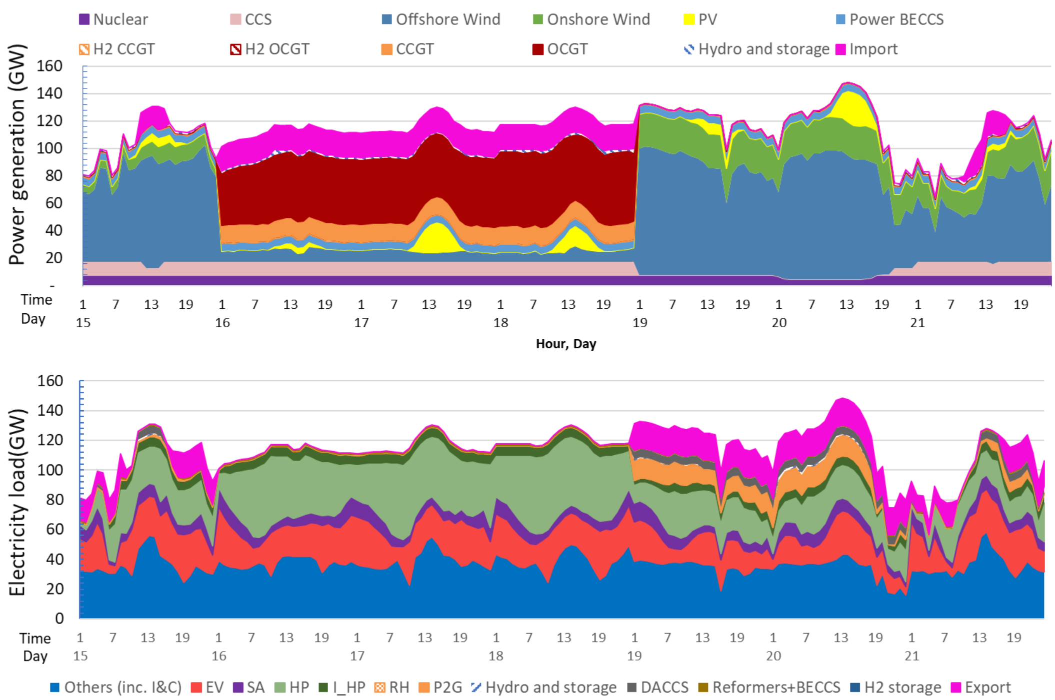


Figure 2-12 Hourly electricity generation and demand for one week with the extreme cold-weather conditions in ELEC

[36] Source: GE. Link: www.ge.com/gas-power/future-of-energy/hydrogen-fueled-gas-turbines

The top diagram depicts the hourly power production from various generation technologies needed to meet the bottom diagram's hourly electricity demand. Modelling considers three days with extremely cold conditions (day 16th – 18th) coinciding with low-wind output to stress-test the system capacity.

During this condition, the absence of significant renewable power output is compensated by mostly conventional gas-fired power generation and electricity import from Europe[37]. The use of conventional gas-fired generation increases the power sector emissions, which need to be nullified by BECCS and DACCS, as discussed previously in section 2.1. When renewable power sources are available, the conventional gas CCGT or OCGT are not utilised. Hydrogen-based power generation is still used in some conditions to provide balancing. It should be highlighted that a significant amount of the balancing services, including fast frequency response, is provided by demand response, and therefore, it reduces the need for operating part-loaded thermal generation plant. BECCS for power is included in the "Other" category in the figure below, and it contributes to providing firm low carbon capacity.

The bottom diagram shows the hourly profile of electricity demand from various categories. During extreme cold conditions, the heat-led electricity load is visibly higher than in other periods, though demand response from other sources minimises the peak load. The peak during these conditions is around 130 GW. Some of the loads are transmission-connected, and others are distribution-connected. The latter drives the peak of distribution flows to 119 GW. It is also observed that during high-wind conditions, power-to-gas (P2G) is used to convert some of the excess electricity to hydrogen.

In the H2 scenario, during the three days with extremely cold conditions (day 16th – 18th), as shown in Figure 2-13, the heat demand is supplied by hydrogen. Therefore, the electricity peak demand during this period is lower than in ELEC. In addition to low-carbon generation, conventional OCGT and importing power via interconnectors are used to meet the electricity demand. It is worth noting that the electricity production from hydrogen power generation is low. During this period, hydrogen demand for heating is at its peak and therefore, the use of hydrogen to produce power will increase demand for hydrogen production capacity or storage. During this period, electrolysers produce hydrogen even with low wind output to support the hydrogen system. This again highlights the need for planning and operation coordination between the hydrogen and power sectors.

Another example is shown in Figure 2-14, illustrating the electricity generation and demand profile in a winter week in the H2 scenario. Wind output is average, although it has a period of low wind (at the right part of the diagram) coinciding with low demand. The graph below shows the interconnectors' importance, hydrogen CCGT and demand response in balancing electricity supply-demand. Due to significant demand response, the demand profile's shape varies hour by hour following renewable energy availability.

[37] The model considers that renewable generation has a limited capacity credit and additional reserve to cope with plant outages. This will affect both the GB and Europe generation capacity portfolio.

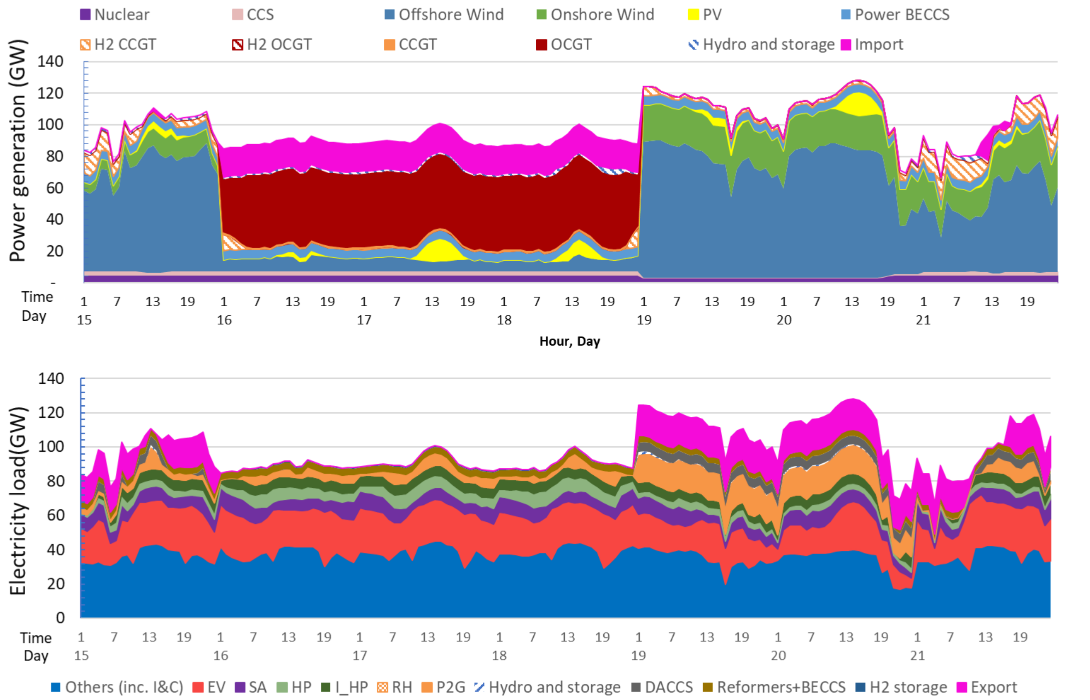


Figure 2-13 Hourly electricity generation and demand for one week with the extreme cold-weather conditions in H2

Figure 2-14 (top) shows the dispatch of hydrogen CCGT and electricity import from interconnectors, balancing the supply and demand of electricity following wind and PV generation variability. The output of gas CCUS and nuclear is relatively flat at maximum across the week in question.

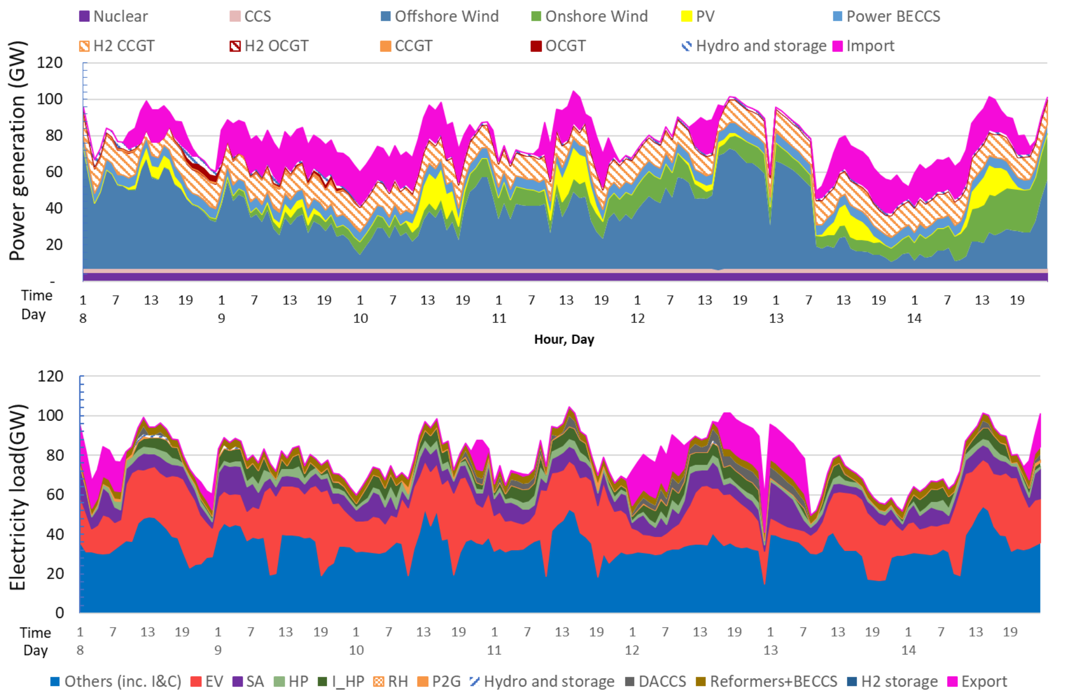


Figure 2-14 Hourly electricity generation and demand for another winter week in H2

2.11 Offshore and onshore transmission

The modelling results build between 16900 and 17400 GW-km of the offshore network connecting the offshore wind farms to the onshore grid. The onshore transmission capacity across different regions ranges from 22000 to 22700 GW-km. Using the same topology modelling, the current system's total onshore transmission capacity is 20500 GW-km. The model suggests significant onshore transmission reinforcement between Scotland and England to facilitate large-scale wind deployment.

The offshore network cost is estimated at around 15% of the offshore wind farm project cost[38]. The offshore wind capacity proposed by the model (92 – 94 GW) for 2050 is nine times the current capacity, and therefore, it is expected to have substantial offshore network investment. The capacity requirement for the offshore and onshore transmission for different scenarios is shown in Figure 2-15. It is worth highlighting that the model optimises the portfolio of generation and the locations concurrently with the transmission expansion programme. Thus, the trade-off between having better renewable resources and the cost of transmission expansion is considered.

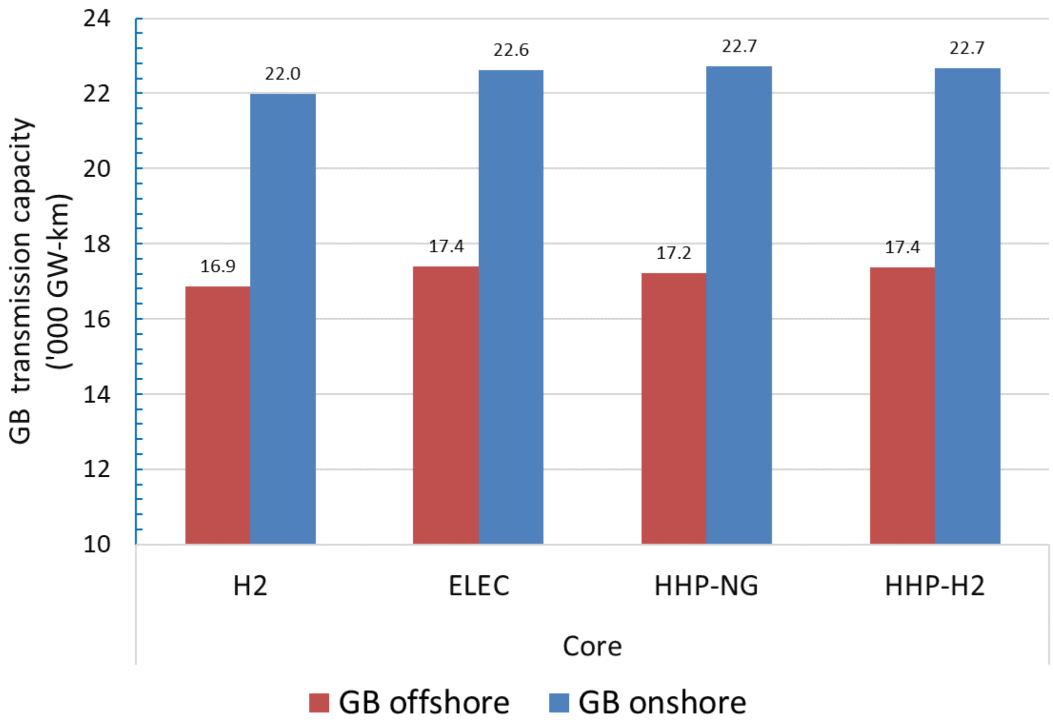


Figure 2-15 Offshore and onshore network capacity requirement

Transmission capacity requirement is primarily driven by renewables and, in this context, wind power generation. Considering the similar wind power level that needs to be built across different scenarios (see Figure 2-11), the transmission requirements are very similar.

[38] Source: Energy Catapult (Offshore Renewable Energy)

2.12 Hydrogen demand and hydrogen production output

Hydrogen demand across scenarios varies between 295 TWh/year in HHP-NG and 657 TWh/year in H2, as shown in Figure 2-16. Between 10 and 76 TWh/year hydrogen demand comes from its use in the power sector, which can be found in all scenarios. The use of hydrogen for power in H2 and HHP-H2 is higher compared to ELEC and HHP-NG. With the widespread use of hydrogen for heating in H2 and HHP-H2, more extensive hydrogen infrastructure is built to supply industrial and heat demand. Therefore, using the same infrastructure to produce hydrogen for power will simultaneously improve hydrogen asset utilisation and reduce power sector emissions. In ELEC and HHP-NG, the model proposes both gas CCUS and hydrogen power generation for balancing. The results demonstrate the need to integrate hydrogen-based power generation irrespective of the adopted heat decarbonisation scenario.

In H2 and HHP-H2, hydrogen demand for heating (H2 gas boiler) is around 301 and 78 TWh/year, respectively. Some DACCS may also use hydrogen for heating, but in these core studies, the model proposed all-electric heating for DACCS in all scenarios. There is also hydrogen demand for transport (HGV, shipping) and industry. Based on cost optimisation results of the interim BEIS Sixth Carbon Budget analysis using the UK TIMES model (UKTM), these sectors require around 285 TWh of hydrogen per year in all heat decarbonisation scenarios.

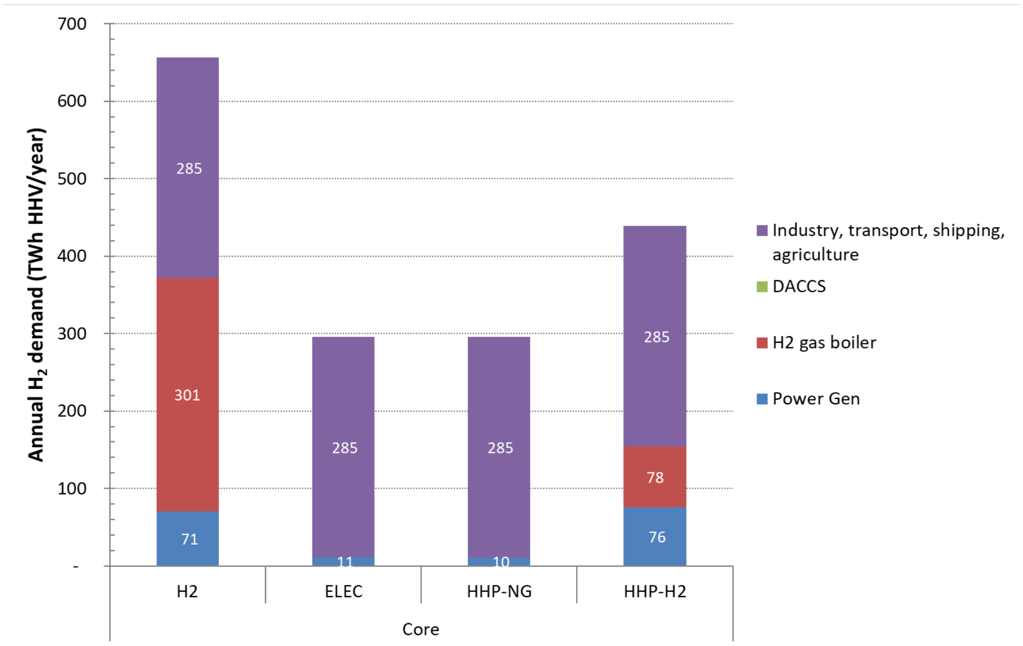


Figure 2-16 Annual hydrogen demand

To supply this demand for hydrogen, the model optimises the mix of hydrogen production technologies, including the use of auto thermal reformers (ATR) with CCUS, Power to Gas (P2G) using Proton Exchange Membrane (PEM), biomass gasification hydrogen (BECCS H2) and considers 16 TWh of hydrogen from gasification of dry waste with CCUS (as input from UKTM). The hydrogen production mix for each scenario is shown in Figure 2-17.

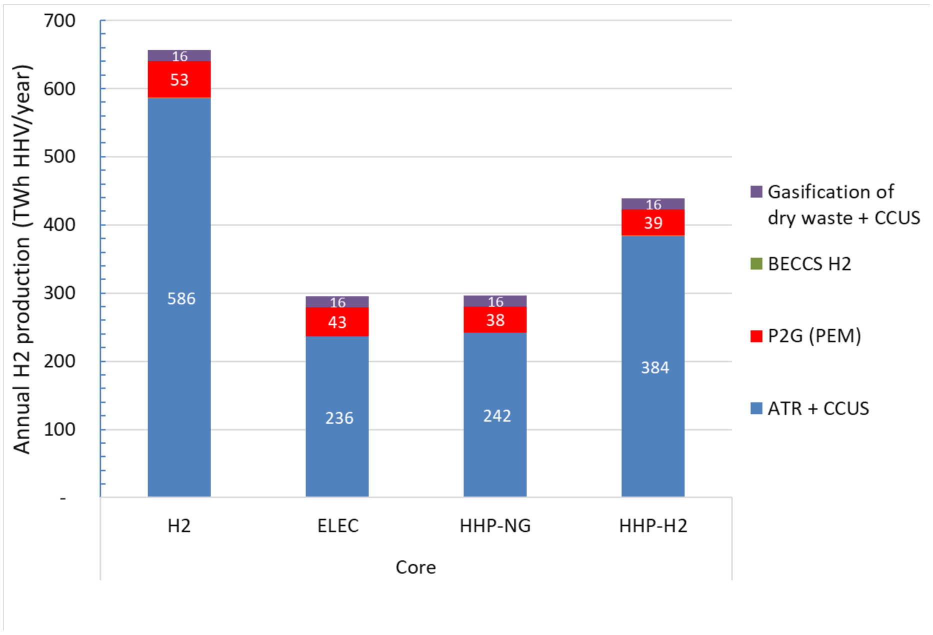


Figure 2-17 Annual hydrogen production

The study demonstrates that it is cost-optimal for the primary hydrogen source to be natural gas processed via auto thermal reformer (ATR) with CCUS. Hydrogen production from ATR with CCUS varies between 236 and 586 TWh/year. It is worth noting that the residual emissions of ATR with CCUS are 4%, contributing to between 2.1 and 5.2 $MtCO_2$/year. Therefore, this technology can only be used in the 2050 net-zero emission system if there is sufficient capacity for negative emission technologies such as BECCS and DACCS to offset residual emissions. However, there is uncertainty about those technologies.

P2G makes a relatively small contribution to hydrogen production, i.e. between 38 and 53 TWh/year. This indicates that at large, the hydrogen produced with electrolysers is still less cost-efficient than hydrogen production from ATR, given the study's assumptions. Besides cost, the use of electrolysers is primarily driven by the volume of renewables in the system, which dominates the electricity supply in all scenarios. Electrolysers can reduce renewable curtailment and contribute to system balancing enabling more renewables to be installed. Therefore, electrolysers are still a part of the optimal hydrogen production mix. It is worth noting that the model assumes flexible operation of electrolysers that mainly follows the renewable output.

The capacity factor of electrolysers is between 34% and 38% across the four core scenarios. It suggests that electrolysers are not supplied from dedicated capacity either from curtailed renewable output only. If electrolysers are supplied from dedicated renewables, the capacity factor is expected to be higher, considering the offshore wind capacity factor is around 60%. While if electrolysers depend on the surplus renewables that otherwise will be curtailed, the capacity factor is expected to be small. Investment in renewable typically considers a relatively small percentage of renewable curtailment. Therefore, the results indicate that electrolysers are fed from various generation sources.

Table 2-3 shows the correlation factor between electrolyser output and the output of various technologies.

Table 2-3 Correlation factor between electrolyser output and other technologies

	Offshore wind	Onshore wind	PV	Storage discharge	H2 CCGT	CCGT	OCGT
Electrolyser	0.53	0.34	0.16	-0.78	-0.51	-0.28	-0.19

The table demonstrates that electrolyser has a relatively high linear correlation with offshore wind output. It also positively correlates with onshore wind and PV, although as not as strong as with offshore wind – this implies that when renewable output is high, electrolyser production also increases. It indicates the role of electrolysers for improving system balancing and dealing with variability in renewable output. However, it has a strong negative correlation with storage discharge (-0.78) and H2 CCGT, CCGT and OCGT. Those technologies typically supply peak demand or operate more during low renewable output, and therefore, the model reduces the use of electrolysers during those conditions to mitigate electricity system scarcity.

There are three electrolysis technologies modelled: (i) Proton Exchange Membrane (PEM), (ii) Alkaline and (iii) Solid Oxide Electrolyser (SOE), and the model chooses to select PEM based on cost and efficiency assumptions. The energy conversion efficiency of those three technologies is similar (around 82%), but the cost of PEM (£340/kW)[39] is lower compared to the other two technologies[40] (for more detail on assumptions, see Appendix A section A.4).

Another key source of hydrogen is bioenergy through gasification with CCUS. However, the modelling results suggest it is more efficient for the available bioenergy to be used entirely to produce electricity instead of hydrogen. The hydrogen production portfolio may change, for example, if the gas price is high or the hydrogen production from ATR becomes less cost-effective. This is discussed in section 3.2.

Figure 2-18 and Figure 2-19 illustrate the hourly hydrogen supply and demand balance (including storage) for three weeks in winter and summer. The winter profile includes the peak condition (day 16 – 18).

[39] Unit cost in 2050 (expressed in 2018 real value)

[40] Cost of Alkaline and SOE is £455/kW and £700/kW, respectively.

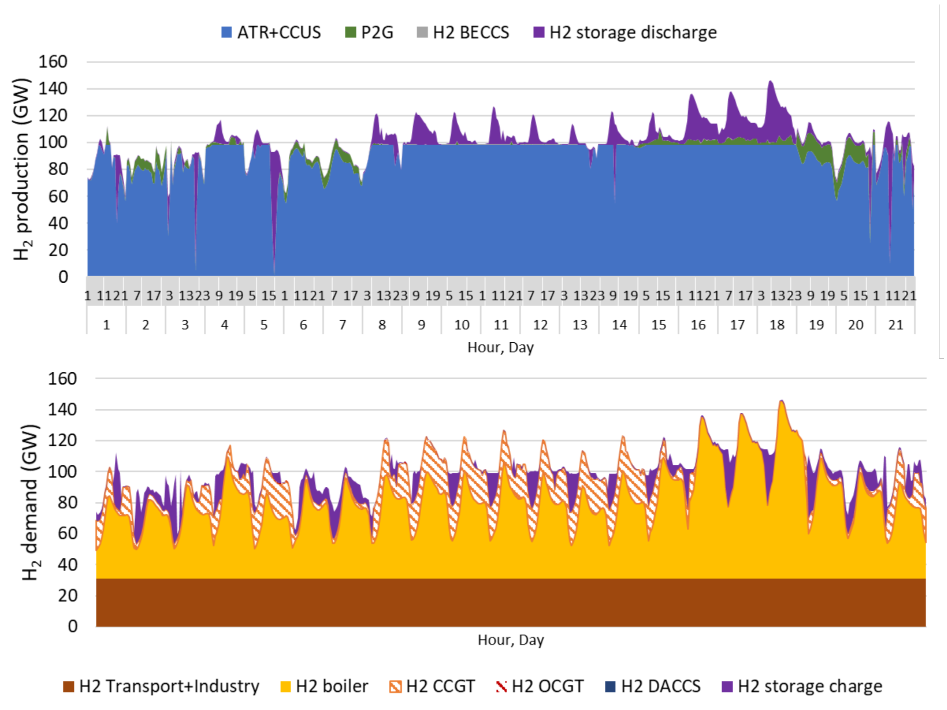


Figure 2-18 Hourly hydrogen supply (top) and demand (bottom) for 21-days in winter (H2 scenario)

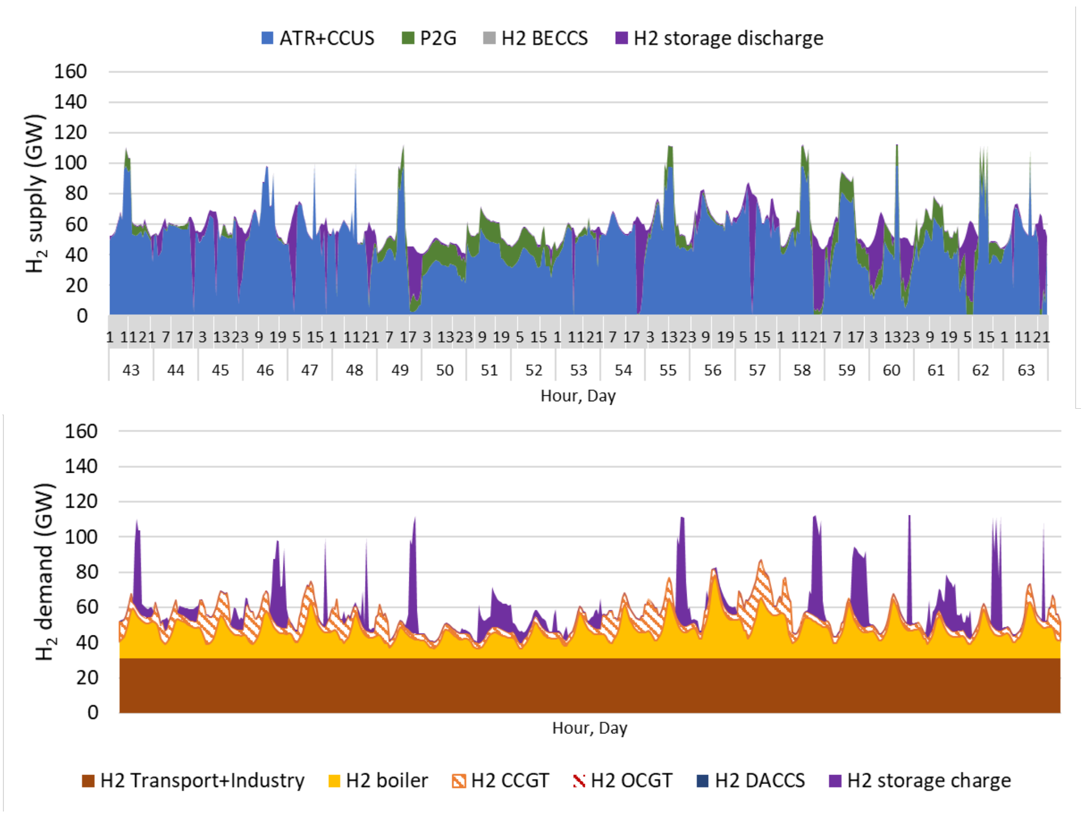


Figure 2-19 Hourly hydrogen supply (top) and demand (bottom) for 21-days in summer (H2 scenario)

On the supply side, ATR+CCUS delivers the bulk of hydrogen supply and provides the hydrogen system balancing besides hydrogen storage. In some instances, the production output from

ATR+CCUS has to be adjusted to provide room for hydrogen production from electrolysis (P2G). Hydrogen storage provides balancing, especially for electrolysis and helps the hydrogen system meet the peak demand in winter, as shown in Figure 2-18 (day 16-18). The results show some infrequent rapid changes in the ATR+CCUS operation profile. The profile can be smoothened if ramp-rate constraints are considered. If the hydrogen production from ATR+CCUS is kept constant, the variability of hydrogen demand and production from electrolysers will need to be balanced by using hydrogen storage. This would increase the capacity and usage of the storage.

On the demand side, the hydrogen used for transport and industry sectors is modelled as a baseload with a flat profile. Hydrogen consumed by hydrogen boiler follows the heat demand profile while the profile for hydrogen used in power generation follows the electricity system operating conditions. Therefore, the hydrogen system's flexibility will also impact the operation and investment in the electricity sector.

The modelling results, shown in Figure 2-18 and Figure 2-19, demonstrate that IWES considers the system operation requirements, which vary hour by hour and seasonal, to determine the optimal capacity and technology portfolio of the hydrogen infrastructure. IWES also considers the interaction between electricity and hydrogen systems through electrolysis and hydrogen-based power generation (that also provide frequency and energy balancing services).

IWES also coordinated hydrogen production between PEM and ATR while considering the need for balancing in the electricity sector. As shown in Figure 2-19, there is variability in hydrogen production between PEM and ATR and that hydrogen demand balancing is supported by hydrogen storage.

2.13 Green gas production capacity

Figure 2-20 shows the green gas portfolio, including hydrogen and biogas[41] production capacity in different heat decarbonisation scenarios. The total capacity varies between 51 GW (the lowest) in HHP-NG, and 120 GW (the highest) in H2, while the required ATR capacity varies between 32 and 98 GW. The results indicate that ATR+CCS is the most economic hydrogen production technology, even with some residual (4%) emissions[42]. The production capacity for H2 and HHP-H2 is larger than the capacity for ELEC and HHP-NG because of the higher hydrogen demand in the first two scenarios, driven by hydrogen use in heat.

[41] Biogas includes bioSNG (from BECCs) and requires upgrading to biomethane to meet National Grid specification.

[42] The capture rate of ATR+CCS is 96%.

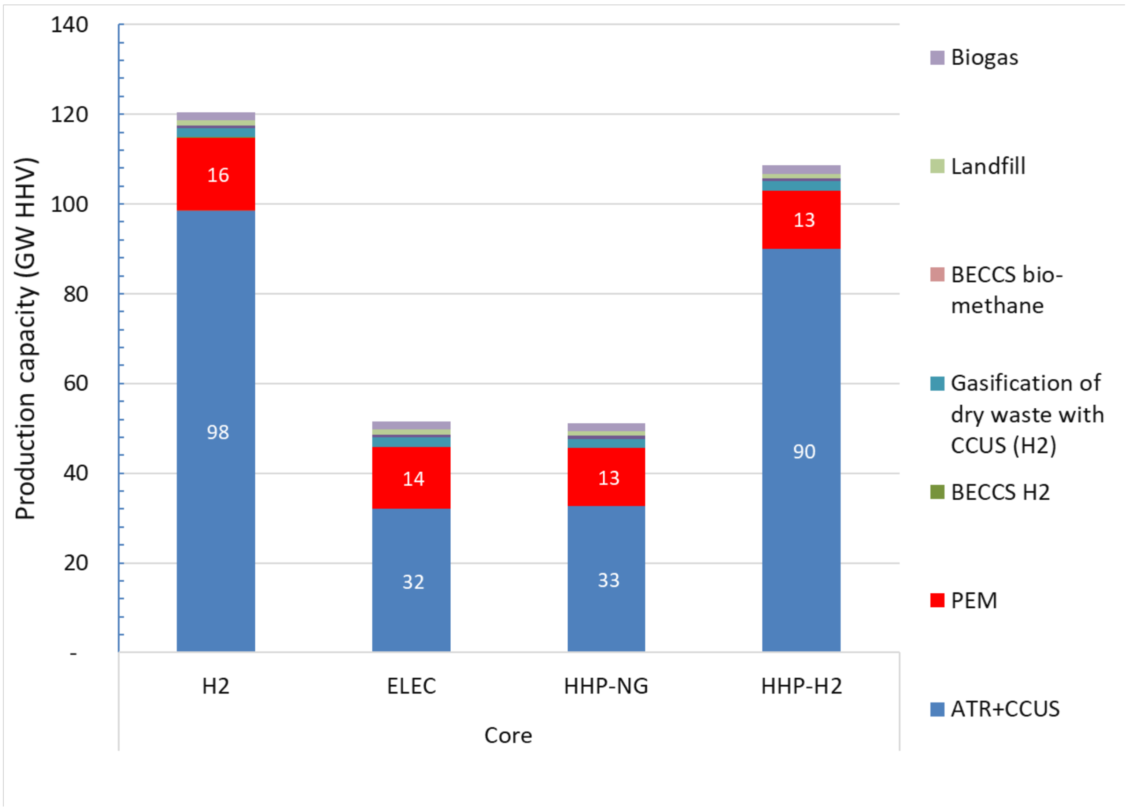


Figure 2-20 Green gas production capacity

Electrolyser capacity is between 13 and 16 GW, with PEM as the leading technology. The remainder of hydrogen comes from renewable waste, landfill and biogas sources.

Figure 2-21 shows the capacity factor of ATR+CCUS and PEM as the main hydrogen producers. ATR+CCUS operates between 43% in HHP-H2 and 85% in HHP-NG. In the scenarios with hydrogen for heating, the capacity factor is lower as the hydrogen demand for heating varies. In contrast, the hydrogen demand for industry and transport is modelled flat and therefore, the ATR+CCUS capacity factor in ELEC and HHP-NG is around 85%. The results also indicate that ATR+CCUS runs at baseload while the electrolysers run less often and operate when the electricity prices are low or when hydrogen demand is at a peak.

