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Developing a Techno-Economic Framework for National-Level End-State Decarbonisation Resource Analysis: A UK Application

Lin Gao *, Philip Naylor, Abdelrahman Hegab and Pericles Pilidis *

Centre for Propulsion and Thermal Power Engineering, Faculty of Engineering and Applied Science (FEAS), Cranfield University, Bedford MK43 0AL, UK; philip.naylor@cranfield.ac.uk (P.N.); a.hegab@cranfield.ac.uk (A.H.)

* Correspondence: lin.gao@cranfield.ac.uk (L.G.); p.pilidis@cranfield.ac.uk (P.P.)

Abstract

Amid growing urgency for net-zero delivery and calls for simplified energy system modelling, this study presents a techno-economic framework, termed “End-state Decarbonisation Resource Analysis” (EDRA), for evaluating national decarbonisation strategies. EDRA integrates demand estimation, technology replacement, generation calculation and economic assessment, and employs scenario modelling and optimisation to estimate the technical, geographical, and financial resources required for full national decarbonisation. The framework offers a simplified yet comprehensive approach for national energy system assessment. Applied to the UK, EDRA reveals substantial gaps between current government capacity targets and the requirements of a fully decarbonised system aligned with the UK’s policy goals of net-zero, energy independence and energy security. Meeting these aims would require more than triple the nuclear target, over double the offshore wind target, more than 400 GW of electrolyzers, combined cycle hydrogen turbines and electricity grid, ~50 thousand km² of land for wind and solar, and trillion-pound scale investment. Delivering this scale of resource deployment within 25 years presents a significant policy challenge. Nevertheless, the results demonstrate clear advantages of a decarbonised electrification system over fossil fuel-based alternatives. A key policy recommendation is to prioritise demand reduction to ease generation resource pressure.

Keywords: energy system modelling; decarbonisation; energy policy; energy demand; renewables; nuclear; hydrogen; energy storage

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1. Introduction

The growing urgency of delivering net-zero [1], alongside persistent debates over policy direction [2], highlights the importance of articulating a clear vision for a fully decarbonised country. The UK provides an instructive case. As the world’s first major economy to legislate a net-zero target, the UK committed in 2019 to achieve net-zero by 2050 [3]. Subsequent energy policy uncertainty reflects the scale and complexity of this challenge. The UK’s strategy seeks to combine global leadership in low-carbon technologies with energy security and strategic autonomy [4]. Reconciling these objectives raises a fundamental question: how can a modern industrial economy be fully decarbonised without compromising the resilience and independence of its energy system [2].

The central government have explored decarbonisation pathways using the Integrated MARKAL-EFOM System (TIMES) model, a national energy system optimisation model (ESOM) integrating extensive techno-economic and carbon emission assumptions [5]. However, the proposed pathways retain carbon-emitting fuels beyond 2050 as transitional energy sources and rely on early-stage carbon capturing technologies to achieve carbon neutrality. Critics argue that such reliance risks delaying full decarbonisation [6]. Moreover, it remains unclear whether these pathways can deliver the UK's stated objectives. In parallel, sectoral system operators have developed sector-specific decarbonisation plans [7,8]. However, it remains uncertain whether these plans collectively deliver a coherent end-state vision aligned with the national objectives.

The lack of coherence, combined with fragmented perspectives and limited evidence of achievability, has contributed to public doubts and policy volatility in the UK [2,9,10]. This case demonstrates the importance of defining a clear end-state vision for decarbonisation, supported by aligned and demonstrably achievable objectives. Ultimately, the feasibility of achieving net-zero depends on the scale of resources required and whether they can be delivered within a defined time horizon, i.e., 25 years in the UK case. While comprehensive models such as TIMES provide valuable insights, their complexity and limited accessibility restrict their use to experts, highlighting the need for a simpler and transparent framework that can be understood, scrutinised, and tested by a wide range of stakeholders [11].

Recent studies applying an end-state method to energy system modelling [12–15] provide a useful foundation for such a framework. By focusing on end-state scenarios, these studies substantially simplify model structure while still provide valuable insights into the scale of resources required for a country to reach full decarbonisation, i.e., the ultimate net-zero vision. However, the absence of economic evaluation limits their applicability for comprehensive policy analysis. Moreover, the methods are context-specific and lack generalisability, highlighting the need for further methodological development.

To address these limitations, this study aims to develop a techno-economic framework for evaluating resource requirements associated with national-level full decarbonisation. This proposed framework, termed “End-state Decarbonisation Resource Analysis” (EDRA), is demonstrated through a UK case study that is situated within the context of three energy policy objectives: net-zero, energy security, and energy independence. By presenting the scale of resources required to achieve full decarbonisation, the study provides evidence on the achievability of the UK's net-zero target within 25 years, justifying the necessity of transitional technologies.

The main contributions of the paper are as follows:

- Methodologically, it develops a practical tool for researchers and industry practitioners to conduct early-stage feasibility assessment prior to engaging with complex modelling, as well as for validating outputs from established energy system models.
- It contributes to UK policy development by identifying limitations in existing energy policies and identifies priority areas for policy intervention.

The remainder of the paper is organised as follows. Section 2 reviews the relevant literature. Section 3 presents the proposed methodological framework: EDRA. Section 4 applies EDRA to the UK. Section 5 discuss the results and Section 6 concludes the paper.

2. Literature Review

The techno-economic framework, which combines technological assessment with life-cycle cost evaluation, is widely used to assess technology solutions and support investment decisions [16–19]. By estimating the life-cycle cost of each solution including capital and operating costs, the resulting levelised cost of energy (LCOE) enables

comparisons across different solutions by using the average cost of energy over a system's lifetime [20,21].

This framework is commonly applied in ESOMs to evaluate technology pathways for achieving net-zero [5,19,22,23]. Such models aggregate technologies and identify cost-optimal solutions by utilising linear programming to minimise total system costs under defined constraints [11]. Representative examples include TIMES [24], ESME [22], MESSAGE [25], OSeMOSYS [26], and Temoa [27]. Among these, TIMES is the most prominent largely due to its adoption by International Energy Agency [28]. TIMES has also been adapted for various national contexts, resulting in multiple country-specific versions [19,23,24,29]. The UK TIMES model is applied by the UK Government and the national grid system operator to develop future energy scenarios in support of policy formulation [5,8].

