

Article

‘Greening’ the UK: A Comparative Study of Heat Pumps and Hydrogen Boilers in Residential Heating

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Abstract

With a key policy decision on the role of hydrogen boilers expected by 2026, the UK is at a strategic crossroads in implementing its Heat and Buildings Strategy. This study evaluates the relative advantages of hydrogen boilers and heat pumps in residential heating, focusing on their impact on national energy demand, which is a critical factor in achieving full decarbonisation by 2050. Using the End-state Decarbonisation Resource Analysis framework, this study demonstrates that electrification with widespread heat pumps could reduce current residential primary energy demand by over 53%, whereas a hydrogen boiler-dominant pathway could increase demand by 42%. When translated into generation and infrastructure requirements, the hydrogen pathway would demand significantly more resources than the heat pump alternative. Incorporating heat pumps into the electrification strategy would make the delivery of net-zero targets more achievable. Notably, heat pumps could deliver nearly six times higher economic benefits than hydrogen, while requiring only 67% of investment needed for additional generation assets. These findings support prioritising heat pumps over hydrogen boilers in the UK’s national residential decarbonisation strategy.

Keywords: decarbonisation; hydrogen; natural gas; heat pump; renewables; nuclear; electricity; energy system; energy policy; energy investment

1. Introduction

With only 25 years remaining until 2050, the UK is at a critical time for developing and implementing effective strategies to achieve its net-zero emission target. The government’s Heat and Building Strategy (the “Strategy”) outlines its approach to decarbonise the building sector, the second-largest source of greenhouse emissions in the country [1]. In the residential sector, natural gas is the dominant heating source, used by over 80% of households [2]. When oil and coal are included, the total proportion of homes reliant on fossil fuels rises to over 90%. Among the main technologies proposed by the Strategy to decarbonise domestic heating, hydrogen and heat pumps are key, yet competing, options due to their divergent infrastructure requirements.

Hydrogen boilers are not yet commercially deployable. Their adoption, especially when utilising green hydrogen as feedstock, would necessitate significant investment in hydrogen production, storage, and transportation infrastructure, requiring transformational structural changes to the existing energy system [3–5]. In contrast, heat pumps can be integrated into electricity transportation networks. Advocates for hydrogen argue that replacing gas boilers with hydrogen boilers would be simpler and more cost-effective for



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British households than heat pumps, as the former could utilise existing gas pipes and water-based heating systems with minimal retrofit requirements [6–8]. In comparison, heat pumps often require significant building interventions, such as radiator upsizing, building fabric and insulation upgrades, or underfloor heating installation to ensure their operational efficiency [9,10].

Safety remains a major concern for domestic hydrogen use [3]. Unlike industrial or commercial settings where strict protocols and trained staff can be ensured, achieving similar safety compliance at home is far more difficult. Some surveys suggest that households view the hydrogen safety risk as more worrying than the disruption caused by heat pump installation [11]. By 2024, all three proposed hydrogen village field trials were cancelled, with safety cited as a main concern among local residents [12,13]. In light of these challenges, hydrogen proponents called for stronger community engagement to reduce the social resistance [14,15].

Amid these debates, the government committed to clarifying the role of hydrogen in domestic heating by 2026, acknowledging the extended timeline required for the deployment of domestic hydrogen boilers, the upgrade of existing natural gas networks to accommodate hydrogen, and the necessary public education on hydrogen safety [16]. This study contributes to that decision by introducing an additional perspective: the impact of both technologies on national energy demand reduction and, consequently, the achievability of net zero. Energy demand, as a key performance metric of energy technologies, is considered a first-tier evaluation criterion for assessing a technology's relative advantage to other competing alternatives within the framework of the Diffusion of Innovations theory [17–19]. Reducing energy demand is of paramount importance in achieving net zero, as doing so will reduce the substantial resources otherwise required in power generation and supporting infrastructure [20]. To the authors' knowledge, using national energy system modelling to directly compare domestic hydrogen boilers and heat pumps remains a gap in the existing literature. This study addresses this gap by examining the following three research questions:

1. How would the adoption of hydrogen boilers or heat pumps in residential heating affect national energy demand in a decarbonised UK in 2050?
2. Under both hydrogen boiler and heat pump scenarios, what would be the technical, financial, and geographical resource requirements for achieving net zero by 2050?
3. Which technology solution requires fewer resource to deliver net zero: hydrogen boilers or heat pumps?

The assessment is conducted by using the End-state Decarbonisation Resource Analysis (EDRA) framework developed by Gao et al. [20]. This method integrates demand estimation, technology assessment, energy computation and cost evaluation to quantify the resources required to achieve net zero. These resource requirements, driven by demand-side technologies, form the basis of an assessment criterion referred to as “net-zero deliverability”. A technology demonstrating the highest relative advantage is expected to require the least resources and, consequently, to exhibit the highest net-zero deliverability.

The study enhances the Diffusion of Innovations theory by applying it in the UK net-zero transition context. It also offers timely guidance to policymakers in advance of the planned decision on hydrogen's role in residential heating in 2026.

The remainder of the paper is structured as follows: Section 2 reviews the relevant literature. Section 3 describes the methodology. Section 4 presents the results. Section 5 discuss the findings, and Section 6 outlines the conclusions and policy recommendation.

2. Literature Review

The diffusion of new technologies within society is a complex process that has been extensively studied through the Diffusion of Innovations theory, originally developed by Rogers [18]. Völlink et al. [19] provide empirical evidence that a new technology is first evaluated for its technical performance and economics prior to considering other attributes. Outcault et al. [17] propose more sector-specific characteristics relevant to energy technologies, such as energy savings or demand reduction. Weber and Rohrer [21] apply Diffusion of Innovations theory to the context of energy transition, emphasising the critical role of policy in addressing the complex and long-term challenges in this domain.

In the literature on country-level decarbonisation, three studies on Libya explore the magnitude of power generation capacity from wind, solar, nuclear, electrolyzers, and Combined Cycle Hydrogen-fuelled Turbines (CCHTs) required to transition from an oil-based economy to a green hydrogen economy [22–24]. They highlight the substantial equipment and land and sea areas needed to decarbonise Libya. Gao et al. [20] extended their approach by developing the EDRA framework and by applying it to the UK under a direct electrification scenario, which assumes that the direct supply of decarbonised electricity would become the dominant fuel source in 2050. Their results indicate the substantial resource required to reach net zero. In their base generation scenario, the UK would need 81 GW of nuclear, 119 GW of offshore wind, 29 GW of onshore wind, and 70 GW of solar capacity, supported by over 188 GW of electrolyzers for green hydrogen production and CCHTs for backup power. Capital investment for these assets could exceed GBP 891 billion in addition to existing commitments. The land and sea footprint required for wind and solar farms alone could equal ~85% of Wales and ~3% of UK waters.

When combined with the need for grid upgrades, technology development, project coordination, community acceptance, supply chain expansion, and workforce training—all needed within 25 years—this transformation surpasses all current government targets and presents substantial implementation challenges. These challenges raise serious concerns regarding the achievability of net zero and underscore the urgency to reduce energy demand and, consequently, generation requirements.

Residential heating represents a critical area where such demand reduction can be achieved. By 2023, residential energy use ranked as the second highest sector in fossil fuel usage, accounting for approximately 14% of total primary energy demand in the UK [25]. Decarbonising this sector using green hydrogen involves producing green hydrogen via electrolysis, which is then used to fuel hydrogen boilers in homes. Assessment of the energy demand is closely linked to the energy efficiency at each stage of energy conversion.

Based on a meta-review of 54 studies, Rosenow [26] suggests that the widespread use of hydrogen for building heating is constrained by low energy efficiency. The study estimates ~31% energy loss converting from electricity to useful heat, with a hydrogen boiler efficiency at 90%. Vakkilainen [27] reports that modern natural gas boilers can reach 94% efficiency. Assuming hydrogen boilers eventually reach the same level, the combustion loss will still be 6%.

The most commonly used technology for large-scale hydrogen production is alkaline water electrolysis, which typically operates at 63% to 71% efficiency [3].

Additional losses occur during hydrogen storage and transportation. As both remain at an early-stage of development, efficiency references are often made to natural gas [28,29].

Large-scale long-duration storage options include underground salt caverns and depleted oil and gas fields, which are preferred over above-ground tanks due to the cost advantages [28,30]. Losses during hydrogen injection and withdrawal arise primarily from compression, processing, gas migration, and mixing with other gases or reservoir

characteristics [30]. The withdrawal efficiency, reflecting these losses, has been estimated at over 90% for salt caverns [31] and 78–83% for depleted gas fields [32].

While these losses are present in a national energy system in which hydrogen is deployed, boiler efficiency is the most relevant metric for comparison with heat pumps in residential settings. Heat pumps are a well-established technology capable of significantly reducing the energy demand, owing to their superior energy efficiency in space and water heating applications [33]. These systems operate by extracting ambient thermal energy, either from the air in the case of air-source heat pumps or from the ground in ground-source heat pumps, and transferring it indoors using electricity. This extracted thermal energy, referred to as “heat earned”, contributes to the high energy efficiency of heat pumps. The efficiency of heat pumps is typically measured using the seasonal coefficient of performance, also called the Seasonal Performance Factor (SPF), which represents the ratio of useful heat output to electricity input over a heating season. SPF values are generally considered to be in the range between 200% and 400%, indicating that heat pumps can deliver two to four units of thermal energy for every unit of electricity consumed [34].