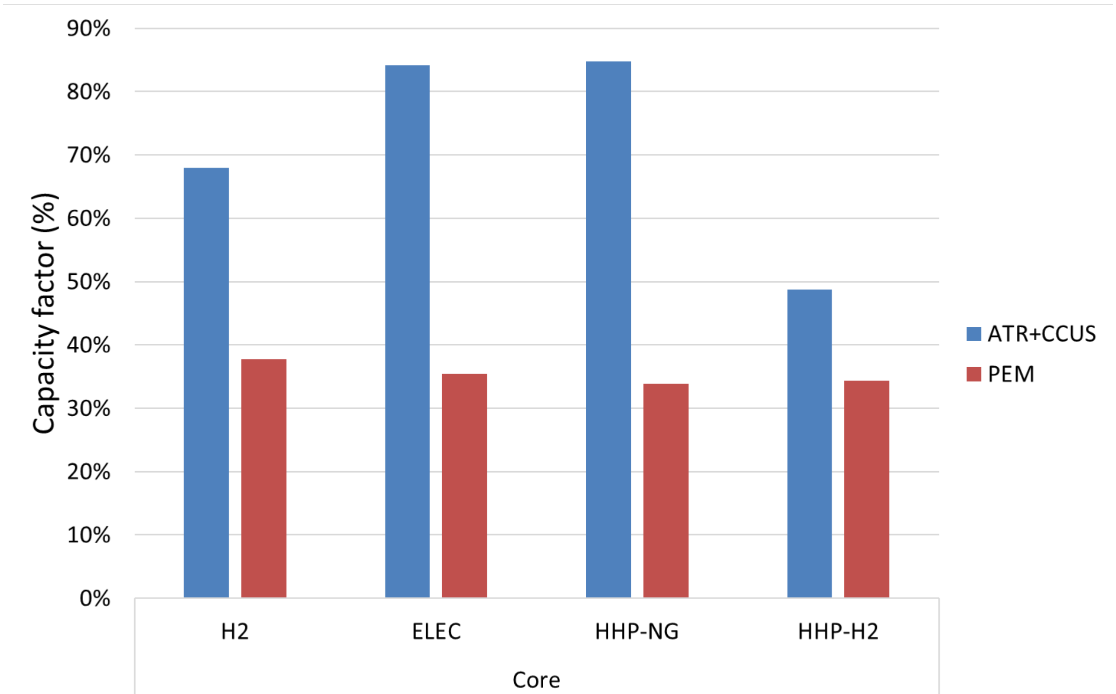


Figure 2-21 Capacity factor of ATR+CCUS and PEM

The capacity factor of ATR+CCUS in HHP-H2 is the lowest across the core scenarios. As most of the heating is still supplied by air-source heat pumps, the use of hydrogen for heating in this scenario is limited; however, the capacity needs to be provided to meet the peak demand leading to a low capacity factor.

2.14 Supply and demand for natural gas

The overall demand for natural gas (and biomethane) varies between 327 and 672 TWh/year. The highest consumption can be found in the H2 scenario and the lowest in ELEC. Most of the demand is driven by hydrogen production via methane reformation, and a small proportion is used in the power sector. Natural gas is also used directly for heat in HHP-NG. The annual supply and demand for methane are depicted in Figure 2-22.

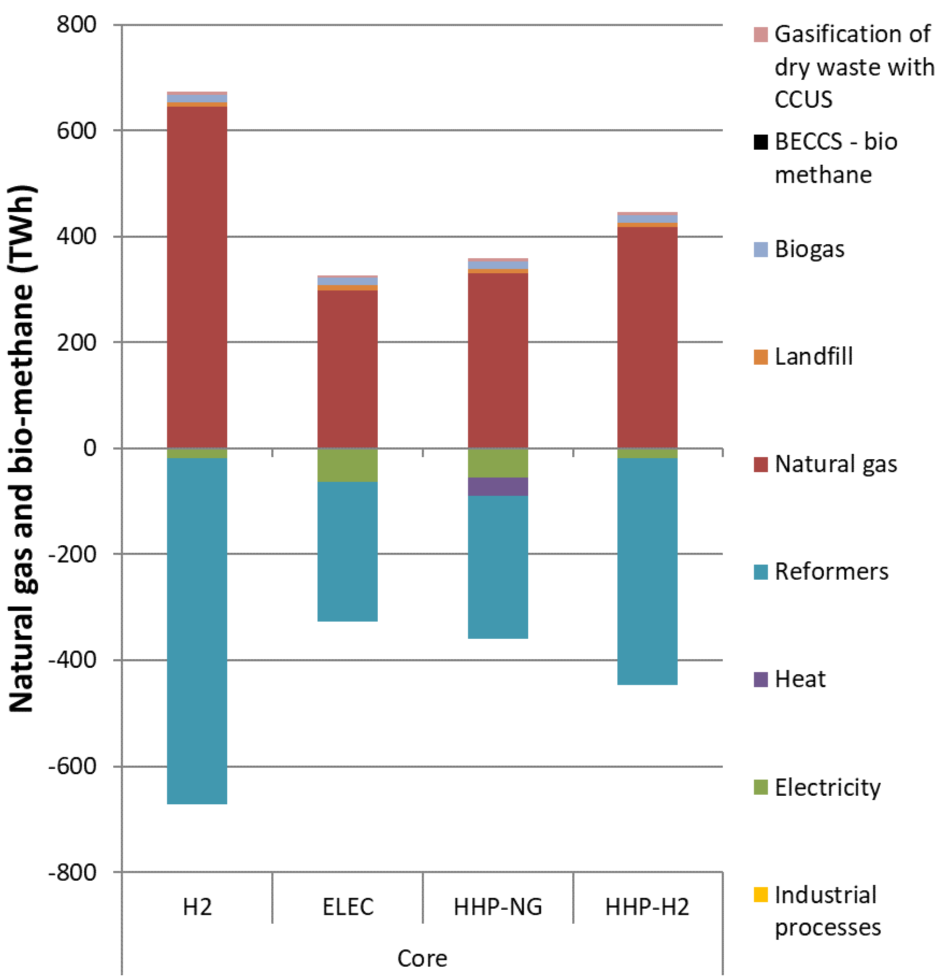


Figure 2-22 Natural gas and biomethane supply and demand

It is worth noting that using natural gas for heating will not be sustainable in the long term, and the reliance on natural gas may expose the energy system to the volatility of the gas price in the future, as discussed in section 3.3.

2.15 Hydrogen storage

This study highlights the potential role of hydrogen in heat decarbonisation in 2050 in both heating and the power sector. Hydrogen storage is an essential element in the hydrogen system, needed to balance hydrogen supply and demand and improve the hydrogen production capacity's utilisation factor. Since hydrogen storage losses are very low (<1%), it may become a competitive energy storage technology for short to long-duration applications. The study considers two types of hydrogen storage: (i) underground storage and (ii) medium-pressure overground storage. IWES optimises the capacities, technologies, and locations of hydrogen storage. These technologies' technical and cost parameters can be found in the Element Energy report (2018)[43].

The need for hydrogen storage is driven by several factors: (i) the variability of hydrogen demand, which is also influenced strongly by diurnal and seasonal variability of heat demand,

[43] Element Energy (2018) Hydrogen for heat technical evidence project

(ii) the variability of renewable output being used to produce hydrogen, (iii) the need to provide sufficient hydrogen supply capacity and local reserves at distribution to enable the delivery of hydrogen in time especially during peak demand. Hydrogen's volumetric energy density is around 30% of natural gas's volumetric energy density. This implies that three times more hydrogen (by volume, compared to natural gas) must be supplied to consumer premises via gas distribution networks to meet the same energy demand. This raises a question about existing gas distribution networks' capability to transport a higher volume of gas flows if they are converted into hydrogen networks and whether these networks would require significant reinforcement. Imperial's study in 2018 for the CCC demonstrated that up to 333 GWh of distributed hydrogen storage would be needed to maintain sufficient gas pressure during peak demand. This is discussed in more detail in the next section.

The hydrogen storage requirement varies substantially across different scenarios. The requirement in ELEC and HHP-NG is relatively low because heat is not supplied by hydrogen, and so the demand for hydrogen is mainly driven by transport and industrial processes, which are assumed to have a relatively flat demand profile. Although hydrogen demand for the power sector varies, the size of this demand is relatively small (see discussion in section 2.12) and does not trigger additional hydrogen storage requirements. It implies that in ELEC and HHP-NG, it is likely that hydrogen produced by electrolyser is used immediately in other sectors assuming flexible ATR+CCUS operation. In contrast, between 2.6 and 3.8 TWh of hydrogen storage capacity is needed in HHP-H2 and H2 scenarios. This is driven by seasonal heating demand. The maximum charge and discharge per hour are 67 GW and 110.2 GW respectively, found in the H2 scenario.

As a comparison, the total gas storage capacity in the UK per August 2018 was 1696 mcm (around 10.5TWh)[44] . It is important to note that there will be natural gas storage in the system, which is not modelled in IWES.

The hydrogen storage capacity portfolio in different scenarios is compared in Figure 2-23. The majority of the hydrogen storage chosen by the model is underground storage, as its cost is one-fifth of the cost of overground storage. However, underground storage has more operating constraints and is inflexible for short-term operation. There is a restriction associated with the discharge of the storage (10% of the energy stored/day) to maintain a "gas cushion" for storage stability. It is also large-scale and not distributed across the system. In contrast, the medium pressure hydrogen storage operation is more flexible, and it can be distributed across the system.

[44] Source: Ofgem, GB gas storage facilities, 2018

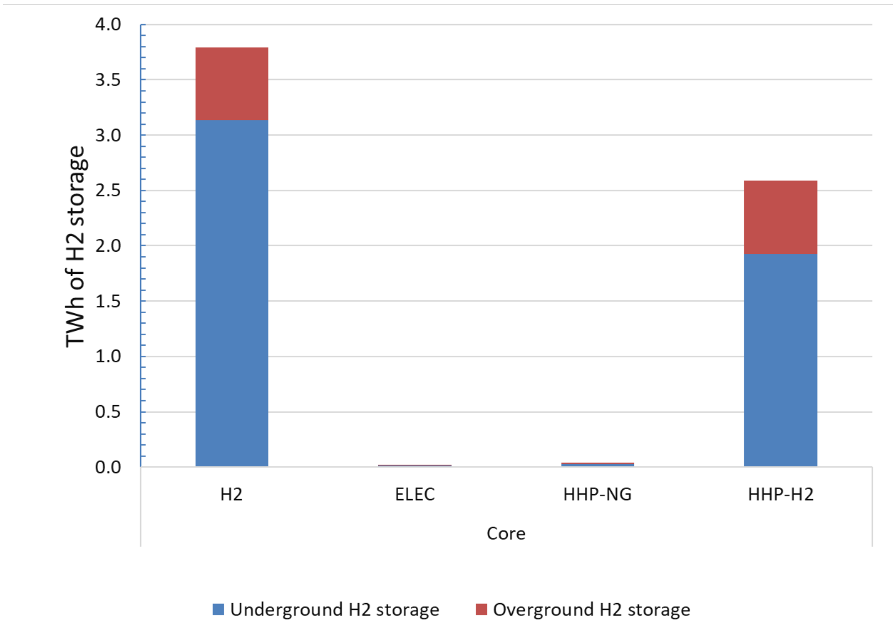


Figure 2-23 Hydrogen storage capacity requirements in different scenarios

Figure 2-24 shows the sum of hydrogen charged and discharged from hydrogen storage in different seasons in the H2 scenario to identify the volume of hydrogen energy carried over across seasons.

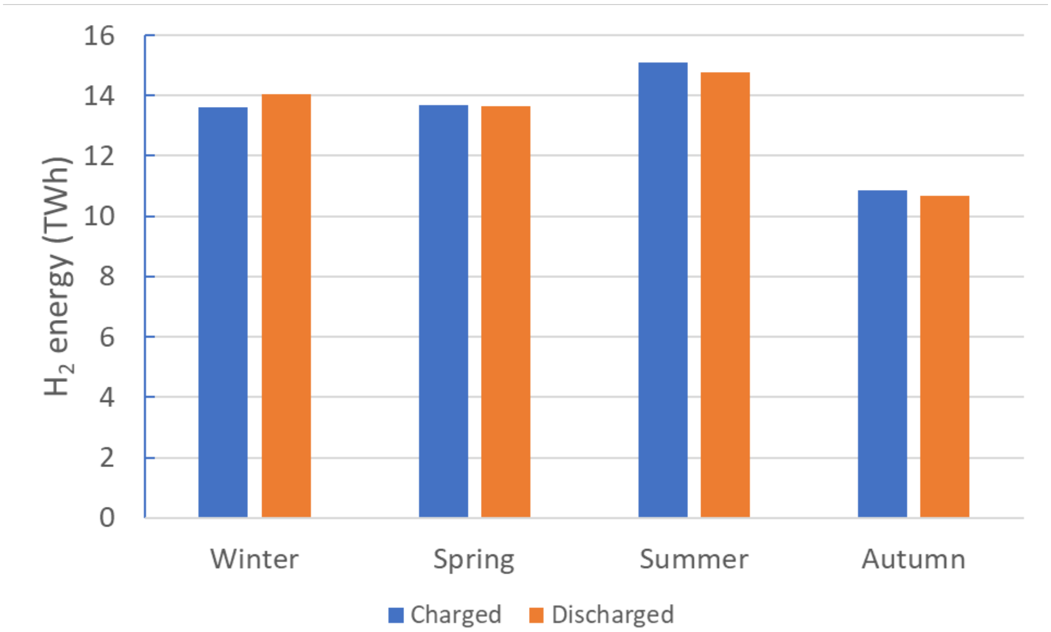


Figure 2-24 Volume of hydrogen storage charged and discharged in H2

Around 440 GWh hydrogen is carried over from summer and autumn to winter to meet the peak demand. It is worth noting that hydrogen storage is charged and discharged regularly in all seasons to deal with the variability in the hydrogen supply produced by electrolysers and hydrogen for power generation (given the variability of production by renewable generation).

2.16 The requirement of hydrogen storage to support the delivery of hydrogen through gas distribution networks

Due to the lower energy density of hydrogen than natural gas, about three times more hydrogen volume is required to supply the same energy. Therefore, maintaining the security of supply will be more challenging in transporting hydrogen via existing distribution gas networks, and hence management of the linepack[45] will play a critical role. Furthermore, hydrogen storage facilities would be required to enable the existing gas distribution networks to deliver hydrogen to the demand centres on time[46].

Considering these challenges, a hydrogen distribution network model has been applied to quantify hydrogen-flow requirements through the local distribution zones (LDZs)[47]. For this purpose, a gas flow model has been implemented to analyse the hydrogen delivery in different pressure tiers, identify gas network bottlenecks and quantify gas flows and pressures in the low, medium and high-pressure gas distribution networks. The modelling demonstrated that the required distributed hydrogen storage capacity would be 333 GWh (i.e., this amount is part of the 3.7 TWh storage capacity mentioned in the previous section), which would cost £0.61bn/year.

Furthermore, additional sensitivity analysis has been conducted to quantify the hydrogen storage requirements for the transport of hydrogen within the existing distribution gas infrastructure under different deployment scenarios of hydrogen-based distributed generation (DG) – such as hydrogen CHP and/or existing distributed gas generation that would use hydrogen in future (as % of the heat-driven hydrogen demand, as presented in Figure 2-25).

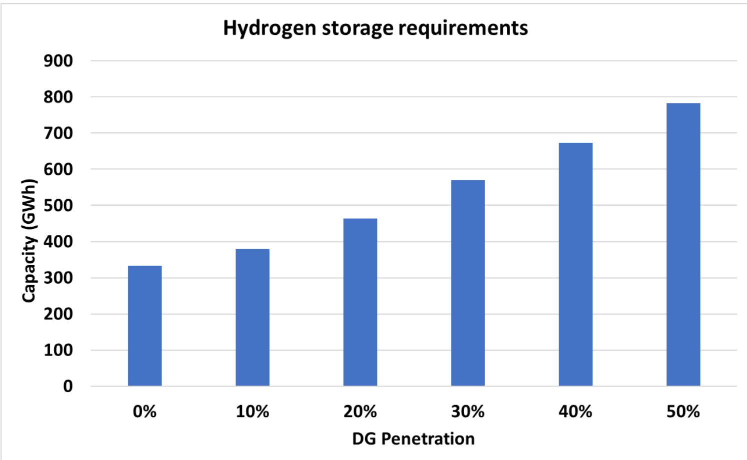


Figure 2-25 Estimated hydrogen storage requirements for LDZs across GB for different levels of penetration of DG (as % of the heat demand-driven hydrogen requirement)

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[45] Linepack is the volume of hydrogen stored in pipelines and can be used to meet abrupt diurnal changes in hydrogen demand.

[46] Imperial College, Analysis of Alternative UK Heat Decarbonisation Scenarios, a report for CCC, 2018

[47] The historical data presented in National grid Gas Ten Year Statement (GTYS) 2019 is considered for the LDZs 1-20 peak demand (~5200GWh/day).

As a result of the deployment of hydrogen-based DGs, the total hydrogen demand[48] is increased. Consequently, to avoid unserved energy demand due to the inability of the existing gas infrastructure to transport hydrogen, reinforcement in hydrogen storage facilities is increased. This additional overground/underground storage capacity is required to enable hydrogen transport through the existing gas infrastructure and the in-time delivery of hydrogen to the demand centres.

As presented in Figure 2-25, in the extreme case, with hydrogen demand for DGs reaching 50% of the amount of hydrogen used to supply heat demand, the hydrogen storage capacity would increase from 333 GWh to 780 GWh, and the corresponding cost would increase from £0.61bn/year to £1.05bn/year[49]

2.17 Hydrogen transmission

This study's two main assumptions are (i) that it is cost-optimal to locate ATR plants with CCUS in regions with natural gas and carbon storage terminals and (ii) that natural gas NTS is retained. Therefore, hydrogen transmission infrastructure is needed to transport hydrogen from the production facilities to areas where hydrogen demand or storage are located. The transmission capacity required (optimised by the model) varies between around 5600 and 14000 GW-km[50]. The highest demand for hydrogen transmission is found in the H2 scenario, followed by HHP-H2, HHP-NG and ELEC scenarios. The hydrogen transmission is much smaller than the natural gas NTS since hydrogen can be produced closer to the demand centres. It is worth noting that the bulk of hydrogen is produced by ATR+CCUS fed by the natural gas NTS.

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[48] Total hydrogen demand equals to hydrogen for heating and hydrogen as fuel for DGs.

[49] The cost function of the storage is derived based on the costs associated for overground and underground storage facilities presented in the following report: Imperial College, Analysis of Alternative UK Heat Decarbonisation Scenarios, a report for CCC, 2018

[50] If the existing natural gas NTS were to be converted to hydrogen (which this study does not assume), its total capacity is estimated around 90,000 GW-km. The total length of the network is around 4000 km with average pipeline diameter of 40 inch.

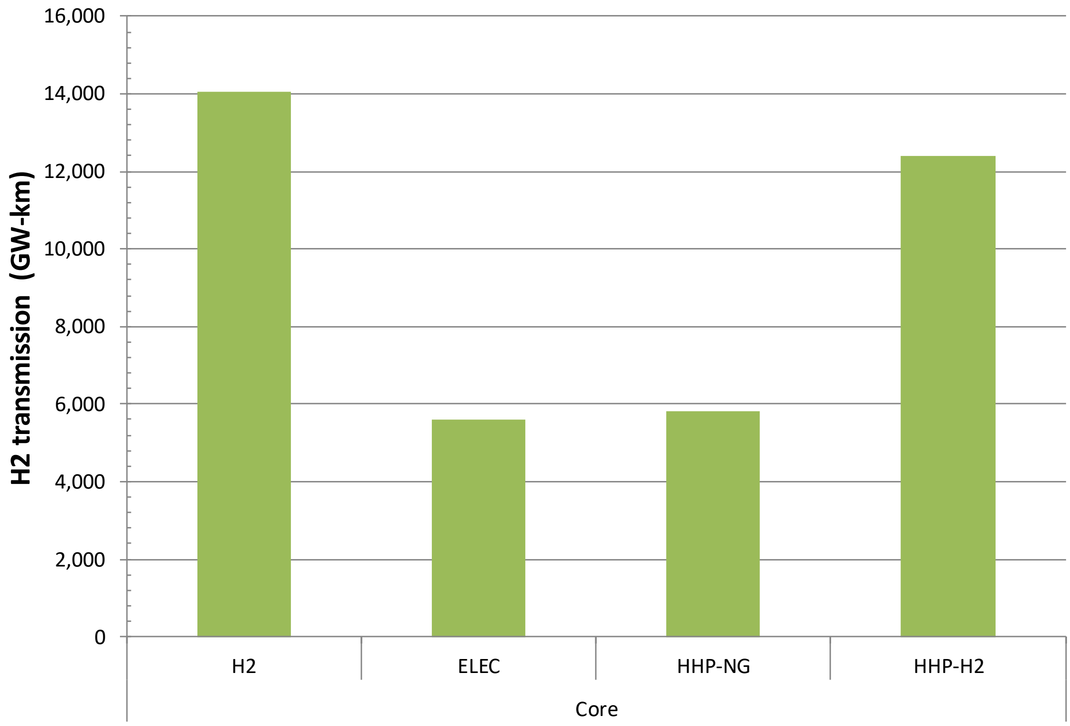


Figure 2-26 Hydrogen transmission capacity

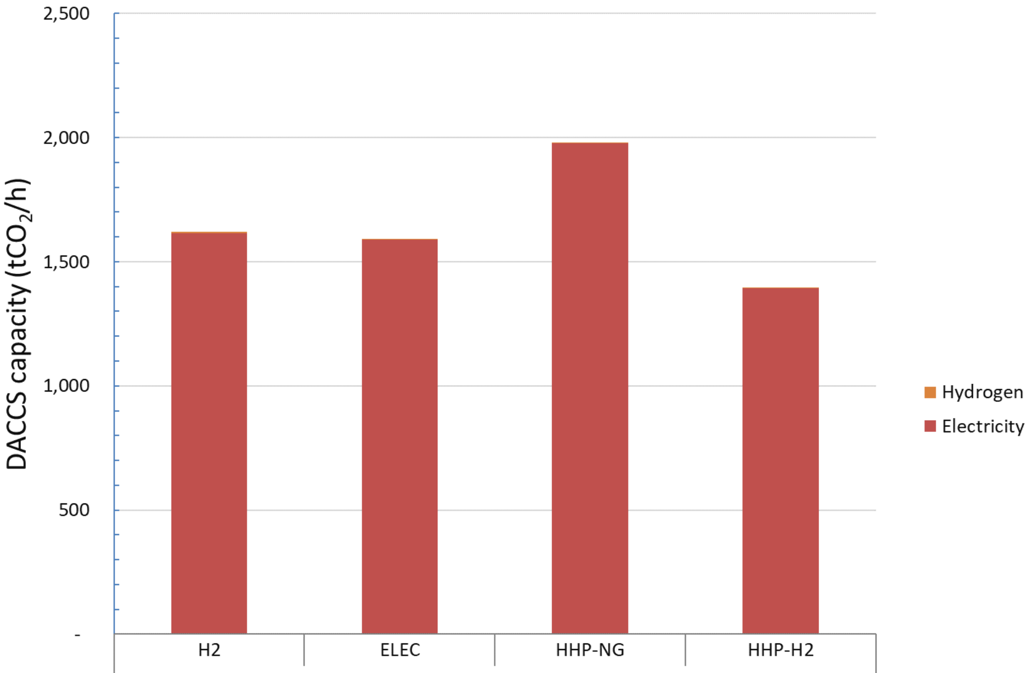
It is worth highlighting that, in this study, hydrogen transmission is built as an additional piece of infrastructure, separate from the existing natural gas transmission system.

2.18 Direct Air Carbon Capture and Storage

DACCS is one of the key technologies needed to achieve net-zero emissions in future energy systems. However, the cost of DACCS is high[51], and it consumes a substantial amount of electricity and heat. IWES optimises the selection of DACCS heating technologies from the choice of (i) electricity or (ii) hydrogen, considering the synergy with the whole-energy system to maximise assets' utilisation and reduce the investment needed to support DACCS operation. The model optimises the capacity of DACCS needed to nullify the emissions and the energy sources for DACCS. It should be noted that hydrogen and electricity are considered the only low-carbon sources of the heat needed for the DACCS process, and the usage of waste heat (for example, from nuclear plants) or natural gas is not explored. The results are shown in Figure 2-27.

The total capacity of DACCS varies between 1.4 ktCO_2/hour[52] in HH2-H2 and 2.0 ktCO_2/hour[53] in HHP-NG. The capacity of DACCS in H2 and ELEC is similar, i.e. around 1.6 ktCO_2/hour. DACCS contributes to the emissions reduction by 10.5 – 14.9 MtCO_2/year in 2050, as discussed in section 2.1.

[51] Capex of DACCS is around £1bn per unit; a unit can capture 1 MtCO_2/year.
[52] Circa 12.2 MtCO2/year of DACCS capacity with 86% utilisation factor
[53] Circa 17.5 MtCO2/year of DACCS capacity with 85% utilisation factor



	H2	ELEC	HHP-NG	HHP-H2
Hydrogen	6	2	4	2
Electricity	1,614	1,589	1,977	1,394

Figure 2-27 Portfolio of DACCS heating technologies

The modelling results suggest that all the DACCS heat demand should be supplied by electricity for these studies. In this case, DACCS can also be used for balancing as it can operate following renewable output. The selection of the DACCS technology shown in this study highlights the need for integrating DACCS with other system infrastructure (such as electricity generation) and the importance of multi-energy system planning and operation. In future, utilising heat from electricity generation technologies such as nuclear may be appropriate.

2.19 Carbon Capture Utilisation and Storage network

This study assumes that most CCUS facilities (e.g. gas-based hydrogen production facilities, power generation with CCUS, DACCS) are based on the coast at gas import terminals with access to offshore infrastructure carbon sequestration and storage. However, a national CCUS network might be needed to transport CO_2 captured from BECCS facilities, distributed across the GB regions (see Appendix A section A.6), to coastal CCUS facilities. For example, there is no carbon storage facility in Midlands and South; therefore, the CCUS network needs to be built to transport the CO_2 from Midlands and South to the North East or East England facilities.

The model proposes to build between 523 and 566 thousand km-ton CO2/h CCUS network capacity for the purpose above. This investment's annuitized cost is between 33 and 36 £m/year, considering the economic life of 40 years. Using various sources for cost information on the CCUS network yields higher values, but the variation in cost is not substantial compared to the magnitude of other cost elements of the system.

However, this modelling result rests on the assumption that biomass transport is more expensive than building a CCUS network, and various sources provide conflicting evidence on this matter. Furthermore, although some allowance has been made for terrestrial CO_2

infrastructure for BECCS technology, the deployment of BECCS has not been examined in detail as it also requires access to feedstock, hydrogen and electricity infrastructure. Although these limitations are likely to affect all scenarios to a similar degree, further investigation is warranted.

2.20 Methane losses

While there is a significant effort to minimise methane's loss due to its commercial value and the associated environmental concerns, some methane or biomethane is inevitably released into the air during its production, transportation, and final consumption. Methane losses are estimated, and the corresponding carbon emission will be compensated by DACCS. Since the level of methane leakage reported varies substantially, based on the Statoil and Sustainable Gas Institute, it is assumed that methane losses of 10 ktCO_2e per TWh of methane consumption in the HHP-NG scenario and 5kt/TWh for the other scenarios[54]. The higher methane losses in HHP-NG take account of the natural gas distribution network losses. This results in increased carbon emissions between 1.5 MtCO_2/year in ELEC) and 3.3 MtCO_2/year in HHP-NG.

More DACCS and its supporting infrastructure would need to be built to offset these emissions. Furthermore, it will also increase the volume of carbon sequestration. Analysis suggests that this will increase the cost between 270 and 580 £mn/year[55], as shown in Figure 2-28. It is worth noting that this cost is not included in the total system cost shown in section 2.3.[56]

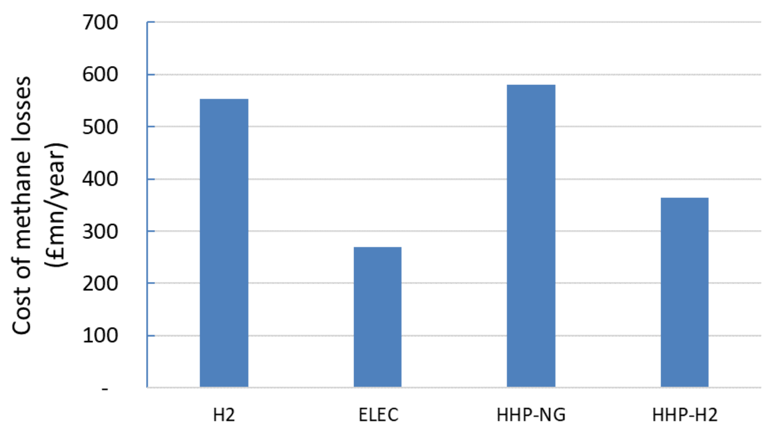


Figure 2-28 System cost of methane losses

[54] Based on the estimated losses reported by Statoil, "Greenhouse gas emissions along the Norwegian gas value chain in 2016" and the Sustainable Gas Institute, "Methane and CO2 emissions from the natural gas supply chain", 2015.

[55] The cost does not include the market value of the methane itself.

[56] Additional analysis after the results section 2.3 been presented and the analysis was carried out only for the core studies.

It is expected that the cost in HHP-NG is the highest considering the methane consumption for hydrogen production, electricity and heating. This is followed by H2 and HHP-H2, and the lowest methane losses occur in ELEC.

Chapter 3. Sensitivity studies on the decarbonization scenarios

A range of sensitivity studies has been carried out on the basis of the core scenarios described in section 1.4 to analyse the implications of different key input assumptions on the cost performance, the portfolio of energy system capacity and its operation, emissions and carbon storage requirements. This section discusses a range of sensitivity studies, investigating the impact of:

- Flexibility
- Less cost-effective ATR
- Higher or lower cost of natural gas
- Higher or lower domestic space heating demand
- Milder temperature assumptions for the extremely cold winter
- Heat Pump COP improvement
- Non-optimal hybrid gas usage
- Mixed roll-out of decarbonisation scenarios
- 50% distribution network headroom

  In all studies except the last one listed above, it is assumed zero headroom for electricity distribution networks to accommodate increased peak load due to electrification. It implies that the distribution network reinforcement costs may be overestimated.

The description of the studies, the key results and the findings are discussed in the subsequent sections.

3.1 Impact of combined electricity and heat flexibility

The Core study results, discussed in section 2, demonstrate the varied sources of flexibility within the energy system. This section shows how varying flexibility in DSR, buildings, and power may change the main findings on the energy design and operability and the optimality of the heat decarbonisation scenarios under study. Compared with other forms of flexibility, such as DSR and electricity storage, the impact of heat flexibility is also of particular interest.

Table 3-1 shows the five flexibility scenarios used in the study. Sources of flexibility include industrial and commercial sectors providing demand-side response services (I&C), electric vehicles (EV), smart appliances (SA), thermal storage, and electricity storage capacity. Those were varied as described below to simulate an energy system with different flexibility levels, from extremely low to extremely high flexibility. The scope of flexibility investigated here includes shifting energy demand temporarily, arbitrage energy storage, and balancing services (frequency response and reserve services).

Table 3-1 Flexibility scenarios

Scenario	Demand response[57,58]	Thermal storage
Extremely low	No	No storage in non-HNs buildings; for HNs, thermal storage up to 20kWh per dwelling
Low DSR	I&C: 5%; EV: 20%; SA: 12%	2kWh for standalone ASHP, equivalent for non-domestic; for HNs, thermal storage up to 20kWh per dwelling
Low thermal storage	I&C: 10%; EV: 40%; SA: 20.5%	No storage in non-HNs buildings; for HNs, thermal storage up to 20kWh per dwelling
Core	I&C: 10%; EV: 40%; SA: 20.5%	2kWh for standalone ASHP, equivalent for non-domestic; for HNs, thermal storage up to 20kWh per dwelling
High thermal storage	I&C: 10%; EV: 40%; SA: 20.5%	7kWh for standalone ASHP, non-domestic same as the core. HNs have a thermal store sized for one week's thermal load, 350kWh per dwelling
High DSR	I&C: 16%; EV: 80%; SA: 26%	2kWh for standalone ASHP, equivalent for non-domestic; for HNs, thermal storage up to 20kWh per dwelling
Extremely high flexibility	I&C: 16%; EV: 80%; SA: 26%	7kWh for standalone ASHP, non-domestic same as the core. HNs have a thermal store sized for one week's thermal load, 350kWh per dwelling

Since the study's focus is on the impact of demand response and thermal storage, the capacity of new electricity storage in all scenarios is kept the same as the value chosen by the model in the core scenario. Storage provided by the thermal mass of a building is inherent in the heat profile used in all Core and sensitivity studies and is not varied in this analysis. The DSR is not costed, and thus the increase in its levels comes without a cost penalty. The increased storage of heat networks is costed, and the extra thermal storage in stand-alone heat pumps is assumed to come at no additional cost, as it is not clear that by 2050 a heat battery would necessarily be more expensive than a hot water cylinder which it would be replacing.

The impact of improving flexibility in different scenarios (H2, ELEC, HHP-NG, and HHP-H2) is analysed and presented below. To quantify the system benefits of flexibility, the "Extreme low

57 For demand-side response, the percentages denote the proportion of demand in any 24hr period which can be shifted

58 I&C: Industry and commercial; EV: Electric vehicles; SA: Smart Appliances; HN: Heat Networks; ASHP: Air Source Heat Pumps

flexibility" case is used as the counterfactual (reference case), even though it is not realistic to expect that an energy system with no flexibility would be found in 2050.

3.1.1 General findings across all scenarios

This section provides general findings across all scenarios before going into more specific discussions for each scenario.

In all flexibility scenarios listed in Table 3-1, the IWES model optimises the flexibility between gas and electricity systems. The results, presented in Figure 3-1, show the impact of flexibility on the annual system costs of different heat decarbonisation scenarios. As discussed previously, the value of flexibility is up to between 5 to 11 £bn/year, and the benefits to the ELEC scenario, which does not have the flexibility of using gas or hydrogen to meet heat peak demand, are higher. The value of flexibility in H2 or hybrid systems is still substantial, i.e. between 5.3 and 6.5 £bn/year. This indicates that gas and hybrid heating systems can relieve the pressure on power system infrastructure. Hybrids can also provide significant flexibility through optimising the use of natural gas or H2 and electricity.