The TIMES model begins with projections of end-use energy demand and links energy demand and supply through a range of technologies and incorporates extensive techno-economic assumptions [30]. Through optimisation, the model determines which technologies to deploy and at what scale and time to meet demand while satisfying all technical, policy and resource constraints. TIMES is also time-dependent requiring assumptions related to future technological, economic, environmental, and political development over a defined time period [5,8,31].

Despite its analytical strength, the model's complexity requires advanced modelling expertise and dedicated computational tools, often limiting its accessibility to a small group of expert practitioners and presenting a specialised research domain in its own right [11]. In response to these challenges and acknowledging the growing influence of ESOMs on policy decisions, DeCarolus et al. [11] advocate simplicity and transparency as guiding principles for model development. Such simplicity can be achieved through prioritising the key questions being addressed while reducing unnecessary complexity.

Four recent studies have adopted this principle to assess country-level decarbonisation challenges by quantifying generation resource requirements associated with decarbonisation [12–15]. By focusing on end-state scenarios only and excluding transitional pathways, these models are substantially simpler than TIMES in both structure and variable count.

Three of the studies examine Libya's energy transition, analysing the generation capacities and land areas needed to transition from an oil-based to a green hydrogen economy. Their methods include a useful energy demand projection for an end-state year, defined as the target year for full decarbonisation, a fossil fuel-based energy system in a base year, and a clean fuel-based system in the end-state year. Their models estimate the quantity of clean fuel generation, backup, and grid capacities required to replace the fossil fuel-based system while meeting the useful energy demand for the end-state year. The three studies evaluate alternative clean fuel technology configurations, including solar farms supported by combined cycle hydrogen turbines (CCHTs), wind farms with CCHTs, and nuclear-CCHT configurations [12–14]. Despite variations in technology assumptions, all studies conclude that the scale of land use and the required electrolyser, CCHT, and grid capacities present significant challenges for transforming the country from an oil-based to a hydrogen-based economy.

Consequently, these studies demonstrate that end-state scenario modelling can effectively capture key structural limitations of a fully decarbonised energy system. However, none of these studies incorporate economic assessments that would enable comparisons across alternative technology solutions. Instead, each focuses on a single generation technology and relies on aggregated national energy demand data. In addition, the models are context-specific and not generalisable to other countries. As a result, their methodological framework remains underdeveloped for broader application.

Pilidis et al. [15] advanced the framework by incorporating sectoral demand estimation and fuel supply replacement using published UK official data. While the use of sectoral, rather than aggregated national, demand data represents a methodological improvement over the three Libyan studies, further model development is required to strengthen the linkage between demand and generation technologies. Moreover, the paper relies on pre-COVID-19 (2019) energy demand data, which requires updating to reflect the UK's net-zero policy and economic development.

Nevertheless, all four studies provide valuable insights into how a simplified alternative to TIMES can be developed for evaluating resource requirements associated with national-level decarbonisation. Building on aforementioned studies, this paper proposes the EDRA framework, which integrates: (i) the demand-driven modelling concept from TIMES; (ii) the end-state scenario approach from Rawesat et al. [12–14] and Pilidis et al. [15]; and (iii) a techno-economic approach for assessing and comparing technology costs.

3. Methodology: The EDRA Framework

3.1. Overview

EDRA is illustrated in Figure 1. EDRA adopts a modular structure and comprises four interlinked sub-models: (i) the Energy Demand Sub-model, (ii) the Replacement Fuel Technology Sub-model, (iii) the Energy Generation Sub-model, and (iv) the Economic Assessment Sub-model. Each sub-model has its own set of exogenous input assumptions, and collectively the framework incorporates variables reflecting demand, technology, geography, economics, and policy.

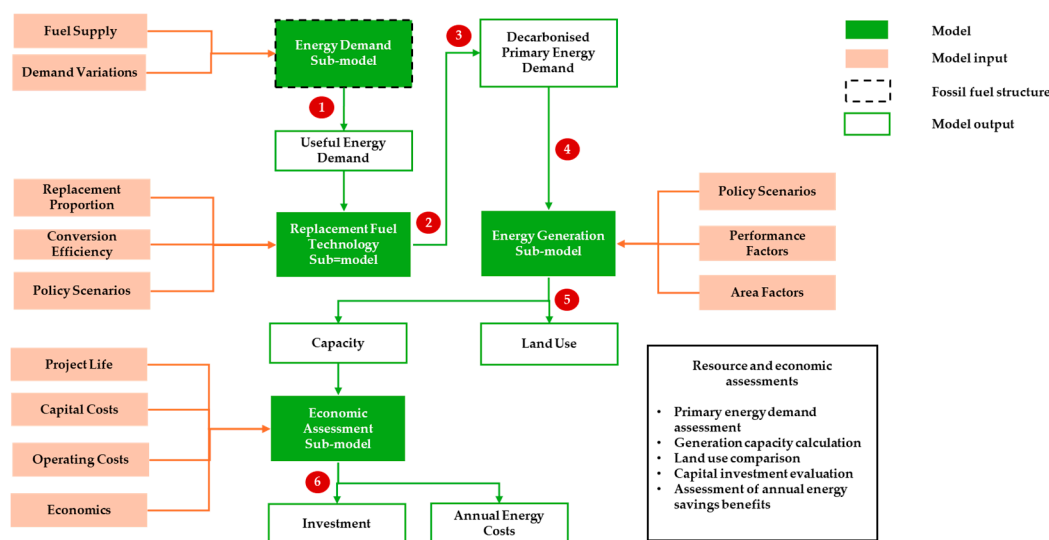


Figure 1. The EDRA structure. Number 1–6 represent process steps. The process starts from Step 1 and ends in Step 6.

Each sub-model is defined by its own set of calculation formulae, with outputs serving as inputs to subsequent sub-models, thereby linking the four components into an integrated analytical framework. The workflow comprises six calculation steps, with each sub-model containing one or two steps. As a demand-driven ESOM, the calculation process is initiated by the Energy Demand Sub-model, whose output determines the generation capacities computed by the Energy Generation Sub-model. These capacity values are subsequently passed to the Economic Assessment Sub-model to estimate the costs associated with the evaluated technology solutions.