In addition to the ambient temperature, achieving the high efficiency potential of heat pumps relies on the user behavioural adaption to heat pump technology, building fabric upgrade, installer competency, and technological advancements by manufacturers [1,34,35]. Table 1 summarises the SPFs reported by three key studies: a government report, a field trial summary, and a consumer use case [10,36,37].

Table 1. UK residential heat pump SPFs.

Source	Type	Flow Temperature	SPF
Sixth Carbon Budget [37]	Air-sourced	40 °C	300–345%
		45 °C	373% ¹
		50 °C	254–292%
	Ground-sourced	40 °C	326–375%
		50 °C	284–327%
Field trials [36]	Air-sourced	≥45 °C	150–390%
Consumer case study [10]	Air-sourced	45 °C	322%

¹ Based on the best-case scenario, which assumes technology advancement.

While heat pumps are primarily applied in buildings, hydrogen has broader applications including energy storage, backup power, and grid balancing. Hydrogen is expected to play an important role in hard-to-decarbonise segments across multiple sectors, particularly aviation and industry [38,39]. While electric batteries and pumped hydro are well suited to short and medium energy storage, hydrogen provides a complimentary solution by enabling long duration and inter-seasonal storage [40].

3. Methodology

The EDRA framework developed by Gao et al. [20] is a simplified approach for national energy system modelling. It assumes a nation has achieved full decarbonisation through a specified technological solution. By linking energy demand, fuel supply, and energy generation, the method estimates the required generation capacity and associated resources to meet the nation’s final end-use demand under that solution. It is particularly suited to comparing the resource needs of different technological options, providing a preliminary feasibility assessment before undertaking more complex modelling. Gao et al. [20] applied this approach to assess the resource requirements of the direct electrification scenario. Building on this work, this study compares hydrogen boiler and heat pump options.

The framework comprises four interlinked models: an energy demand model, a replacement fuel technology model, an energy supply model, and an economic assessment model. The model navigation follows six steps, as outlined below and illustrated in Figure A1 in Appendix A.

- **Energy Demand Model**
Step 1: forecast 2050 total energy demand based on the continuation of the current fuel supply structure.
- **Replacement Fuel Technology Model**
Step 2: estimate sector-specific replacement factors to determine the extent of fuel substitution required across various sectors.
Step 3: calculate annual replacement energy in 2050 for electricity and other fuel sources based on projected sectoral transitions.
- **Energy Supply Model**
Step 4: generate hourly demand profiles in 2050 for electricity and other fuel sources.
Step 5: determine power, energy, and equipment requirements, and construct generation scenarios to meet the projected demand.
- **Economic Assessment Model**
Step 6: estimate generation and storage costs associated with each scenario, evaluating the economic benefits relative to a no-action baseline.

3.1. Energy Demand Estimation

In Step 1, the 2050 demand forecast assumes the continuation of the current sectoral fuel supply structure, using 2023 as the reference year. This represents a static energy demand assumption, enabling the analysis to focus on comparing heat pumps and hydrogen boilers, while keeping other variable assumptions consistent.

Consistent with Gao et al. [20], this study adopts the UK government's energy classification system as outlined in Table 1.1 of the Digest of UK Energy Statistics (DUKES) [25]. The total energy demand is defined to include the energy supplied by coal and its products, oil and petroleum products, natural gas, bioenergy and waste, renewables electricity, nuclear electricity, imported electricity, heat sold via purchase agreements, and energy transportation losses. As shown in Table 2, fossil fuels accounted for 80% of the UK's total energy demand. When including other non-zero-carbon fuel sources such as bioenergy, biodegradable waste, and imported electricity imports via interconnectors, this share rises to 92% or 1692 TWh.

Table 2. UK energy demand and fuel supply by sectors in 2023. This table is based on the UK government's energy classification system in DUKES. The total demand includes fossil fuels for energy use, which are assumed to result in CO₂ emissions, and excludes fossil fuels for non-energy use. Losses include those occurring during fuel transmission and distribution.

Fuel Source	Sector	2023 Demand TWh	% of Total
Coal Products	Electricity	15	1%
	Heat Networks	0	0%
	Industrial	33	2%
	Rail	0	0%
	Residential	3	0%
	Commercial and Public	0	0%
	Others	0	0%
	Losses	1	0%

Table 2. *Cont.*

Fuel Source	Sector	2023 Demand TWh	% of Total
Oil and Petroleum Products	Electricity	5	0%
	Heat Networks	1	0%
	Industrial	74	4%
	Road transport	410	22%
	Rail	7	0%
	Aviation	143	8%
	Shipping	9	0%
	Residential	24	1%
	Commercial and Public	27	1%
	Others	14	1%
Natural Gas	Electricity	206	11%
	Heat Networks	26	1%
	Industrial	137	7%
	Road transport	1	0%
	Residential	237	13%
	Commercial and Public	78	4.2%
	Others	11	0.6%
	Losses	5	0.3%
Bioenergy and Waste	Electricity	120	7%
	Heat Networks	3	0%
	Industrial	20	1%
	Road transport	30	2%
	Aviation	1	0%
	Residential	15	1%
	Commercial and Public	15	1%
	Others	2	0%
Zero-carbon Electricity	Onshore Wind	33	2%
	Offshore Wind	50	3%
	Hydro	6	0%
	Solar PV	14	1%
	Wave and Tidal	0	0%
	Nuclear Electricity	41	2%
Other Electricity	Interconnector Import	24	1%
Total Energy Demand		1839	100%

Numbers are presented without decimals; underlying figures are not rounded.

3.2. Sectoral Technology Replacement Assessment

3.2.1. Model Step 2

In this step, each end-use sector's fuel supply is replaced with electricity, hydrogen, and heat networks, with heat sourced from waste heat at nuclear power plants. See Tables A1 or A2 in Appendix B for demonstration. Replacement factors are estimated to represent the percentage of existing carbon-emitting or imported energy replaced by these alternatives. Assumptions for the replacement factors are consistent with Gao et al. [20], except for variations related to residential hydrogen boilers and heat pumps, which depend on fuel supply scenarios. The losses reported in Table 2 are assumed to remain at the same level in the decarbonised system. See the further discussion in Section 5.

Four fuel supply scenarios are discussed. Two are developed herein, Heat Pump and Hydrogen, while the remaining two, Fossil Fuel-focused and Direct Electricity, are adopted from Gao et al. [20].

Each decarbonised scenario, Direct Electricity, Heat Pump, and Hydrogen, represents the dominance of one technology in the residential sector. The assumptions for the other

sectors remain the same as in Direct Electricity (Table 3). This approach enables a focused comparison of residential technologies while keeping other areas consistent.

- Fossil Fuel-focused

This scenario assumes that the fuel supply and consumption structure in 2050 remains unchanged from that of 2023. It represents an “as-is” projection.

- Direct Electricity

This scenario assumes that all sectors are decarbonised by 2050. Electricity becomes the primary energy carrier, supported by heat networks and a limited share of green hydrogen for hard-to-decarbonise segments of the transport and industrial sectors. Heat networks are supplied by recycled waste heat from nuclear power plants. The adoption of heat pumps in the residential sector remains below 0.5%, reflecting deployment rates as of 2024 [10]. Using the current heat pump adoption rate as the basis removes the authors’ estimation bias related to user behaviour or policy change, allowing the analysis to focus on technology comparison.

- Heat Pump

This scenario is largely the same as Direct Electricity, except that it assumes widespread adoption of heat pumps in the residential sector (Table 3). It assumes 10% of the residential fossil fuel supply is replaced by direct electricity. These figures are derived from the projections by the Climate Change Committee [38], with a slight uplift to reflect ongoing development. The remaining fuel supply, after direct electricity and heat networks, is 82% and is provided by heat pumps.

- Hydrogen

This scenario assumes a policy decision supporting the large-scale deployment of hydrogen boilers for buildings by 2026. As a result, incentives for heat pump adoption are expected to be withdrawn, with policy and financial support redirected toward the rollout of hydrogen-based systems. It is assumed that the adoption of heat pumps will stagnate at the current level, consistent with the assumption in Direct Electricity.

Table 3. Sectoral electricity replacement factors by scenarios. % = percentage of fossil fuels replaced by zero-carbon electricity. TWh = replacement factor x sectoral fossil fuel demand. The sectoral fossil fuel demand is shown in Table 2.

Sector	Replacement Fuel	Direct Electricity		Heat Pump		Hydrogen	
		%	TWh	%	TWh	%	TWh
Residential	Direct Electricity	91.6%	256	10.0%	28	10.0%	28
	Heat Pumps	0.5%	1	82.0%	229	0.5%	1
	Hydrogen	-	-	-	-	82.0%	229
	Heat Networks	8.0%	22	8.0%	22	8.0%	22
			279		279		279
Commercial and Public	Direct Electricity	78.0%	93				
	Heat Pumps	0.0%	0				
	Hydrogen	0.0%	-				
	Heat Networks	22.0%	26				
			120	As Direct Electricity		As Direct Electricity	
Industrial	Direct Electricity	92.0%	243				
	Hydrogen	8.0%	21				
			264				

Table 3. Cont.