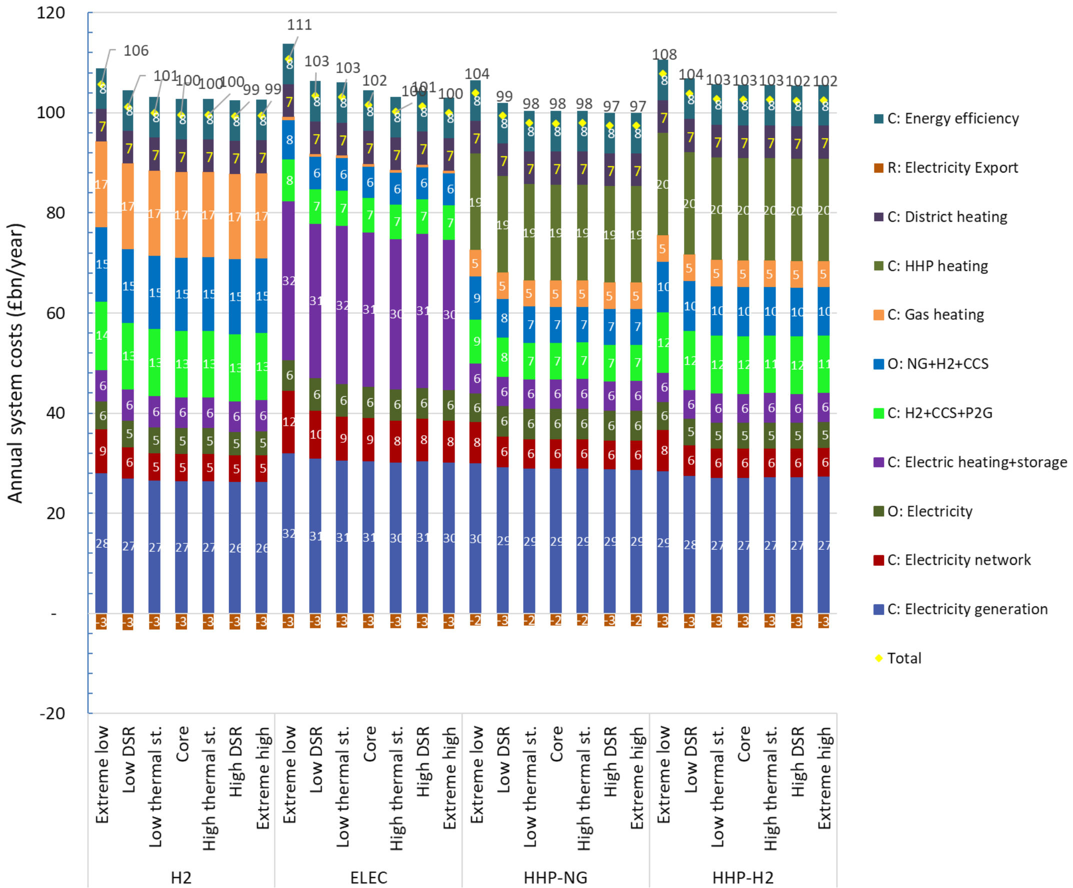


Figure 3-1 Impact of flexibility from electricity and heat on annual system costs

Flexibility reduces the electricity system's costs to a greater extent than in a gas system, as balancing and storing electricity are more challenging than gas (including natural gas and hydrogen) and heat. The results shown in Figure 3-2 demonstrate that in all heat decarbonisation scenarios, higher flexibility leads to lower cost of conventional generation and electricity distribution network due to the reduction in peak load, operating cost of electricity and gas, hydrogen production capacity, DACCS requirement and the volume of carbon that needs to be stored.

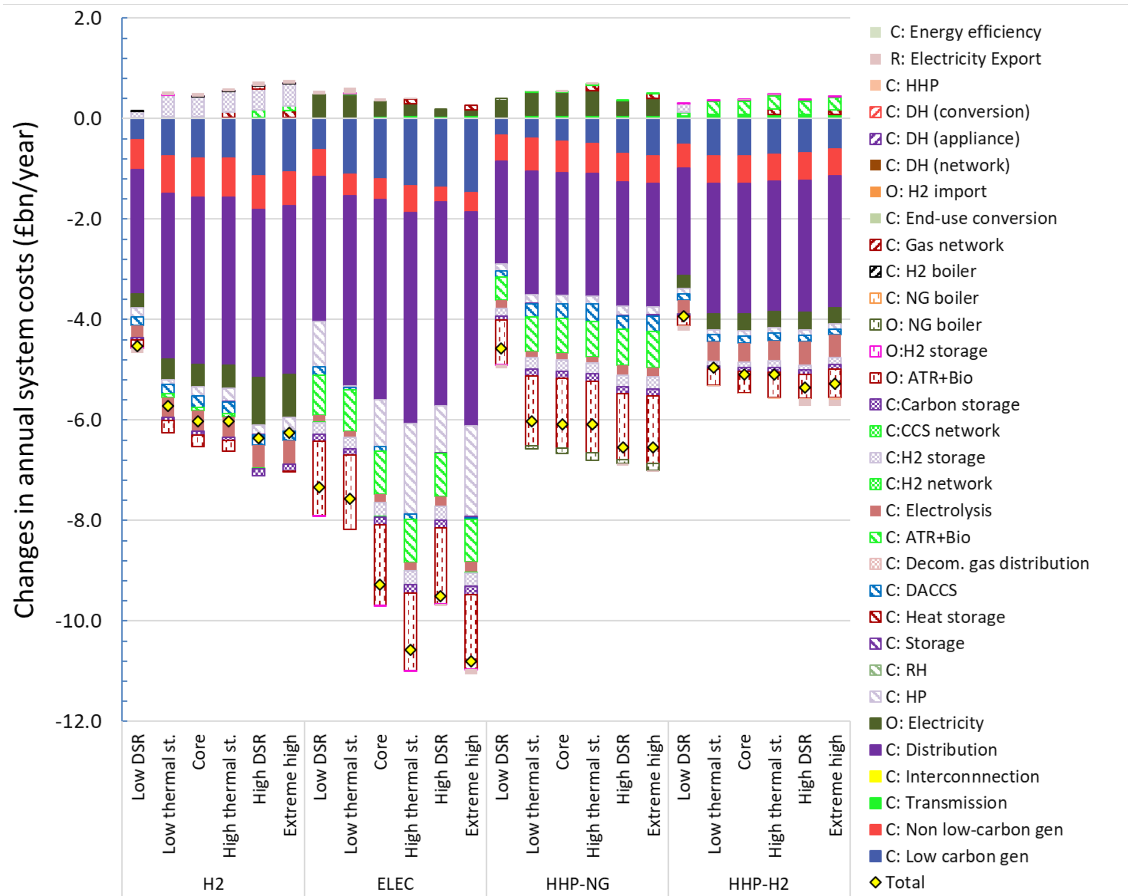
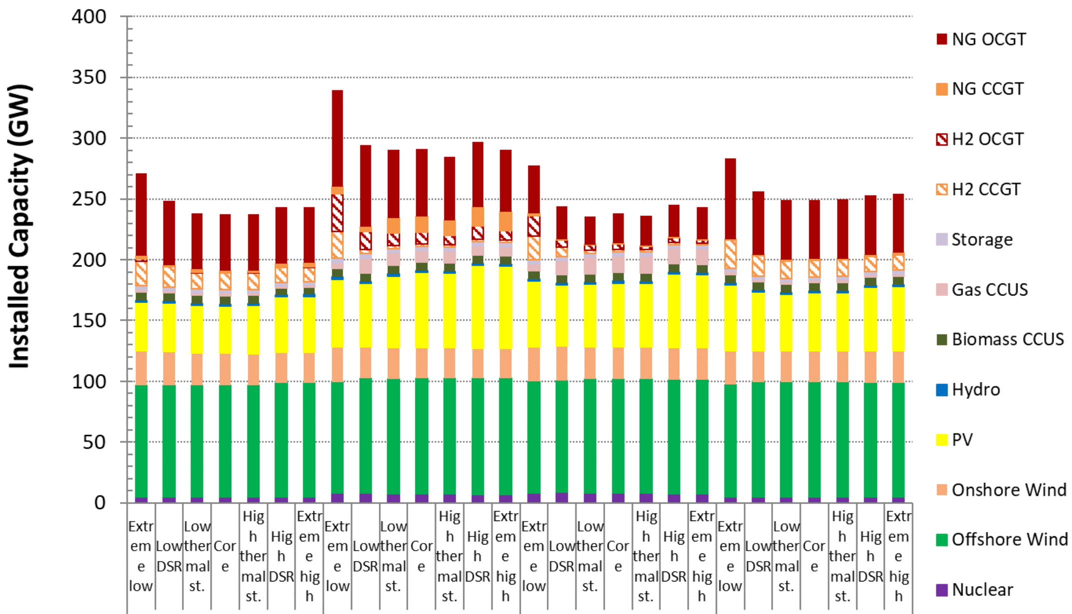


Figure 3-2 Changes in system costs due to system flexibility improvement

The value of flexibility diminishes once system flexibility is improved in all scenarios. A relatively small amount of flexibility is sufficient to align supply and demand across many operating conditions. Higher flexibility will be needed but less often to deal with more extreme conditions, such as high demand and low renewable output or high renewable but low demand. For example, in ELEC, improving flexibility from the extreme low case to the low DSR benefits up to £7.3 bn/year. The savings are much less, about £2bn/year, for improving flexibility from low DSR to the core case. The incremental savings become smaller when the flexibility is improved further. This trend is observed in other scenarios.

Figure 3-3 shows the impact of flexibility on the optimal electricity generation capacity portfolio. Improving flexibility increases offshore wind and PV installed capacity and reduces generation from nuclear and mid-merit, peaking, and backup plants as some loads during peak demand can be shifted to off-peak periods to reduce the peak load.



	H2							ELEC							HHP-NG							HHP-H2						
	Extreme low	Low DSR	Low thermal st.	Core	High thermal st.	High DSR	Extreme high	Extreme low	Low DSR	Low thermal st.	Core	High thermal st.	High DSR	Extreme high	Extreme low	Low DSR	Low thermal st.	Core	High thermal st.	High DSR	Extreme high	Extreme low	Low DSR	Low thermal st.	Core	High thermal st.	High DSR	Extreme high
NG OCGT	68	53	46	47	46	47	46	80	67	56	55	52	54	51	39	27	23	24	25	26	26	66	53	49	49	49	49	49
NG CCGT	2	1	2	2	2	3	3	6	4	12	13	12	15	15	2	1	0	1	1	0	1	0	0	1	1	1	1	2
H2 OCGT	2	0	1	0	0	0	0	31	15	10	10	8	11	8	17	6	4	4	2	4	3	0	0	0	0	0	0	0
H2 CCGT	20	16	13	13	14	12	12	22	3	3	2	2	2	2	19	8	2	2	2	2	2	23	16	14	13	13	12	13
Storage	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Gas CCUS	2	2	2	2	2	2	2	5	12	10	10	10	8	8	6	11	14	14	14	13	13	2	2	2	2	2	2	2
Biomass CCUS	7	7	7	7	7	5	6	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Hydro	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
PV	40	40	39	39	39	46	46	56	52	59	62	61	68	67	54	51	51	53	52	61	60	54	48	47	48	48	52	53
Onshore Wind	28	28	26	26	26	25	26	28	26	26	25	25	25	25	28	28	27	26	27	26	27	28	26	26	26	25	26	26
Offshore Wind	92	92	92	92	92	94	93	92	94	94	95	95	95	95	92	92	93	94	93	94	93	92	94	94	94	95	94	94
Nuclear	5	5	5	5	5	5	5	8	8	8	8	7	7	7	8	9	9	8	8	8	8	5	5	5	5	5	5	5

Figure 3-3 Impact of flexibility on the electricity generation capacity

In contrast to previous CCC studies[59] , which showed an increased usage of firm low carbon generation such as nuclear and CCUS when the system flexibility is low, the current study shows no increase in nuclear requirement even in the low flex scenarios. Because of the negative emission requirements, there is a need for BECCS and DACCS, which reduces the need for additional firm low carbon generation (such as nuclear). Furthermore, there is an increase in the capacity of hydrogen-based generation.

The capacity of peaking generation also reduces significantly when system flexibility is improved. By shifting the electricity loads from peak periods to off-peak periods, the peak demand decreases, as indicated by the reduction in the electricity distribution peak depicted in Figure 3-4.

[59] Imperial College London, "Analysis of Alternative UK Heat Decarbonisation Scenarios", Report to the Committee on Climate Change, June 2018. Available at: https://www.theccc.org.uk/wp-content/uploads/2018/06/Imperial-College-2018-Analysis-of-Alternative-UK-Heat-Decarbonisation-Scenarios.pdf

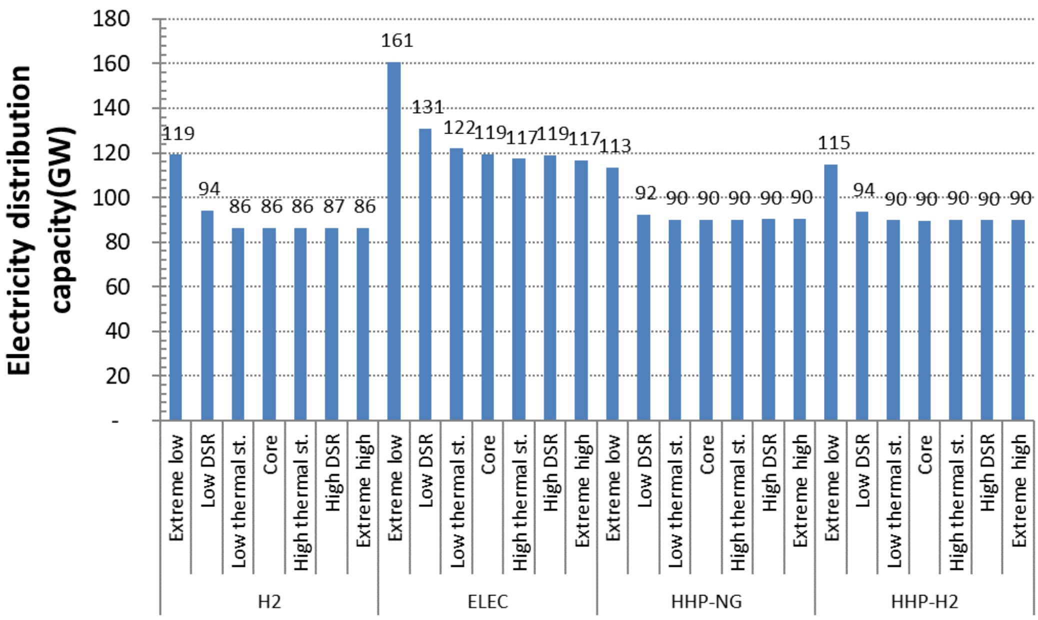


Figure 3-4 Impact of flexibility on the distribution peak

The peak demand reduction occurs in all scenarios, considering that in all scenarios, there are always customers that use electric heating only, e.g. off-gas grid customers. However, the scale of peak reduction in ELEC is much larger than in the other three scenarios. Distribution capacity decreases by 42 GW from 161 GW in the "extreme low" case to 119 GW in the "extreme high" case.

The lack of energy system flexibility reduces the system ability to integrate variable renewables. As a consequence, the system relies more on the use of hydrogen. Therefore, without sufficient flexibility, the demand for hydrogen from the power sector increases substantially, as shown in Figure 3-5. When the volume of system flexibility is higher, the modelling proposes less hydrogen for power. More renewable sources can be integrated as flexibility reduces the system integration cost of renewables, allowing them to compete with hydrogen as the alternative low-carbon energy source.

Across all scenarios, electrolysers' use is higher when the system flexibility from DSR or energy storage is low. Electrolysers can provide additional flexibility to partially compensate for the lack of flexibility in demand or energy storage. Electrolysers can be used as a flexible demand to follow renewables' output and provide system balancing services. The results regarding the changing hydrogen production mix are shown in Figure 3-6.

Therefore, when the system flexibility is improved, electrolysers' use reduces by 25%- 30% across scenarios. Power from low-carbon sources can be used directly, mitigating energy conversion losses.

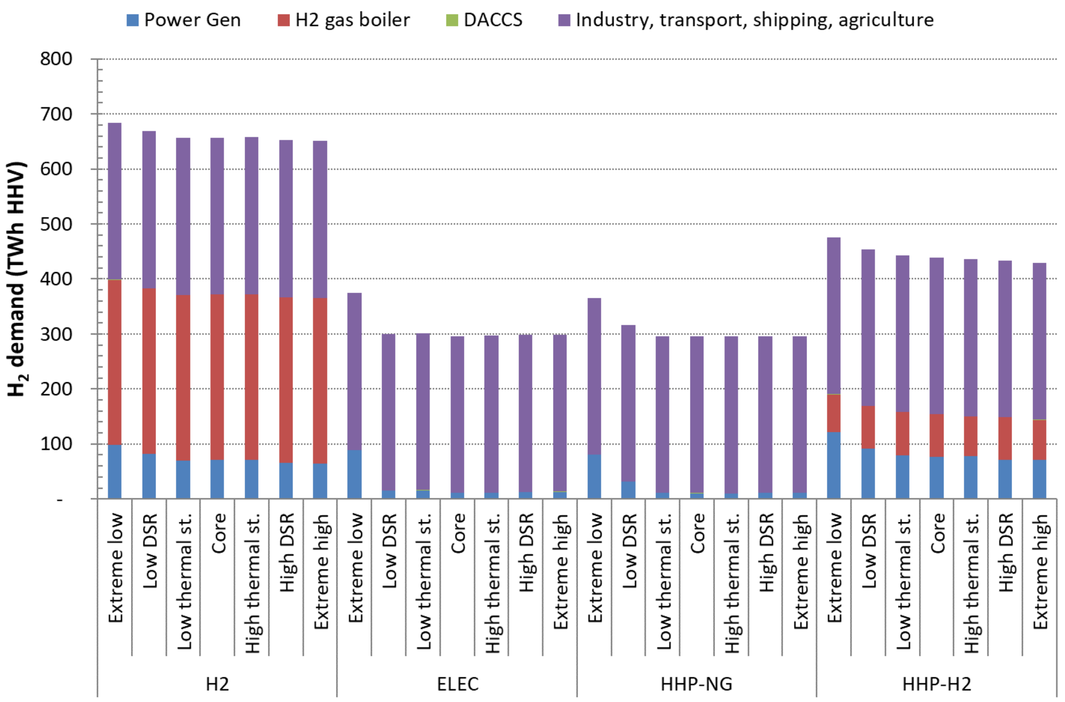


Figure 3-5 Impact of flexibility on the hydrogen demand

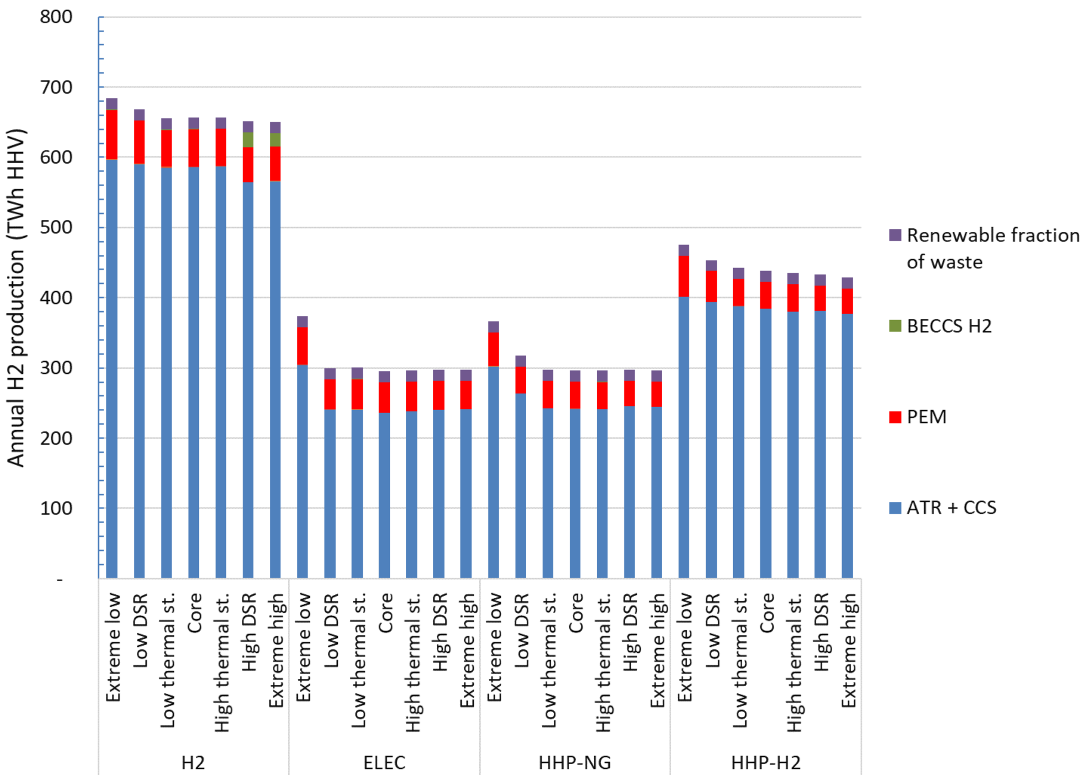


Figure 3-6 Impact of flexibility on the hydrogen production mix

In the H2 scenario with high DSR and extreme high cases, the model allocates circa 20 TWh hydrogen produced by BECCS. Increased renewable energy output due to improved flexibility may shift some bioenergy from power to hydrogen production.

Improving flexibility means more renewable sources can be integrated into the energy system, reducing carbon sequestration volume. In ELEC, the volume of carbon captured drops from 133 $MtCO_2$/year to 122 $MtCO_2$/year. The reduction in H2 and HHP-H2 is slightly lower, i.e. around 9 $MtCO_2$/year. The incremental reduction of the carbon captured also decreases with increased flexibility. For example, the volume of carbon captured in the "High" and "Extreme high" case is very similar. The results are shown in Figure 3-7.

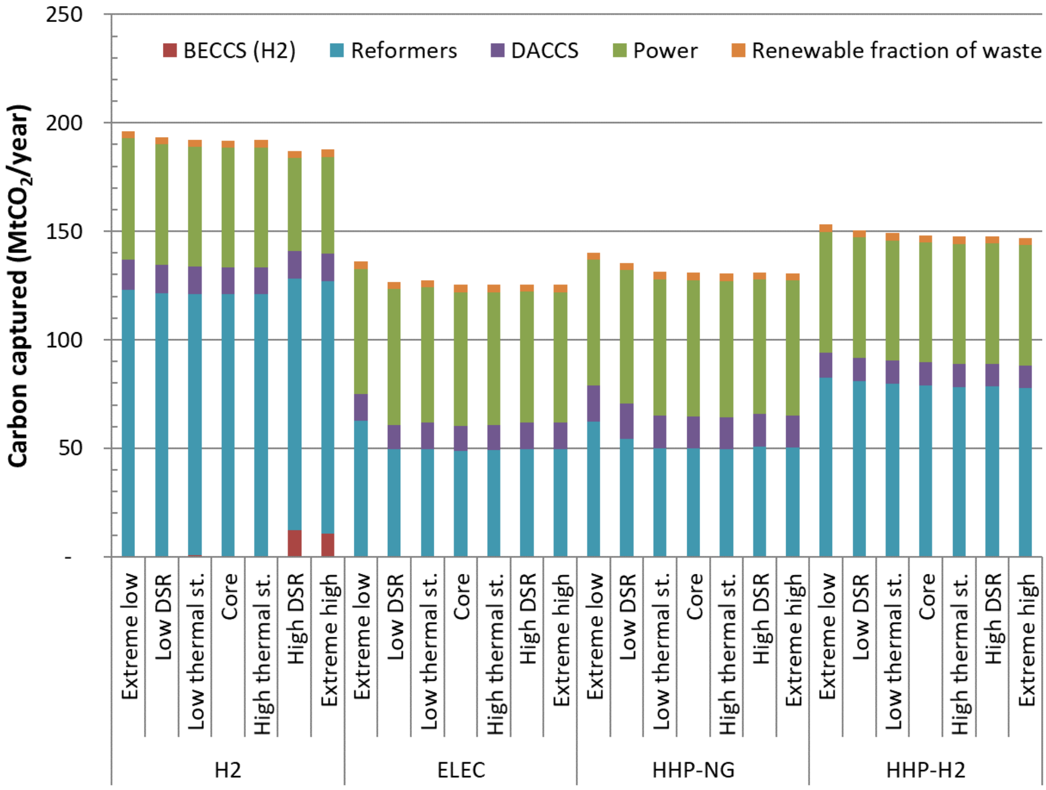


Figure 3-7 Impact of flexibility on the volume of carbon captured and stored

Figure 3-8 shows hydrogen storage capacity for different scenarios on systems with different flexibility. In H2 and HHP-H2, hydrogen storage capacity is much smaller in the low flexible case than the capacity needed in the very high case. This is because in the less flexible system: (i) the system uses less renewable energy, but more hydrogen for power, (ii) the production capacity of ATR with CCUS is higher in "extreme low" flex. The use of hydrogen for power reduces the long-term balancing requirements. Besides that, a higher ATR capacity also leads to less hydrogen storage.

In contrast, the hydrogen storage requirement in ELEC and HHP-NG is higher in the "very low" due to the increased imbalance between supply and demand of hydrogen as the electricity demand becomes less flexible. The lack of demand flexibility is offset by hydrogen power generation that can provide system balancing services. The use of hydrogen for power affects temporal demand for hydrogen that triggers more requirements for hydrogen storage. The results demonstrate that hydrogen storage has two prominent roles: (i) to provide short to long-term balancing and (ii) to provide capacity to meet hydrogen peak demand. Both capacity and short-term balancing are affected by flexibility in the electricity sector.

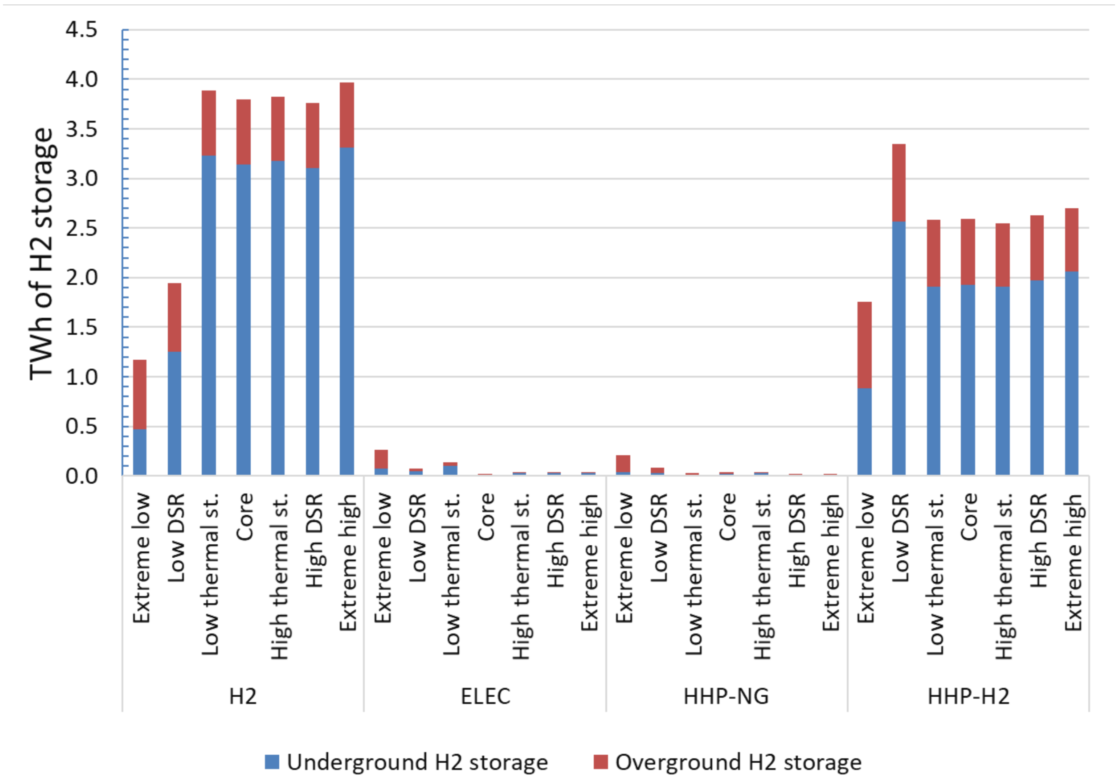


Figure 3-8 Impact of flexibility on the volume of hydrogen storage needed

The overground storage share also increases in the "Extreme low" case driven by the need for short-term flexibility in balancing the hydrogen supply and demand. More low-cost underground storage is deployed in the "Extreme high" case as the short-term flexibility from demand response reduces the role of hydrogen storage for short-term balancing.

3.1.2 Role and value of improving flexibility in H2

The value of having system flexibility in the H2 scenario is 4.5 – 6.4 £bn/year. Increasing flexibility from the core scenario to higher levels of DSR or thermal storage has a smaller system cost reduction, totalling under £1bn. The annual system costs of the H2 scenario under different scenarios are shown in Figure 3-9.

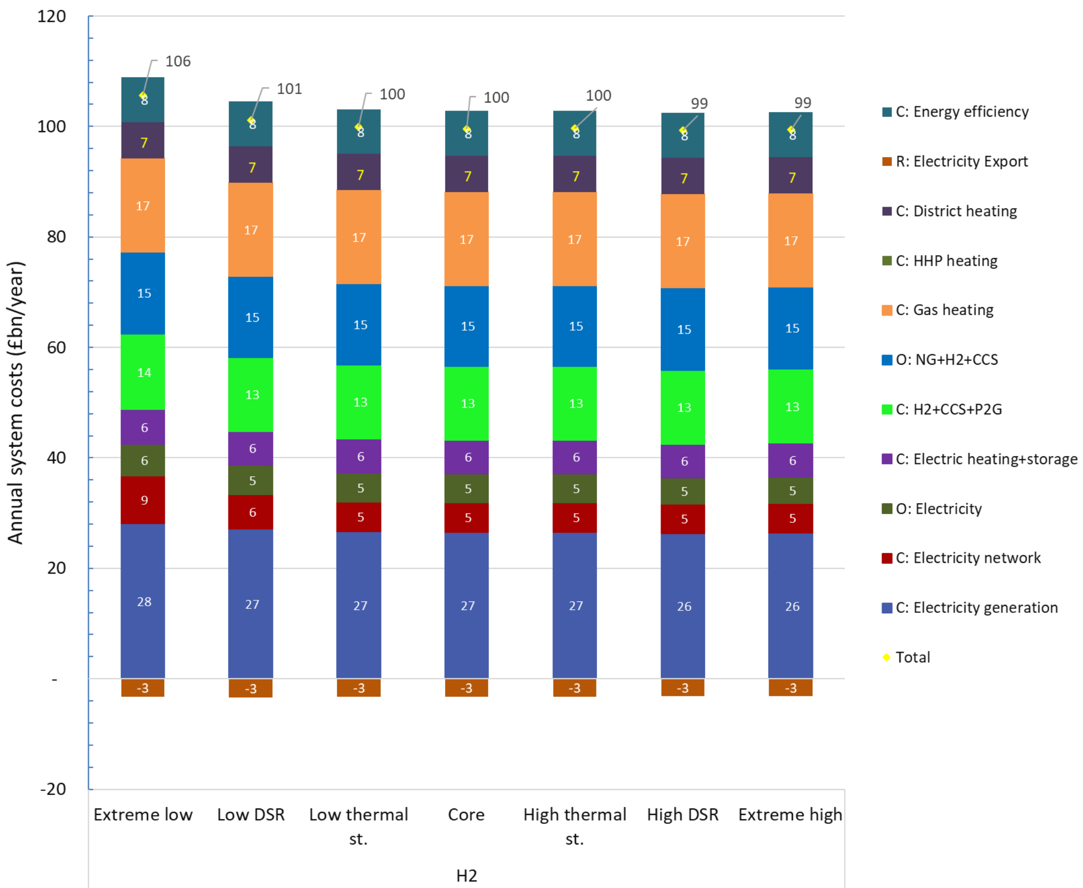


Figure 3-9 Impact of the flexibility on the annual system costs [H2 scenario]

Improving flexibility reduces the peak electricity demand as the load can be shifted away from the peak. Therefore, less electricity system capacity is required, and the electricity system's cost is lower. The changes in the various elements of annual system costs due to flexibility are shown in Figure 3-10.

In moving from no flexibility to the Core or higher flexibility assumptions, the electricity generation costs, both traditional and low-carbon generation and distribution network cost, are reduced by 3.5 – 5 £bn/year. The largest benefit comes from the reduction of distribution network reinforcement Capex. Improving flexibility also allows the system to accommodate more renewables; this reduces the need for higher-cost low-carbon technologies such as gas CCUS or nuclear, and therefore, it reduces the low-carbon generation cost. The remaining 1 – 2 £bn/year savings come from the reduction of:

- Electricity Opex as the system can use lower marginal cost generators to supply electricity demand;

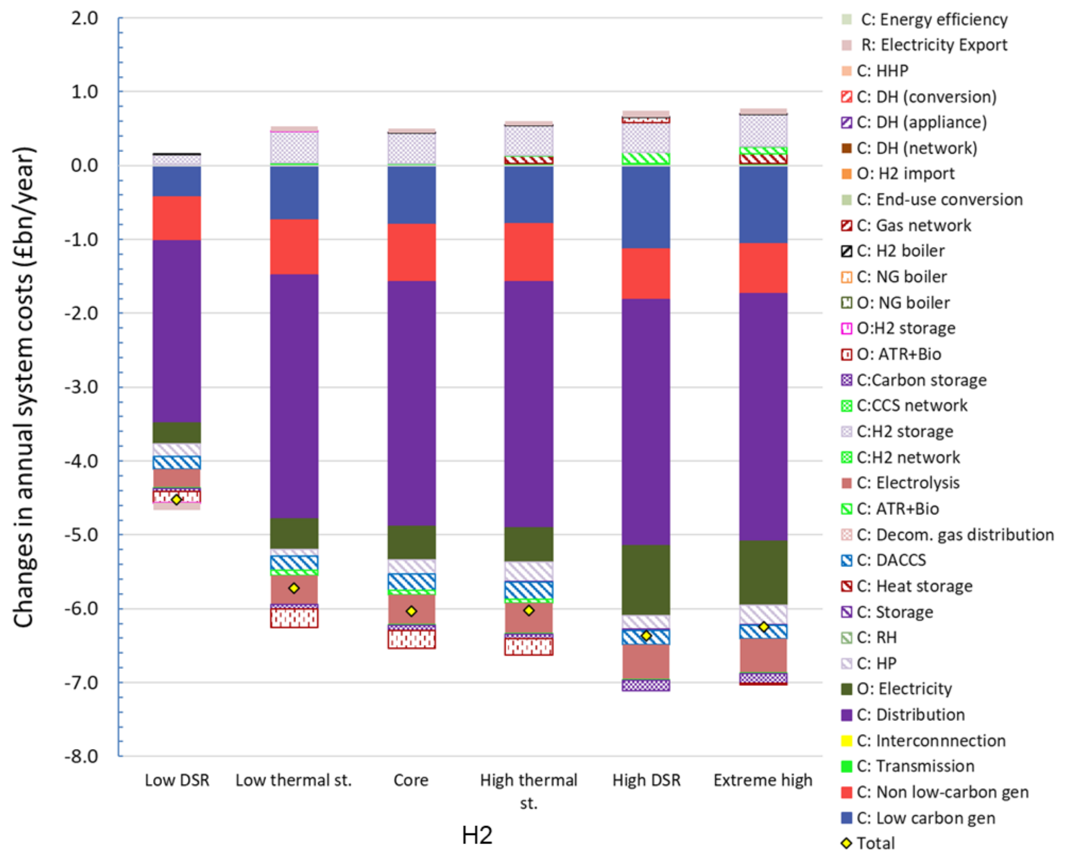


Figure 3-10 Changes in the annual system costs due to system flexibility improvement [H2 scenario]

- Electric heating Capex cost as the peak of heat demand can also be reduced using thermal storage, and therefore, the system requires smaller electric heating capacity;
- Capex of DACCS capacity required to meet the carbon target – flexibility improves the use of low-carbon generators and, therefore, reducing the emissions that need to be offset by DACCS;
- Capex of electrolysers, as flexibility from the demand-side response and energy storage reduces the need for electrolysers. Electrolysers convert electricity to hydrogen because there is a temporal excess of electricity sources that can be used for hydrogen production. Hydrogen can then be stored efficiently and used later when the system needs it. Improving flexibility reduces the temporal excess by shifting the load and storage cycles to enable a more cost-efficient supply-demand balance. Improving flexibility also reduces the use of hydrogen in the power sector, resulting in lower hydrogen demand and reducing hydrogen production from ATR+CCUS from 596 TWh to 565 TWh and electrolysers from 70 TWh to 49 TWh, as shown in Figure 3-11.