3.2. Components and Process

3.2.1. Energy Demand Sub-Model

Process Step 1 is conducted through the Energy Demand Sub-model, which forecasts useful energy demand in the end-state year based on demand on a defined start year, i.e., baseline. Annual useful energy demand is estimated by sector and by fuel supply technology at the start year and is expressed as:

$$U_{\text{end},s,i_{\text{start}}} = D_{\text{start},s} \times \eta_{s,i_{\text{start}}} \times k_s \quad (1)$$

where

- $U_{\text{end},s,i_{\text{start}}}$ is the annual useful energy demand at the end-state year associated with the start-year fuel supply technology i in sector s ;
- $D_{\text{start},s}$ is the annual primary energy demand in sector s at the start year;
- $\eta_{s,i_{\text{start}}}$ is the efficiency of the start-year fuel supply technology i in sector s ;
- k_s is the demand growth ratio between the start year and the end-state year in sector s .

The start-year technology set includes carbon-emitting technologies, which are subsequently replaced by zero-carbon alternatives in the Replacement Fuel Technology Sub-model.

Total sectoral annual useful energy demand, $U_{\text{end},s}$, is obtained by aggregating the demand across fuel supply technologies:

$$U_{\text{end},s} = \sum_{i_{\text{start}}} U_{\text{end},s,i_{\text{start}}} \quad (2)$$

Total all-sector annual useful energy demand, U_{end} , at the end-state year is then calculated by summing the demand across sectors:

$$U_{\text{end}} = \sum_s U_{\text{end},s} \quad (3)$$

3.2.2. Replacement Fuel Technology Sub-Model

The Replacement Fuel Technology Sub-model converts sectoral useful energy demand into primary energy demand through exogenously defined fuel substitution assumptions reflecting full decarbonisation. It contains process Step 2 and 3.

Step 2 estimates sector-specific replacement factors to determine the extent of fuel substitution required in each sector. Annual sectoral useful energy by each end-state fuel supply technology is expressed as a fraction of total sectoral useful energy:

$$U_{\text{end},s,i_{\text{end}}} = U_{\text{end},s} \times R_{s,i_{\text{end}}} \text{ and } \sum_{i_{\text{end}}} R_{s,i_{\text{end}}} = 1 \quad (4)$$

where

- $U_{\text{end},s,i_{\text{end}}}$ is the annual useful energy demand associated with the end-state year fuel supply technology i in sector s ;
- $R_{s,i_{\text{end}}}$ is the fraction of fuel supplied by technology i in sector s at the end-state year and represents the replacement factor;
- $U_{\text{end},s}$ is the total sectoral annual useful energy demand, as defined in Equation (2).

The end-state year technology set contains exclusively zero-carbon technologies.

Step 3 calculates primary zero-carbon fuel demand in the end-state year based on the estimated useful energy demand in Step 2. The conversion is conducted by applying the efficiency of zero-carbon technology i :

$$D_{\text{end},s,i_{\text{end}}} = U_{\text{end},s,i_{\text{end}}} \div \eta_{s,i_{\text{end}}} \quad (5)$$

where

- $D_{\text{end},s,i_{\text{end}}}$ is the primary energy demand for the end-state year technology i in sector s ;
- $\eta_{s,i_{\text{end}}}$ is the efficiency of the end-state year technology i in sector s ;
- $U_{\text{end},s,i_{\text{end}}}$ is the annual useful energy demand associated with the end-state year fuel supply technology i in sector s , as defined in Equation (4).

Total annual national primary energy demand, D_{end} , is obtained by summing the demand across all technologies and sectors:

$$D_{\text{end}} = \sum_s \sum_{i_{\text{end}}} D_{\text{end},s,i_{\text{end}}} \quad (6)$$

Equation (6) completes the demand estimation for zero-carbon fuels, with the resulting value serving as an input into the Energy Generation Sub-model to calculate the required generation capacities.

3.2.3. Energy Generation Sub-Model

The Energy Generation Sub-model constructs generation scenarios and estimates power and energy values for each scenario. It contains process Step 4 and 5.

Step 4 disaggregates the annual demand value from Equation (6) into an hourly demand profile to capture the temporal dynamics of demand and supply. A representative demand curve is constructed over a full year (8760 h) and scaled such that:

$$D_{\text{end}} = \sum_{h=1}^{h=8760} d_{\text{end},h} \quad (7)$$

where h is the hour and $d_{\text{end},h}$ is the hourly energy demand at the end-state year.

Step 5 determines the required power and storage capacities to meet the projected demand profile from Step 4. This step involves constructing an energy system including multiple generation and storage technologies. Hourly electricity generation is estimated using exogenous assumptions on technology-specific plant availability and hourly load profiles of each generation technology, and is expressed as

$$g_{h,i} = C_i \times AF_i \times LF_{h,i} \quad (8)$$

where

- $g_{h,i}$ is the electricity generated in hour h by technology i ;
- C_i is the installed capacity of technology i ;
- AF_i is the plant availability factor of technology i ;
- $LF_{h,i}$ is the hourly load factor of technology i .

Total hourly and annual energy generation are obtained by aggregating energy generation across all technologies and hours:

$$g_{\text{end},h} = \sum_i g_{h,i} \quad (9)$$

$$G_{\text{end}} = \sum_{h=1}^{h=8760} g_{\text{end},h} \quad (10)$$

where $g_{\text{end},h}$ denotes total energy generation at hour h , and G_{end} represents total energy generation at the end-state year.

Annual energy generation for technology i is:

$$G_{\text{end},i} = \sum_{h=1}^{h=8760} g_{h,i} \quad (11)$$

Temporal mismatches between hourly supply and demand are balanced through energy storage, which absorbs surplus generation and supplies energy during periods of deficit. The required installed storage capacity is therefore determined as the maximum absolute hourly difference between total energy generation and demand:

$$S_{\text{end}} = \max_{0 \leq h \leq 8760} |g_{\text{end},h} - d_{\text{end},h}| \quad (12)$$

where

- S_{end} is the total storage capacity;
- $g_{\text{end},h}$ is the hourly energy generation at the end-state year, as defined in Equation (9);
- $d_{\text{end},h}$ is the hourly energy demand at the end-state year, as defined in Equation (7).

In addition to installed capacity, land use by solar and wind farms presents another important measure of resource requirements, reflecting the geographical resources needed for deployment [13,14,32,33]. The required land or sea area is:

$$\text{Area}_i = C_i \times \text{Area Factor}_i \quad (13)$$

where

- Area_i is the land or sea area required for technology i ;
- C_i is the total installed capacity of technology i , as defined in Equation (8);
- Area Factor_i is the area required per unit of installed capacity.