Sector	Replacement Fuel	Direct Electricity		Heat Pump		Hydrogen	
		%	TWh	%	TWh	%	TWh
Power	Direct Electricity	100.0	346				
Road Transport	Direct Electricity	98.7%	435				
	Hydrogen	1.3%	6				
			441				
Rail	Direct Electricity	95.0%	7				
	Hydrogen	5.0%	0				
			7				
Aviation	Direct Electricity	15.0%	21	As Direct Electricity		As Direct Electricity	
	Hydrogen	85.0%	122				
			144				
Shipping	Direct Electricity	4%	0				
	Hydrogen	96%	9				
			9				
Others	Direct Electricity	78%	21				
	Hydrogen	22%	6				
			27				

Numbers are presented without decimals; underlying figures are not rounded.

An additional analysis is carried out to evaluate three extreme cases where residential heating is supplied entirely by one fuel type: 100% direct electricity, 100% heat pump electricity, or 100% hydrogen. The findings are presented in Section 4.3.

3.2.2. Model Step 3

After applying replacement factors, Step 3 estimates the demand for each fuel source in 2050 under each fuel supply scenario. The transition from an existing carbon-emitting fuel to a replacement fuel follows Equation (1). The efficiency assumptions are shown in Table 4 and are based on industry reports and academic research, reflecting mid-range values or conservative assumptions.

$$\text{Energy}_{\text{Replacement}} = (\text{Energy}_{\text{Existing}} \times \text{Efficiency}_{\text{Existing}}) / \text{Efficiency}_{\text{Replacement}} \quad (1)$$

One of the main challenges in this analysis is the uncertainty surrounding SPFs of heat pumps, due to the limited empirical evidence available from UK-based studies. For residential heat pumps, an average SPF of 311% is assumed. This value is derived from multiple sources (Table 1):

- A consumer case study by Gao et al. [10];
- Field trial results by Foster et al. [36];
- A projected improvement in heat pump technology, with future SPFs estimated to reach up to 373% as suggested in the Sixth Carbon Budget [37];
- Ratios from the Sixth Carbon Budget [37] to account for reduced efficiency under specific conditions, such as the need for higher flow temperatures (e.g., 50 °C) in less well-insulated homes, houses with under-sized radiators, or properties in colder northern regions, as well as improved efficiency with lower flow temperatures (e.g., 40 °C).

A sensitivity analysis with a lower SPF ratio is conducted, using the lowest estimate (i.e., 254%) in the Sixth Carbon Budget. The SPF ratio of 283% for non-residential heat pumps is also based on the same source.

Hydrogen is involved at each stage of the energy chain. This step focuses primarily on end-use processes and transport losses, as outlined in (Table 2). The efficiency of hydrogen boilers is assumed to be 94%, the same as gas boilers. Hydrogen transport losses are assumed to be comparable to those of natural gas and are included in the demand calculation. A sensitivity analysis is conducted, assuming transportation losses are 10% higher than those of natural gas, and the results are shown in Section 4.3.

Appendix B demonstrates the calculation and results for all sectors using Equation (1), with Table A1 for the Heat Pump scenario and Table A2 for the Hydrogen scenario.

Table 4. Plant and equipment efficiency ratios. H₂ = hydrogen.

Fuel Type	System Type	System	Sector	Efficiency
Fossil Fuel	Transport	Steam engine	Rail	7%
		Petrol engine	Road	15%
		Diesel car engine	Road	25%
		Diesel lorry engine	Road, Rail, Shipping	30%
		LNG engine	Road	25%
		Gas turbine engine	Aviation	30%
	Heating	Coal furnace	Industrial, Others	60%
		Oil furnace	Industrial, Others	80%
		Gas furnace	Industrial, Others	90%
		CHP	Industrial, Others	80%
		Coal boiler	Residential	88%
		Oil boiler	Residential	92%
		Gas boiler	Residential	94%
Clean Fuel	Power plant	Green H ₂ electrolyser	Electricity, Industrial, Transport	65%
		CCHT	Electricity, Industrial	53%
		Liquified H ₂ production	Aviation	55%
	Transport	H ₂ fuel cell	Road, Rail	30%
		Electrical system	Transport	70%
		Additional loss with H ₂ -powered aircraft	Aviation	10%
		Additional loss with H ₂ -powered ships	Shipping	2%
	Heating	Bioenergy CHP	Industrial, Others	80%
		Bioenergy boiler	Residential	85%
		Hydrogen boiler	Residential	94%
		Electrical heating	Residential, Industrial, Others	100%
		Heat pump	Residential	311%

3.3. Energy Supply Calculation

3.3.1. Model Step 4

In this step, both the annual electricity and hydrogen demand are distributed over an 8760 h demand curve to generate hourly values.

The demand curve is based on the 2013 weather year, covering December 2012 to November 2013, as it is considered representative of typical UK weather conditions [41,42]. Weather significantly impacts both renewables generation and energy consumption, with colder periods increasing heating needs. Winter spans December 2012 to February 2013, spring spans March to May, summer spans June to August, and autumn spans September to November.

3.3.2. Model Step 5

This step analyses how the projected electricity demand can be met primarily through generation from offshore wind, onshore wind, solar, and nuclear sources. The generation mix is based on the Co-development scenario from Gao et al. [20]. In this scenario, the baseload demand is provided by nuclear power to ensure energy security, with the remaining electricity supplied by renewables. It assumes that onshore wind and solar capacities are maintained at the government's targets, while any additional capacity is met by offshore wind, given its superior energy output and alignment with the UK's seasonal demand patterns. Generation from hydro, wave, tidal, and non-biodegradable waste-to-power is assumed to remain at the 2023 level, contributing 10 TWh.

A simplified energy system, shown in Figure A2 in Appendix A, is modelled to reflect the interactions between electricity generation, hydrogen production, energy storage (via electric battery, pumped hydro and hydrogen), and backup power provision by CCHTs. An electricity surplus occurs when the power generation exceeds demand, while an electricity deficit arises when the demand surpasses generation. Managing these imbalances is critical for maintaining grid stability and ensuring reliable energy supply.

Solar energy is estimated using hourly solar radiation data from 80 Met Office weather stations for the 2013 weather year [43]. Wind power generation is modelled using the Virtual Wind Farm tool [44], with notional turbine ratings of 10 MW for offshore wind and 3 MW for onshore wind. Six offshore and nine onshore locations are selected across the UK. Area factors are assumed to be approximately 24 km² per GW for solar farms, 193 km² per GW for onshore wind farms, and 240 km² per GW for offshore wind farms. The availability ratios are presented in Table 5.

Table 5. Plant availability factors.

	Availability
Wind farm	88%
Solar farm	93%
Nuclear power plant	90%
Hydrogen cavern storage	97%
Electric battery storage	91%
Pumped hydro storage	95%

The energy storage efficiency assumptions are listed in Table 6. Hydrogen storage assumes 50% cushion gas and a reserve equivalent to two weeks of supply. Electric battery storage assumes a minimum state-of-charge of 20%. The interactions among the three types of storage systems are illustrated in Figure A2 in Appendix A.

Table 6. Energy storage efficiency.

	Efficiency
Electric battery storage ¹	85%
Pumped hydro storage ¹	80%
Underground hydrogen storage ²	80%

¹ Electricity to electricity. ² Hydrogen to hydrogen: injection and withdrawal efficiency.

3.4. Economic Assessment

Step 6 estimates the impact of the technology solutions on the national energy costs, as well as the associated technology investment costs. The Levelised Cost of Energy (LCOE) is used to compare the lifetime costs of different technologies, whereas the capacity cost compares their investment costs [20].

The total annual energy cost of each scenario is the sum of the annual energy costs of all generation technologies in the system, following Equation (2). The storage costs are excluded due to their data absence in DUKES and the complexity of estimating storage churn rates; therefore, they require separate studies. The storage capacity costs are included in Equation (3) when assessing investments required for additional capacities in the decarbonised scenarios.

$$\text{Total Annual Energy Cost} = \sum \text{Annual Energy Output}_i \times \text{LCOE}_i \quad (2)$$

$$\text{Total Additional Investment} = \sum (\text{Total Capacity}_i - \text{Committed Capacity}_i) \times \text{Capacity Cost}_i \quad (3)$$

where i denotes the technology type, “Energy Output” is the energy generated by a technology, and “Committed Capacity” is the capacity from projects under construction or with secured finance.

This study adopts official sources for costs to support policy discussions. The data are drawn from two UK government publications [28,45], representing the 2023 government view on future costs. Table 7 presents the LCOE and capacity cost assumptions based on the projections for 2040 or the nearest available year [28,45]. The year 2040 is used instead of 2050 to allow time for investment decisions and plant construction.

Table 7. LCOE and capacity cost assumptions. The data represent the UK government’s projections for 2040 or the nearest available year, as of 2023. All financial data are reported in 2023 real prices.