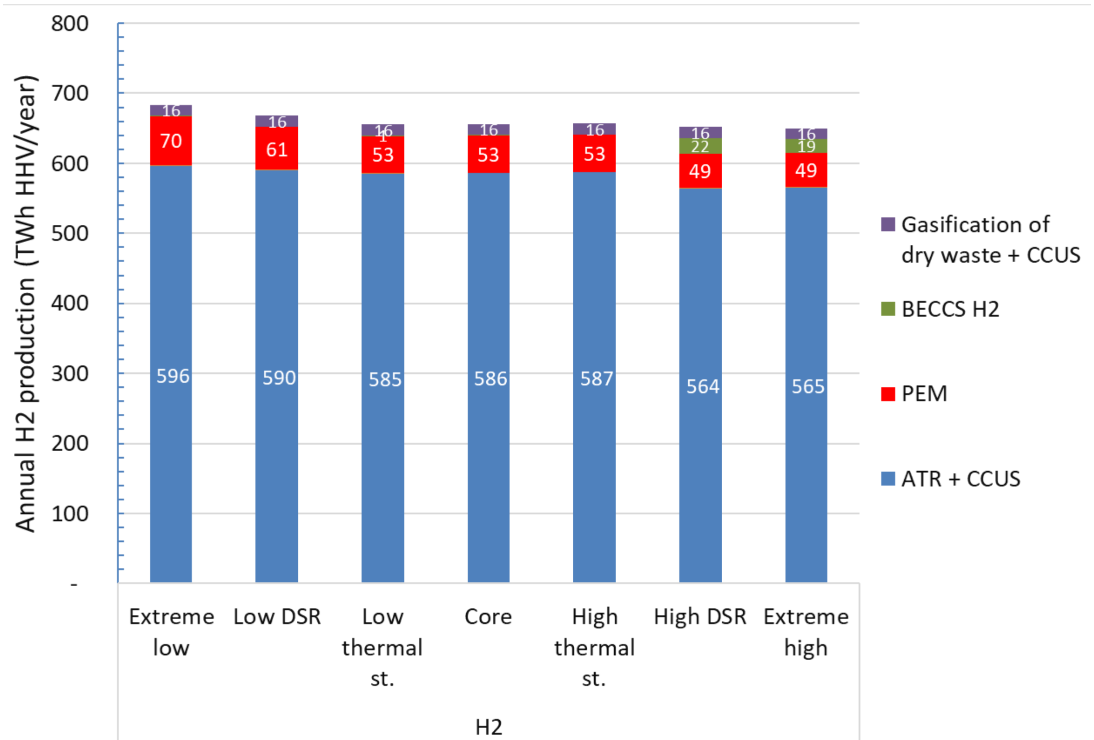


Figure 3-11 Annual hydrogen production in systems with different flexibility levels [H2 scenario]

However, some additional system costs (i.e. positive changes in Figure 3-10) are also triggered by the system's changes due to improved flexibility; these include the cost of hydrogen and thermal storage. Hydrogen storage is needed to support more renewables and provide additional hydrogen capacity to meet the peak demand, as discussed previously (Figure 3-8). It is worth noting that improving power system flexibility reduces the demand for hydrogen production capacity due to less hydrogen for power. The results also indicate that one form of flexibility does not always compete with other forms of flexibility. For example, hydrogen storage can supplement heat and electricity's flexibility (as specified in Table 3-1)[60] . Therefore, it maximises the synergy across various flexibility technologies across multi-energy vectors is essential.

The results also demonstrate that flexibility benefits are not linear and diminish with an increased flexibility level. For example, the benefits of having “low DSR” are £4.5 bn/year, but the benefits increase only by £1.5 bn/year when the flexibility is improved to the level set by the core scenario. The benefits are only £0.4bn/year more when the flexibility is increased to the “Extreme high” case.

In these studies, the benefits of higher thermal storage levels are also analysed. Similarly to the other flexibility technologies, the benefits of marginal increases in thermal storage levels diminish. By having 2kWh more flexible thermal storage, e.g. from the “Low thermal storage” to “Core” scenario, the benefits are about £300m/year. Increasing it further to “High thermal storage” does not bring a visible benefit. This suggests that, at some levels, the system benefits

[60] Ability to exchange and store energy from hydrogen to electricity and vice versa

of thermal storage can also be provided by other flexibility technologies such as DSR and electricity storage. This indicates both competition and synergy between thermal storage and other flexibility technologies, and therefore, optimising the flexibility technologies across multi-energy vectors is crucial. For example, thermal storage can be used to modify the electricity load from electric heating appliances, and it needs to be operated in synergy with the demand response to optimise its impact.

3.1.3 Role and value of improving flexibility in ELEC

The benefits of having extremely high levels of flexibility in ELEC are roughly double compared to the benefits in H2; the total system savings are up to £11 bn/year. The value of having the levels of flexibility set in the Core scenarios is about £9bn. The annual system costs in ELEC with different flexibility levels are presented in Figure 3-12.

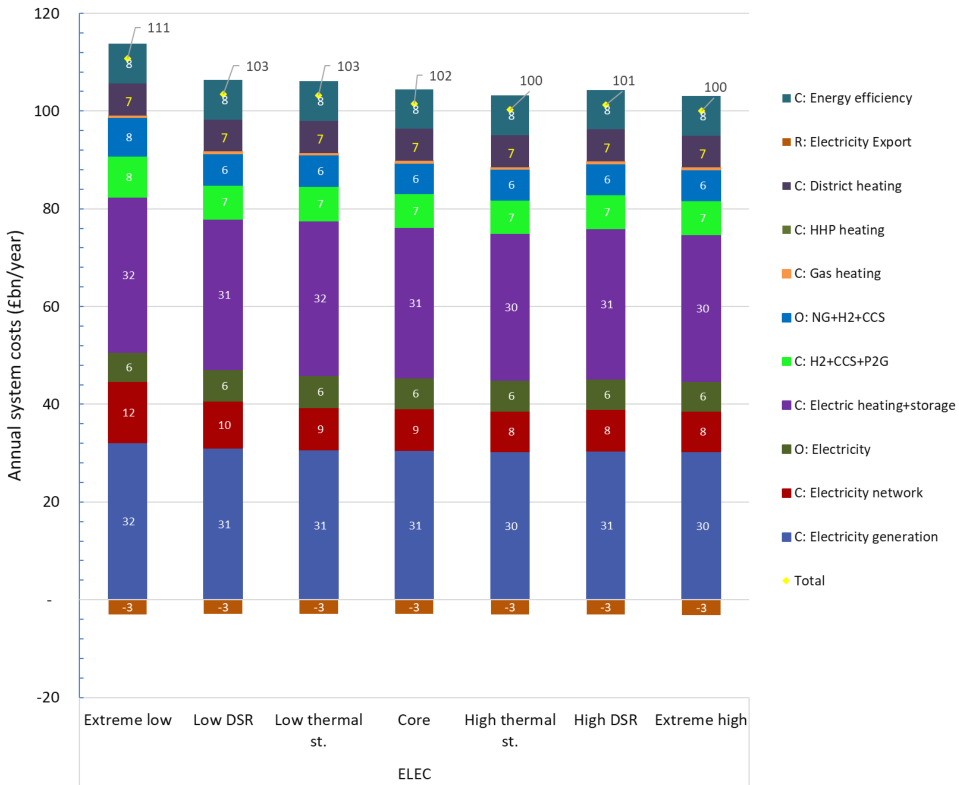


Figure 3-12 Impact of the flexibility on the annual system costs [ELEC scenario]

Similarly to what has been observed in the result in the H2 scenario, the benefits of flexibility also diminish when flexibility increases. Substantial benefits (more than £8bn/year) are obtained by deploying a low level of DSR (Low DSR) or low thermal storage (low thermal storage) [61]. Increasing flexibility further to extremely high (in DSR and thermal storage) reduces the system costs by a further £3bn/year.

The changes in the various elements of the annual system costs attributed to the increased flexibility are shown in Figure 3-13. The savings are primarily related to a cost reduction in

[61] The counterfactual scenario is the Extreme Low.

electricity generation Capex, electricity network Capex, and electric heating costs. The hydrogen system's total Capex and Opex also decrease from 16 to 13 £bn/year due to less demand for hydrogen-fuelled power generation driven by improved system flexibility. For example, the electricity output from hydrogen CCGT decreases from 49 TWh (“Extreme low”) to 8 TWh (“Extreme high”). The savings in power system infrastructure contribute to around 50% of the total cost reduction, highlighting flexibility’s role in reducing power infrastructure costs. Increased flexibility allows some load to be shifted away from the peak and reduces the capacity of electricity infrastructure needed and its associated costs.

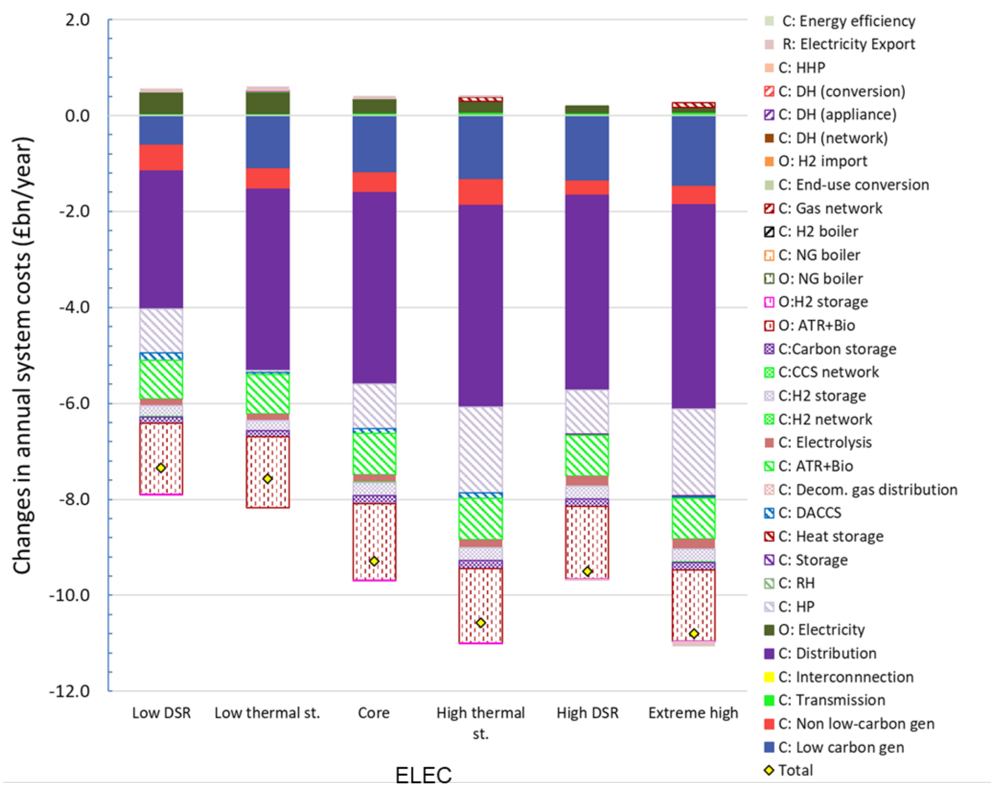


Figure 3-13 Changes in the annual system costs due to system flexibility improvement [ELEC scenario]

There is a slight increase in the electricity Opex as thermal storage increases; this can be seen in the “High thermal storage” results below. This is caused by the shift from using hydrogen CCGT[62] to RES and gas CCUS (discussed further in section 3.1.5). Increased flexibility from demand-side response allows demand to follow variable renewables output and reduces the need for balancing from dispatchable low-carbon generation such as hydrogen CCGT, which can subsequently reduce the hydrogen infrastructure needed. However, some of the balancing capability will need to be retained by increasing gas CCUS. It indicates the trade-off between gas CCUS and hydrogen CCGT, considering its impact on hydrogen infrastructure.

The impact of improved flexibility on annual electricity production is shown in Figure 3-14.

[62] It is worth noting that the fuel cost of hydrogen CCGT is included in the cost of hydrogen production.

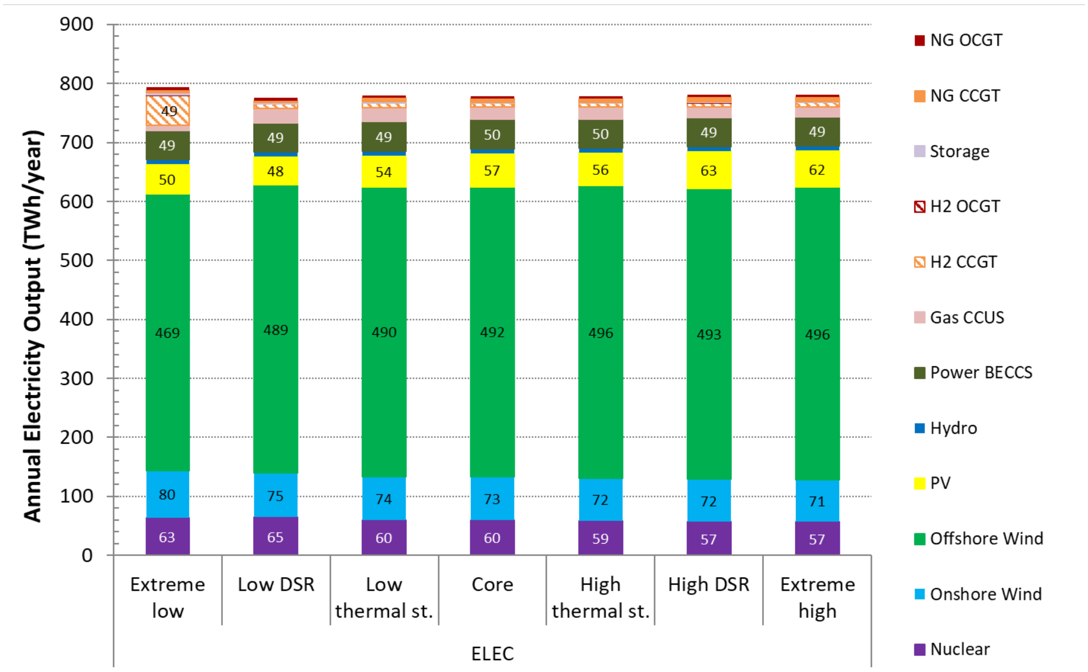


Figure 3-14 The impact of improving system flexibility on the annual electricity output [ELEC scenario]

In this study, thermal storage benefits are higher (i.e. £0.7bn/year) compared to the previous study within H2. This is because thermal storage reduces the Capex of HPs (as the storage can supply heat during peak demand), which reduces the HP capacity needed[63]. Thus, thermal storage is particularly beneficial for systems that rely on electric heating to meet the heat demand.

3.1.4 Role and value of improving flexibility in HHP-NG

Flexibility also benefits heat decarbonisation in HHP-NG by reducing the annual system costs by £6.1 bn/year in the Core results compared to a counterfactual with no flexibility. Additional £0.4bn cost savings can be achieved if the flexibility increases as in the Extreme high scenario. The annual system costs of HHP-NG for different scenarios listed in Table 3-1 are shown in Figure 3-15. Significant cost reduction (around £5bn/year) is observed after deploying flexibility, even at the low level of DSR. Increasing further flexibility will reduce the cost by up to £1.5 bn/year.

[63] Heat pumps are sized differently depending on the peak heat demand.

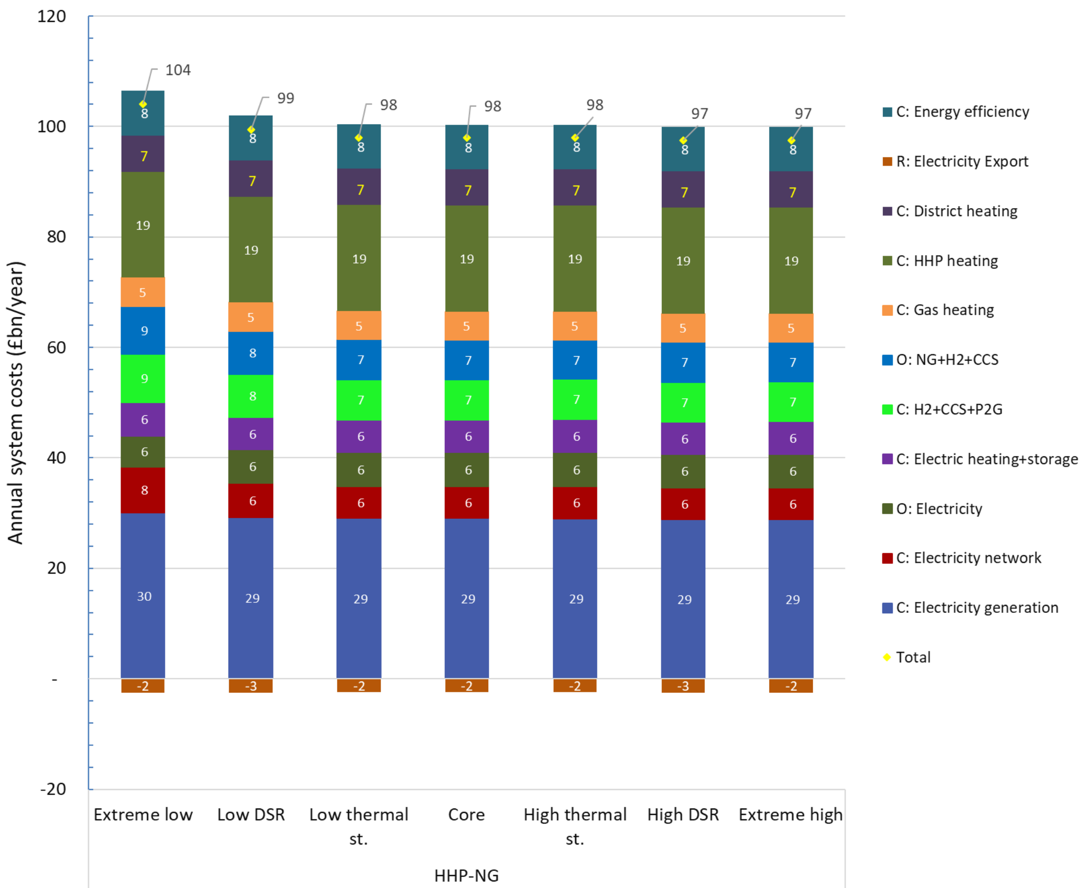


Figure 3-15 Impact of the flexibility on the annual system costs [HHP-NG scenario]

Similarly to the studies on the H2 and ELEC scenarios, improving flexibility in HHP-NG reduces the cost of the energy system primarily through the cost of electricity generation and distribution network reinforcement, cost of DACCS and cost of hydrogen production capacity, storage, and Opex. In contrast to the H2 scenario, the required hydrogen storage in ELEC and HHP-NG scenario decreases when the flexibility increases. The improved flexibility reduces hydrogen demand for power generation in the ELEC and HHP-NG scenario more substantially than in the H2 scenario.

The result is expected as the hybrid system uses electric heating as the primary heat source; in this context, it is similar to ELEC. However, the impact of thermal storage is minimal since the use of gas heating already relieves the capacity pressure during peak demand conditions. The changes in annual system costs due to flexibility are shown in Figure 3-16.

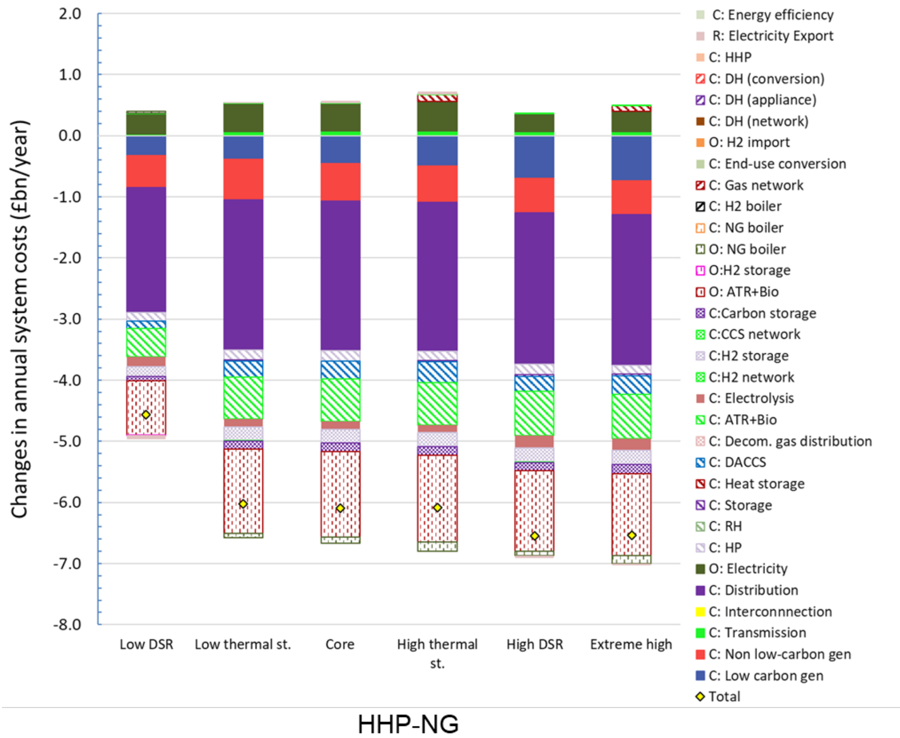


Figure 3-16 Changes in the annual system costs due to system flexibility improvement [HHP-NG scenario]

Although HHP-NG can use gas heating to reduce the need for power system capacity to meet the electricity peak demand, the use of natural gas boiler increases emissions (and so carries costs of associated DACCS) and therefore, it is limited. The impact of flexibility on NG boilers' usage is shown in Figure 3-17.

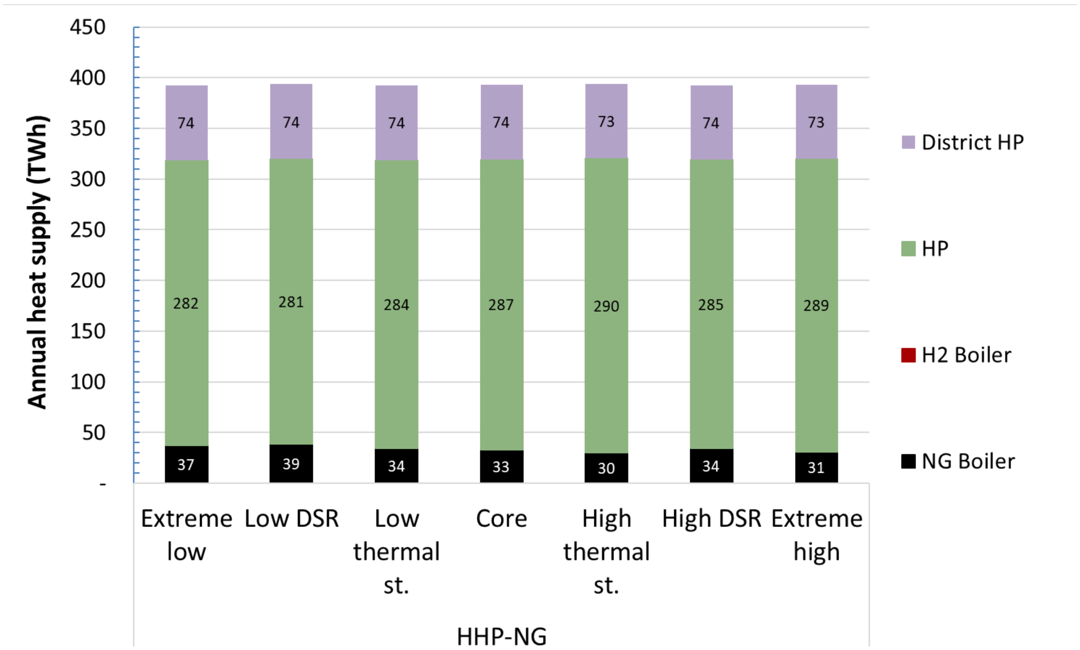


Figure 3-17 Impact of system flexibility on the annual heat supply [HHP-NG scenario]

Improving flexibility also reduces the use of gas heating from 37 TWh/year in the Extreme Low case to 31 TWh/year in the "Extreme High" case, and therefore, it reduces the need for DACCS.

The reduction in gas heating is compensated by increased heat pumps usage, allowing low-carbon electricity generation to decarbonise heating.

3.1.5 Role and value of improving flexibility on HHP-H2

Improving system flexibility also brings savings up to £6 bn/year in HHP-H2 (between the no-flexibility and extremely high flexibility cases). The annual system costs of HHP-H2 with different flexibility levels are shown in Figure 3-18. The majority of the savings come from reducing electricity generation and network costs, particularly distribution. However, the electricity distribution network savings are based on a pessimistic 'no thermal headroom' scenario. These savings could be lower if there are high levels of spare capacity in the distribution network.

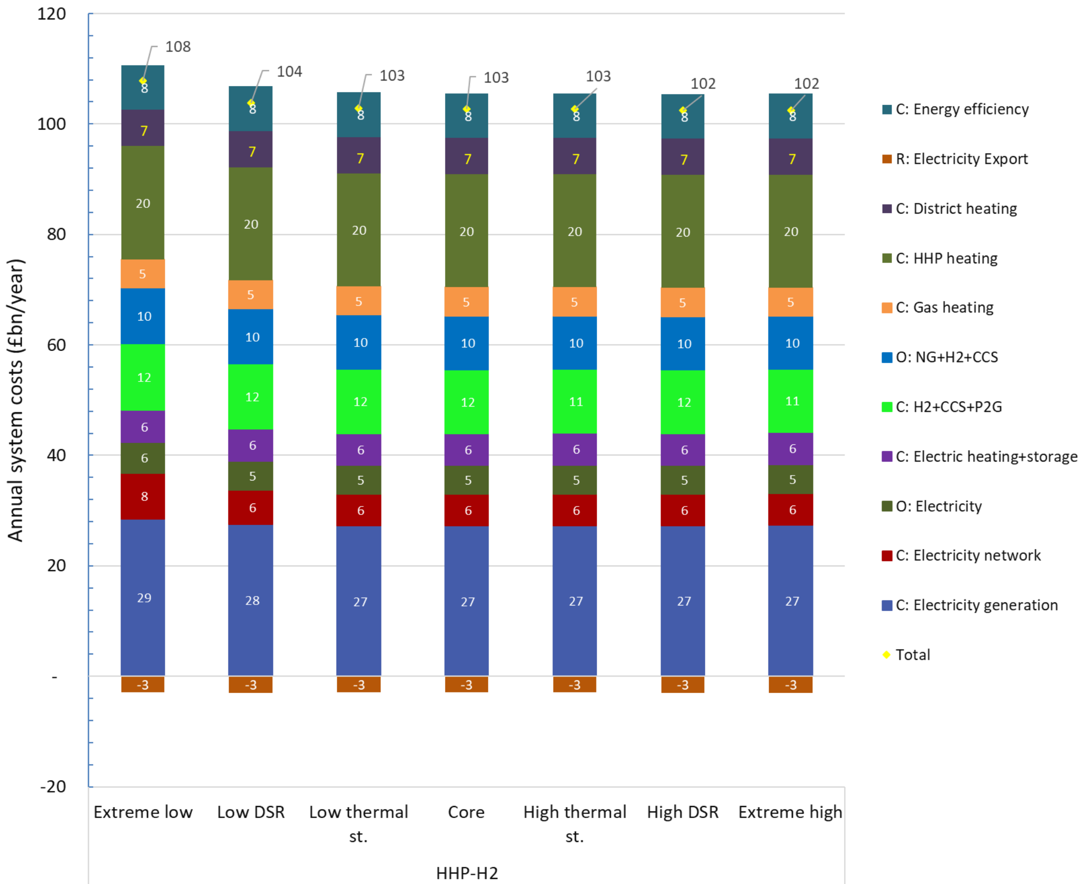


Figure 3-18 Impact of the flexibility on the annual system costs [HHP-H2 scenario]

Detailed cost changes attributed to increased flexibility are shown in Figure 3-19. Flexibility reduces the cost of low-carbon generation as more RES can be integrated. Lower peak demand also leads to a lower capacity of peaking generation and distribution network capacity. Flexibility also reduces the operating cost of electricity, the cost of heat pumps, DACCS, electrolysers, and Opex of hydrogen production.

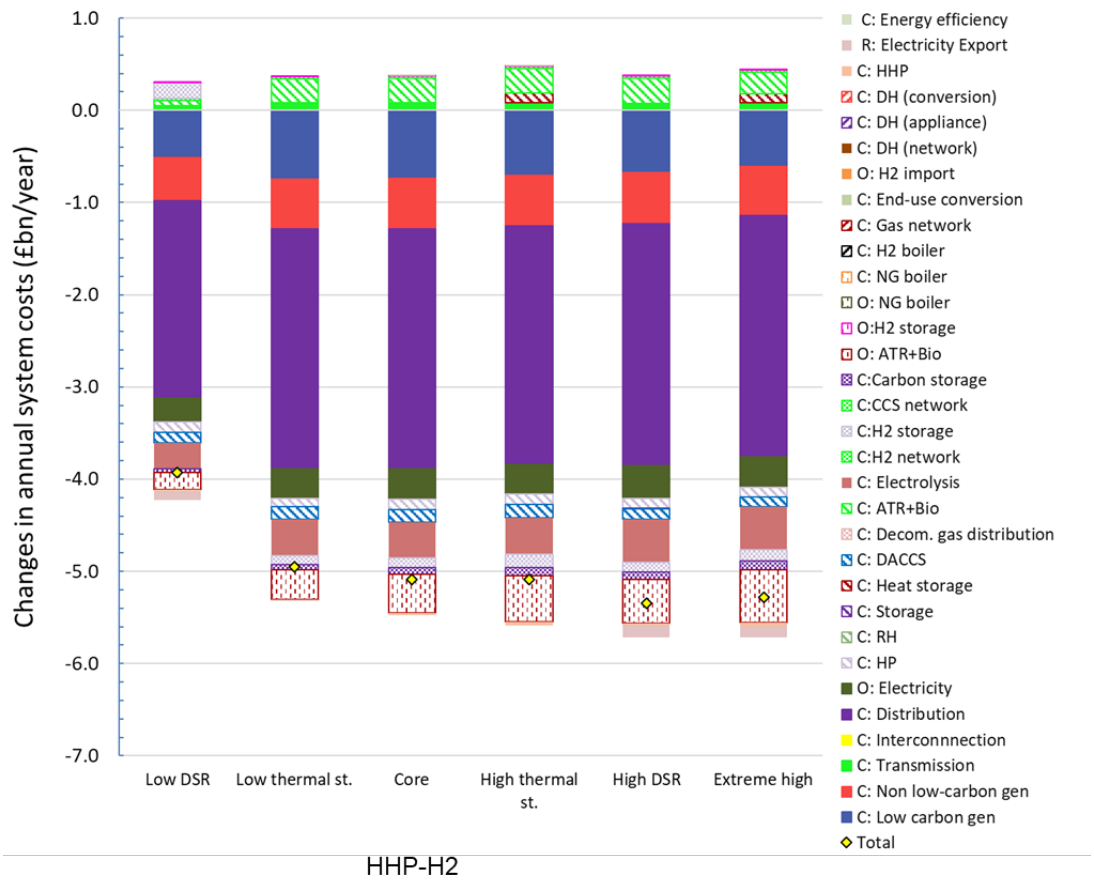


Figure 3-19 Changes in the annual system costs due to system flexibility improvement [HHP-H2 scenario]

In this case, improving flexibility reduces the hydrogen demand from the power sector and electrolysers; there is also a shift from electrolysers to gas-based hydrogen (ATR+CCUS) production capacity. Given the study's assumptions, most hydrogen production comes from gas reforming processes instead of electrolysis, as the cost of producing hydrogen from gas is lower than the cost of green hydrogen production. Therefore, the shift from electrolysers to reforming processes increases the Capex of ATR. In this case, the increased ATR+CCS capacity displaces the electrolyser capacity (which has a higher cost) and is not followed by the increased hydrogen production. Instead, the hydrogen production from ATR+CCUS also decreases. Therefore, the residual emissions from ATR+CCUS also decrease.

3.2 Impact of less-cost effective ATR

Given the cost and technical assumptions in this study, most hydrogen is produced from methane through ATR with CCUS (see section 2.12). Hence, the results are sensitive to the assumed gas price (as discussed later in section 3.3) and the efficiency and cost of hydrogen production from ATR with CCUS. It is worth noting that the model optimises hydrogen demand only for the power sector and heat; therefore, hydrogen demand from other sectors is not affected by the less-cost effective ATR.

The study uses a scenario where the cost of hydrogen production from ATR+CCS is higher, driven by a higher Capex of ATR and lower energy conversion efficiency and carbon capture rate. Table 3-2 compares the parameters for ATR+CCS used in the core and this sensitivity study.

Table 3-2 Parameters of ATR+CCS in the core and higher ATR cost scenario[64]

ATR+CCS	Core	Less cost-effective ATR
Efficiency (HHV)	89.6%	80%
Capex units (£/kW)	364.0	630
Carbon capture rate, %	96%	95%

Higher hydrogen production cost from ATR+CCS increases the cost of all scenarios by 1.5 – 3.8 £bn/year, as shown in Figure 3-20. It increases the cost of H2 from 100 to 103 £bn/year and the cost of ELEC from 102 to 103 £bn/year. The cost of H2 is now on par with the cost of ELEC. The hybrid systems' total costs also increase by around 1-2 £bn/year. HHP-NG is still the least-cost scenario to decarbonising heat.