3.2.4. Economic Assessment Sub-Model

Process Step 6 is conducted using the Economic Assessment Sub-model, which estimates the annualised costs of generation technologies for each generation scenario constructed in the Replacement Fuel Technology Sub-model. The resulting cost estimates also enable the evaluation of the economic benefits of decarbonisation relative to a no-action baseline.

The annualised costs of generation technologies are represented by the total annual energy system cost, which is defined as the sum of the annualised costs of all generation technologies in the system:

$$\text{TEC} = \sum_i G_{\text{end},i} \times \text{LCOE}_i \quad (14)$$

where

- TEC is the total annual energy system cost;
- $G_{\text{end},i}$ is the annual energy generation of technology i , as defined in Equation (11);
- LCOE_i is the levelised cost of energy of technology i .

LCOE for each generation technology is calculated using the standard life-cycle cost formulation:

$$\text{LCOE} = \frac{\text{Discounted sum of costs over lifetime}}{\text{Discounted sum of energy generated over lifetime}} \quad (15)$$

While LCOE reflects the lifetime costs of a technology, capacity cost captures upfront investment costs [34,35], which also influence investment decisions. Total investment cost is estimated for each scenario and calculated as the aggregate capital costs associated with new generation capacities:

$$\text{TIC} = \sum_i (C_i - C_i^{\text{comm}}) \times \text{CC}_i \quad (16)$$

where

- TIC is the total investment cost of an energy system;
- C_i is the target installed capacity for technology i , as defined in Equation (8)
- C_i^{comm} is the committed installed capacity including projects that are in operation, under construction or with secured finance for technology i ;
- CC_i is the capacity cost of technology i .

Capacity cost for each generation technology is:

$$\text{CC} = \frac{\text{Capital Expenditure}}{\text{Installed Capacity}} \quad (17)$$

The total annual energy system cost (TEC) and total investment cost (TIC) are the two measures used for scenario comparison. Scenarios with lower costs are viewed as more economically competitive.

Comparing the TEC of a decarbonisation system with that of the fossil fuel-based system prior to decarbonisation provides an indication of the economic benefits of decarbonisation. Economic benefits, defined in Equation (18), arise when annual energy costs of a decarbonised scenario are lower than the benchmark, meaning national savings from decarbonisation.

$$\text{Economic Benefits} = \text{TEC}_{\text{end}} - \text{TEC}_{\text{start}} \quad (18)$$

where TEC_{end} is the total annual energy system cost at the end-state year, and $\text{TEC}_{\text{start}}$ represents the corresponding at the start year, which serves as the non-action baseline.

3.3. Application Considerations

EDRA can be applied either to compare predefined technology configurations or to identify system configurations subject to specified constraints, in which case optimisation is required. The method provides static system views. When EDRA is used to compare demand-side technologies, configurations that result in lower national energy demand are preferred as they require less generation resources. For generation-side technology comparisons, solutions yielding lower installed capacities and lower system costs are considered more favourable.

EDRA identifies four key resource measures: installed capacity (C_i), land and sea use (Area_i), annual energy system cost (TEC), and upfront investment cost (TIC). Together they capture technological, geographical and financial resource requirements of energy system decarbonisation. Quantifying the level of resources needed for full national decarbonisation provides an indication of the scale of resource deployment and the feasibility of their realisation. When combined with delivery-timeline considerations, this assessment supports the evaluation of national decarbonisation targets and informs the development of alternative strategies where necessary.

When applying EDRA across different countries, it is essential to account for country-specific energy policies, energy system characteristics and resource constraints, as these factors define the feasible solution space. Consequently, the optimisation formulae are case-specific. Additionally, the energy generation Equation (8) and storage Equation (12) may include additional sub-equations reflecting technology-specific elements and multiple storage technologies across different cases. Furthermore, all costs should be expressed in real terms for the selected start year to ensure comparability.

Given the inherent uncertainty in long-term energy planning, it is neither feasible nor desirable to represent all possible future outcomes, as this would leave to excessive model complexity. Instead, analytical focus should be placed on the assumptions under evaluation, while less critical assumptions are treated in a simplified manner. This reduces the risk of obscuring key insights with unnecessary model complexity.

4. Application: The UK Case

4.1. UK Decarbonisation Overview

The UK has set 2050 as the target year of achieving net-zero; however, fossil fuels currently still remain the dominant energy source, posing significant decarbonisation challenges. According to the Digest of UK Energy Statistics (DUKES) [21], the UK's official data, fossil fuels accounted for 80% of total primary energy supply in 2023 (Table 1). When combined with bioenergy and biodegradable waste and electricity imports via interconnectors, these sources constituted 92% of total energy mix, corresponding to 1692 TWh. Road transport is the largest fossil fuel consumer (22%), followed by residential (14%),

industrial (13%), power (12%), aviation (8%), commercial and public (6%), heat networks (2%), others (2%), and shipping (1%).

Table 1. UK primary 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	Demand, $D_{start,s}$ TWh	% of Total
Coal Products	Power	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%
Oil and Petroleum Products	Power	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	Power	206	11%
	Heat Networks	26	1%
	Industrial	137	7%
	Road transport	1	0%
	Residential	237	13%
	Commercial and Public	78	4%
	Others	11	1%
	Losses	5	0%
Bioenergy and Waste	Power	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		1839	100%

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

UK's decarbonisation plans are set out in the government's 5-yearly Carbon Budgets [5,36] and sectoral strategies [7], which prioritise electrification while reserving hydrogen for hard-to-decarbonise areas. Heat pumps and heat networks are two additional key technologies supporting this transition.

Decarbonisation relies on the large-scale deployment of zero-carbon electricity generation technologies. Wind, solar, and nuclear power are the primary contributors and collectively supplied 43% of total electricity demand in 2023 (Table 2). The government has set targets to expand installed capacities to 50 GW of offshore wind and 29 GW of onshore wind by 2030, 70 GW of solar PV by 2035, and 24 GW of nuclear power by 2050 [4,37]. In contrast, hydro, wave, and tidal energy contributed only 2% of electricity supply in 2023. Hydroelectric expansion is constrained by geographical limitations, while wave and tidal technologies remain at early stages of development.

Table 2. Electricity demand by fuel sources in 2023. This table is based on the UK Government's energy classification system in DUKES.