Source	LCOE	Capacity Cost	
	GBP/MWh	GBP Thousand/MW	GBP/MWh
Generation:			
Diesel generator	470	n/r	
CCGT	202	n/r	
CCGT CHP	315	n/r	
OCGT	391	n/r	
Biomass	115	n/r	
Bioenergy and waste CHP	156	n/r	
Solar PV	34	282	
Onshore wind	41	1390	
Offshore wind ¹	56	2485	
Nuclear	101	5605	
Hydro	87	n/r	
Tidal	252	n/r	
Non-biodegradable waste	37	n/r	
Green hydrogen electrolysis	57	757	
CCHT with surplus fuel ²	13	689	
Storage:			
Hydrogen salt cavern storage	n/r		955

n/r = not required. ¹ This represents the average LCOE or capacity costs for fixed-bottom and floating offshore wind. In the Fossil Fuel-focused scenario, fixed-bottom offshore wind is applied with an LCOE of GBP 46/MWh.

² Green hydrogen is produced from surplus renewables or nuclear electricity that would otherwise be curtailed; therefore, no fuel cost is assumed.

Consistent with Gao et al. [20], this analysis focuses on the energy generation costs and excludes wider infrastructure costs such as grid and building retrofits. It also assumes future cost parity among boilers and heat pumps, transport across different fuel sources, as well as end-of-life asset replacement. These components necessitate separate extensive studies. Maintaining the same cost categories as Gao et al. [20] ensures comparability across scenarios. Further discussion is provided in Section 5.

The annual energy costs of the Fossil Fuel-focused scenario, GBP 170 billion estimated by Gao et al. [20], serve as the benchmark for evaluating the economic impact of decarbonisation. Economic benefits occur when a decarbonised scenario incurs lower annual energy costs than this benchmark. Unlike the decarbonised scenarios, which benefit from “free” renewable fuel, the fossil fuel-focused scenario includes costs for carbon-emitting fuels and imported electricity for use in transport and other non-power non-industrial sectors.

All financial data are reported in 2023 real prices [20].

3.5. Scenario Comparison

The EDRA framework quantifies the capacity and financial and land use requirements for each scenario. Comparison of these resources requirements addresses the third research question. A technology solution is considered to have higher net-zero deliverability if it requires fewer resources than the alternative options. Deliverability is further enhanced when the annual deployment rates fall within recent historical build rates or current government targets, indicating fewer implementation challenges. Gao et al. [20] suggest that meeting the resource requirements of the direct electrification scenario is very unlikely. Their results are used as a reference for comparing the Hydrogen and Heat Pump scenarios.

4. Results

4.1. National Primary Energy Demand

The summarised results for Sections 3.1 and 3.2 are provided in Table 8 for all sectors and Table 9 for the residential sector only. Detailed calculations for the Heat Pump and Hydrogen scenarios are presented in Tables A1 and A2 in Appendix B. Statistics for the benchmark scenarios, Fossil Fuel-focused and Direct Electricity, are sourced from Gao et al. [20].

Table 8. Scenario comparison of all sectors’ primary energy demand in 2050.

	Fossil Fuel-Focused	Direct Electricity	Heat Pump	Hydrogen
Fossil	1466			
Bioenergy	207			
Renewables and nuclear	142	1121	976	1256
Interconnector imports	24			
Waste heat for heat networks		85	85	85
Total primary energy	1839	1205	1061	1341
Generation savings from thermal losses	n/a	634	778	497
Renewables and nuclear breakdown:				
Electricity for direct electricity supply		986	841	773
Electricity for hydrogen production		135	135	483
Hydrogen production breakdown:				
Hydrogen		80	80	306
Hydrogen production thermal loss		55	55	177

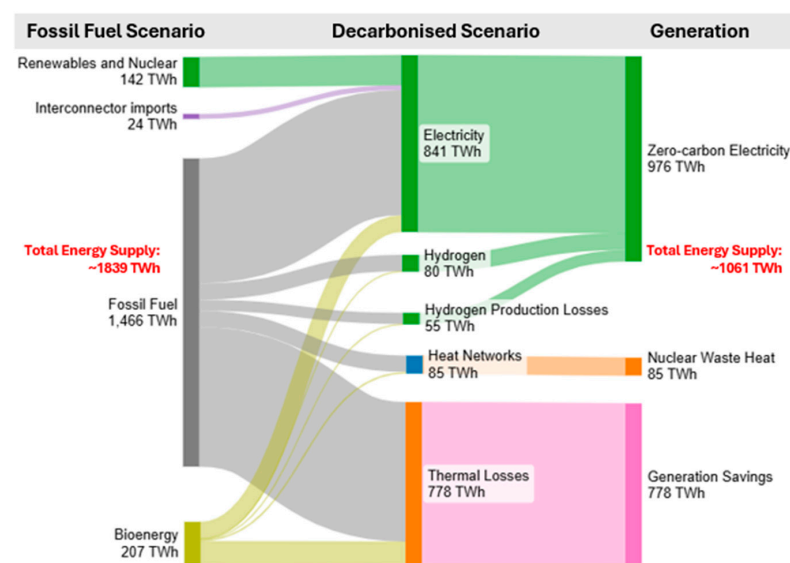
Numbers are presented without decimals; underlying figures are not rounded.

Table 8 reports the primary energy demand, including the gas transportation losses, assuming identical end-use energy supplied by the four fuel sources. The differences among the scenarios reflect variations in fuel conversion efficiency. Fossil fuel engines and power plants incur significant thermal losses, whereas the direct use of zero-carbon electricity to power motors reduces losses and, therefore, requires less primary energy. Figure 1 illustrates this transition using the Heat Pump scenario as a representative decarbonised system.

Table 9. Scenario comparison of the residential sector primary energy demand in 2050.

	Fossil Fuel-Focused	Direct Electricity	Heat Pump	Hydrogen
Carbon-emitting fuel	279			
Zero-carbon electricity		239	95	374
Zero-carbon heat		22	22	22
Total primary energy	279	261	117	397
Zero-carbon electricity breakdown:				
Electricity for direct electricity supply		239	95	26
Electricity for hydrogen production				348
Hydrogen production breakdown:				
Hydrogen				226
Hydrogen production thermal loss				122

Numbers are presented without decimals; underlying figures are not rounded.

**Figure 1.** The Heat Pump scenario: illustration of fuel supply transition. All numbers are presented without decimals; underlying figures are not rounded.

All three decarbonised scenarios exhibit substantial reductions in primary energy demand, driven by decreased thermal losses. The reductions range from 27% (497 TWh) in Hydrogen to 42% (778 TWh) in Heat Pump. Among the decarbonised scenarios, Heat Pump results in the lowest primary electricity demand, at ~1061 TWh.

Hydrogen production requires a significant amount of electricity with some lost in the conversion process. This effect is present in all three scenarios. In Direct Electricity and Heat Pump, hydrogen is used in hard-to-decarbonise segments of the non-residential sectors. The Hydrogen scenario exhibits the highest hydrogen production thermal losses, as hydrogen is also deployed in the residential sector.

Table 9 details the residential sector. The total primary energy demand for Direct Electricity is close to Fossil Fuel-focused. However, incorporating residential heat pumps significantly reduces the demand by approximately 58%, from ~279 TWh to ~117 TWh. Conversely, deploying hydrogen boilers would worsen the situation, increasing the primary energy demand by around 42% to ~397 TWh. This increase is mainly due to the thermal losses in green hydrogen production, which would amount to ~122 TWh. As a result, significantly more electricity would be required to produce enough hydrogen to meet the same residential energy demand. When comparing Heat Pump directly with Hydrogen, the electricity demand of the latter is 3.4 times that of the former.

4.2. Energy Supply Resources

This section presents results corresponding to Sections 3.3 and 3.4. Tables 10–13 demonstrate the generation-related resources required to meet the energy demand under the three decarbonisation scenarios in Table 8. Consistent with the findings from the energy demand model, the energy supply model indicates that Hydrogen requires the highest levels of equipment capacity, capital investment, and land and sea areas, whereas Heat Pump demonstrates the lowest requirements.

Table 10. Scenario comparison of energy generation. Cap. = capacity, Elec = electricity, HWTW = hydro, wave, tidal, and non-bio-degradable waste.

	Direct Electricity			Heat Pump			Hydrogen		
	Cap. GW	Elec. TWh	Area km ²	Cap. GW	Elec. TWh	Area km ²	Cap. GW	Elec. TWh	Area km ²
Offshore Wind	119	555	28,452	102	479	24,576	206	966	49,553
Onshore Wind	29	65	5593	29	65	5593	29	65	5593
Solar	70	65	12,141	70	65	12,141	70	65	12,141
Nuclear	81	638		71	556		91	715	
HWTW		10			10			10	
Total	299	1333	46,186	272	1175	42,309	396	1821	67,286

All numbers are presented without decimals; underlying figures are not rounded.

Table 11. Scenario comparison of electrolyser, CCHT, and electricity grid. Cap. = capacity, Op. Hours = annual operating hours.

	Direct Electricity		Heat Pump		Hydrogen	
	Cap. GW	Op. Hours %	Cap. GW	Op. Hours %	Cap. GW	Op. Hours %
Electrolyser	107	77%	100	78%	179	92%
CCHT	81	23%	70	22%	71	8%
Grid	225		202		310	

Table 12. Scenario comparison of storage capacity. H₂ = hydrogen, Cap. = capacity.