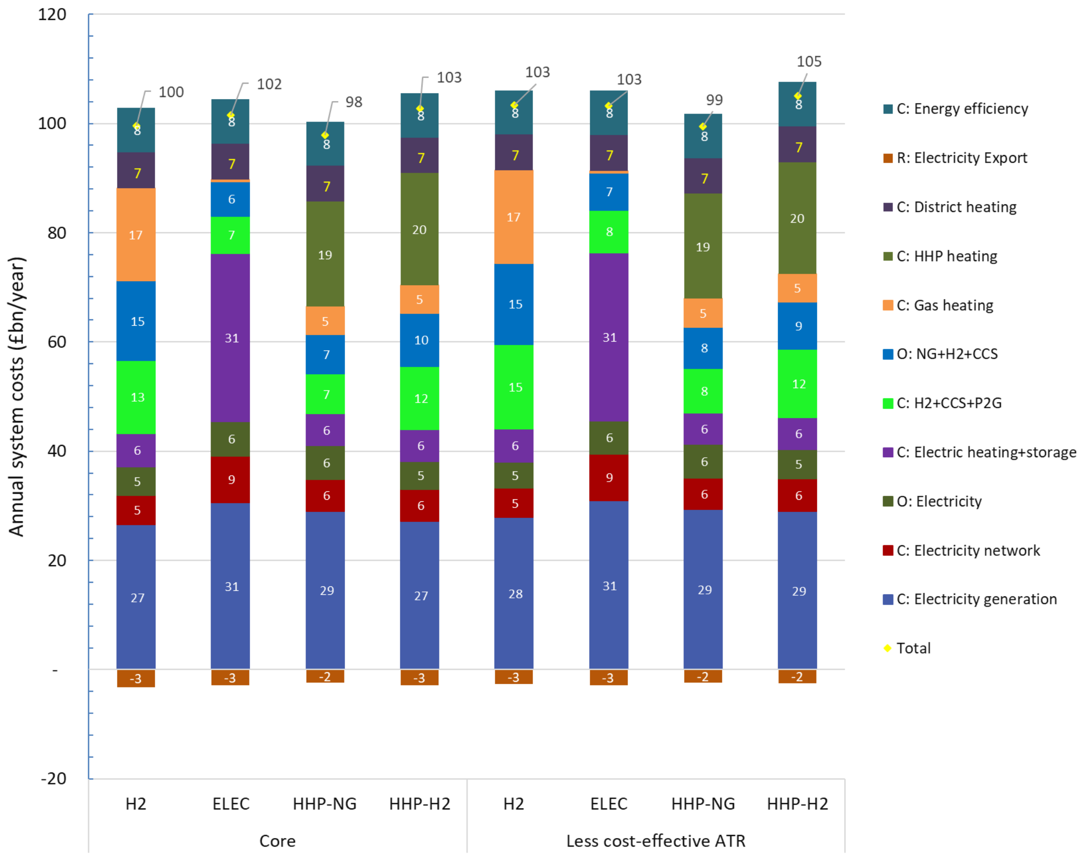


Figure 3-20 Impact of higher ATR cost on the annual system costs

As expected, less cost-effective ATR increased the cost of producing hydrogen and therefore, it reduces hydrogen demand from the power sector and heat. It may also affect other hydrogen demand, e.g. for industry and transport, but this was not optimised in the model. In contrast, it incentivises increased usage of HP and reduces NG/H2 usage in HHP systems.

[64] Source: BEIS

Consequently, the heat-led electricity load increases. Moreover, there is also an increase in electrolyser load and DACCS. Increased electricity load drives higher electricity generation investment and Opex, as shown in Figure 3-21.

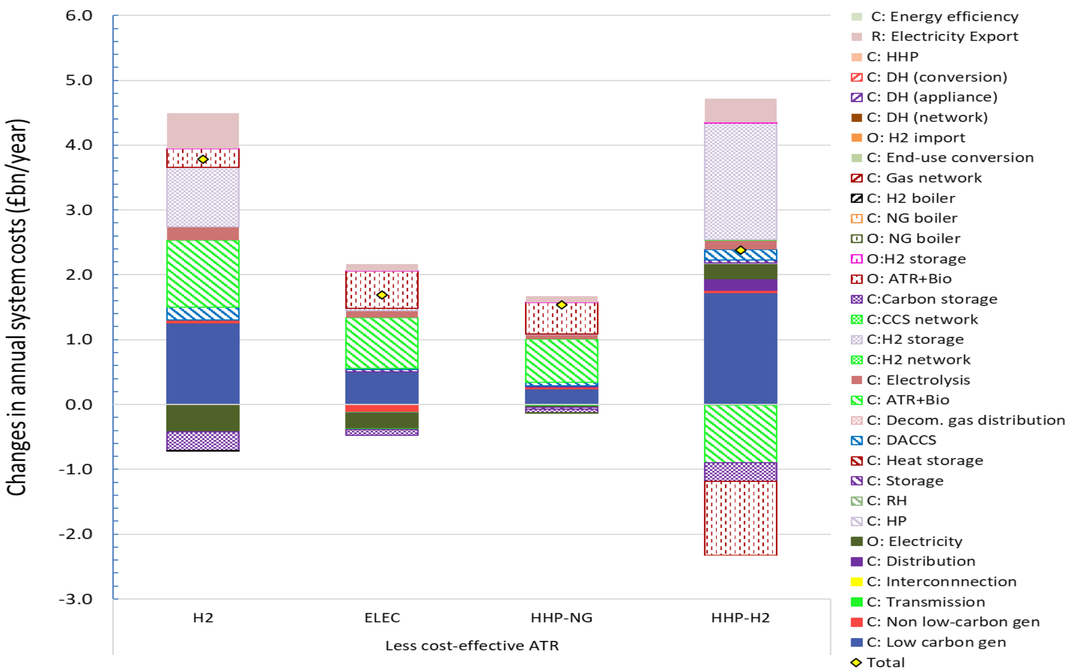
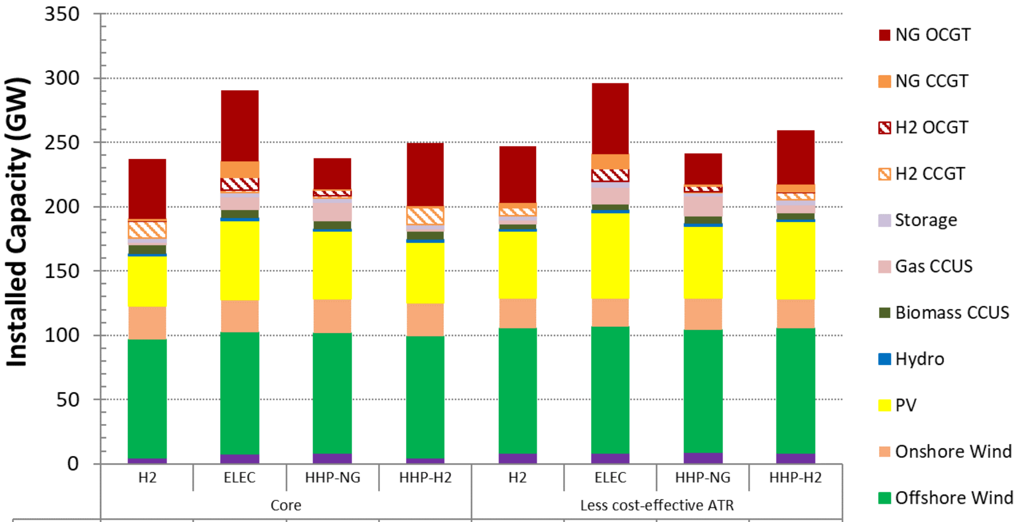


Figure 3-21 Changes in annual system cost due to less cost-effective ATR

The impact of less cost-effective ATR on the electricity generation portfolio is shown in Figure 3-22.

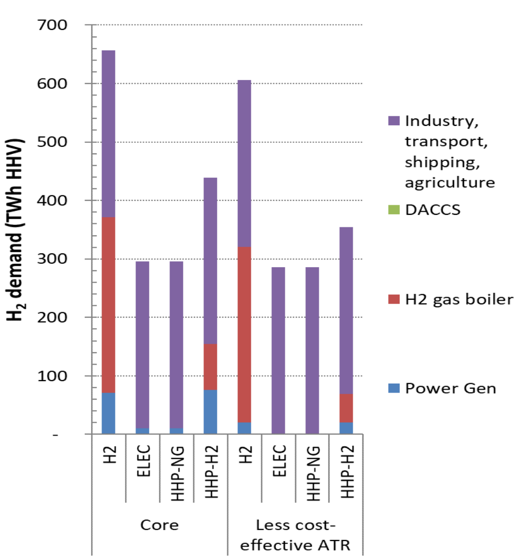


	Core H2	Core ELEC	Core HHP-NG	Core HHP-H2	Less cost-effective ATR H2	Less cost-effective ATR ELEC	Less cost-effective ATR HHP-NG	Less cost-effective ATR HHP-H2
NG OCGT	47	55	24	49	44	55	24	42
NG CCGT	2	13	1	1	4	11	1	5
H2 OCGT	0	10	4	0	0	10	4	0
H2 CCGT	13	2	2	13	6	0	0	6
Storage	3	3	3	3	3	4	3	3
Gas CCUS	2	10	14	2	3	13	16	6
Biomass CCUS	7	7	7	7	4	5	6	6
Hydro	1	1	1	1	1	1	1	1
PV	39	62	53	48	52	67	56	60
Onshore Wind	26	25	26	26	23	22	25	23
Offshore Wind	92	95	94	94	97	98	95	97
Nuclear	5	8	8	5	9	9	9	8

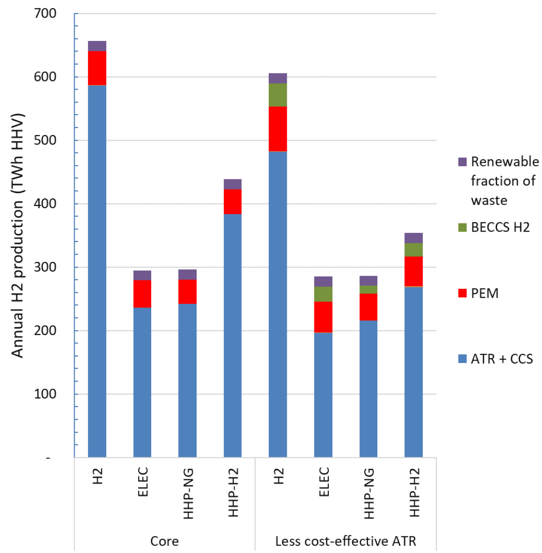
Figure 3-22 Impact of less cost-effective ATR on the optimal portfolio of electricity generation capacity

The shift from hydrogen to low-carbon electricity resources drives 3 to 4 GW of higher nuclear capacity and around 1 and 3 GW more CCUS, but a lower capacity for hydrogen CCGT. It does not affect hydrogen OCGT as its capacity factor is relatively low, i.e. it does not use much hydrogen.

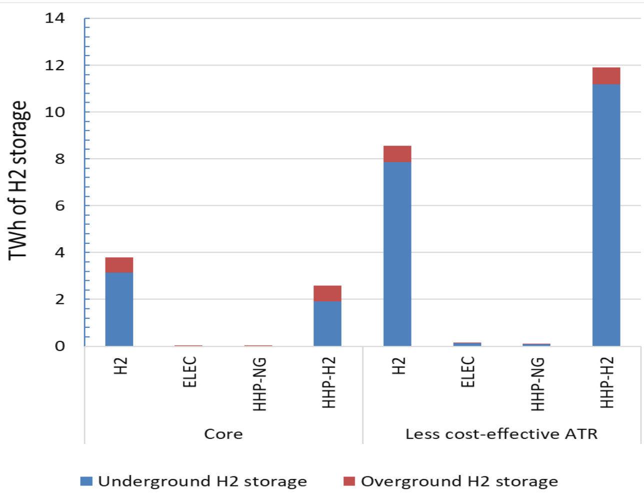
A substantial reduction in hydrogen production from ATR+CCS is compensated partly by increased production from electrolysers, but ATR remains the primary source of hydrogen production. Less cost-effective ATR also incentivises more allocation of bioenergy from power BECCS to hydrogen BECCS. The reduction of hydrogen production capacity and a fall in the amount of hydrogen used to produce electricity drive an increase in hydrogen storage requirement, especially in H2 and HHP-H2. The reduction in hydrogen production capacity means that more hydrogen storage is needed to meet the hydrogen peak demand. The reduction of hydrogen used for power generation also increases storage requirements as more hydrogen needs to be stored for a more extended period. The results are presented in Figure 3-23.



(a) Hydrogen demand



(b) Hydrogen supply



(c) Hydrogen supply

Figure 3-23 The impact of less cost-effective ATR on the annual hydrogen demand (a) and supply (b) from various technologies and (c) hydrogen storage

3.3 Impact of lower or higher gas prices

In this study, natural gas remains the principal energy source for hydrogen production. Natural gas is also used for traditional gas-fired power generation or gas boilers, although intermittently and limited. Consequently, the system cost performance will be sensitive to the gas price assumption. Based on BEIS 2019 Fossil Fuel Price Assumptions, this study estimates the effect of a lower gas price (33% lower than the 2.1p/kWh gas price in the core scenario) and a higher gas price (43% higher than in core results)[65]. The results are presented in Figure 3-24.

[65] The lower gas price used is 1.4p/kWh and the higher gas price is 3.0p/kWh.

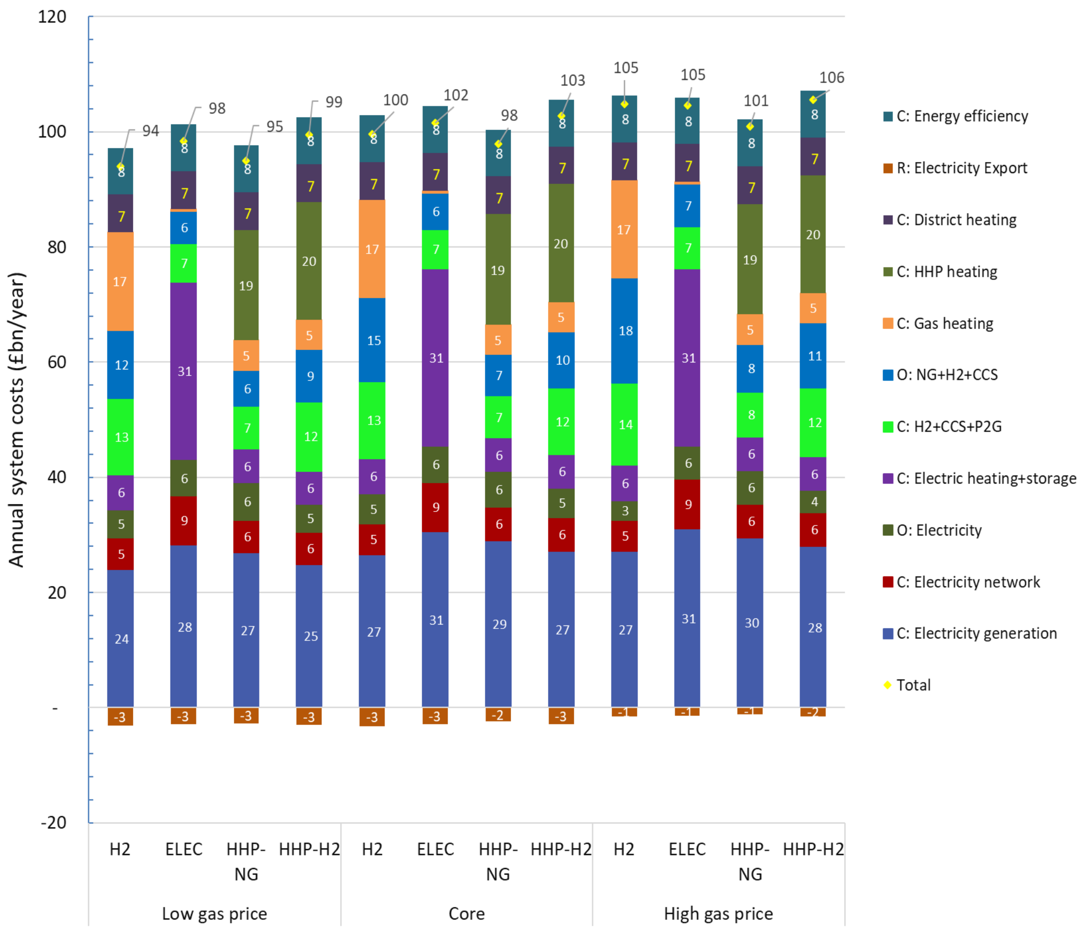


Figure 3-24 Impact of low gas price on the annual system costs

Having a lower gas price reduces the cost of all scenarios between 3 – 6 £bn/year, with the highest cost reduction on the H2 scenario making it most cost-effective; the cost of the H2 scenario becomes slightly lower than the cost of HHP-NG. A lower gas price leads to a lower hydrogen system Opex and reduces the cost of low-carbon electricity generation. A low gas price shifts demand from electricity to hydrogen. Therefore, it triggers a modest increase in the Capex of gas-based hydrogen production capacity. It also increases natural gas usage for producing hydrogen and gas heating while reducing hydrogen production electrolysers. Higher gas usage due to the lower gas price leads to more carbon capture from BECCS to power and methane reformers, driving a higher requirement for DACCS because of increased residual emissions and, consequently, increases carbon storage costs.

The opposite applies when the higher gas price is considered. In addition to increased hydrogen Opex and higher use (and cost) of electrolysers, the Capex of hydrogen production capacity also increases due to a rise in BECCS for hydrogen. With a higher gas price, more bioenergy is used to produce hydrogen using gasification with CCUS. The changes in the various components of annual system costs due to a lower and higher gas price are shown in Figure 3-25.

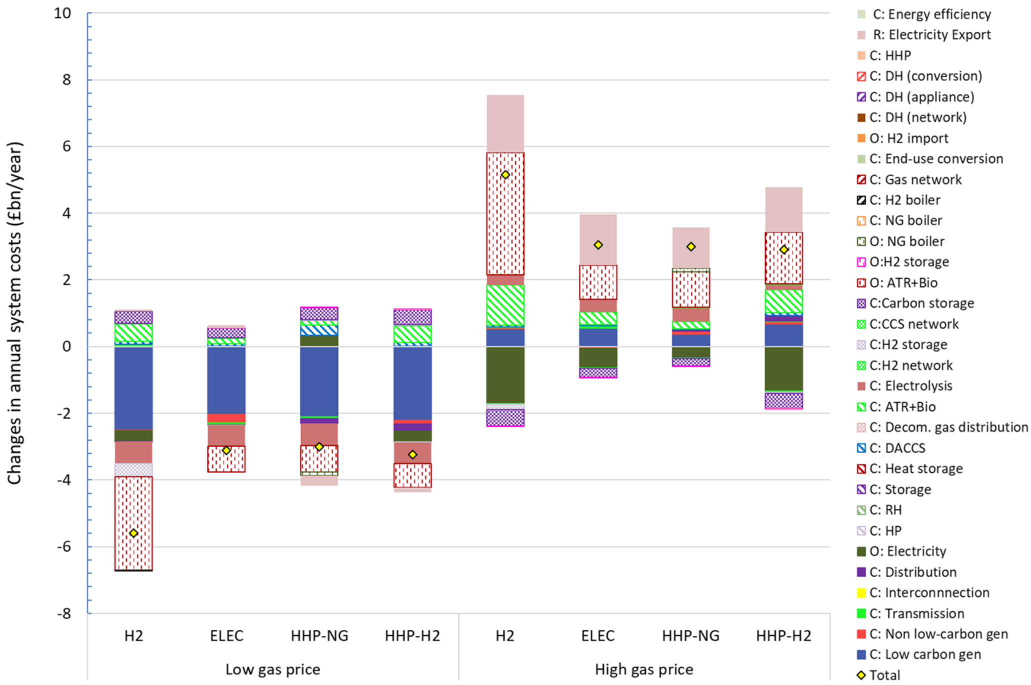
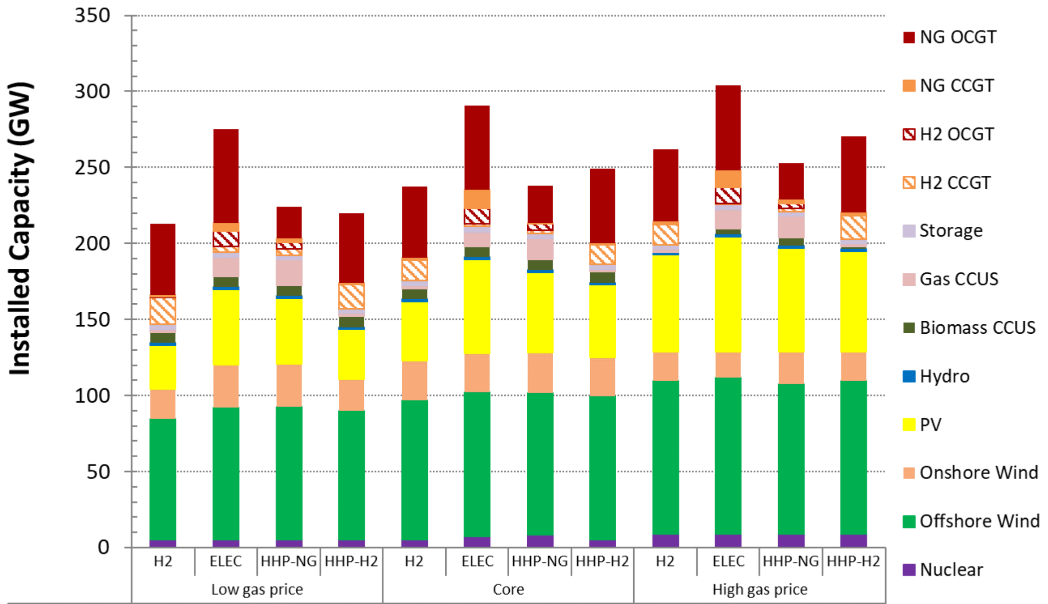


Figure 3-25 Changes in the system costs driven by lower or higher gas price

The gas price assumptions also affect the optimal portfolio of electricity generation. A higher gas price disincentivises gas usage and shifts the system to use more low-carbon electricity generation (nuclear, gas CCUS and RES), reduce hydrogen-fired generation and the use of BECCS for power. More bioenergy is allocated for hydrogen production. The results are demonstrated in Figure 3-26.



	Low gas price				Core				High gas price			
	H2	ELEC	HHP-NG	HHP-H2	H2	ELEC	HHP-NG	HHP-H2	H2	ELEC	HHP-NG	HHP-H2
NG OCGT	47	62	21	46	47	55	24	49	47	56	24	50
NG CCGT	1	5	3	1	2	13	1	1	2	11	2	2
H2 OCGT	0	10	4	0	0	10	4	0	0	10	4	0
H2 CCGT	18	4	4	16	13	2	2	13	13	0	2	16
Storage	3	4	3	3	3	3	3	3	3	4	3	3
Gas CCUS	2	12	17	2	2	10	14	2	2	12	14	2
Biomass CCUS	7	7	7	7	7	7	7	7	0	4	5	2
Hydro	1	1	1	1	1	1	1	1	1	1	1	1
PV	29	49	43	33	39	62	53	48	64	76	68	66
Onshore Wind	20	28	28	21	26	25	26	26	19	17	22	20
Offshore Wind	80	87	87	85	92	95	94	94	101	103	98	100
Nuclear	5	5	5	5	5	8	8	5	9	9	9	9

Figure 3-26 Impact of a lower and higher gas price on the optimal portfolio of electricity generation capacity

A higher gas price also reduces the overall hydrogen demand, particularly in the power sector. Hydrogen demand for industry and transport, as given by the UKTM, is not optimised by IWES, as explained earlier in section 1.4.1. On the production side, higher investment in electrolysers is needed given the reduction in ATR production, and more bioenergy can be allocated for hydrogen production to reduce the cost of hydrogen. The results are presented in Figure 3-27.

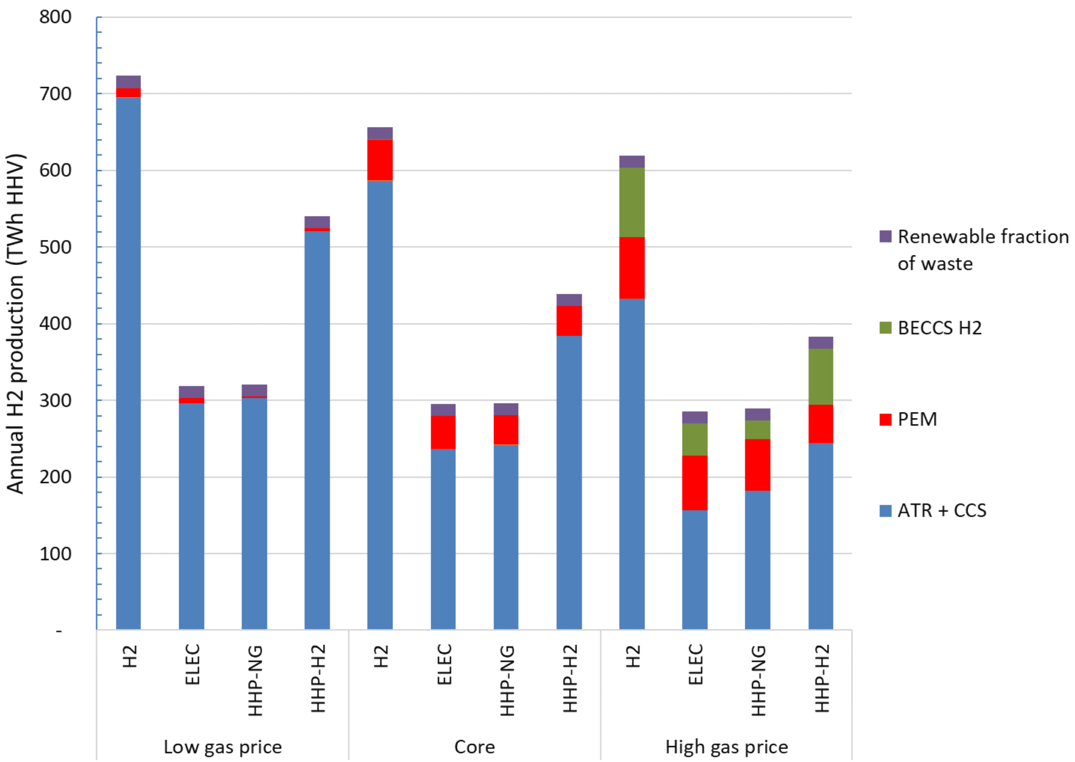


Figure 3-27 Impact of lower and higher gas prices on the annual hydrogen production

3.4 Impact of lower or higher domestic heating demand

The core scenarios assume the reduction of domestic space heating demand that can be achieved by implementing some energy efficiency measures which make changes to the buildings modelled here[66]. Some examples of other factors which could change the total space heat demand include building other forms of thermal insulation, behavioural changes to use heating more efficiently, implementing smart energy system management to minimise energy usage, and significantly using highly energy-efficient appliances to impact the whole energy system operation and infrastructure requirement. Thus, it is essential to investigate the system implications and the costs of having lower or higher domestic space heating demand. The study investigates the system implications and annual costs of a system with 208 (low), 228 (Core), 260 TWh/year (High) domestic space heating demand. Domestic water heating is 71 (low), 80 (Core) and 71 (High) TWh/year. The difference in the domestic water heating between the core and the sensitivity studies is based on different UK Times case studies, but it should not affect the results substantially. Non-domestic heat demand is the same across all scenarios. The heat demand for different scenarios is shown in Figure 3-28.

[66] Example measures include solid wall insulation or double-glazing windows.

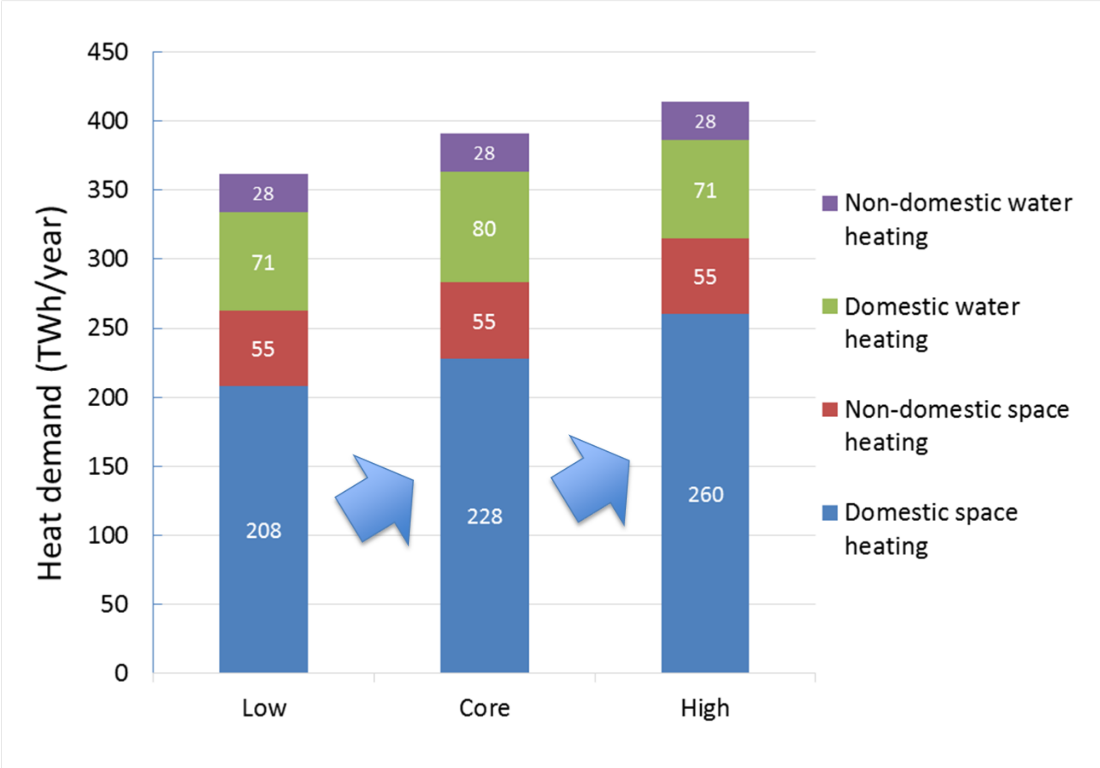


Figure 3-28 Sensitivity of heat demand scenarios

In this study, the "Core" domestic heat demand case is used as the counterfactual scenario for a cost comparison. As shown in Figure 3-29 and Figure 3-30, 29 TWh heat demand reduction from both space and water heating demand reduces all scenarios' annual costs by 0.8 – 1.6 £bn/year. In contrast, a higher heat demand in the "High" scenario increases the total annual system cost by 0.9 – 2 £bn/year. The largest impact is in ELEC, followed by HHP-H2, H2, and HHP-NG scenarios. It is worth noting that the ASHP COP is assumed not to be affected by different heat demands as the output temperature remains the same across all studies (in reality the level of energy efficiency may impact the achievable output temperature dependent on a home's heat loss rate), but a more granular representation of buildings would be needed to explore this)

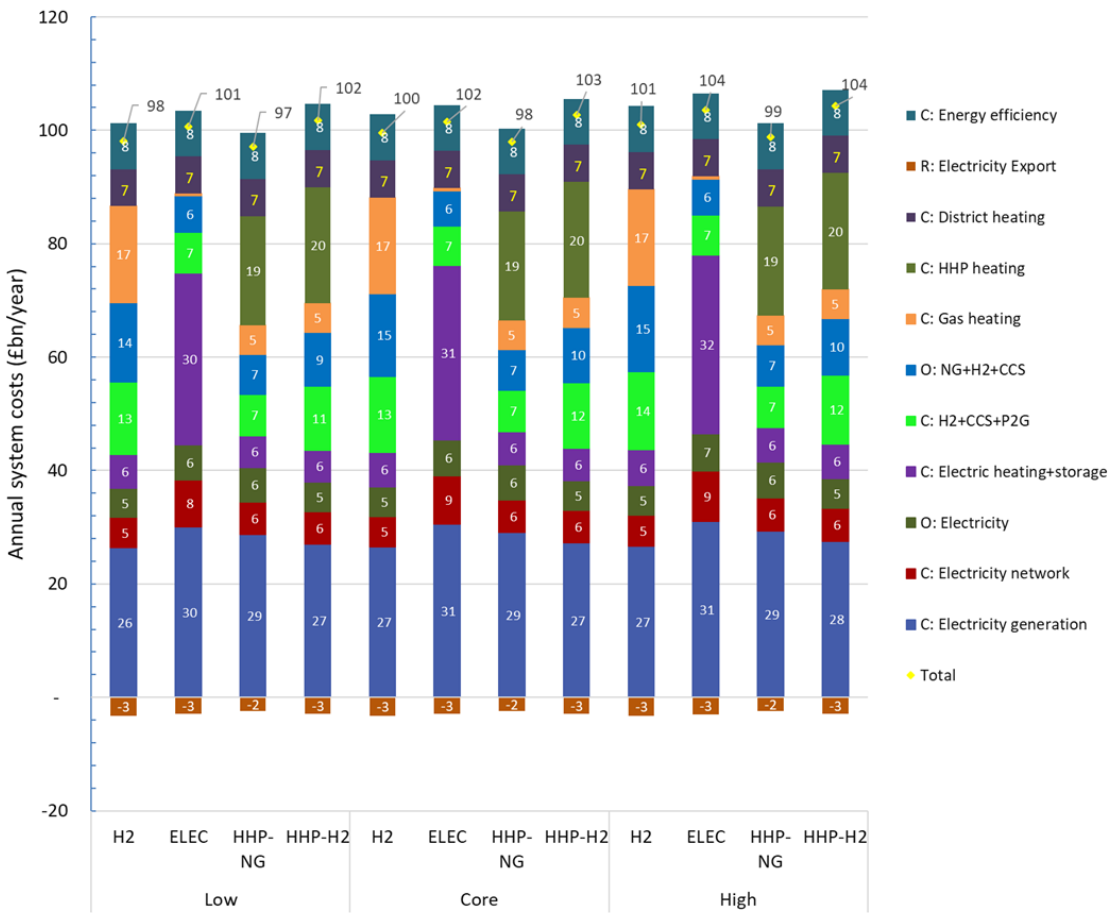


Figure 3-29 Impact of higher domestic space heating demand on the annual system costs

Figure 3-30 shows the changes in annual system costs attributed to different domestic heat demand scenarios.