Source	Energy TWh	% of Total
Onshore Wind	33	10%
Offshore Wind	50	16%
Solar PV	14	4%
Hydro	6	2%
Wave or Tidal	0	0%
Nuclear	41	13%
Non-Biodegradable Waste	5	1%
Bioenergy Electricity	34	11%
Coal Electricity	5	2%
Petroleum Electricity	2	1%
Gas Electricity	102	32%
Interconnector Electricity Import	24	8%
Total	314	100%

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

Electric batteries and pumped hydro storage are two main electricity storage technologies in the UK, providing short-duration (typically 4 h) and medium-duration (typically 20 h) storage, respectively [38]. Hydrogen is expected to complement these technologies by enabling both medium- and long-duration storage, including inter-seasonal storage. Although experimental hydrogen storage in salt caverns exists in the UK, large-scale, long-duration hydrogen storage remains at an early stage of development [39], despite significant theoretical potential in salt caverns and depleted oil and gas fields [40,41].

4.2. Energy Demand Sub-Model

The end-state year is 2050 and 2023 is selected as the start year because it is one of the most recent datasets in DUKES and aligns with the country's latest Carbon Budget [5].

Over the past 25 years, the UK's total primary energy demand has declined by one-third [21], although demand from data centres may reverse this trend in future years [42]. As this study focuses on fuel supply analysis, useful energy demand in 2050 is assumed equal to the 2023 level ($k_s = 1$ in Equation (1)).

For other parameters in Equation (1), $D_{\text{start},s}$ is the sectoral primary energy demand in 2023, shown in Table 1, while $\eta_{s,i,\text{start}}$ is the efficiency ratios of carbon-emitting

technologies in the same year, presented in Table 3. The ratios are drawn from previous studies [15,43] and the Carbon Budgets [5,36], with values based on mid-range estimates or conservative assumptions. Efficiency ratios for fossil fuel power plants are not required as DUKES provides the corresponding electricity generation data (Table 2), eliminating the need for conversion via efficiency ratios.

Table 3. Efficiency ratios for carbon-emitting fuel technologies.

System Type	System	Sector	Efficiency, $\eta_{s,i_{start}}$
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%
	Bioenergy boiler	Residential	85%

4.3. Replacement Fuel Technology Sub-Model

4.3.1. End-Use Fuel Supply Scenario

A maximum direct electrification scenario, termed Direct Electricity, is constructed assuming widespread direct electrification across end-use sectors. Green hydrogen is used in hard-to-decarbonise areas, while waste heat is utilised for heat networks. Due to deployment barriers associated with heat pumps [44], their uptake is assumed to remain at current levels. This avoids introducing estimation bias related to user behaviour or policy change, allowing the analysis to focus on technology comparison. By minimising uncertainties related to technology deployment, this scenario provides a reference case for evaluating policy decisions for technologies alternative to direct electrification, such as large-scale deployment of heat pumps or hydrogen boilers [45].

4.3.2. Input Assumptions

The input assumptions for the replacement factors, $R_{s,i_{end}}$ from Equation (4) are summarised in Table 4. The ratios for non-direct electrification are based on the government projections and supplemented by academic studies where policy details are insufficient. In cases where the government reports indicate that decarbonisation technology choices are undecided or still rely on carbon-emitting fuels, direct electrification is assumed, except for aviation where 85% of aircraft are assumed to be hydrogen-powered based on Pilidis et al. [15]. For sectors with projections available only up to 2040, values are primarily based on the 2040 figures with minor adjustments based on observed trends. This method ensures that direct electrification remains the primary assumption for the scenario.

Table 4. Sectoral replacement factors in 2050. Technologies without references represent the balance required to reach 100% within each sector.

Sector	Replacement Fuel	Replacement Factor, $R_{s,i_{end}}$	Reference
Power	Direct Electricity	100.0	
Industrial	Direct Electricity	92.0%	
	Hydrogen	8.0%	[5]
Road Transport	Direct Electricity	98.7%	
	Hydrogen	1.3%	[5,46]
Rail	Direct Electricity	95.0%	
	Hydrogen	5.0%	[7]
Aviation	Direct Electricity	15.0%	[15]
	Hydrogen	85.0%	[15]
Shipping	Direct Electricity	4.0%	[36]
	Hydrogen	96.0%	
Residential	Direct Electricity	91.6%	
	Heat Pump Electricity	0.5%	[47–50]
	Hydrogen	0.0%	[51]
	Heat Networks	8.0%	[5]
Commercial and Public	Direct Electricity	78.0%	
	Heat Pump Electricity	0.0%	[52]
	Hydrogen	0.0%	[51]
	Heat Networks	22.0%	[5]
Others	Direct Electricity	78.0%	
	Heat Networks	22.0%	[5]

The assumptions for zero-carbon fuel technology efficiencies specified in Equation (5) are presented in Table 5. They are obtained from previous studies [15,45] and key UK Government reports [5,36]. The selection of these ratios is guided by one or more of the following considerations: (i) use of mid-range values, (ii) adoption of conservative assumptions, and (iii) incorporation of expected efficiency improvements for future technologies.

Table 5. Efficiency ratios for zero-carbon fuel technologies. H₂ = hydrogen.

System Type	System	Sector	Efficiency, $\eta_{s,i_{end}}$
Power plant	Green H ₂ electrolyser	Power, Industrial, Road, Rail	65%
	Liquified H ₂ production	Aviation, Shipping	55%
	CCHT	Power, Industrial	53%
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	Direct electric heating	Residential, Industrial, Others	100% ^a
	Heat pump	Residential	311%

^a assuming all electricity is converted into heat.

4.4. Energy Generation Sub-Model

This section introduces the creation of the hourly demand profile, the proposed energy system, and four generation scenarios developed to reflect the UK's energy policy targets. The embedded equations within the Energy Generation Sub-model and the optimisation approach are then presented. Finally, the input data assumptions are summarised.

4.4.1. Hourly Demand Profile Creation

The demand curve is constructed following the method by DECC [53] and based on the 2013 weather year, which is considered representative of typical UK weather conditions and has been used in the recent future energy scenario modelling by National Grid ESO [8]. Winter spans December 2012 to February 2013, spring March to May, summer June to August, and autumn September to November.