	Direct Electricity		Heat Pump		Hydrogen	
	Cap. GW	Mean Storage	Cap. GW	Mean Storage	Cap. GW	Mean Storage
H ₂	108,606	79%	98,386	79%	125,157	82%
Electric Battery	26	76%	26	77%	26	86%
Pumped Hydro	32	72%	32	73%	32	84%

Specifically, under the Heat Pump scenario, the projected capacity requirements comprise ~102 GW of offshore wind, ~29 GW of onshore wind, ~70 GW of solar, and ~71 GW of nuclear power (Table 10). This translates into annual built rates of ~4 GW for offshore wind, ~1 GW for onshore wind, and less than 3 GW for solar. These rates fall within the deployment targets set by the UK government for 2030 [46], suggesting they are technically achievable rather than overly ambitious. However, the requirement to sustain an annual build rate of nearly 3 GW for nuclear power represents a scale of deployment that the UK has not experienced in recent decades. Achieving this would require sustained nationwide commitment.

Consistent reductions are observed across all resources requirements when comparing Heat Pump with Direct Electricity (Tables 10–13). Furthermore, lower investment in

generation assets consequently decreases the annual energy generation costs of Heat Pump relative to Direct Electricity and increases the economic benefits of transitioning from the fossil fuel-based system (Figure 2).

Table 13. Scenario comparison of costs. HWTW = hydro, wave, tidal, and non-bio-degradable waste, H₂ = hydrogen, Ene. Gen. = energy generation, Ene. Cost = energy cost, Add. Cap. = additional capacity, Add. Inv. = additional investment.

	Direct Electricity				Heat Pump				Hydrogen			
	Ene. Gen. TWh	Ene. Cost GBP bn	Add. Cap. GW ²	Add. Inv. %	Ene. Gen. TWh	Ene. Cost GBP bn	Add. Cap. GW ²	Add. Inv. %	Ene. Gen. TWh	Ene. Cost GBP bn	Add. Cap. GW ²	Add. Inv. %
Offshore Wind	555	31	91	225	479	27	74	185	966	54	178	444
Onshore Wind	65	3	9	13	65	3	9	13	65	3	9	13
Solar	65	2	46	13	65	2	46	13	65	2	46	13
Nuclear	638	64	71	399	556	56	61	341	715	72	81	454
HWTW	10	1	-	-	10	1	-	-	10	1	-	-
H ₂ Electrolyser	160	11	107	81	146	10	100	75	374	25	179	135
CCHT	34	0	81	56	27	0	70	48	11	0	71	49
H ₂ Storage ¹			109 TWh	104			98 TWh	94			125 TWh	120
	1526	112		891	1349	99		769	2207	157		1227

¹ Excluded in energy costs due to data absence in the DUKES. ² Units are in GW unless otherwise stated.

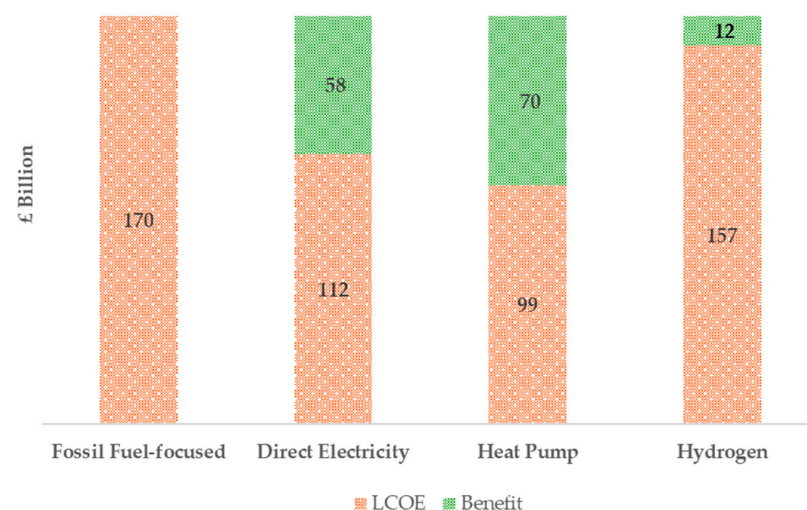


Figure 2. 2050 annual energy generation costs by scenario. All numbers are presented without decimals; underlying figures are not rounded. The figure presents the outputs of Equation (2) and shows that the Heat Pump scenario could deliver nearly six times higher economic benefits than the Hydrogen scenario in 2050.

Meeting ~1256 TWh of primary electricity demand under the Hydrogen scenario would require ~206 GW of offshore wind and ~91 GW of nuclear, while keeping the onshore wind and solar capacities unchanged (Table 10). This translates to a total additional generation capacity requirement of ~98 GW compared to Direct Electricity. The annual build rate for offshore wind would need to exceed 8 GW, a level that appears ambitious when measured against historical build rates and current national targets.

Under Hydrogen, substantial increases in electrolyzers and grid networks are observed, alongside only a marginal rise in CCHTs compared to Direct Electricity (Table 11), suggesting that a higher installed generation capacity reduces the reliance on CCHT backup systems. The difference in hydrogen storage capacity is less pronounced than for generation (Table 12), reflecting a closer temporal alignment between electricity production and end-use demand. Higher capital investment (Table 13) increases the annual energy generation costs (Figure 2). Consequently, the economic benefits relative to the current

fossil fuel-based system reduce to only 7%, in large contrast to the 34% savings estimated under Direct Electricity (Figure 2).

Comparing Hydrogen directly with Heat Pump, the former requires more than double the offshore wind capacity and ~29% more nuclear power (Table 10). The wind farm footprint would also more than double, reaching nearly 6% of the total UK sea area. The total capacity of electrolyzers, CCHTs, and grid networks is estimated to be around 50% higher (Table 11). Capital investment for generation assets could rise by 60%, corresponding to incremental annualised costs of GBP 18 billion. However, this significantly higher investment would not be matched by proportional economic benefits relative to the current fossil fuel-based system. Heat pumps could deliver nearly six times higher annual generation energy cost savings than Hydrogen (Figure 2).

Overall, this analysis demonstrates that deploying heat pumps improves the net zero deliverability of an electrification-based system, whereas reliance on hydrogen boilers further reduces the likelihood of achieving net zero.

4.3. Additional Analysis

Some additional analyses are conducted to strengthen the findings. First, a lower national average SPF of 254% is applied, corresponding to the lower bound reported in the Sixth Carbon Budget (Table 1). Under this assumption, residential energy savings relative to the current fossil fuel-based structure decrease marginally to 53%.

Second, the hydrogen transportation losses increase by 10% relative to natural gas to reflect hydrogen's smaller molecule size and higher permeability. Given the small magnitude of those losses to the total system energy demand, the findings remain unchanged.

Third, three extreme cases are assessed where residential heating is supplied exclusively by direct electricity, heat pump electricity, or hydrogen. These scenarios are named Direct Electricity 100%, Heat Pump 100%, and Hydrogen 100%, respectively. The findings from the results presented in Tables A3–A7 in Appendix B are consistent with those from the main analysis, further reinforcing the comparative advantages of heat pumps over hydrogen boilers.

5. Discussion

The relative advantage of heat pumps over hydrogen boilers is ultimately driven by the significantly higher efficiency of the former. The underlying difference in physics underpins the observed disparities in capacity, area, and costs. While technological advancements and cost reductions are expected over time, they are unlikely to alter the underlying physics governing efficiencies. Accordingly, this study reaches the same conclusion as Rosenow [26].

This study also highlights significant net-zero implementation challenges. Even with widespread residential heat pump deployment, achieving net zero would still require nuclear construction rates not observed in recent decades. Adopting a hydrogen boiler pathway would further exacerbate delivery risks due to higher nuclear and renewable requirements. Renewables expansion would also demand more electrolyzers to manage weather variability, a finding consistent with previous studies [20,23,24].

In addition, grid upgrades would need to occur at an unprecedented scale. The UK's grid operator has highlighted that meeting a doubling of the current electricity demand would require more networks than have been constructed over the past three decades [47]. This study suggests that electricity demand could quadruple or more with hydrogen boiler deployment. Furthermore, a hydrogen pathway would require major upgrades to the existing gas infrastructure, as indicated in a recent government report [48]. Overall, net-zero delivery risks are substantially higher under hydrogen boilers than heat pumps.

This study uses technology-dominant scenarios to isolate and compare the impact of technology selection on energy demand. The favourable results for heat pumps do not

imply the complete exclusion of hydrogen boilers in all contexts. Hydrogen boilers may be appropriate in settings, where the safety risks can be effectively managed, and where heat pump deployment is constrained. The two technologies may also coexist within hybrid systems. More broadly, hydrogen technologies are likely to play important roles in hard-to-decarbonise sectors, long-duration energy storage, backup power, and grid balancing—an assumption already incorporated into the non-residential sectors in this study.

This study has a few limitations. First, EDRA represents a simplified energy system modelling approach which is best suited for early-stage screening studies. As its outputs are driven by input assumptions, the results should be interpreted within the context of those assumptions. Accordingly, the findings are not intended to represent a definitive perspective or a singular solution but rather one of many plausible scenario combinations illustrating potential pathways towards net zero.