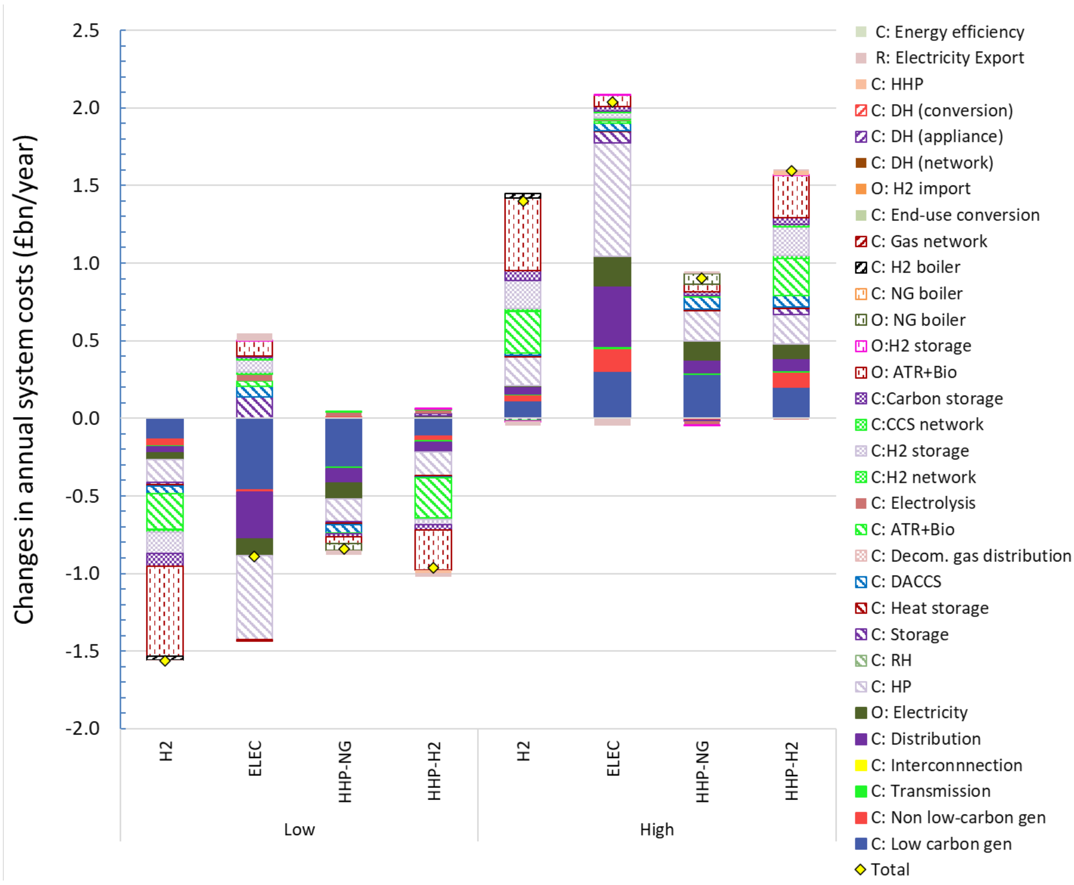


Figure 3-30 Impact of lower or higher domestic heating on the annual system costs

The reduction of domestic space heating demand will benefit all scenarios. The benefits include the cost reduction of electricity generation Capex, distribution network Capex, HP, DACCS, and carbon storage. In H2 and HHP – H2, heat demand reduction also reduces the Capex of H2 production capacity and H2 Opex. As heat demand is seasonal, reduced space heating demand also decreases the need for H2 storage. In Elec and HHP – NG, having less heat demand reduces electricity Opex.

The reduction in space heating demand does not change each scenario's heat-supply characteristic. In hybrid scenarios, most of the heat is supplied by air-source HP. The usage of NG boilers within the hybrids remains at less than 8% and hydrogen boilers at less than 18% (in the households using hybrids in the HHP – H2 scenario). The use of the boiler elements in the hybrid scenarios decreases proportionally with reduced heat demand. The impact of having different heat demands on the annual heat supply is shown in Figure 3-31.

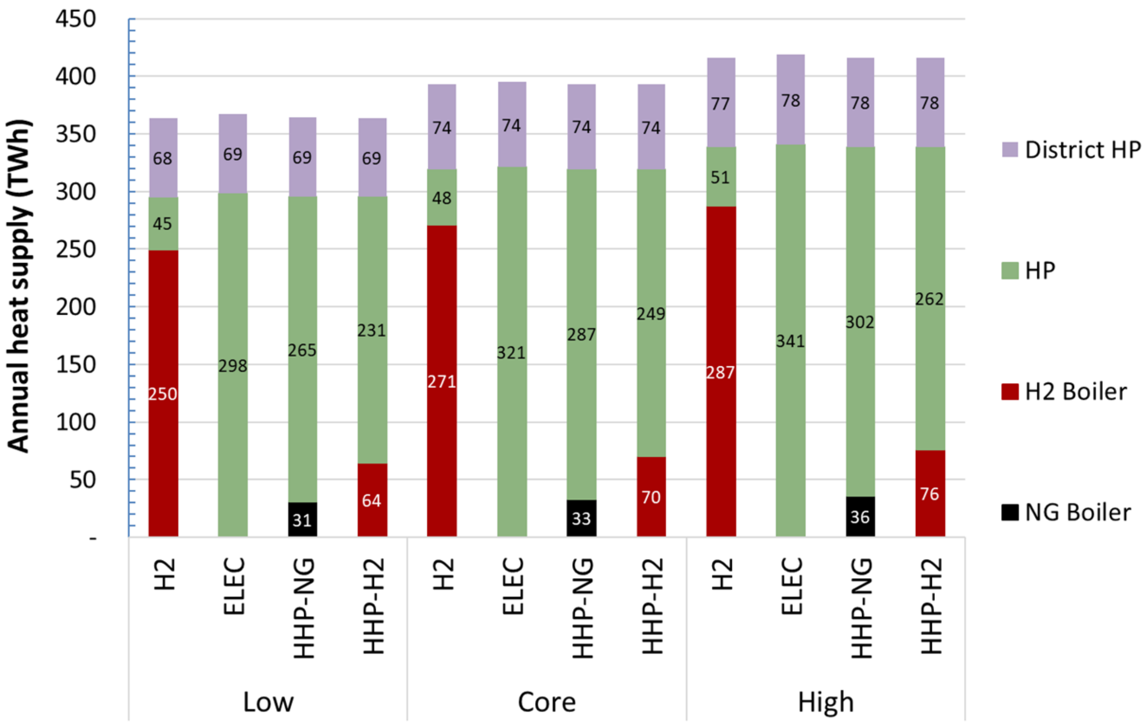


Figure 3-31 Impact of higher heat demand on the annual heat supply

3.5 Impact of a milder minimum temperature in winter

The energy system capacity requirement is determined by the size of energy demand combined with the scarcity in its renewable supply. The core study models a 3-day cold winter where the minimum hourly temperature reaches -7.51°C and a daily minimum -6.43°C. To stress-test the system, wind power output is modelled to be at its lowest in the same period. In this study, the implications of having a milder winter are investigated. This milder cold winter has an hourly minimum temperature of -2.88°C and a daily minimum of -1.80°C. The data are selected to resemble median temperatures between 2000 and 2019. The remainder of the temperature profiles is the same in both scenarios. The comparison between the mild and cold winter temperature profiles used in the study is shown in Figure 3-32.

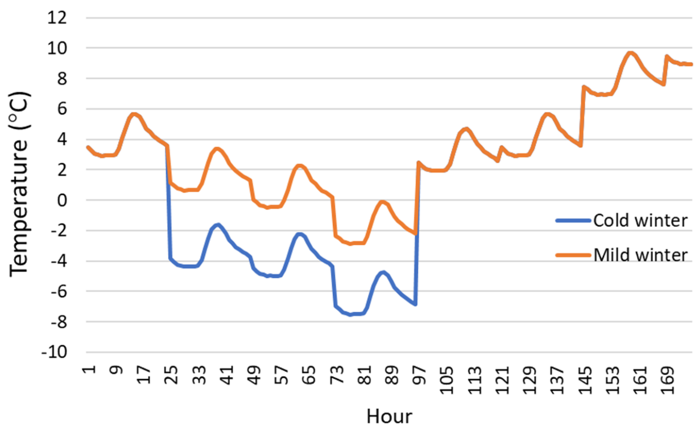


Figure 3-32 Temperature profiles during a winter week with peak demand for the cold and mild winter scenario

The system's annual costs with a milder cold winter are compared with the system's costs with the cold winter assumed in the core studies in Figure 3-33. The results suggest that designing the energy system for a colder winter will cost 0.8 – 3£bn/year more. ELEC scenario is the most sensitive scenario to this assumption's changes, while HHP-NG has the lowest impact. For H2 and HHP-H2, designing the system to deal with a colder winter increases the cost by around 1 – 1.3 £bn/year.

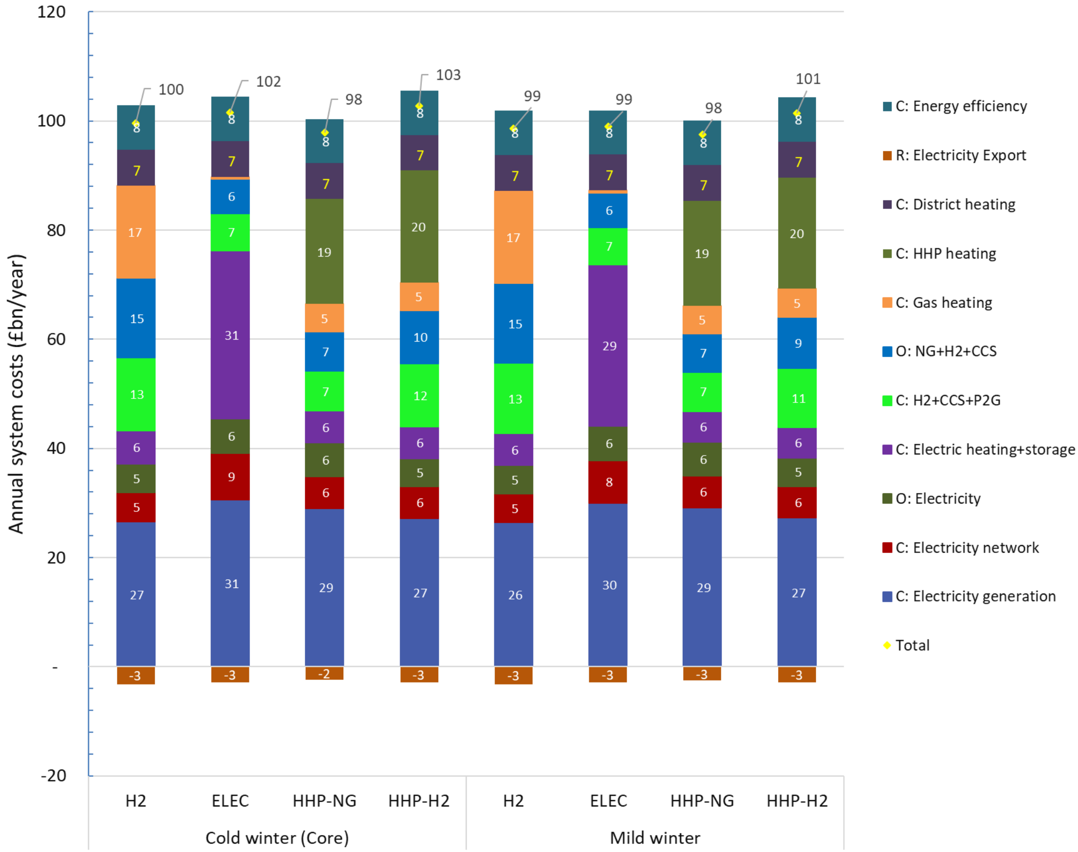


Figure 3-33 Annual system costs designed for cold and mild winter

The detailed annual system costs changes between the Core and milder cold winter assumptions are shown in Figure 3-34. The fundamental changes include lower cost of electric heating, Capex of the distribution network and peaking generation, particularly in ELEC. Again, if there are high levels of spare thermal capacity in the distribution network, the differences between scenarios in terms of distribution network costs would be more modest (see section 3.9 "Impact of distribution network headroom"). In H2 and HHP-H2, cost reductions are also driven by lower H2 production capacity, storage, and Opex of H2. In HHP-NG, the mild winter reduces the usage of NG boilers, and therefore, in the sensitivity, this scenario produces fewer emissions from heat, resulting in a lower cost of DACCS (but calling into question the realism of operating a gas network with such a small amount of natural gas use).

As a result of this change in assumptions, some shifts between the low carbon and hydrogen systems occur. Therefore, some additional costs partially offset the cost savings in other system elements—for example, the cost of low-carbon generation, distribution network Capex and electricity Opex increase in HHP-H2 to partially compensate the savings in hydrogen production Capex and Opex.

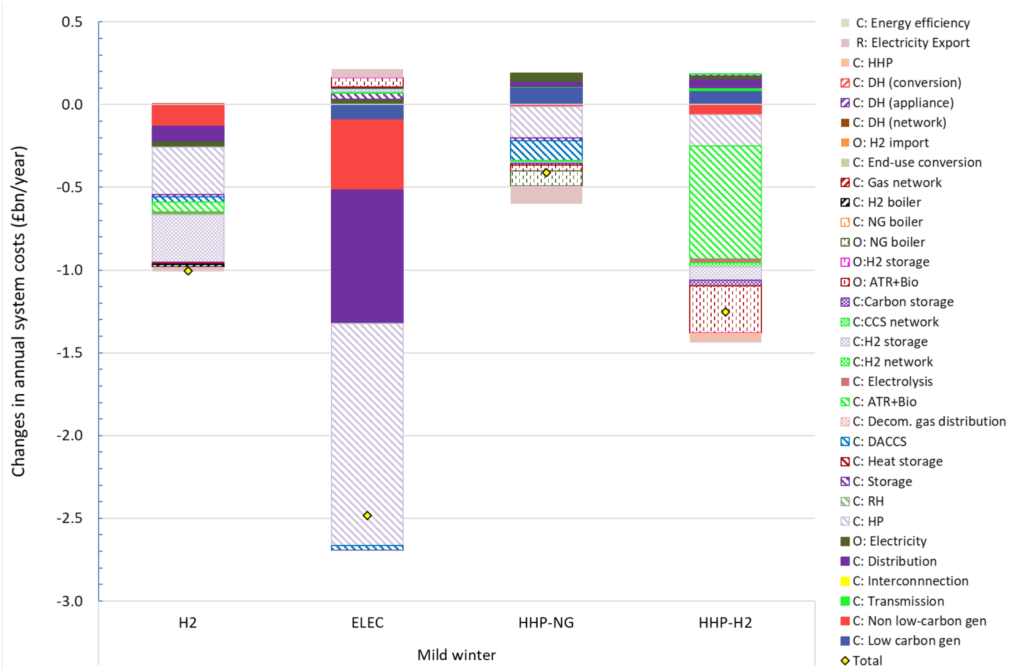
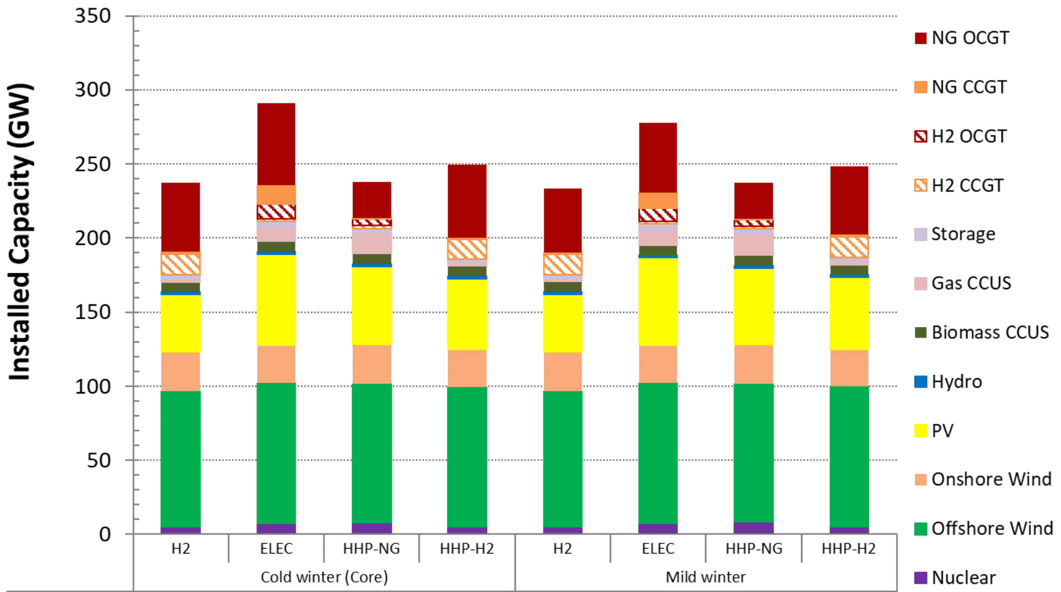


Figure 3-34 Changes in the annual system costs if it is designed for mild winter

The optimal generation portfolio for the two cases is compared in Figure 3-35. Peaking capacity is less for the system with mild winter, especially in ELEC. The total OCGT capacity (NG and hydrogen) reduces from 65 to 56 GW, as the distribution peak demand decreases from 119 to 110 GW in Figure 3-36. The reduction in other scenarios is significantly smaller.



	Cold winter (Core) H2	Cold winter (Core) ELEC	Cold winter (Core) HHP-NG	Cold winter (Core) HHP-H2	Mild winter H2	Mild winter ELEC	Mild winter HHP-NG	Mild winter HHP-H2
NG OCGT	47	55	24	49	43	47	25	46
NG CCGT	2	13	1	1	1	10	0	2
H2 OCGT	0	10	4	0	0	9	4	0
H2 CCGT	13	2	2	13	13	2	2	13
Storage	3	3	3	3	3	4	3	3
Gas CCUS	2	10	14	2	2	10	15	2
Biomass CCUS	7	7	7	7	7	7	7	7
Hydro	1	1	1	1	1	1	1	1
PV	39	62	53	48	39	59	51	49
Onshore Wind	26	25	26	26	27	25	26	25
Offshore Wind	92	95	94	94	92	95	94	95
Nuclear	5	8	8	5	5	7	8	5

Figure 3-35 Power generation portfolio of the system designed for cold and mild winter

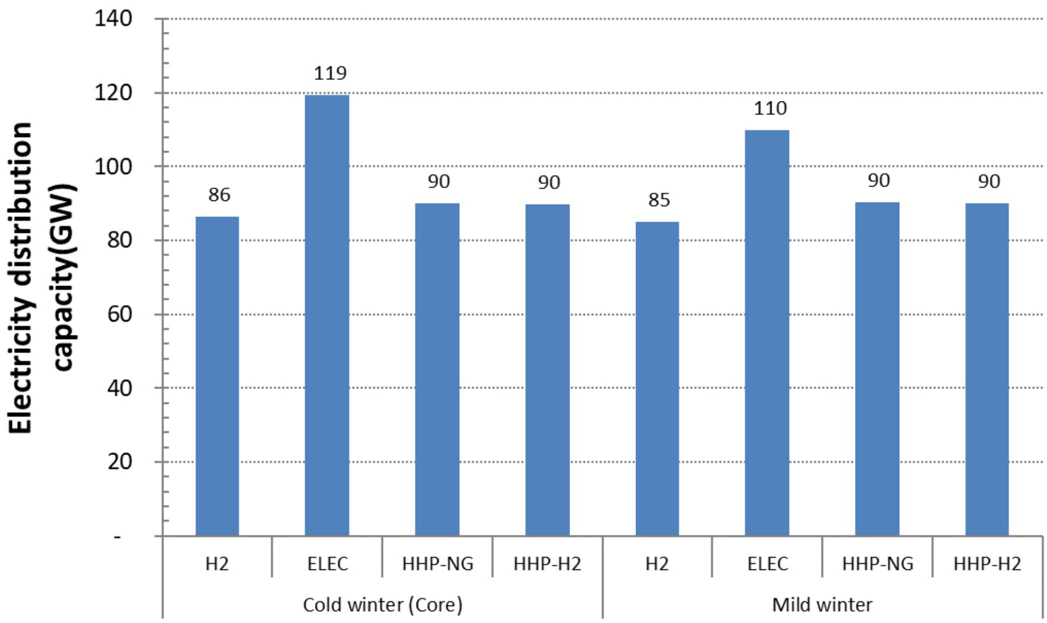


Figure 3-36 Comparison between distribution network capacity with cold and mild winter

A milder cold winter also reduces the seasonality of heat demand and consequently, the hydrogen demand in H2 and HHP-H2. Therefore, the capacity requirement for hydrogen storage can reduce substantially by 0.9 – 1.9 TWh, as shown in Figure 3-37.

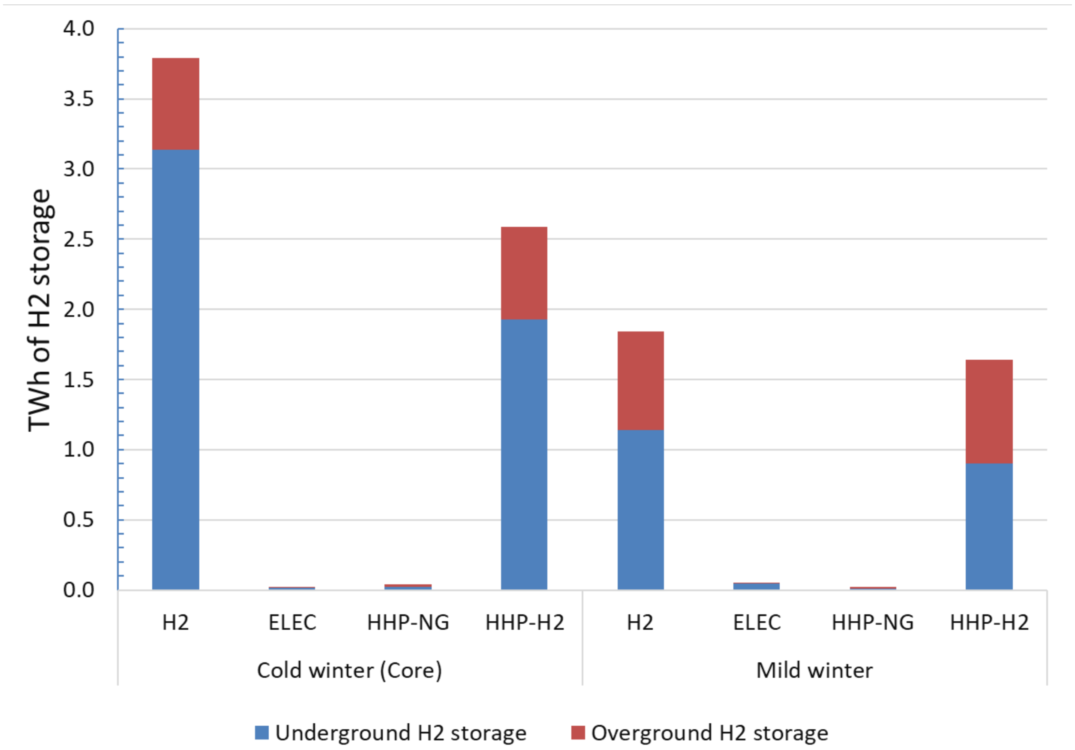


Figure 3-37 Comparison of the hydrogen storage portfolio for the system designed with cold and mild winter

3.6 Impact of improving COP of HPs

Deploying heat pumps as one of the primary heating sources is an attractive option partly due to their high COP advantage over other heating technologies. In the core scenario, the COP of ASHPs varies between 2.07 and 4.46, with a weighted average of 3.11. Compared to resistive heating efficiency (close to 100%), heat pumps have a significant advantage though also a higher Capex. In this context, the study analyses the system benefits of future technologies that can further improve COP for ASHPs. For simplicity, it is assumed that the COP of ASHPs will be uplifted to have a weighted average of 4. The COP profiles used in the study and the core scenario are compared in Figure 3-38.

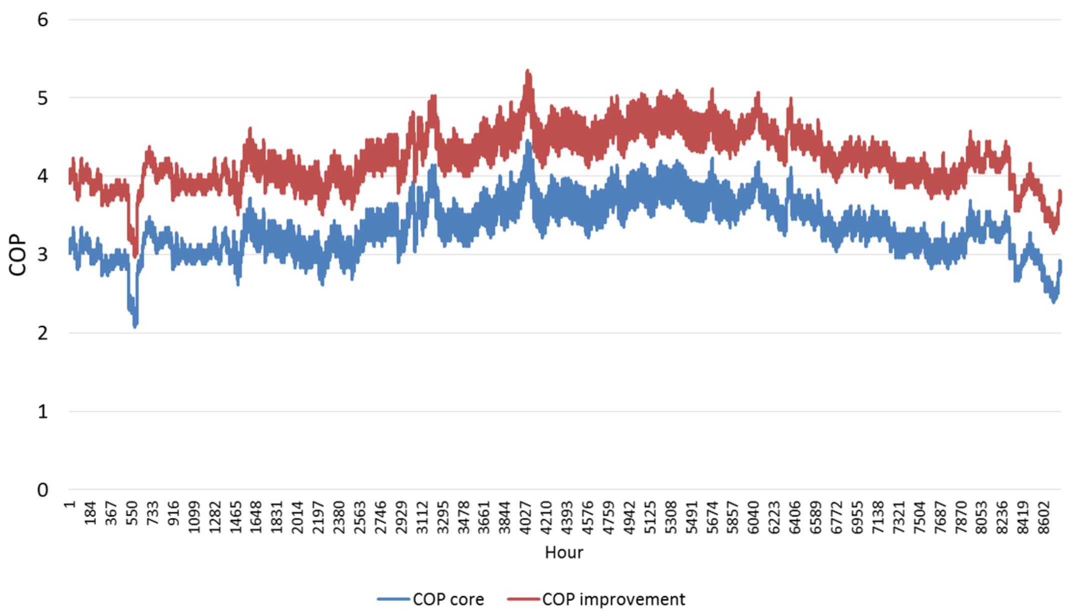


Figure 3-38 ASHP COP profiles used in the studies

As shown in Figure 3-39, the improvement of HP COP leads to the reduction of the annual system costs across scenarios by 0.7 to 4.8 £bn/year. The impact is more profound on ELEC than on other scenarios. The cost of ELEC becomes lower than the cost of H2, while the cost of HHP-NG is still the lowest. The savings are primarily driven by a reduced cost of heat pumps, electricity infrastructure Capex and Opex, and the hydrogen system. The latter is driven by a shift of some hydrogen demand to electricity. The changes in the various elements of the annual system costs due to HP COP improvement are depicted in Figure 3-40.

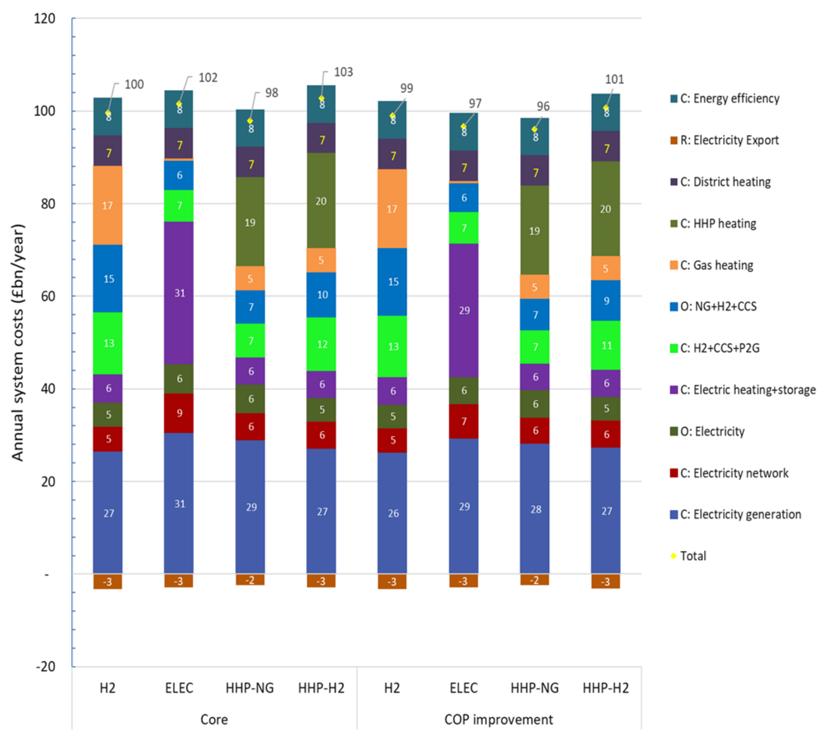


Figure 3-39 Impact of improving COP of HPs on the annual system costs

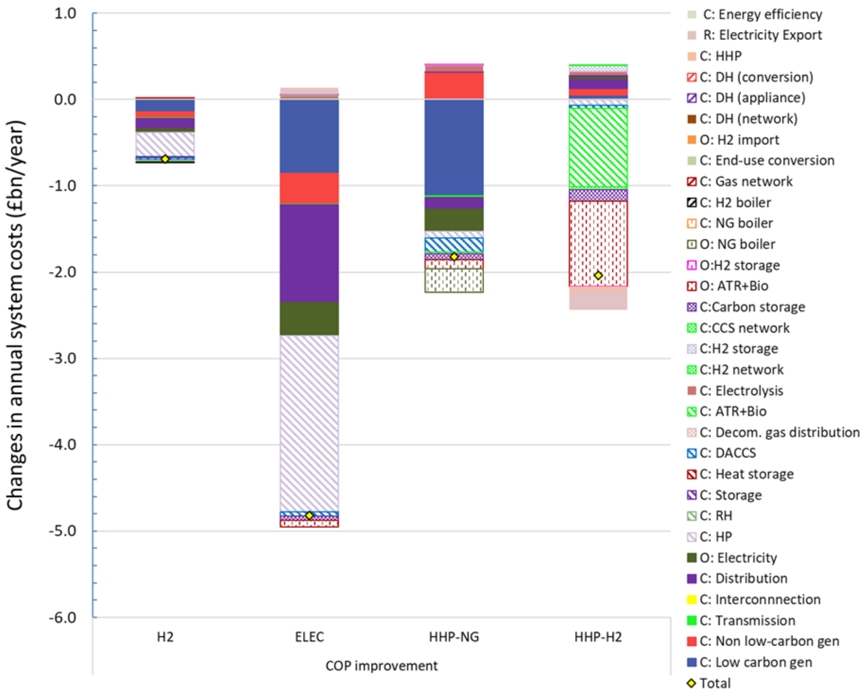


Figure 3-40 Changes in annual system cost due to higher HP COP

Having a higher HP COP incentivises the increased use of heat pumps and decreased gas heating. The changes in the annual heat supply mix are shown in Figure 3-41. The gas usage in HHP-NG decreases from 33 TWh/year in the core scenario to 20 TWh/year, while in HHP-H2, it decreases from 70 to 27 TWh/year.

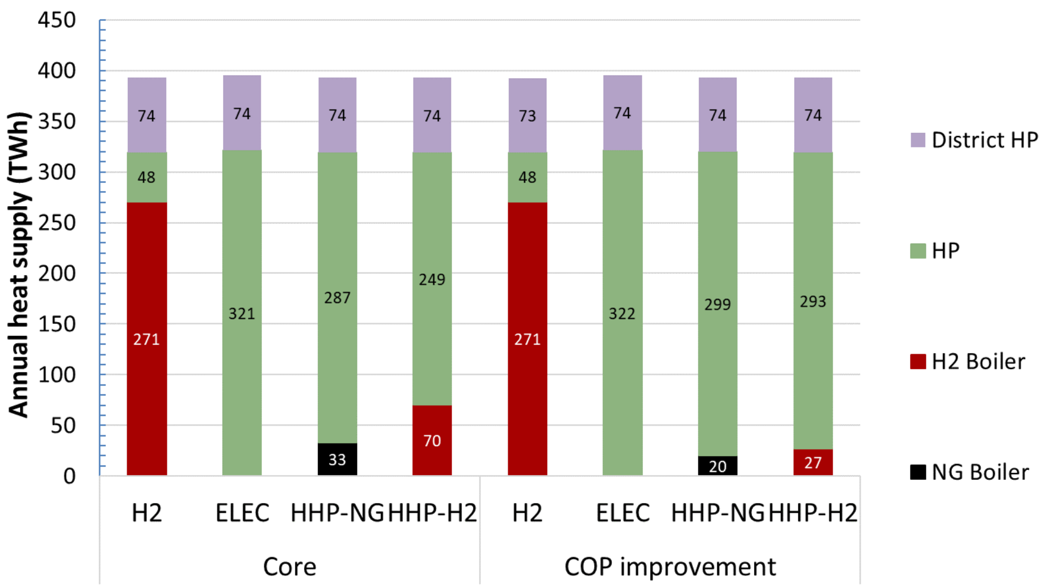


Figure 3-41 Changes in annual heat supply due to higher HP COP

The impact of the COP improvement on the electricity demand is presented in Figure 3-42. In all scenarios, the heat-led electricity demand decreases. In the hybrid systems, the increased usage of electric heating (as shown in Figure 3-41) is offset by the increased COP and therefore, the heat-led electricity demand falls overall. It is important to note that the heat-led electricity demand is driven by a combination of ASHP and the WSHP used in district heating.

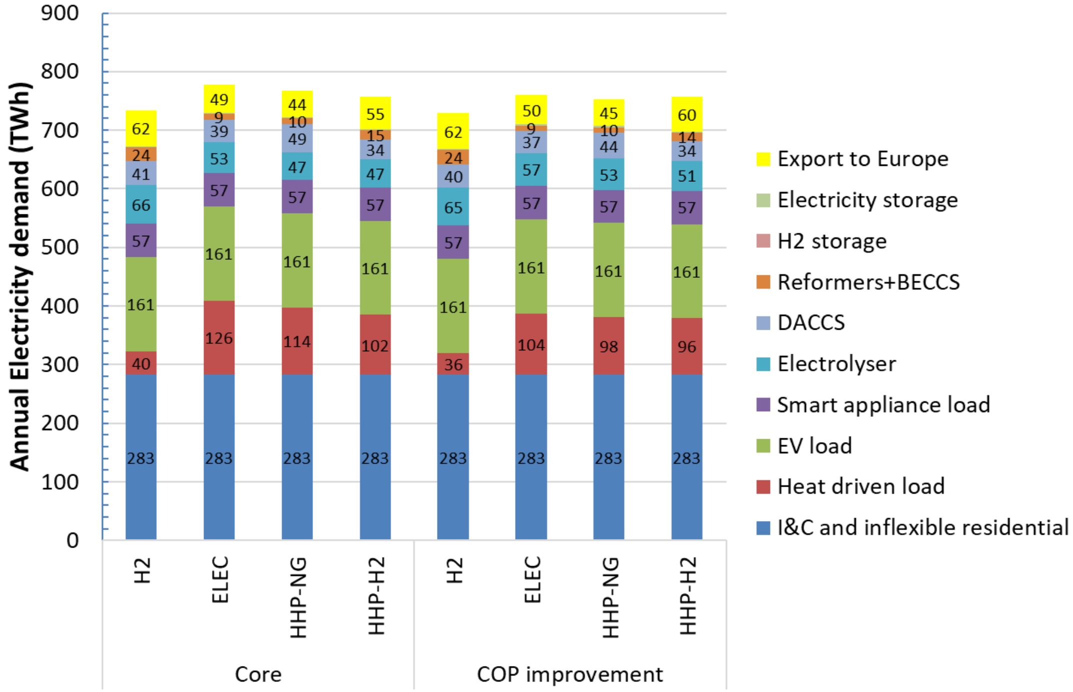


Figure 3-42 Impact of COP improvement on the electricity demand

3.7 Impact of non-optimal gas usage in hybrids

While a hybrid heating system provides dual fuel flexibility, there is realism concern to the design of this scenario, and it is thus essential to review the impact of non-optimal gas use. For example, a system where gas is used more than in the optimal scenario (for example, because of end-customer preference) would drive a higher requirement for DACCS or other energy infrastructure capacities or compromise the energy system decarbonisation. In this context, the study investigates the cost and system implications of having twice gas usage as the optimal result obtained in the core scenario in the HHP-NG and HHP-H2 scenarios. The impact on the heat supply mix is demonstrated in Figure 3-43.