Applying the 2013 demand curve to the projected 2050 annual demand for electricity produces the daily electricity demand profile. Hydrogen demand is assumed to follow the same hourly pattern as electricity demand given its small magnitude. This produces the daily hydrogen demand. The total hourly electricity demand (D_{end} in Equation (7)) is the sum of hourly electricity required for hydrogen production and the daily electricity demand. This summed hourly electricity profile is the 2050 hourly demand curve (Equation (7)).

4.4.2. Energy System Structure

While renewables are subjective to weather-related intermittency and nuclear power lacks operational flexibility, green hydrogen can compensate for both by providing flexible storage and dispatch when electricity generation and demand are mismatched [54]. This flexibility is achieved by converting surplus electricity into green hydrogen via electrolysis [55], which can subsequently be reconverted to electricity via CCHTs [12–14] during periods of electricity deficit. The storage, liquefaction, transport, and combustion of hydrogen must be conducted under stringent safety procedures [55]. Based on these characteristics, a future energy system is proposed, as illustrated in Figure 2. Electricity generation is from solar, onshore wind, offshore wind, nuclear, hydro, wave, tidal, and non-biodegradable waste.

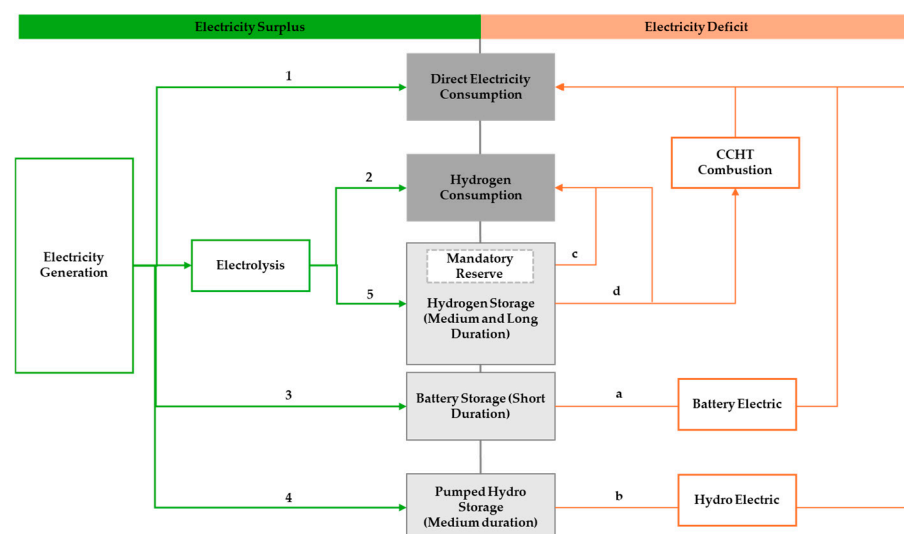


Figure 2. Energy flow during electricity surplus and deficit. a–d and 1–5 represent each stage of energy flow.

Electricity surplus occurs when power generation exceeds demand, while electricity deficit arises when demand surpasses generation. Managing these imbalances is critical for maintaining grid stability and ensuring reliable energy supply.

For each hour, electricity generated is first allocated to meet direct electricity demand (1). Subsequently, the required amount of electricity is directed to electrolyzers to produce green hydrogen to meet daily hydrogen consumption needs (2). Any surplus electricity is then stored in battery storage systems (3). Once 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 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 daily hydrogen demand (c).

4.4.3. Electricity Generation Scenarios

Four generation scenarios are created, assuming no or low hydrogen exports. The low export level is intended for system balancing when storage is full.

- **Targets-focused**

In this scenario, the installed capacities of wind, solar, and nuclear meet the UK Government's targets. This scenario aims to analyse whether the target generation capacity is sufficient to meet the daily electricity and hydrogen demand.

- **Renewables-focused**

This scenario assesses the wind and solar capacities required to achieve net-zero and energy independence. Nuclear remains at the current committed capacity of 10 GW [4].

- **Nuclear-focused**

This scenario focuses on nuclear power development with renewable capacities remaining at the current committed level, i.e., 28 GW for offshore wind [56], 20 GW for onshore wind [57], and 24 GW for solar [37].

- **Co-development**

In this scenario, all wind, solar, and nuclear capacities increase. The baseload demand is provided by nuclear power to ensure energy security, with the remaining contributed by renewables. Offshore wind offers the best energy output and aligns with the UK's seasonal demand pattern. However, solar farms are the fastest to build. Therefore, this scenario assumes onshore wind and solar capacities remain at the government's targets, with the additional capacity sourced from offshore wind.

In all scenarios, the total of hydro, wave, tidal, and non-biodegradable generation remain at the 2023 level of 10 TWh.

4.4.4. Technology-Specific Equations

The proposed energy system and scenarios require technology-specific variations of Equation (8), along with extensions to Equation (12) to enable calculations for each technology. These additional equations are listed in Table 6, reflecting the modelling assumptions in this study. A working example of the equations implemented in the model is in Table A1 in the Appendix A.

Table 6. Technology specific equations. Symbols not defined in this table are provided in the reference equations. Ref. = Reference.

	Equation	Denotation	Equation No.	Ref. Equation
Generation:				
Solar	$g_{h,solar} = C_{solar} \times AF_{solar} \times \text{Solar Radiation}_h \times 1 \text{ hour}$	$g_{h,solar}$ = solar electricity at hour h; Solar Radiation_h = solar radiation at hour h	(19)	(8)
Wind	$g_{h,wind} = C_{wind} \times AF_{wind} \times \text{Wind Power}_h \times 1 \text{ hour}$	$g_{h,wind}$ = onshore or offshore wind electricity at hour h; Wind Power_h = wind power at hour h	(20)	(8)
Nuclear	$g_{h,nuclear} = C_{nuclear} \times AF_{nuclear} \times SF_{season} \times 1 \text{ hour}$	$g_{h,nuclear}$ = nuclear electricity at hour h; SF_{season} = nuclear power plant seasonal availability adjustment factor for each season	(21)	(8)
Storage:				
Electric Battery	Storage Level _{i,h} = Storage Level _{i,h-1} + (Electricity Charged _{i,h} – Charging Loss _{i,h}) – (Electricity Discharged _{i,h} + Discharging Loss _{i,h}) where Charging Loss _h or Discharging Loss _h = electricity charged or discharged X (1– η_i)/2; $S_{i,min} \leq \text{Storage Level}_{i,h} \leq S_i, \forall h$; $S_i = SC_i \times AF_i$	Storage Level _{i,h} = the storage level for storage technology i at hour h; η_i = round trip efficiency from charging to discharging; $S_{i,min}$ = the minimum storage level for technology i; S_i = the available capacity of storage technology i; SC_i = installed capacity of storage i.	(22)	(8), (12)
Pumped Hydro	Same as Electric Battery			
Hydrogen	$H_2 \text{ Stored}_h = [H_2 \text{ Stored}_{h-1} + (H_2 \text{ Produced}_h - \text{Injection Loss}_h) - (H_2 \text{ Withdrawn for Daily } H_2 \text{ Demand for Powering CCHT}_h + \text{Withdrawal Loss}_h)]$ where Injection Loss _h or Withdrawal Loss _h = hydrogen injected or withdrawn X (1– $\eta_{H_2 \text{ storage}}$)/2; $S_{H_2,min} \leq H_2 \text{ Stored}_h \leq S_{H_2}, \forall h$; $S_{H_2} = SC_{H_2} \times AF_{H_2}$	$H_2 \text{ Stored}_h$ = hydrogen stored at hour h; $\eta_{H_2 \text{ storage}}$ = round-trip efficiency from injection to withdrawal; $S_{H_2,min}$ = the minimum storage level for underground hydrogen storage; SC_{H_2} = installed capacity of underground hydrogen storage.	(23)	(8), (12)
Hydrogen Production, Backup Power, and Export:				