Second, due to data availability constraints in DUKES, this study focuses primarily on the generation costs, while other cost components, such as grid network, building retrofits for heat pump installation, and the amortisation of storage investment into annual energy costs, remain for future studies. The reported cost estimates should therefore be interpreted as lower-bound values in the broad ranges of costs associated with decarbonisation. Nevertheless, the approach is consistent with the UK government's Carbon Budget [38], and both studies conclude that decarbonisation can deliver long-term economic benefits despite requiring trillion pound-scale upfront investment.

Third, this study assumes a static demand forecast and energy transport losses. Further work should explore different assumptions. While variations may affect the quantitative results, they are not expected to alter the main conclusion regarding the comparative advantage of heat pumps over hydrogen boilers in demand reduction.

Lastly, this study models an ultimate end-state scenario, focusing on the requirements for complete decarbonisation rather than outlining transitional pathways. Transitional pathway modelling will require more complex and resource-intensive models [20].

6. Conclusions

With a policy decision on the future of hydrogen boilers expected by 2026, the UK is currently at a strategic implementation crossroads in delivering its Heat and Buildings Strategy. Building on the Diffusion of Innovations theory, this study evaluates the relative advantages of hydrogen boilers and heat pumps in residential heating, focusing on their contribution to national energy demand, a key metric for achieving full decarbonisation in 2050.

The analysis adopts the EDRA framework developed by Gao et al. [20], incorporating two fuel supply scenarios as benchmark cases. The Fossil Fuel-based scenario represents the existing fossil fuel-based energy system, while Direct Electricity serves as the benchmark for decarbonised scenarios. Heat Pump and Hydrogen are evaluated against the benchmarks to assess the implication of electrification with heat pumps versus the deployment of hydrogen boilers in the residential sector.

The findings demonstrate that the widespread adoption of heat pumps could reduce the sectoral primary energy demand by 53–58%, assuming SPFs in the range of 254–311%. This reduction reflects heat pumps' ability to extract "free heat" from ambient environments. In contrast, a hydrogen boiler-dominant scenario could increase demand by 42%, primarily because of the thermal losses associated with green hydrogen production. Consequently, hydrogen boilers could require more than three times the electricity needed by heat pumps to meet the same level of residential energy demand.

This study then estimates the generation resources required to meet all-sector energy demand by adopting the co-development generation scenario of Gao et al. [20]. The analysis demonstrates that large-scale deployment of heat pumps within an electrified system substantially reduces

the requirements for generation capacity, supporting infrastructure, land use for solar and wind farms, and capital investment in generation and storage assets, whereas reliance on hydrogen boilers produces the opposite effect. Lower capital investment reduces future energy costs and increases the economic benefits of transitioning from the current fossil fuel-based system. Notably, the Heat Pump scenario could deliver nearly six times higher economic benefits than Hydrogen, while requiring only 67% of the investment of the latter. This comparison demonstrates that heat pumps have higher net-zero deliverability than either direct electrification or hydrogen boilers. Heat pump deployment therefore improves the feasibility of achieving net-zero targets. Overall, the findings strongly support heat pumps as the primary residential decarbonisation solution.

This study contributes to the Diffusion of Innovation theory by expanding its application to the net-zero transition. By linking diffusion theory to the UK government's forthcoming 2026 policy decision on hydrogen boilers, this study provides a theoretically grounded perspective to inform policy decision-making.

This study recommends that government policy should prioritise and accelerate the deployment of heat pumps and consequently limit the envisioned role of hydrogen boilers, as a main pathway for residential decarbonisation.

Future research should address the limitations of this study by extending the cost analysis beyond generation costs to include additional components, such as grid upgrades and building retrofit. Further work could explore the effects of alternative assumptions, including non-static demand profiles, variations in energy transportation losses, and the potential role of hybrid heat pump–hydrogen systems. Additionally, future studies could expand the scope of the analysis to include non-residential buildings to assess heat pumps' wider contribution to national decarbonisation.

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Conflicts of Interest: The authors declare no conflicts of interest.

Abbreviations

The following abbreviations are used in this manuscript:

GW	gigawatt
km ²	square kilometre
MW	megawatt
MWh	megawatt hour
TWh	terawatt hour
CCHT	combined cycle hydrogen-fuelled turbine
CHP	combined heat and power
DESNZ	Department for Energy Security and Net Zero
DUKES	Digest of UK Energy Statistics
EDRA	End-state Decarbonisation Resource Analysis
LCOE	levelised cost of energy
SPF	seasonal performance factor

Appendix A. Methodological Framework

While the full explanation of the methodological framework is provided in Gao et al. [20], this appendix highlights the key elements. The framework is illustrated in Figure A1 and comprises four models. Each model relies on specific input assumptions. Collectively, the framework incorporates variables reflecting demand, technology, geography, economics, and policy.

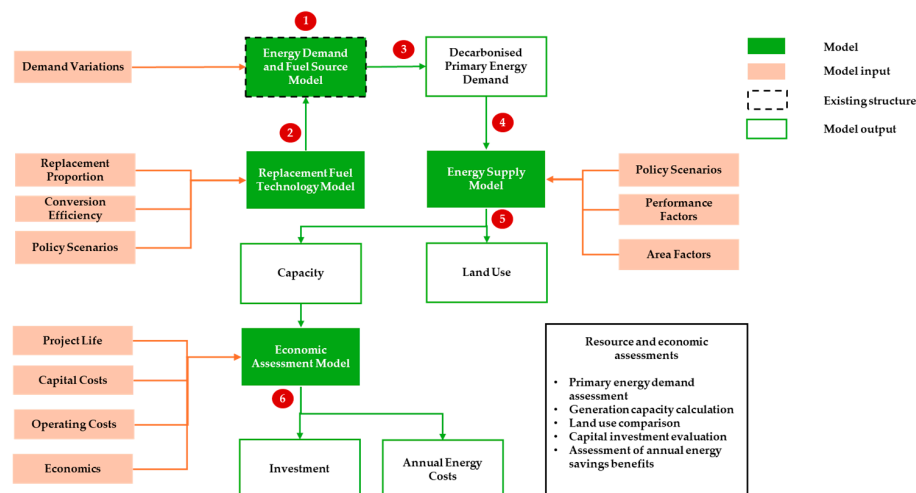


Figure A1. Methodological framework for EDRA. 1–6 represent each stage of energy flow.

The energy supply model, illustrated in Figure A2, is formulated as an hourly model to balance analytical accuracy with data volume and the availability of data sources.

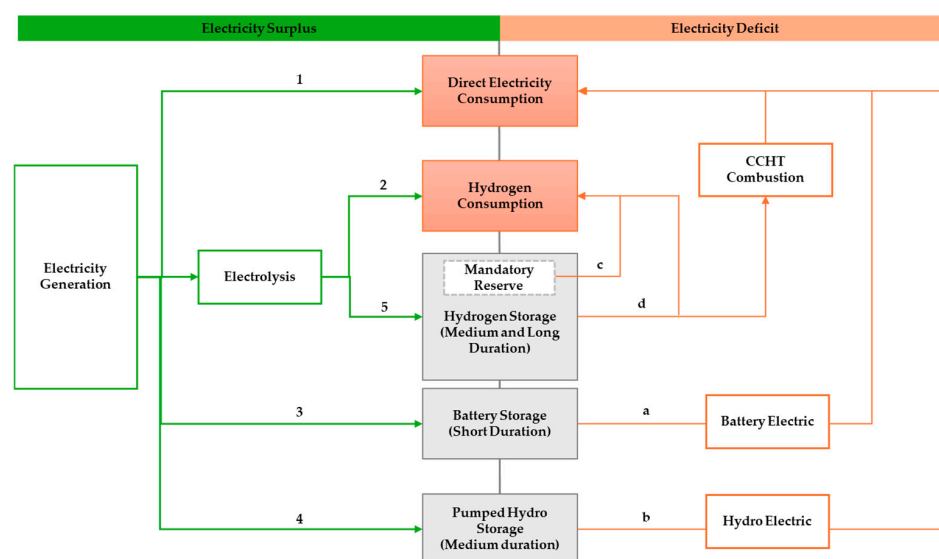


Figure A2. Energy flow during electricity surplus and deficit. 1–5 and a–d represent each stage of energy flow. For each hour, the electricity generated is first allocated to meet the direct electricity demand (1). Subsequently, the required amount of electricity is directed to electrolyzers to produce green hydrogen to meet the daily hydrogen consumption needs (2). Any surplus electricity is then stored in battery storage systems (3). Once the battery storage reaches full capacity, additional surplus electricity is stored in pumped hydro storage (4). Any remaining excess is used to produce green hydrogen via electrolysis, which is then stored in underground hydrogen storage facilities (5). In the event of an electricity deficit, electricity is first drawn from the battery storage (a), followed by pumped hydro (b), and finally from hydrogen storage (d). Hydrogen storage will require a CCHT system to convert hydrogen back into electricity to use. Additionally, a mandatory reserve is maintained in the hydrogen storage to ensure uninterrupted supply for the daily hydrogen demand (c).