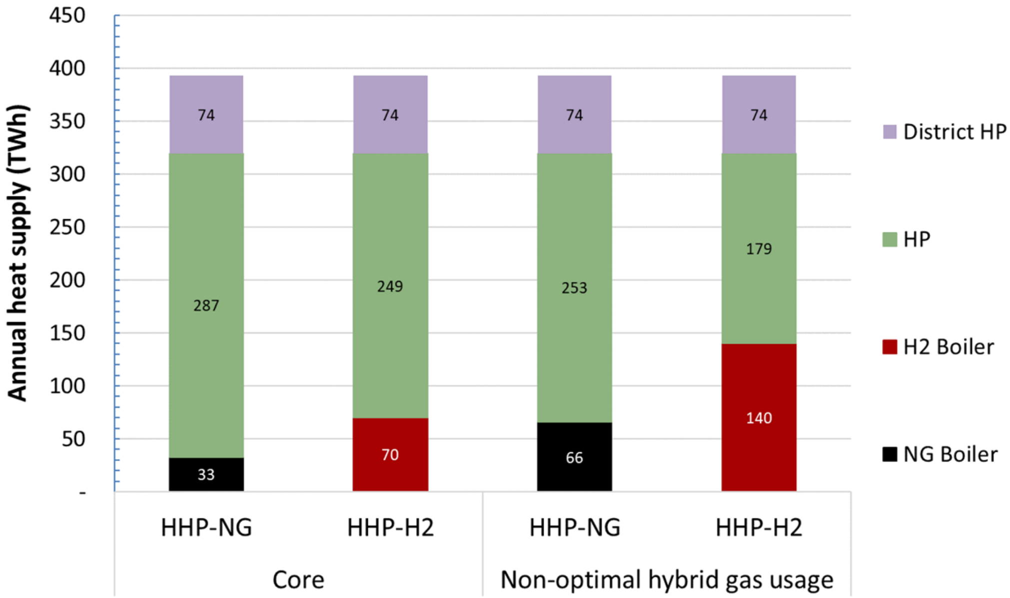


Figure 3-43 Comparison between the heat supply mixes in the core scenario and the study with non-optimal gas usage

Doubling the use of gas heating increases the cost of both HHP-NG and HHP-H2 by 1 - 1.5 £bn/year. This does not change the scenarios' cost ordering, though the HHP-NG scenario still carries the risks described in the sections above.

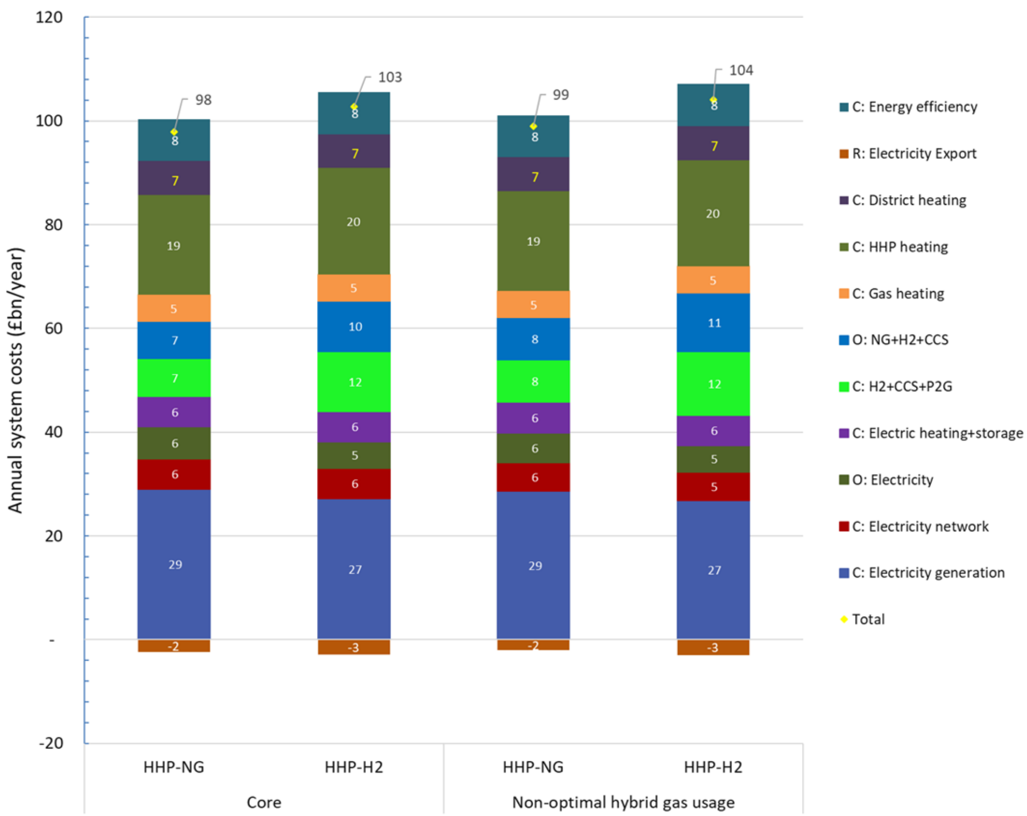


Figure 3-44 Impact of non-optimal gas usage on the annual system costs

In HHP-NG, higher gas heating usage will increase heating emissions, as demonstrated in Figure 3-45. Consequently, it drives higher costs of DACCS, carbon storage, gas boiler Opex and Opex of the hydrogen system. Higher gas usage reduces the electricity consumption for heating, and therefore, we observe a fall in the costs of electricity Capex and Opex and hydrogen Capex and hydrogen storage.

The impact of non-optimal hybrid gas usage on emissions is demonstrated in Figure 3-46.

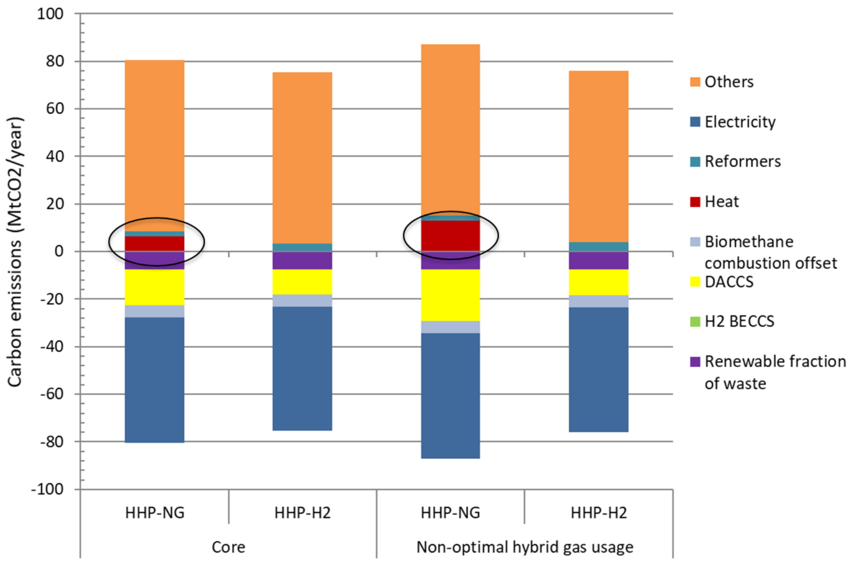


Figure 3-45 Impact of non-optimal hybrid gas usage on emissions

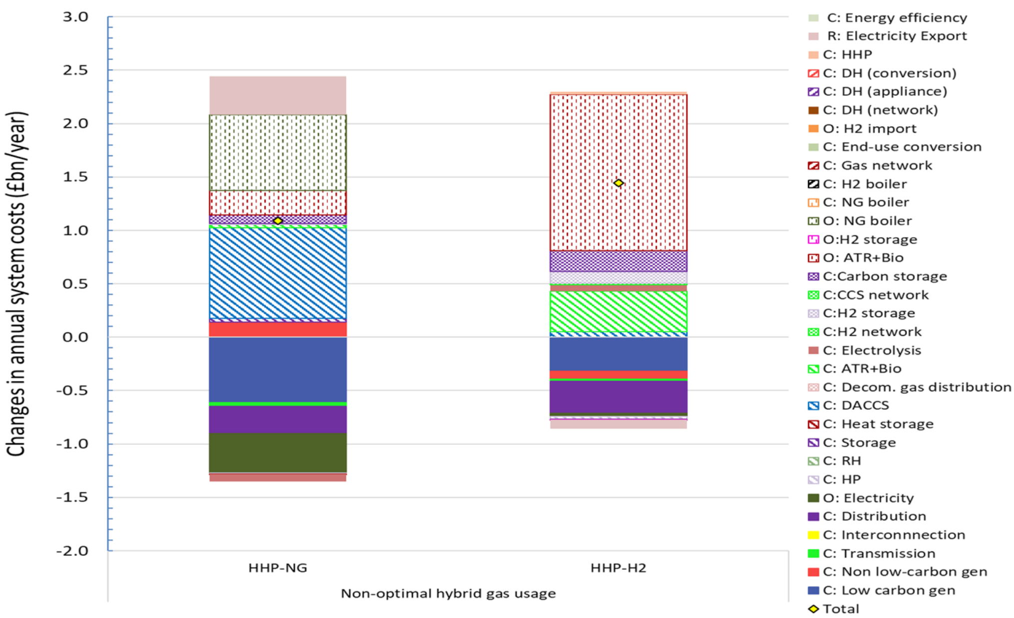


Figure 3-46 Changes in the annual system costs driven by the non-optimal usage of gas heating

In HHP – H2, hydrogen boilers' higher usage increases the total demand for hydrogen, which triggers more hydrogen production capacity to be installed and, consequently, higher cost of hydrogen system Capex and Opex. We also observe an increase in the cost of DACCS and carbon storage. However, there is a slight cost reduction in electricity generation and network and hydrogen storage, driven by higher hydrogen heating.

3.8 Impact of mixed roll-out decarbonisation scenarios

The study investigates the impact of having mixed roll-out decarbonisation scenarios, using the following assumptions:

- A mixed scenario 'on top of' an H2 for heat scenario; the study simulates a world where fewer hydrogen boilers are installed as heat pumps are considered more effective for specific building types.
  - Installation of heat pumps is higher than expected; the number of customers with HP is 8 million higher than in the core scenario.
  - HPs distributed evenly in all regions to create the 'maximum disturbance' to H2 for heat scenario
- A mixed scenario 'on top of' electrification
  - This study uses a regional scenario where North West, North East, Scotland and Wales choose to deploy hydrogen boilers for on-gas-grid buildings instead of HPs while other regions use HPs.
- A mixed scenario 'on top of' hybrids
  - A sizeable proportion of on-gas grid homes (that are not in heat dense areas) now use heat pumps, the same as outlined in H2 above.

The scenarios are applied to both domestic and non-domestic buildings.

The annual system costs for the core and mixed roll-out scenarios are shown in Figure 3-47. The mixed roll-out increases the system costs by £2.5 bn/year in H2, reducing the costs by £0.5 bn/year in ELEC. Given the assumptions used in the study, the cost of H2 is lower than the cost of ELEC, so when ELEC is combined with H2, the annual system costs slightly reduce. This also increases the hybrid systems' costs by around 0.8 – 1.2 £bn/year.

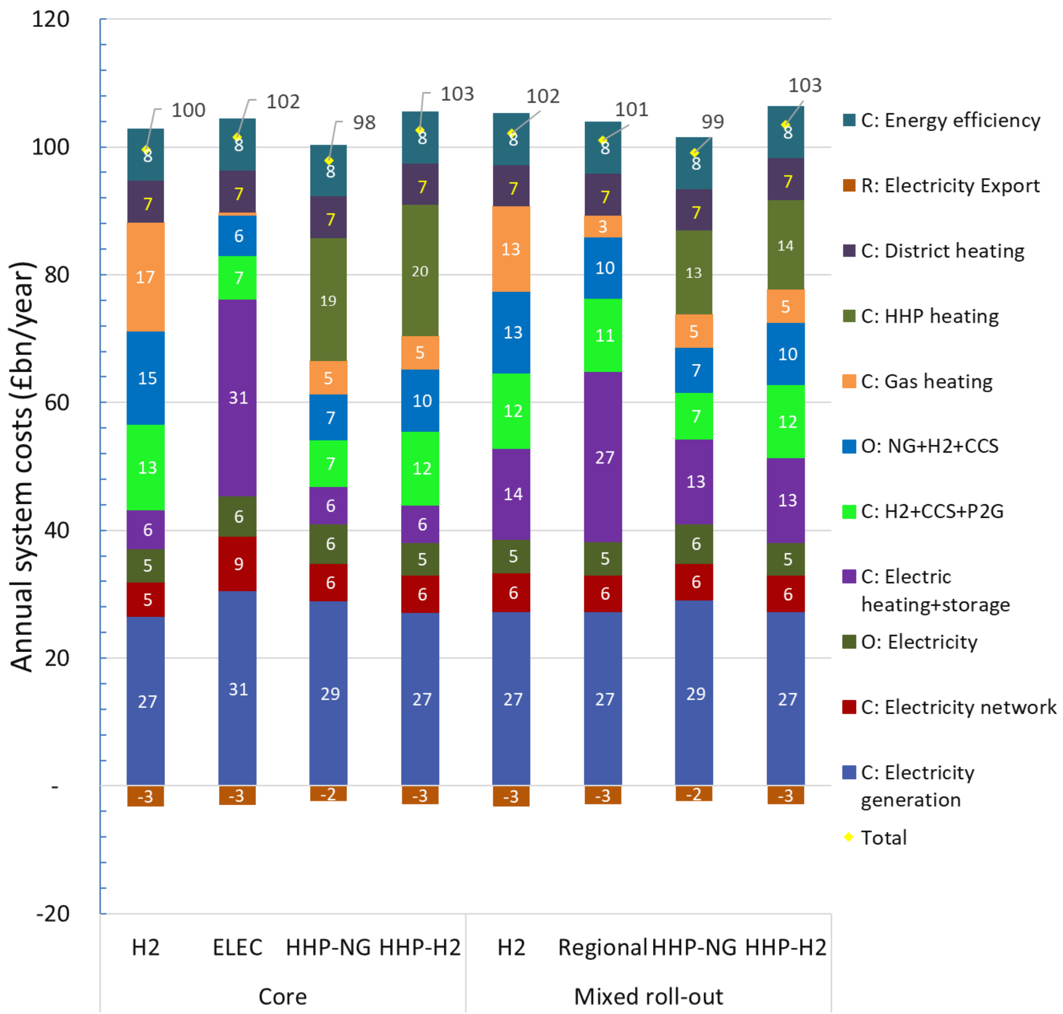


Figure 3-47 Impact of mixed roll-out on the annual system costs

To identify the impact of the mixed roll-out, the changes in the components of the annual system costs between the core and sensitivity scenarios are shown in Figure 3-48. In H2, the increased deployment of heat pumps leads to around £8bn/year increase in the electric heating cost and under £1bn/year increase in electricity generation and distribution network Capex. The increased use of heat pumps reduces hydrogen consumption, and therefore the increased cost is offset by the reduction in the Capex and Opex of the hydrogen system (including hydrogen storage) and a reduction in the Capex of hydrogen boilers.

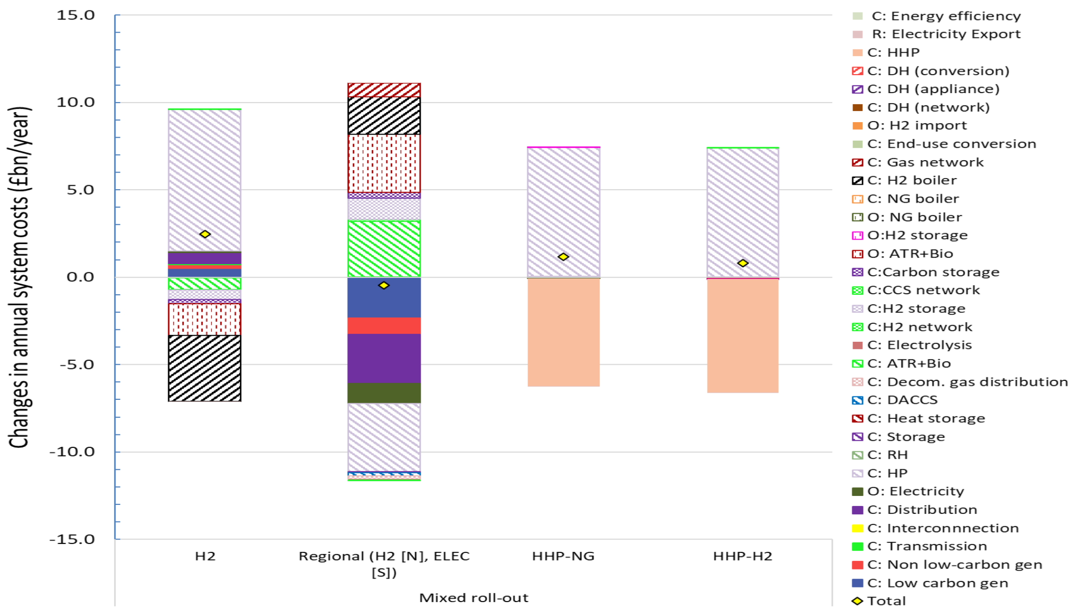


Figure 3-48 Changes on the annual system costs driven by the mixed rolled-out

By deploying hydrogen in the North of GB and Wales and electrification in the South, the annual system costs decrease by £0.5bn/year. In this scenario, the costs of hydrogen production capacity, hydrogen storage, hydrogen Opex, Capex of hydrogen boilers and cost of maintaining gas distribution increase. These increased costs are required for deploying hydrogen-based heating in the North. However, the increased cost is offset by reducing the electricity generation Capex, electricity distribution Capex and electricity Opex, and Capex of HPs. This reduction is caused by the replacement of heat pumps by hydrogen boilers in the North of GB and Wales.

The system implications of having more heat pumps in HHP-NG and HHP-H2 are minimal as the hybrid systems already rely on heat pumps to provide most of the heat demand. The cost changes are mainly driven by replacing HHP with HP. It is worth noting that the model assumes a uniform distribution of increased HP and, therefore, customers with hybrids can switch to gas to mitigate constraints in the electricity grid. If the increased HP is concentrated, it may trigger local network reinforcement.

3.9 Impact of distribution network headroom

All previous studies assume that electricity distribution networks do not have the spare capacity to deal with the increased electricity peak demand driven by electrification in the heating and transport sectors. The objective is to quantify the cost of increasing the distribution network capacity requirement due to electrification. It should be noted that this is a conservative assumption, as data from DNOs indicates that most distribution level primary substations still have significant amounts of spare thermal capacity. This spare capacity could also be present downstream at the secondary substation level, but data on the latter are very sparse. High levels of network headroom would lead to lower distribution network reinforcement costs – however, data on network headroom varies hugely by location and is very patchy at the Low Voltage level. Using a pessimistic “no network headroom” assumption, there is a risk that the modelling would overestimate the amount of additional distribution network capacity needed to facilitate electrification.

The level of distribution network reinforcement varies across different scenarios, as demonstrated in section 2.5. ELEC scenario has the highest requirement and, therefore, the highest distribution network cost. However, as stated above, electricity distribution networks may, in reality, have significant levels of spare capacity. In this context, the impact of having a 50% electricity distribution network headroom is analysed to understand its implication to the heat decarbonisation scenarios. This "50% headroom" scenario was created using averaged data on distribution network primary substation utilisation across Great Britain.[67]

The headroom will reduce the cost for reinforcing distribution networks in all scenarios, especially in the ELEC scenario, as shown in Figure 3-49. The annual system cost reduces by 2.2 – 4.7 bn/year. In this case, the annual system cost of ELEC is slightly below the cost of the H2 scenario, but it is still around £2bn/year more than the cost of the HHP-NG scenario.

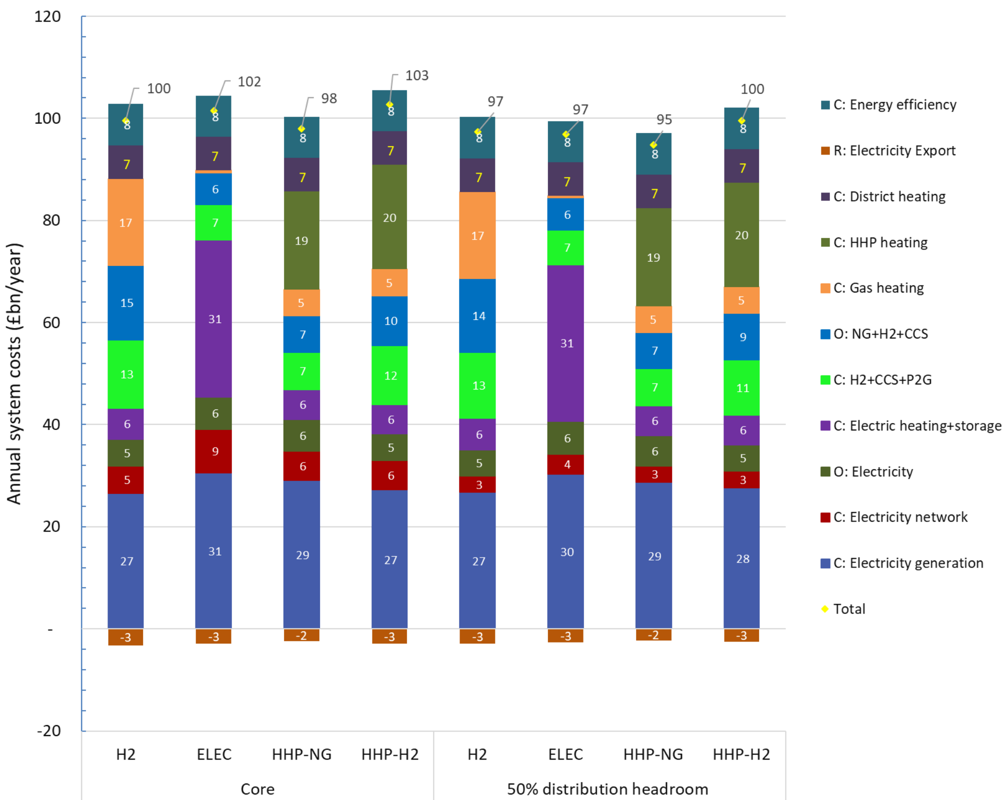


Figure 3-49 Impact of 50% distribution network headroom on annual system costs

Figure 3-50 shows the changes in annual system costs dominated by savings in distribution network cost.

[67] Data on this can be found in the DNOs' Long Term Development Statements.

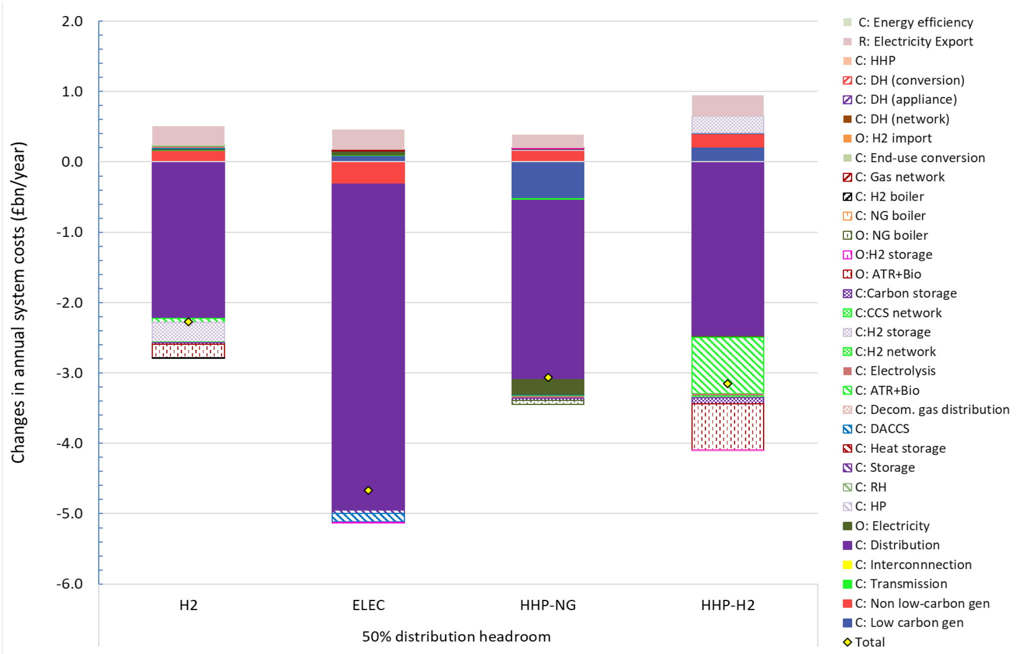


Figure 3-50 Changes on the annual system costs driven by 50% distribution network headroom

With 50% distribution network headroom, the use of heat pumps in both hybrid scenarios increases. This is demonstrated in Figure 3-51. In HHP-NG, it increases by 3 TWh/year. A substantial increase occurs in HHP-H2, where the heat produced by heat pumps increases from 249 TWh/year to 274 TWh which reduces the hydrogen demand and, therefore, the system requires less hydrogen production and its production capacity. This reduces the Capex and Opex of hydrogen, as shown in Figure 3-50.

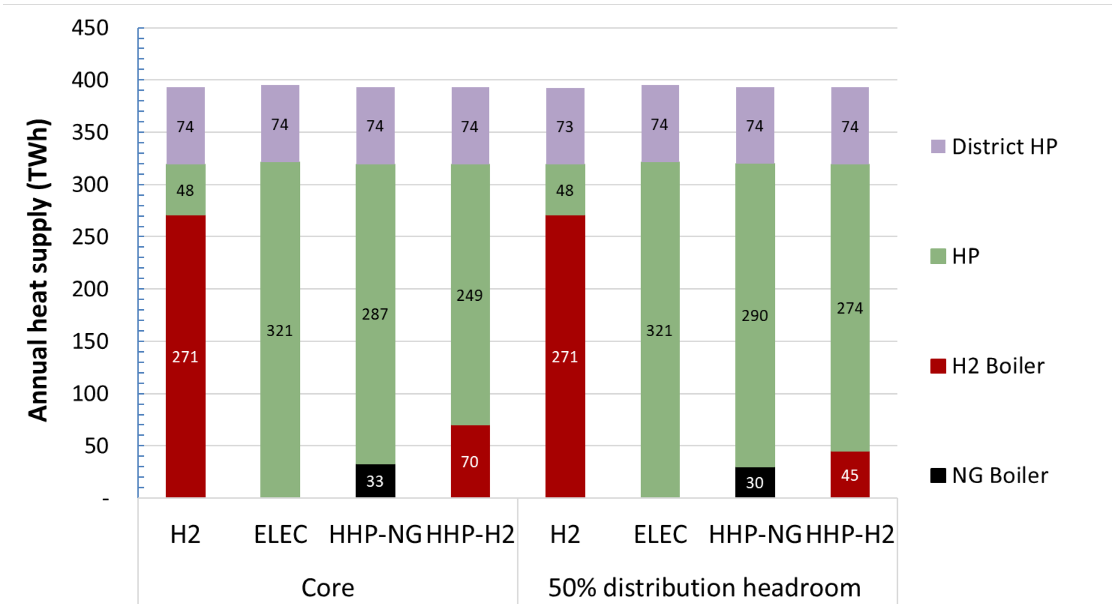


Figure 3-51 Impact of having 50% distribution network headroom on the annual heat supply

3.10 Comparison across scenarios

Figure 3-52 shows the cost comparison across all studies that have been analysed previously. At the bottom of the chart, the core scenarios' total annual system cost is presented in different colours and serves as a counterfactual. The impact of different assumptions investigated in the sensitivity studies is presented as a cost change from the counterfactual.

The results demonstrate that the worst-case situation, where all scenarios' cost is highest, is where the system has very low flexibility, with ELEC the most affected scenario. The flexibility assumed in the core scenarios is relatively moderate, and therefore, if combined with the low gas price, it will bring H2, HHP-NG and HHP-H2 to the minimum cost. In comparison, the minimum cost for ELEC is found when the core scenario is combined with the improvement in HP's COP. The ELEC scenario also becomes more competitive than the H2 scenario if there is a 50% distribution network headroom. As demonstrated earlier, one of the main challenges in ELEC is the increased peak demand. The headroom will reduce the cost of ELEC. This result shows just how uncertain distribution network costs can be and underscores just how essential network utilisation data is. This data is highly sparse and uncertain below the primary substation level (i.e., the vast majority of the distribution network) – significant work needs to be done in this space by DNOs to make this data more transparent, granular and readily available.

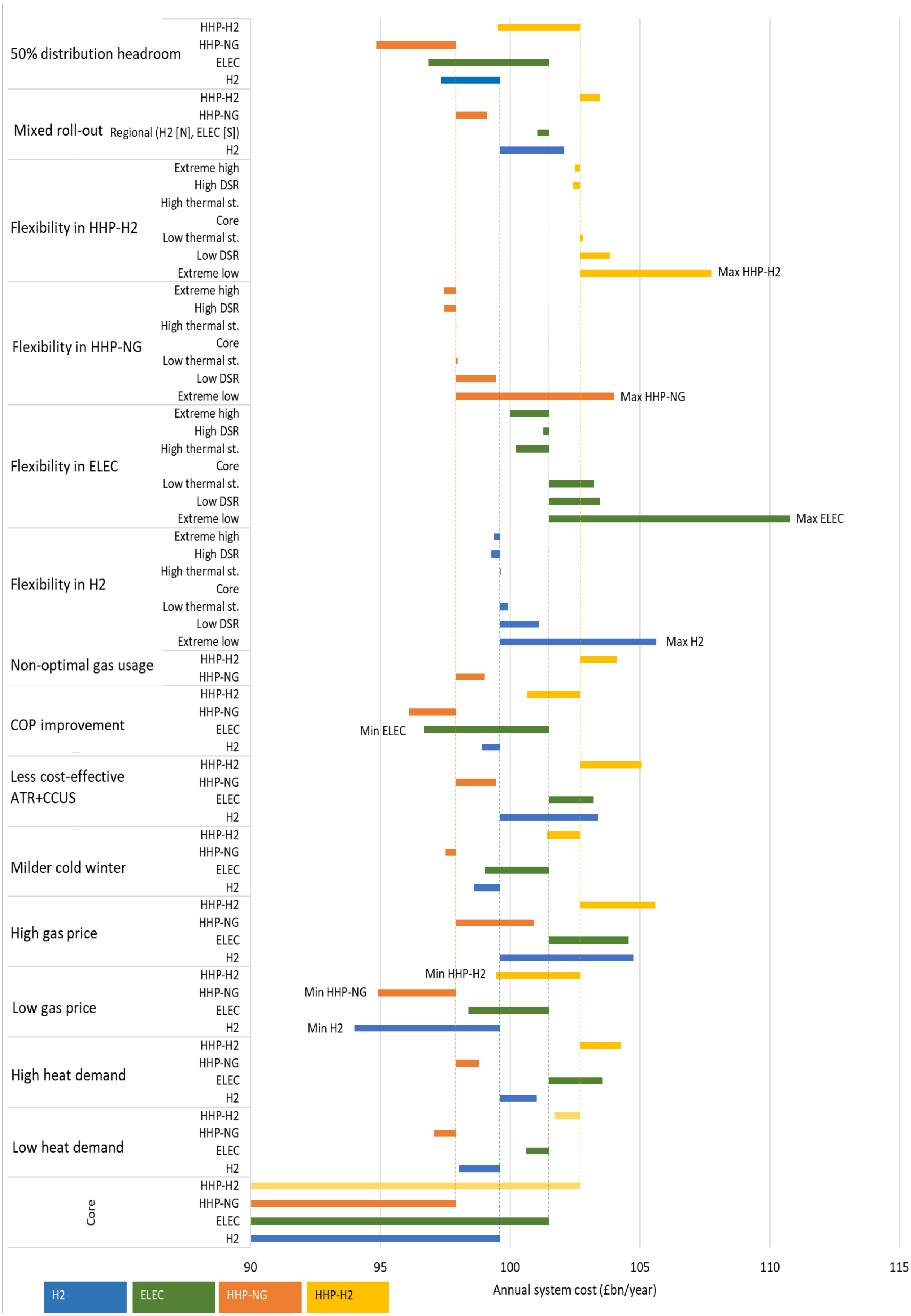


Figure 3-52 Cost comparison across scenarios – the results of the sensitivity studies are shown as the changes from the core scenarios

Chapter 4. Summary of key findings

A spectrum of studies has been carried out to analyse the key cost performance and the energy system required for different heat decarbonisation strategies. Four mainstream (core) scenarios are tested, including hydrogen for heating, electrification, and two hybrid heating systems, i.e. heat pumps with natural gas boilers and heat pumps with hydrogen boilers (furthermore, 17% of the domestic and 24% of non-domestic heat demand in urban areas is supplied through district heating systems in all scenarios). Strong interactions between the electricity, hydrogen, and heat energy systems are demonstrated, indicating the need to integrate the heat decarbonisation strategy with the electricity system decarbonisation. The transport sector is decarbonised by electrification and hydrogen. Therefore, a holistic evaluation approach, using IWES, is used to simulate and determine the optimal energy systems given different assumptions tested in the study. Different scenarios are used in the sensitivity studies to identify the system and cost implications of having different assumptions and test the robustness of the scenarios considering future uncertainty.