Electro- lyser	$H_2 \text{ Produced}_h = (g_{\text{end},h} - d_{\text{end},h}) \times \eta_{\text{electrolyser}}$		$H_2 \text{ Produced}_h = \text{hydrogen produced at hour } h;$		(24)	(12)
	where $g_{\text{end},h} > d_{\text{end},h}$		$\eta_{\text{electrolyser}}$ = electrolyser efficiency			
	$C_{\text{electrolyser}} = \max_{0 \leq h \leq 8760} ((g_{\text{end},h} - d_{\text{end},h}) \div 1 \text{ hour})$		$C_{\text{electrolyser}} = \text{the available electrolyser capacity}$		(25)	(22)
CCHT	$H_2 \text{ for Powering CCHT}_h = (d_{\text{end},h} - g_{\text{end},h}) \div \eta_{\text{CCHT}}$		$H_2 \text{ for Powering CCHT}_h = \text{hydrogen used to power CCHT at hour } h;$		(26)	(12)
	where $d_{\text{end},h} > g_{\text{end},h}$		η_{CCHT} = CCHT efficiency			
	$C_{\text{CCHT}} = \max_{0 \leq h \leq 8760} ((d_{\text{end},h} - g_{\text{end},h}) \div 1 \text{ hour})$		$C_{\text{CCHT}} = \text{the available CCHT capacity}$		(27)	(24)
Grid	$C_{\text{grid}} = \max_{0 \leq h \leq 8760} (\max(d_{\text{end},h}, g_{\text{end},h}) \div 1 \text{ hour})$		$C_{\text{grid}} = \text{the available electricity grid capacity}$		(28)	(12)
Hydro- gen Ex- port	$H_2 \text{ Export}_h = H_2 \text{ Stored}_h - S_{H_2}$		$H_2 \text{ Export}_h = \text{hydrogen exported at hour } h; S_{H_2} = \text{the available capacity of underground hydrogen storage}$		(29)	(25)
		where $H_2 \text{ Stored}_h > S_{H_2}$				

Solar energy (Equation (19)) is estimated using hourly solar radiation data from the UK Met Office [58]). Wind power generation (Equation (20)) is modelled using the Virtual Wind Farm tool [59]. The tool simulates wind speeds at specified geographical locations and hub heights, then converts these to power outputs using manufacturer-provided power curves. Nuclear power plants are assumed to operate with seasonally varying availability to reflect seasonal demand patterns, with higher availability in winter and lower in summer (Equation (21)).

All storages technologies are subject to capacity limits and their storage balances account for losses incurred during charging and discharging in the case of electric batteries and pumped hydro (Equation (22)), or during injection and withdrawal in the case of underground hydrogen storage (Equation (23)). Hydrogen storage balances additionally account for withdrawals to meet daily hydrogen demand and CCHT operation (Equation (23)). The total available storage capacity of the country (S_{end} in Equation (12)) is obtained by summing the available capacities of the three storage types:

$$S_{\text{end}} = S_{\text{battery}} + S_{\text{pumped hydro}} + S_{H_2} \quad (30)$$

Hydrogen production is subject to electrolyser efficiency (Equation (24)) and electricity generated by CCHTs depends on CCHT efficiency (Equation (26)). The capacities of electrolysers, CCHTs, and electricity grid are driven by electricity surplus and deficit levels (Equations (25), (27), and (28)). These equations define theoretical capacities without accounting for utilisation patterns, losses, or availability factors. Consequently, actual installed capacities are expected to be higher.

When the storage capacity is fully utilised, excess hydrogen is exported (Equation (29)).

4.4.5. Optimisation

Optimisation is performed for all generation scenarios. In each scenario, selected generation and storage capacities are fixed while others are varied iteratively until the relevant objective functions (Equations (31)–(33)) converge to values approaching zero (ϵ). Table 7 lists the scenario-specific constraints and relevant objective functions. Figure 3 presents a flowchart illustrating the optimisation process for the Co-development scenario. Other scenarios involve fewer objective functions and can use the same flowchart.

Equation (31) determines the smallest underground hydrogen storage capacity required to accommodate hourly generation–demand imbalances.

$$\min_{SC_{H_2}} |H_2 \text{ Stored}_h(SC_{H_2}) - S_{H_2, \min}| \quad (31)$$

subject to:

$$0 \leq H_2 \text{ Stored}_h(SC_{H_2}) - S_{H_2, \min} \leq \epsilon_{H_2}, \quad \forall h$$

Equation (32) determines the capacity C_i of any particular decision variable generation technology. An assumption is made that demand is met exclusively by locally produced electricity, and so is aligned with the government's energy independence policy. Hydrogen imports are not considered and exports are negligible.

$$\min_{C_i} (G_{\text{end}}(C_i) - D_{\text{end}}) \quad (32)$$

subject to:

$$0 \leq G_{\text{end}}(C_i) - D_{\text{end}} \leq \epsilon_i;$$

$$g_{\text{end},h} + g_{h,\text{CCGT}} - d_{\text{end},h} \geq 0, \quad \forall h;$$

$$H_2 \text{ Export}_h \rightarrow 0, \quad \forall h;$$

where $g_{\text{end},h}$ is the total electricity generation at hour h by generation technologies, and $g_{h,\text{CCGT}}$ is the electricity generation by CCHTs at hour h .