Appendix B. Sectoral Fuel Supply Replacement Calculation

Table A1. The Heat Pump scenario: sectoral fuel supply replacement in 2050. Repl. = Replacement. The aviation sector is used as an example to demonstrate the calculation. The existing fuel demand from oil is ~143 TWh, with 15% replaced by electricity and 85% by hydrogen, equivalent to ~21 TWh and ~121 TWh, respectively. Applying Equation (1), ~21 TWh of existing fuel is replaced by ~9 TWh of electricity for battery-electric planes, based on 30% gas turbine efficiency (existing) and 70% electrical system efficiency (replacement). ~121 TWh of existing fuel is replaced by ~40 TWh of hydrogen, requiring ~73 TWh of electricity. This is based on the same existing efficiency and two replacement efficiency ratios: 90% for hydrogen aircraft (reflecting a 10% energy loss due to extra volume and consequent increase in aerodynamic drag, see Table 3) and 55% for the conversion of electricity to liquid hydrogen.

	2050 Demand TWh	Replace with	Repl. Factor	Repl. Energy TWh	Existing System Efficiency	Repl. System Efficiency	H ₂ Electrolyser Efficiency	Replacement Energy			
								Electricity TWh	H ₂ TWh	Heat TWh	% of H ₂ Use
Coal Products:											
Electricity	15							5			
Heat Networks	0									0	
Industrial	33	Direct Electricity	92%	31	60%	100%		18			
		Hydrogen	8%	3	60%	53%	65%	5	3		4%
Rail	0	Direct Electricity	95%	0	7%	70%		0			
		Hydrogen	5%	0	7%	30%	65%	0	0		0%
Residential	3	Direct Electricity	10%	0	88%	100%		0			
		Heat Pumps	82%	3	88%	311%		1			
		Hydrogen	0%	0	88%	94%	65%	0	0		0%
		District Heating	8%	0						0	
Commercial and Public	0	Direct Electricity	78%	0	60%	100%		0			
		Heat Pumps	0%	0	60%	283%		0			
		Hydrogen	0%	0	60%	100%	65%	0	0		0%
		District Heating	22%	0						0	
Others incl. Agriculture	0	Direct Electricity	78%	0	60%	100%		0			
		District Heating	22%	0						0	
Losses	1	Direct Electricity	100%	1				1			
Oil and Petroleum Products:											
Electricity	5							2			
Heat Networks	1									1	
Industrial	74	Direct Electricity	92%	68	80%	100%		54			
		Hydrogen	8%	6	80%	53%	65%	14	9		11%

Table A1. Cont.

Replacement Energy											
	2050 Demand TWh	Replace with	Repl. Factor	Repl. Energy TWh	Existing System Efficiency	Repl. System Efficiency	H ₂ Electrolyser Efficiency	Electricity TWh	H ₂ TWh	Heat TWh	% of H ₂ Use
Road Transport	410	Direct Electricity	99%	404	Petrol 15% Diesel Car 25% Diesel Lorry 30%	70%		115			
		Hydrogen	1%	6	Petrol 15% Diesel Car 25% Diesel Lorry 30%	30%	65%	6	4		5%
Rail	7	Direct Electricity	95%	6	30%	70%		3			
		Hydrogen	5%	0	30%	30%	65%	1	0		0%
Aviation	143	Direct Electricity	15%	21	30%	70%		9			
		Hydrogen	85%	121	30%	90%	55%	73	40		51%
Shipping	9	Direct Electricity	4%	0	30%	70%		0			
		Hydrogen	96%	9	30%	98%	55%	5	3		3%
Residential	24	Direct Electricity	10%	2	92%	100%		2			
		Heat Pumps	82%	20	92%	311%		6			
		Hydrogen	0%	0	92%	94%	65%	0	0		0%
		District Heating	8%	2						2	
Commercial and Public	27	Direct Electricity	78%	21	80%	100%		17			
		Heat Pumps	0%	0	80%	283%		0	0		
		Hydrogen	0%	0	80%	100%	65%	0	0		0%
		District Heating	22%	6						6	
Others incl. Agriculture	14	Direct Electricity	78%	11	80%	100%		9			
		District Heating	22%	3						3	
Natural Gas: Electricity	206							102			
Heat Networks	26									26	
Industrial	137	Direct Electricity	92%	126	85%	100%		107			
		Hydrogen	8%	11	85%	53%	65%	27	18		22%
Road Transport	1	Direct Electricity	99%	1	25%	70%		0			
		Hydrogen	1%	0	25%	30%	65%	0	0		0%
Residential	237	Direct Electricity	10%	24	94%	100%		22			
		Heat Pumps	82%	195	94%	311%		59			
		Hydrogen	0%	0	94%	94%	65%	0	0		0%
		District Heating	8%	19						19	

Table A1. Cont.

	2050 Demand TWh	Replace with	Repl. Factor	Repl. Energy TWh	Existing System Efficiency	Repl. System Efficiency	H ₂ Electrolyser Efficiency	Replacement Energy			
								Electricity TWh	H ₂ TWh	Heat TWh	% of H ₂ Use
Commercial and Public	78	Direct Electricity	78%	61	85%	100%		52			
		Heat Pumps	0%	0	85%	283%		0			
		Hydrogen	0%	0	85%	100%	65%	0	0		0%
		District Heating	22%	17						17	
Others incl. Agriculture	11	Direct Electricity	78%	9	85%	100%		7			
		District Heating	22%	2						2	
Losses	5	Direct Electricity	100%	5	100%			5			
Bioenergy and Waste: Electricity	120							39			
Heat Networks	3									3	
Industrial	20	Direct Electricity	92%	19	80%	100%		15			
		Hydrogen	8%	2	80%	53%	65%	4	2		3%
Road Transport	30	Direct Electricity	99%	30	25%	70%		11			
		Hydrogen	1%	0	25%	30%	65%	1	0		1%
Aviation	1	Direct Electricity	15%	0	30%	70%		0			
		Hydrogen	85%	1	30%	90%	55%	1	0		1%
Residential	15	Direct Electricity	10%	2	85%	100%		1			
		Heat Pumps	82%	12	85%	311%		3			
		Hydrogen	0%	0	85%	94%	65%	0	0		0%
		District Heating	8%	1						1	
Commercial and Public	15	Direct Electricity	78%	12	80%	100%		9			
		Heat Pumps	0%	0	80%	283%		0			
		Hydrogen	0%	0	80%	100%	65%	0	0		0%
		District Heating	22%	3						3	
Others incl. Agriculture	2	Direct Electricity	78%	2	80%	100%		1			
		District Heating	22%	0						0	
Other Clean Fuel Electricity: Onshore Wind	33							33			
Offshore Wind	50							50			
Hydro	6							6			
Solar PV	14							14			
Wave and Tidal	0							0			

Table A1. Cont.

	2050 Demand TWh	Replace with	Repl. Factor	Repl. Energy TWh	Existing System Efficiency	Repl. System Efficiency	H ₂ Electrolyser Efficiency	Replacement Energy			
								Electricity TWh	H ₂ TWh	Heat TWh	% of H ₂ Use
Nuclear Electricity	41							41			
Interconnector Electricity	24							24			
Import											
Total Energy Demand	1839							976	80	85	100%

Numbers are presented up to one decimal place; underlying figures are not rounded.

Table A2. The Hydrogen scenario: sectoral fuel supply replacement in 2050. Repl. = Replacement. The aviation sector is used as an example to demonstrate the calculation. The existing fuel demand from oil is ~143 TWh, with 15% replaced by electricity and 85% by hydrogen, equivalent to ~21 TWh and ~121 TWh, respectively. Applying Equation (1), ~21 TWh of existing fuel is replaced by ~9 TWh of electricity for battery-electric planes, based on 30% gas turbine efficiency (existing) and 70% electrical system efficiency (replacement). ~121 TWh of existing fuel is replaced by ~40 TWh of hydrogen, requiring ~73 TWh of electricity. This is based on the same existing efficiency and two replacement efficiency ratios: 90% for hydrogen aircraft (reflecting a 10% energy loss due to extra volume and consequent increase in aerodynamic drag, see Table 3) and 55% for the conversion of electricity to liquid hydrogen.

	2050 Demand TWh	Replace with	Repl. Factor	Repl. Energy TWh	Existing System Efficiency	Repl. System Efficiency	H ₂ Electrolyser Efficiency	Replacement Energy			
								Electricity TWh	H ₂ TWh	Heat TWh	% of H ₂ Use
Coal Products:											
Electricity	15							5			
Heat Networks	0									0	
Industrial	33	Direct Electricity	92%	31	60%	100%		18			
		Hydrogen	8%	3	60%	53%	65%	4.67	3		1.0%
Rail	0	Direct Electricity	95%	0	7%	70%		0			
		Hydrogen	5%	0	7%	30%	65%	0	0		0.0%
Residential	3	Direct Electricity	10%	0	88%	100%		0			
		Heat Pumps	0%	0	88%	311%		0			
		Hydrogen	82%	3	88%	94%	65%	4	2		0.8%
		District Heating	8%	0						0	
Commercial and Public	0	Direct Electricity	78%	0	60%	100%		0			
		Heat Pumps	0%	0	60%	283%		0			
		Hydrogen	0%	0	60%	100%	65%	0	0		0.0%
		District Heating	22%	0						0	

Table A2. Cont.