Key findings

The key findings from the analyses are as follows:

Feasibility to meet the net-zero requirement and cost characteristics of different heat decarbonisation scenarios

- The analysis demonstrated the cost performance of different heat decarbonisation scenarios: the most cost-effective is HHP-NG, then H2, followed by ELEC and HHP-H2. However, the total annual costs are comparable, as the differences are within the range of ±2%. Therefore, none of the scenarios (HHP-NG, H2, ELEC and HHP-H2) should be marginalised based on cost or the ability to meet the emissions target.
- CAPEX mostly dominates the cost structure in all scenarios; more than 80% of the cost is Capex related. Therefore, it should be expected that the results would be sensitive to the uncertainty in Capex and financing cost.
- Since renewable sources will supply most electricity demand, the electricity Opex costs are small (5%-6% of the overall annual system cost).
- In contrast, gas Opex can be substantially larger, i.e. around 15% of the total annual cost, particularly in the H2 scenario. In other scenarios, it is between 6% and 10%.
- Although the total costs are comparable, the underpinning energy infrastructure and operation across different scenarios can be significantly different. It indicates the importance of developing consistent heat decarbonisation policies and appropriate market signals to guide the transition process and the convergence of future energy system development.
- The cost of heating appliances across different scenarios can be substantially different, although the overall system costs are similar. For example, a hydrogen boiler cost is currently assumed to be much lower than a heat pump or a hybrid heat pump. From a

customer perspective, low-cost heating technologies will be attractive. While the long-term system cost is not directly visible to customers, eventually, the end-users will need to contribute to meeting system costs, and so choosing the heating technology should consider the whole-system costs, not only the cost of heating appliances. It will require appropriate policies and commercial frameworks to incentivise the users to select the optimal technologies.

Critical role of BECCS and DACCS

- BECCS and DACCS technologies play a critical role in achieving the UK's net-zero GHG emission target due to their negative emission capability. Without these technologies, the model cannot offset GHG emissions from other sectors.
- Technologies that can offset emissions, such as BECCS and DACCS, can facilitate the transition for decarbonising heat by allowing the use of lower-cost but higher-carbon content technologies, subject to limited utilisation, e.g. NG boilers or gas-fired CCGT/OCGT, in order to minimise the overall system cost.
- Hence, the assumptions related to the volume of bioenergy and emissions that can be offset through BECCS is essential in the overall energy system planning. Given the assumptions, BECCS can offset about 65 $MtCO_2$/year out of 80 Mt CO_2/year. The rest of the emissions (up to 15 $MtCO_2$/year) needs to be offset by DACCS.
- It is important to note that the model does not optimise offsetting action outside the energy sector.

Strong multi-energy system interactions

- The substantial changes in the energy infrastructure led by different heat decarbonisation scenarios suggest that coordinated energy system optimisation across all energy vectors considering simultaneously short-term operation and long-term investment timescale is vital. For example, the study has demonstrated:
  - Strong interactions across various system components, especially power, heat, gas (NG, hydrogen), and multiple energy storage technologies;
  - Sector coupling optimisation is essential, for example, the portfolio optimisation of BECCS (hydrogen, methane, and electricity) due to limited bioenergy resources, optimal operation of hybrid heating systems, the selection of heating technologies for DACCS and H2 production mix (gas-based, electrolysers, and BECCS);
  - DACCS, BECCS, hydrogen-fuelled generation, and enhanced system flexibility improve the system ability to integrate RES and reduce the need for firm low carbon generation such as nuclear and CCUS.
- It also highlights the need for a holistic and integrated decarbonisation strategy for electricity, heat and cooling, gas, and transport. A silo decarbonisation strategy will lead to suboptimal systems and increase the overall system costs

Efficiency and flexibility of heating appliances

- The heat demand during the coldest winter condition drives the heating system's capacity. This assumption becomes less relevant for gas heating since the boiler capacity (24 kW_{th}), driven by the need to provide instantaneously hot water, is above the peak demand. For heat pumps, this assumption is essential. Colder temperatures will drive a higher capacity of heat pumps and vice versa.
- The availability of thermal storage can also drive HP capacity. Thermal storage can increase heat flexibility and reduce the size of heat pumps.
- Heat pumps are the most energy-efficient heating appliance with a modelled coefficient of performance (COP), ranging between 200% and 450%, while the efficiency of natural gas or hydrogen boilers is only around 90%.
- Heat pump performance (heat output and COP) is adversely affected by air temperature, but hybrid heat pumps can compensate for it by operating natural gas or hydrogen boilers. Heat pumps supply most of the heat demand in the hybrid system, but the optimal use of gas-based heating can help to reduce electricity system capacity requirements.

The pros and cons of each decarbonisation scenario are summarised in Table 4.1

Table 4-1 Pros and cons of different heat decarbonisation scenarios

Scenarios	Pros	Cons
Hydrogen	Lower-cost heat appliances (boilers) Diversified low-carbon sources It does not stress the capacity of the electricity system Utilise existing gas distribution infrastructure upgraded to H2 compliance	Lower energy conversion efficiency Cost of "Green" hydrogen, RES-based H2 production is high, while "Blue" hydrogen relies on NG (fossil fuel), which is not renewable and has residual emissions. Sensitive to gas price High investment in H2 infrastructure
Electrification (HP)	High energy conversion efficiency, COP of HP > 2 Integrate high RES Lowest NG consumption (less sensitive to gas-price fluctuation) Low operating cost Allow flexibility from the electric heating system to support system balancing	High-cost heat appliances (heat pumps) Sensitive to the uncertainty in HP cost Sensitive to HP sizing and weather conditions Substantial increase in power system capacity
Hybrid with NG (HHP-NG)	Use HP to provide base heating demand and <10% NG boiler Similar to the benefits obtained in electrification Allow fuel switching flexibility from electricity to gas-based heating Relieve capacity requirement from the power system by utilising existing gas distribution assets Resilience heating system	High-cost heat appliances (hybrid heat pumps) Sensitive to the uncertainty in HHP cost Increased emissions from heating that need to be offset by negative emissions technologies (BECCS and DACCS)

Scenarios	Pros	Cons
Hybrid with H2 (HHP-H2)	Similar to HHP-NG but with a greener gas-based heating system with no emissions	Similar to HHP-NG but with a lower energy conversion efficiency and higher H2 storage since heating demand is seasonal

Electricity system

- The results indicate that offshore and onshore wind, solar PV, and nuclear will be the primary low-carbon electricity sources. More than 75% of the total electricity generation comes from wind power and between 6% - 8% from nuclear, solar PV, and biomass with CCUS. The remainder comes from hydrogen and natural gas plants with and without CCUS – unabated gas plants are operated very infrequently.
- Gas plants, including hydrogen-fired plants, conventional gas CCGT, OCGT, and gas CCUS, hydro, and storage, will support system balancing supplemented by system services from demand response technologies.
- The generation mixes and the locations are optimised to minimise the overall system costs, considering the temporal and spatial diversity of resources. Wind farms are located more in the north of GB, where the capacity factor is high, while solar PV is located more in the south.
- Electrification of heat drives the increase in peak demand and electricity consumption, and therefore, it drives the highest electricity system capacity (generation, transmission and distribution network) required compared to the other three scenarios. The use of gas heating in H2 and hybrid scenarios reduces the demand for the electricity system capacity of generation and electricity network.
- The results of the 50% network headroom sensitivity underscore just how uncertain electricity distribution network costs can be – they can vary widely with different levels of headroom, especially in high electrification (ELEC) scenarios. These costs should be used cautiously due to the large amount of uncertainty around network headroom on the secondary distribution network.
- In all scenarios, the role of hydrogen-fired power generation is essential. It can support short-term balancing and strengthening the sector-coupling between the hydrogen system with electricity by enabling the conversion from hydrogen to electricity. Hydrogen can be produced via electrolysers that minimise the curtailment of renewable energy. By having a two-way energy conversion between electricity and hydrogen, the hydrogen system's flexibility can also benefit the electricity system.
- Electricity production from the UK is competitive compared to continental Europe, most likely driven by low-cost wind resources. Between 40 and 60 TWh of excess electricity produced in the UK can be exported to Europe annually. The estimated revenue from electricity export is between 2.4 and 3.2 £bn/year.
- Although the volume of electricity exported is higher than imported, occasionally, electricity is imported from Europe, particularly during the peak demand period or when

the supply system is scarce. Having robust interconnected systems between the GB and Europe is vital and benefits both systems.

Hydrogen system

- Hydrogen provides a flexible and firm source of low-carbon electricity generation. Most of the hydrogen comes from methane through ATR+CCS and the rest from bioenergy and electrolysers. Therefore, the role of CCUS in hydrogen production is essential to minimise the emissions from hydrogen processes.
- Bioenergy is used to produce mainly power, but some may be used for hydrogen production in some cases (e.g. high gas price).
- As hydrogen for heating is seasonal, hydrogen storage is needed to optimise the hydrogen production capacity factor. The need for hydrogen storage depends on the hydrogen demand and supply profiles. In Elec and HHP-NG, most of the hydrogen demand comes from industry and a small proportion from power generation, while in H2 and HHP-H2, a substantial amount of hydrogen is required for heating which has a variable demand profile. Therefore, the volume of hydrogen storage in H2 and HHP-H2 is higher than in Elec and HHP-NG cases. More distributed hydrogen storage should also be added across the system to maintain gas distribution pressure, enabling hydrogen delivery for heating and electricity production needed to meet peak demand.
- Around 5.5 – 14.1 TW-km of hydrogen transmission would need to be built, and both H2 and HHP require more extensive H2 transmission than Elec and HHP-NG.

CCS network

- The assumption has been made that CCUS facilities are based on the coast at gas import terminals with access to offshore infrastructure for sequestration and storage. However, a CCUS network is also needed to transport CO_2 captured from BECCS facilities to coastal CCUS facilities. Some allowance has been made for terrestrial CO_2 infrastructure for BECCs technology, but the deployment of BECCS has not been examined in detail as it also requires access to feedstock and hydrogen infrastructure. Hence further investigation is warranted.

Impact of energy system flexibility

- Improving energy system flexibility by enabling load shifting and providing ancillary system services is essential for the system that relies on variable renewable energy sources. Flexibility has a more profound impact on the electricity system as balancing and storing electricity is more challenging than other systems such as gas which has inherent energy storage. The value of flexibility varies in different scenarios, as follows:
  - H2: up to £6.4 £bn/year
  - ELEC: up to £10.8 bn/year
  - HHP-NG: up to £6.5 bn/year
  - HHP-H2: up to £5.3 bn/year

- Hybrid heating systems provide significant flexibility through optimising the use of natural gas or hydrogen and electricity (IWES inherently optimises this). The use of gas heating in the hybrid system to reduce the power system capacity needed is beneficial as it reduces costs.
- Lack of flexibility from demand response and energy storage leads to higher Opex and Capex of electricity and hydrogen infrastructure due to increased peak demand. It also increases the need for CCUS and the volume of carbon sequestration and reduces the system ability to integrate variable renewable energy sources.

Impact of less-cost effective ATR

- ATR with CCUS is the primary technology for hydrogen production besides electrolysers and hydrogen BECCS. 10% efficiency reduction and a 73% uplift in the cost of ATR will increase the annual system costs by 1.5 – 3.8 £bn/year. H2 is the most affected scenario, while HHP-NG has the least impact.
- Less cost-effective ATR leads to increased investment in low-carbon electricity, higher hydrogen production cost with more electrolysers and BECCS, hydrogen storage, and DACCS. More bioenergy is allocated for hydrogen production.
- It reduces hydrogen in the power system and incentivises more nuclear, RES and gas CCUS.

Impact of low and high gas price

- Since natural gas is still the primary source of hydrogen, a low gas price reduces the cost of all scenarios between 3 – 6 £bn/year. The cost of the H2 scenario is more sensitive to fluctuation in gas price. H2 is the most cost-effective scenario if the gas price is low. If the gas price is high, the cost of H2 is on par with ELEC.
- The low gas price shifts demand from electricity to hydrogen. It increases natural gas usage for hydrogen production and gas heating, reducing bioenergy for hydrogen. More bioenergy is allocated to produce electricity.
- A higher volume of methane consumption leads to a higher carbon sequestration volume and increases the demand for DACCS with hydrogen heating.
- A low gas price incentivises more gas heating. Especially in the HHP-H2, it increases the seasonal effect of hydrogen demand which triggers more hydrogen storage.
- The impact of a higher gas price does the opposite. The energy demand is shifted from hydrogen towards electricity, and therefore, more low-carbon generation needs to be built, including nuclear and gas CCUS.

Impact of lower or higher domestic heating demand

- 19 TWh reduction of domestic heat demand from the core scenario will save the system between 0.8 and 1.6 £bn/year, while 23 TWh increase in domestic heat demand will cost the system 0.9 – 2.0 £bn/year. The impact is less profound in HHP-NG scenario.
- Reducing domestic heat demand reduces the costs of electric heating appliances, electricity and hydrogen systems, DACCS and carbon storage. It reduces natural gas usage and, consequently, the volume of carbon sequestration and DACCS.

- Reduction in domestic heat demand does not change each scenario's heat supply characteristic. For example, NG boilers' usage is still less than 8%, hydrogen boilers less than 18%. Heat pumps still supply the heat baseload in hybrid cases.

Impact of milder cold winter

- The most affected scenario is ELEC, where the size of heat pumps can be smaller, bringing savings in heat pump costs and reducing other system costs. The additional system cost to cover the cold winter is between 0.8(HHP-NG) and 3 £bn/year (ELEC). In the “milder cold” scenario, HHP-MG is still the least-cost decarbonisation strategy, but the difference with ELEC becomes smaller (circa £1bn/year). The savings come from reducing the cost of electric heating and the electricity system capacity requirement due to lower peak demand, around 9 GW less distribution and generation capacity. It also requires less hydrogen infrastructure and Opex.
- The impact is less profound in H2, HHP-NG, and HHP-H2 since gas heating already minimises the impact of heat demand on electricity peak demand. The gas usage is less in the “mild” scenario in hybrid cases.
- Milder cold winter also reduces the seasonality strength of heat demand and subsequently, hydrogen demand in H2 and HHP-H2. Therefore, hydrogen storage's capacity requirement can reduce substantially by 0.9 – 1.9 TWh.

Impact of improving COP of HPs

- Around 30% COP improvement of HP reduces the annual system costs by 0.7 – 4.8 £bn/year. The largest benefit is for ELEC and the lowest benefit for H2.
- The savings mainly include reducing the electricity generation and distribution infrastructure, electricity Opex, reducing HP size, and cost.
- COP improvement also increases the use of HPs in the hybrid system and reduces gas heating. In HHP-NG, it reduces the heat emissions from NG boilers, and therefore, it requires less DACCS. It also reduces hydrogen infrastructure Capex and Opex due to less hydrogen demand for heating in HHP-H2.

Impact of non-optimal gas usage in hybrids

- 100% increase in gas heating usage in HHP-NG and HHP-H2 costs 1-1.5 £bn/year.
- In HHP-NG, the cost also increases due to a higher requirement for DACCS to offset increased emissions from NG boilers' non-optimal usage.
- In HHP-H2, the cost increases due to higher hydrogen demand for heating, increasing the hydrogen Opex and Capex. It also increases the volume of carbon stored.
- The increased gas heating usage decreases the electricity demand and peak, reducing the electricity system capacity requirements, Capex and Opex. However, the electricity system's benefit is smaller than the increased cost.

Impact of mixed roll-out decarbonisation scenarios

- The mixed roll-out affects the annual system costs of different scenarios by -0.5 to 2.5 £bn/year. The cost in H2 increases by £2.5 bn/year, while the regional usage of H2 in the North and electrification to decarbonise heating in the South reduces the annual cost by £0.5bn/year. In comparison, the increased cost in the hybrid systems is around £1bn/year.
- In H2, the increased cost is primarily driven by the increased cost of electric heating appliances and the supporting electricity infrastructure. The cost is offset by the cost reduction in hydrogen heating appliances, hydrogen production Capex and Opex.
- In ELEC, substituting HPs in the North with hydrogen boilers reduces the electricity cost and HP cost, compensating for the increased cost from hydrogen boilers Capex and increased hydrogen infrastructure Capex and Opex.
- The system implication is marginal in hybrid systems because the systems already rely on HPs as the primary heating source. The increased cost is driven primarily by the cost of HPs, which is slightly higher than the cost of HHP.

Comparison across scenarios

- The worst-case situation where all scenarios' cost is maximum is where the system has low flexibility, with ELEC being the most affected scenario.
- The low gas price and flexibility level assumed in the core scenario will bring the cost of H2, HHP-NG and HHP-H2 at the minimum. In comparison, the minimum cost for ELEC is found when there is around 30% improvement in HP’s COP.

Appendix A. Key assumptions and setup of the core studies

A.1. Heating appliances

Annuitised Capex and fixed O&M cost of various domestic heating appliances can be found in Table A- 1. Installation cost and future cost reduction due to deployment of HP or hybrids are included. The cost of a heat pump system includes the conversion cost from gas heating to heat pump system assuming wet heating applications. The cost of heat pump for direct electric homes compared to hybrid heating homes are shown in the table below.

Table A- 1 Cost of domestic heating appliances[68]

Technology	Annuitised CAPEX and O&M (£/unit per year)	Size (kW_{th})	Lifetime (years)
Hydrogen gas boiler	340	24	15
Heat Pump	750	10	20
Hybrid with gas boiler	600	3(HP) 24 (gas boiler)	20
Hybrid with hydrogen boiler	610	3(HP) 24 (hydrogen boiler)	20

The model optimises the size of HP for the stand-alone and hybrid application using linearised cost.

The size of non-domestic heating appliances will be larger than the domestic ones, and therefore, the cost per kW capacity will be lower by 5% - 15% due to economies of scale. As IWES considers the aggregated heat demand profile after diversity, the size of the heating appliances is multiplied by a factor of 2.3[69]

The average cost of district heating network infrastructure is around £6k per dwelling covering all costs needed to take heat from a central source and deliver it to a number of domestic and non-domestic buildings via insulated pipes. In addition, the connection cost of district heating to buildings is around £8k per dwelling. This includes cost of connecting district heating network to the building heating system, metering system, heat interface unit and the installation costs. For retrofitting, the average conversion cost is around £2k per dwelling. It includes gas pipe removal, installation of hot water storage, and replacement of gas appliances.

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[68] Delta EE.," The Cost of Installing Heating Measures in Domestic Properties, July 2018

[69] Love et al., "The addition of heat pump electricity load profiles to GB electricity demand: Evidence from a heat pump trial," Applied Energy, Vol. 204, 2017, pp. 332-342

A.2. Electricity generation

Some assumptions for low-carbon generation technologies in 2050 are summarised as follows:

Table A- 2 LCOE and capacity range of low-carbon power generation technologies

Technology	Estimated LCOE[70] (£/MWh)	Minimum capacity[71] (GW)	Maximum capacity[72] (GW)
PV	40	15	120
Onshore wind	45	15	60
Offshore wind	40	40	120
Nuclear	80	5	40
Gas CCUS	60	2	30

All costs here and elsewhere in the report are in the 2018 price level.

Other generation technologies considered in the model include hydrogen or natural-gas-fired combined cycle gas turbine (CCGT) and open-cycle gas turbine (OCGT), and biomass with CCUS (BECCS to power), and hydro. Except for hydro capacity (and pumped hydro storage), which is fixed to the present capacity, all other capacities are optimised by the model. The annuitized fixed cost for NG or hydrogen CCGT or OCGT is assumed identical, as shown in Table A- 3.

Table A- 3 Annuitised cost for CCGT, OCGT, and battery energy storage

Technology	Annuitised Capex including fixed Opex (£/kW per year)
NG/H2 CCGT	70.2
NG/H2 OCGT	37.3
Battery storage (2h capacity)	74.6

A.3. Interconnection

Unless otherwise stated, the study assumes 17.9 GW interconnection capacity between the UK and the neighbouring regions. The study considers the existing interconnectors and new interconnectors projected to be built in the future. Interconnection capacity is optimised to balance the electricity system and improve system flexibility.

70 Source:BEIS, Electricity generation cost 2020, link: https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020

71 Source:BEIS, Modelling 2050 – electricity system analysis, link: https://www.gov.uk/government/publications/modelling-2050-electricity-system-analysis

72 Ibid.

A.4. Electricity distribution headroom

Unless otherwise stated, the study assumes no headroom on distribution network capacity. The increased electricity peak demand (from the transmission grid supply) due to electrification or load shifting will trigger distribution network capacity reinforcement.

It should be noted that this is a conservative assumption, as data from DNOs indicates that most distribution level primary substations still have significant amounts of spare thermal capacity. This spare capacity could also be present downstream at the secondary substation level, but data on the latter are very sparse. High levels of network headroom would lead to lower distribution network reinforcement costs – however, data on network headroom varies hugely by location and is very patchy at the Low Voltage level. Therefore, the analysis also includes a sensitivity study, using a "50% headroom" scenario to analyse the impact of high headroom levels on network costs. This scenario was created using averaged data on distribution network primary substation utilisation across Great Britain from DNOs' Long Term Development Statements.

A.5. Hydrogen production technologies

The methane reforming technology available to IWES in this study includes Auto Thermal Reformers (ATR) with CCUS[73]. Hydrogen from gas reforming is produced in a centralised manner to benefit from economies of scale. It constrains production to coastal sites with access to natural gas terminals and offshore CO_2 storage, reducing the national CCUS network's need[74]. Studies carried out by Imperial in 2018[75] demonstrated that the centralised approach is more cost-effective than the distributed approach.

Three different electrolyser technologies for hydrogen production from electricity have been included: Solid Oxide Electrolyser (SOE), Alkaline, and Proton Exchange Membrane (PEM). The technologies' cost and key technical parameters are summarised in Table A- 4.

Table A- 4 Cost, efficiency, and capture rate of different hydrogen production technologies[76]

Technology	Capex (£/kW)	Fixed Opex (£/kW/year)	Efficiency (%)	CO2 Capture Rate (%)
ATR + CCUS	364	24.4	89%	96%
Solid Oxide Electrolyser	700	50.0	84%	
Alkaline	455	21.7	82%	
Proton Exchange Membrane	340	23.8	82%	

[73] Due to ATR's higher efficiency, CO_2 capture rates and lower cost than traditional Steam Methane Reformers (SMR).

[74] There is a need for a national CCUS network for BECCS driven by its distribution across the GB

[75] G.Strbac, D. Pudjianto, et al,"Analysis of Alternative UK Heat Decarbonisation Scenarios", a report to the Committee on Climate Change, June 2018. Available at: https://www.theccc.org.uk/wp-content/uploads/2018/06/Imperial-College-2018-Analysis-of-Alternative-UK-Heat-Decarbonisation-Scenarios.pd

[76] Source: Element Energy, Hydrgen supply chain evidence base, 30 Nov 2018. Link: https://www.gov.uk/government/publications/hydrogen-supply-chain-evidence-base

Biomass Gasification + CCUS (H2 BECCS)	1,142	43.9	54%	95%

The assumed parasitic electricity load for ATR+CCS is 0.04 MW/MW output and H2 BECCS 0.25 MW/ MW output.

A.6. Availability of bioenergy and biogas

Another source of hydrogen considered in this study is bioenergy. It is assumed that 177 TWh/year of bioenergy (from purpose-grown feedstock) is available and converted into either electricity, hydrogen or biomethane via biomass gasification with CCUS. It is exclusive of biomass and biofuels used directly in industry and transport (based on BEIS' UK TIMES analysis) and biomass feedstocks which cannot be used in clean gasification. The costs of processes required to utilise this bioenergy to decarbonise other sectors are not included in the results.

The capital cost of biomass gasification with CCUS infrastructure and the fuel costs are considered in the optimisation model. The transport cost of biomass is included in the cost analysis. As bioenergy resources are distributed across the GB, the BECCS plant may need CCUS infrastructure to transport CO_2 to the offshore storage. The distribution of bioenergy[77] is shown in the table below.

Table A- 5 Bioenergy resources across the GB

	Bioenergy resources
North Scotland	15%
South Scotland	10%
North West England	8%
North East England	10%
North Wales	16%
East Midland	3%
West Midlands	9%
East England	6%
South West England	12%
South East England	12%
Total	100%

A.7. Hydrogen network

The model assumes that the existing national gas transmission is not suitable for large-scale transport of hydrogen, and there is still a need to transport natural gas for the methane reforming process, power generation, and gas heating. Therefore, it is assumed that the national natural gas transmission network (NTS) will be retained in all scenarios. Considering

[77] Derived data from Di Zhang et.al. Unlocking the potential of BECCS with indigenous sources of biomass at a national scale. Sustainable Energy and Fuels, 2020

that hydrogen demand from sectors other than heat is substantial in all scenarios, irrespective of whether the heating is decarbonised using hydrogen or not, a new national hydrogen transmission infrastructure will be needed. The model optimises the capacity of the hydrogen transmission.

For gas distribution, it is assumed that in the H2 and HHP-H2 scenario, the gas distribution is converted to be 100% hydrogen compliant[78]. In the HHP-NG scenario, the natural-gas-based distribution network is retained. In the ELEC scenario, only a fraction of gas distribution that has been converted to be 100% hydrogen compliant is retained to supply industrial hydrogen demand with the remainder decommissioned. The decommissioning cost is included in the total cost.

A.8. Hydrogen storage

Two hydrogen storage technologies[79] are modelled:

- Underground storage: it is assumed that underground storage is used as centralised and long-term hydrogen storage. There is a restriction associated with the discharge of the storage (10% of the energy stored/day) to maintain a "gas cushion" for storage stability.
- Overground medium-pressure storage: it is assumed that this is used as distributed storage close to high energy demand locations to support the gas supply to meet the localised peak demand. This storage is flexible as it can be discharged or charged rapidly.

A.9. Carbon prices and carbon capture

No explicit carbon price is assumed in the modelling, as the model is set to achieve a specific emissions target. The cost of storing carbon at the carbon storage terminal is assumed to be £15/tCO_2 [80], including the Capex and Opex of the offshore carbon storage system.

CCS network, which might be needed for industrial CCUS, is not included in this study.

A.10. Direct air carbon capture and storage (DACCS)

DACCS is an important technology to achieve net-zero emissions, as demonstrated in this report. The operation of DACCS consumes electricity and heat. Two low-carbon heat sources are considered: (i) DACCS with hydrogen boilers and (ii) DACCS with electric heaters. The IWES model will optimise the portfolio of DACCS to maximise the synergy with the energy system in question.

A.11. Comparison between temperature scenarios

Unless otherwise stated, the study uses a temperature profile ("Central"), as shown in Figure A-1. The "Central" temperature profile is compared with the historical Normal temperature profile from the year 2004. The key parameters of both profiles are compared in Table A- 6.

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78 Replacing iron pipes with polyethelene pipes in the Iron Mains Replacement Programme supports the use of hydrogen; in addition, there will be a need for distributed hydrogen storage, meters, sensors, compressors.

79 Modelling data of the hydrogen storage are obtained from Element Energy (2018) Hydrogen for heat technical evidence project.

80 Ibid.

While both profiles' average temperature is similar, the “Central” profile has colder winter and a higher maximum temperature in summer. The objective of using a more peaky profile is to ensure the system is designed to cope with such extreme conditions.

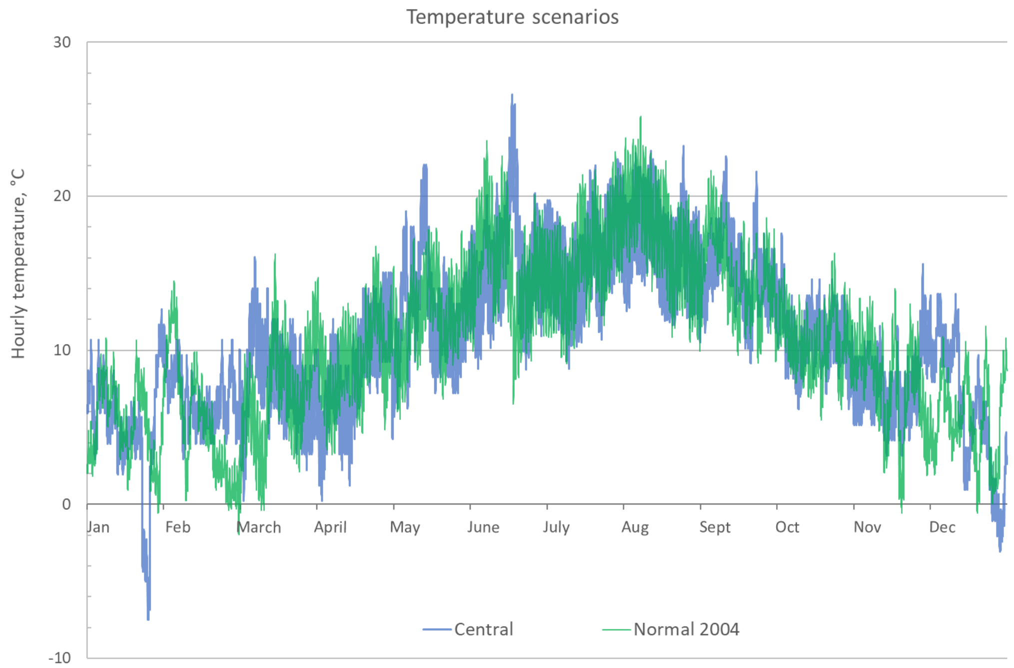

Figure A-1 Temperature scenarios

Table A- 6 Temperature scenarios' key parameters

	Central	**Normal (2004)**
Daily max	23.10	21.70
Daily min	-6.43	0.50
Average	10.63	10.55
Winter average	5.83	5.37
Summer average	16.07	16.28
Hourly max	26.60	25.20
Hourly min	-7.51	-1.97

Appendix B. External Review

Prof Tony Roskilly from Durham University reviewed the report and identified future topics related to energy system analysis/modelling.

B.1. Modelling approach and key findings

The IWES modelling tool developed for this study enables the opportunity to gain extremely useful insights and provides new evidence to allow future heating and the wider energy system to be planned. The model provides spatial granularity and simultaneously optimises operation and investment in local district and national/international level energy infrastructure, including energy-flow interactions with mainland Europe via interconnectors. The IWES model also provides temporal granularity, taking into account real-time balancing of supply and demand while considering essential changes in the system inertia, the use of flexibility technologies including energy storage, demand-side response and interconnectors, which will be critical in the future zero-carbon energy system which includes a very significant contribution from renewable generation sources. The analysis offers new evidence of the drivers that determine the annual system costs for the pathways chosen and the opportunity to explore other options. The key findings of this analysis are:

- All heat decarbonisation pathways can reach net-zero emissions at comparable 2050 total annual costs with a marginal difference in costs (less than 5%). However, the underpinning energy infrastructure and operation across different pathways can differ very significantly – the analysis demonstrates the importance of coordinated multi-energy system planning and operation, which should inform the development of appropriate heat decarbonisation policies, regulatory and market arrangements to guide the transition process.
- In all heat decarbonisation pathways, improving energy system flexibility by enabling load shifting and provision of ancillary services through demand-side response, energy storage, and cross-vector alignment is essential given the very high penetration of variable renewable generation. The benefits of improving flexibility are the highest in the heat electrification pathway, as expected.
- CCUS, BECCS, and DACCS play a critical role in achieving the UK's net-zero GHG emission target (as the energy sector is expected to deliver negative emissions). All pathways indicate that synergy between hydrogen and electricity systems is a significant feature.

Hybrid heat solutions require the delivery of natural gas or hydrogen through the gas transmission and distribution network. Naturally, these pathways provide resilience through the use of two energy vectors to provide heat. However, this will increase CAPEX for each home. The report states that system cost may not be visible directly by consumers, and therefore choosing the lowest heating cost may not be optimal from the system perspective. This may be true because of overriding concerns over the security of supply and system resilience. However, the cost burden, in that case, will be indirectly met by taxpayers and consumers. Heat technology efficiency is not the most important factor and should not over-dominate the conclusions drawn from such studies. High domestic appliance CAPEX required by homeowners will make it difficult for any pathway to be adopted. The cost of providing heat is the most important factor and the requirement to supply affordable heating that provides the right comfort level.

B.2. Need for further analysis/energy system modelling

Based on the assumptions made and the limited sensitivity analysis conducted, all modelled pathways could achieve net-zero CO_2 emissions and neither produced a significant difference in total annual costs. The differences between the core and the sensitivity analysis results were much smaller than the range of uncertainty in the assumptions used and the modelling exercise. As a result, it is not possible to conclude that any of the pathways modelled can be considered an optimum solution around which to make clear policy decisions can be based. It indicates that more work is required to understand the potential energy mix better to transform heating by 2050. While the report provides very useful insight on the impact of different factors, the sensitivity studies explore a limited number of perturbations, and it would be beneficial that these are extended in future.

Several topics are being identified during the review process to be considered in future studies:

1. Inclusion of all Greenhouse Gases (GHG) such as nitrous oxides (NOx) and methane.
2. Uncertainty in large-scale deployment of DACCS as the efficacy of these technologies is far from certain. A sensitivity analysis should be conducted to explore various CAPEX and OPEX scenarios to understand the potential contribution of this technology on the decarbonisation of heat and the possible synergy between DACCS and other thermal plants (geothermal, solar thermal, nuclear heat).
3. The sustainability of biomass sources should be addressed and consider its transportation, particularly if imported. The CAPEX and OPEX for BECCS are uncertain, and a sensitivity study would be important to understand the cost associated with offsetting CO_2 emissions elsewhere. Nitrous oxide emissions also need to be considered to determine whether the plant results in net negative GHG emissions.
4. Uncertainty in costs assumed for CO_2 storage and the corresponding impact on different pathways should be considered.
5. Uncertainties in the costs of technologies and financing costs: the modelling results are dominated by infrastructure capital and financing costs, and there is significant uncertainty in this area, making it extremely difficult to draw concrete conclusions. There have been significant cost reductions in offshore wind, PV and lithium-ion battery technology over a short time because many factors have changed the energy landscape. The same is possible for the technologies which are explored in this study. Therefore, it is necessary to conduct a more extensive sensitivity analysis to obtain a clearer picture of the impact of capital cost variation.
6. Energy system resiliency - what seems evident from these studies is that multiple energy vectors, primarily hydrogen and electricity, will play an important role to ensure heating is cost-effective and a reliable and resilient system evolves. System failure, extreme weather conditions and other factors, such as shortages of supply, cyber security issues,

domestic and international conflicts, that affect the delivery of heat need to be explored more thoroughly, and potential shocks to the energy system and their impacts should be modelled to design a truly resilient system. It would be sensible to model the impact of a longer period of cold weather and periods with near-zero wind and solar power generation to explore the resilience of the energy system for each pathway.;

7. Sensitivity on COP - the report states that the modelling used a COP of between 2.07 and 4.46, giving a weighted average of 3.11. If this is assumed for ASHP then these figures are very high. Therefore, it is important to conduct a sensitivity study using lower COP values in future studies.

8. To explore the impact of a modified pathway which included blending hydrogen into the natural gas network, for example, a Hybrid with NG+%H2 pathway.

9. Sensitivity on costs of hydrogen production technologies, hydrogen storage and transport - the study indicates a requirement of between 2.6 TWh and 3.6 TWh of hydrogen storage which is very modest since the UK has the potential for an estimated 9000 TWh underground hydrogen storage available in depleted fields and saline aquifers. Major advances in hydrogen storage materials and technology could change the balance between overground and underground storage requirements and the infrastructure costs incurred.

10. The sensitivity studies should be extended to assess the impact of reduced electrolyser CAPEX, improved efficiency of electrolyser, greater use of heat networks etc., which would provide useful insights.

11. An extended study to look at a broader spectrum of incremental reductions and increases in natural gas prices would provide a clearer understanding of its bearing on the optimisation and annual system costs.