	2050 Demand TWh	Replace with	Repl. Factor	Repl. Energy TWh	Existing System Efficiency	Repl. System Efficiency	H ₂ Electrolyser Efficiency	Replacement Energy			
								Electricity TWh	H ₂ TWh	Heat TWh	% of H ₂ Use
Others incl. Agriculture	0	Direct Electricity District Heating	78% 22%	0 0	60%	100%		0		0	
Losses	1	Direct Electricity	100%	1				1			
Oil and Petroleum Products: Electricity	5							2			
Heat Networks	1									1	
Industrial	74	Direct Electricity Hydrogen	92% 8%	68 6	80% 80%	100% 53%		54 14	9		2.9%
Road Transport	410	Direct Electricity	99%	404	Petrol 15% Diesel Car 25% Diesel Lorry 30%	70%		115			
		Hydrogen	1%	6	Petrol 15% Diesel Car 25% Diesel Lorry 30%	30%	65%	6	4		1.2%
Rail	7	Direct Electricity Hydrogen	95% 5%	6 0	30% 30%	70% 30%		3 1	0		0.1%
Aviation	143	Direct Electricity Hydrogen	15% 85%	21 121	30% 30%	70% 90%		9 73	40		13.2%
Shipping	9	Direct Electricity Hydrogen	4% 96%	0 9	30% 30%	70% 98%		0 5	3		0.9%
Residential	24	Direct Electricity Heat Pumps	10% 0%	2 0	92% 92%	100% 311%		2 0			
		Hydrogen District Heating	82% 8%	20 2	92%	94%	65%	29	19	2	6.3%
Commercial and Public	27	Direct Electricity Heat Pumps	78% 0%	21 0	80% 80%	100% 283%		17 0	0		
		Hydrogen District Heating	0% 22%	0 6	80%	100%	65%	0	0	6	0.0%
Others incl. Agriculture	14	Direct Electricity District Heating	78% 22%	11 3	80%	100%		8.85		3	
Natural Gas: Electricity	206							102			

Table A2. Cont.

	2050 Demand TWh	Replace with	Repl. Factor	Repl. Energy TWh	Existing System Efficiency	Repl. System Efficiency	H ₂ Electrolyser Efficiency	Replacement Energy			
								Electricity TWh	H ₂ TWh	Heat TWh	% of H ₂ Use
Heat Networks	26									26	
Industrial	137	Direct Electricity Hydrogen	92% 8%	126 11	85% 85%	100% 53%	65%	107 27	18		5.7%
Road Transport	1	Direct Electricity Hydrogen	99% 1%	1 0	25% 25%	70% 30%	65%	0 0	0		0.0%
Residential	237	Direct Electricity	10%	24	94%	100%		22			
		Heat Pumps	0%	0	94%	311%		0			
		Hydrogen	82%	195	94%	94%	65%	298	193		63.2%
		District Heating	8%	19						19	
Commercial and Public	78	Direct Electricity	78%	61	85%	100%		52			
		Heat Pumps	0%	0	85%	283%		0			
		Hydrogen	0%	0	85%	100%	65%	0	0		0.0%
		District Heating	22%	17						17	
Others incl. Agriculture	11	Direct Electricity District Heating	78% 22%	9 2	85%	100%		7		2	
Losses	5	Direct Electricity	100%	5	100%			5			
Bioenergy and Waste: Electricity	120							39			
Heat Networks	3									3	
Industrial	20	Direct Electricity Hydrogen	92% 8%	19 2	80% 80%	100% 53%	65%	15 4	2		0.8%
Road Transport	30	Direct Electricity Hydrogen	99% 1%	30 0	25% 25%	70% 30%	65%	11 1	0		0.1%
Aviation	1	Direct Electricity Hydrogen	15% 85%	0 1	30% 30%	70% 90%	55%	0 1	0		0.1%
Residential	15	Direct Electricity	10%	2	85%	100%		1			
		Heat Pumps	0%	0	85%	311%		0			
		Hydrogen	82%	12	85%	94%	65%	17	11		3.6%
		District Heating	8%	1						1	

Table A2. Cont.

Replacement Energy											
	2050 Demand TWh	Replace with	Repl. Factor	Repl. Energy TWh	Existing System Efficiency	Repl. System Efficiency	H ₂ Electrolyser Efficiency	Electricity TWh	H ₂ TWh	Heat TWh	% of H ₂ Use
Commercial and Public	15	Direct Electricity	78%	12	80%	100%		9			
		Heat Pumps	0%	0	80%	283%		0			
		Hydrogen	0%	0	80%	100%	65%	0	0		0.0%
		District Heating	22%	3						3	
Others incl. Agriculture	2	Direct Electricity	78%	2	80%	100%		1			
		District Heating	22%	0						0	
Other Clean Fuel Electricity: Onshore Wind	33							33			
Offshore Wind	50							50			
Hydro	6							6			
Solar PV	14							14			
Wave and Tidal	0							0			
Nuclear Electricity	41							41			
Interconnector Electricity Import	24							24			
Total Energy Demand	1839							1256	306	85	100%

Numbers are presented up to one decimal place; underlying figures are not rounded.

Table A3. All sector energy demand estimates in extreme fuel source scenarios. This table summarises the total replacement energy demand under three extreme scenarios, where residential heating is supplied entirely by one fuel type: 100% direct electricity, 100% heap pump electricity, or 100% hydrogen.

Replacement Energy	Direct Electricity 100% TWh	Heat Pump 100% TWh	Hydrogen 100% TWh
Electricity	1142	965	1337
Heat	62	62	62
Total energy	1205	1028	1400

Numbers are presented without decimals; underlying figures are not rounded.

Table A4. Extreme fuel source scenarios: comparison of generation. This table compares three extreme scenarios, where residential heating is supplied entirely by one fuel type: 100% direct electricity, 100% heap pump electricity, or 100% hydrogen. HWTW = hydro, wave, tidal, and non-bio-degradable waste.

	Direct Electricity 100%			Heat Pump 100%			Hydrogen 100%		
	Capacity GW	Electricity TWh	Area km ²	Capacity GW	Electricity TWh	Area km ²	Capacity GW	Electricity TWh	Area km ²
Offshore Wind	121	566	29,052	101	473	24,276	230	1074	55,109
Onshore Wind	29	65	5593	29	65	5593	29	65	5593
Solar	70	65	12,141	70	65	12,141	70	65	12,141
Nuclear	83	650		70	550		95	745	
HWTW		10			10			10	
Total	303	1357	46,785	270	1163	42,010	423	1959	72,842

Numbers are presented without decimals; underlying figures are not rounded.

Table A5. Extreme fuel source scenarios: comparison of electrolyser, CCHT, and electricity grid. This table compares three extreme scenarios, where residential heating is supplied entirely by one fuel type: 100% direct electricity, 100% heap pump electricity, or 100% hydrogen.

	Direct Electricity 100%		Heat Pump 100%		Hydrogen 100%	
	Capacity GW	% Annual Operating Hours	Capacity GW	% Annual Operating Hours	Capacity GW	% Annual Operating Hours
Electrolyser	109	77%	99	78%	198	93%
CCHT	83	23%	69	22%	70	7%
Grid	229		200		333	

Numbers are presented without decimals; underlying figures are not rounded.

Table A6. Extreme fuel source scenarios: comparison of energy storage. This table compares three extreme scenarios, where residential heating is supplied entirely by one fuel type: 100% direct electricity, 100% heap pump electricity, or 100% hydrogen.

	Direct Electricity		Heat Pump		Hydrogen	
	Capacity GW	Mean Storage	Capacity GW	Mean Storage	Capacity GW	Mean Storage
Hydrogen Storage	110,162	79%	98,051	79%	133,858	83%
Electric Battery Storage	26	76%	26	77%	26	87%
Pumped Hydro Storage	32	72%	32	73%	32	86%

Numbers are presented without decimals; underlying figures are not rounded.

Table A7. Extreme fuel source scenarios: comparison of costs. This table compares three extreme scenarios, where residential heating is supplied entirely by one fuel type: 100% direct electricity, 100% heap pump electricity, or 100% hydrogen. HWTW = hydro, wave, tidal, and non-bio-degradable waste, Ene. Gen. = energy generation, Ene. Cost = energy cost, Add. Cap. = additional capacity, Add. Inv. = additional investment.

	Direct Electricity 100%				Heat Pump 100%				Hydrogen 100%			
	Ene. Gen. TWh	Ene. Cost GBP bn	Add. Cap. GW ²	Add. Inv. GBP bn	Ene. Gen. TWh	Ene. Cost GBP bn	Add. Cap. GW ²	Add. Inv. GBP bn	Ene. Gen. TWh	Ene. Cost GBP bn	Add. Cap. GW ²	Add. Inv. GBP bn
Offshore Wind	566	32	93	231	473	26	73	182	230	60	202	501
Onshore Wind	65	3	9	13	65	3	9	13	29	3	9	13
Solar	65	2	46	13	65	2	46	13	70	2	46	13
Nuclear	650	66	73	408	550	55	60	336	95	75	85	475
HWTW	10	7	-	-	10	1	-	-	-	1	-	-
Hydrogen Electrolysis	162	11	109	82	145	10	99	75	429	29	198	150
CCHT	35	0	83	57	27	0	69	48	9	0	70	49
Hydrogen Storage ¹			110 TWh	105			98 TWh	94			134 TWh	128

Numbers are presented without decimals; underlying figures are not rounded. ¹ Excluded in energy costs due to data absence in DUKES. ² Units are in GW unless otherwise stated.

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