Equation (33) determines nuclear capacity C_{nuclear} under the assumption that nuclear generation provides baseload demand and so aligned with the government's energy security policy.

$$\min_{C_{\text{nuclear}}} |g_{H,\text{nuclear}}(C_{\text{nuclear}}) - \min(d_{\text{end},h})| \quad (33)$$

subject to:

$$0 \leq g_{H,\text{nuclear}}(C_{\text{nuclear}}) - \min(d_{\text{end},h}) \leq \epsilon_{\text{nuclear}}, \quad \forall h$$

where H corresponds to the hour of minimum electricity demand representing the base-load.

Table 7. Optimisation specification for each scenario.

Scenario	Decision Variables	Additional Constraints	Objective Function
Target-focused	hydrogen storage capacity, SC_{H_2}	$C_{\text{nuclear}} = 24 \text{ GW};$ $C_{\text{solar}} = 70 \text{ GW};$ $C_{\text{onshore wind}} = 29 \text{ GW};$ $C_{\text{offshore wind}} = 50 \text{ GW}$	(31)
Renewables-focused	hydrogen storage capacity, SC_{H_2} ; offshore wind capacity, $C_{\text{offshore wind}}$	$C_{\text{nuclear}} = 10 \text{ GW};$ $C_{\text{solar}} = 140 \text{ GW};$ $C_{\text{onshore wind}} = 87 \text{ GW}$	(31) then (32), iteration between equations

Nuclear-focused	hydrogen storage capacity, SC_{H_2} ; nuclear capacity, $C_{nuclear}$	$C_{solar} = 24$ GW; $C_{onshore\ wind} = 20$ GW; $C_{offshore\ wind} = 28$ GW	(31) then (32), iteration between equations
Co-development	nuclear capacity, $C_{nuclear}$; hydrogen storage capacity, SC_{H_2} ; offshore wind capacity, $C_{offshore\ wind}$	$C_{solar} = 70$ GW; $C_{onshore\ wind} = 29$ GW;	(33) then (31) then (32); iteration between (31) and (32)

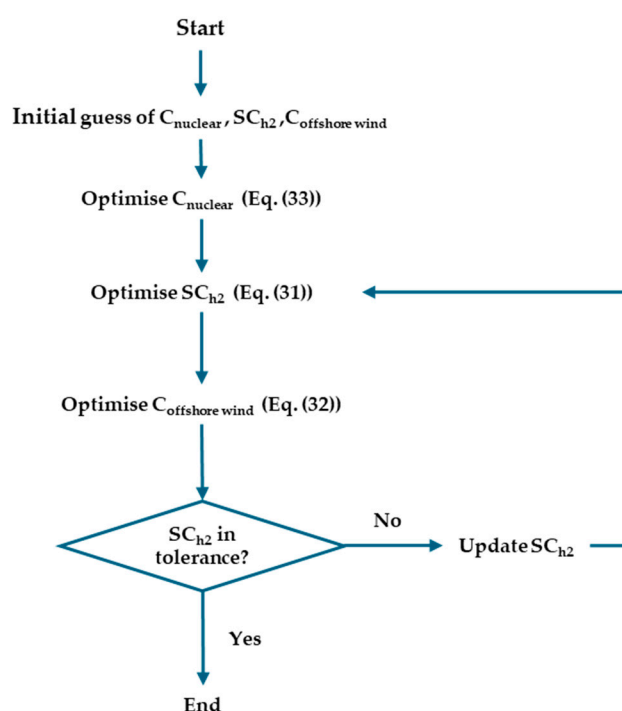


Figure 3. Optimisation flowchart for the Co-development scenario. Eq. = Equation.

4.4.6. Input Assumptions

Solar radiation data is from 80 Met Office weather station for the 2013 weather year [58]. For wind farms, the selected notional turbines are rated at 10 MW for offshore wind and 3 MW for onshore wind, with specifications shown in Table 8. For offshore wind farms, six locations are selected across the English North Sea, Scottish North Sea, North Atlantic Sea, Irish Sea, Celtic Sea, and English Channel [33,60]. For onshore wind farms, nine locations are selected, including three sites in Scotland (Shetland, north and south Scotland), one site in Northern Ireland, one site in Wales, and four sites in England, representing the northern, mid-east, mid-south, and southern regions. The remaining assumptions for the Energy Generation Sub-model are listed in Table 9.

Table 8. Wind turbine technical specifications.

	Offshore Wind Turbine	Onshore Wind Turbine
Notional Model	Siemens Gamesa SG 10.0-193	Siemens SWT 3.0-101
Rated Power	10 MW	3 MW
Hub Height	100 m	75
Rotor Diameter	193 m ²	101 m ²
Swept Area	29,256 m ²	8012 m ²
Cut-In Wind Speed	3.5 m/s	3.5 m/s
Cut-Off Wind Speed	25 m/s	25 m/s

Table 9. Other generation and storage input assumptions. HWTW = hydro, wave, tidal, and non-biodegradable waste-to-power.

Technol-ogy	Variables	Symbol	Assumption	Reference
Solar	Installed ^a	C_i	16 GW	[37]
	Committed ^{b,c}	C_i^{comm}	24 GW	[37]
	Area Factor	Area_i	24 km ² per GW	[32]
	Availability Factor	AF_i	93%	[15]
Onshore Wind	Installed ^a	C_i	15 GW	[57]
	Committed ^{a,c}	C_i^{comm}	19 GW	[57]
	Area Factor	Area_i	193 km ² per GW	[36]
	Availability Factor	AF_i	88%	[15]
Offshore Wind	Installed ^a	C_i	13 GW	[56]
	Committed ^{a,c}	C_i^{comm}	28 GW	[56]
	Under-development ^a		51 GW	[56]
	Area Factor	Area_i	240 km ² per GW	[61]
	Availability Factor	AF_i	88%	[15]
Nuclear	Installed ^b	C_i	6 GW	[4]
	Committed ^b	C_i^{comm}	10 GW	[4]
	Potential		>50 GW	[54]
	Availability Factor	AF_i	90%	[15]
	Seasonal Factor	$\text{SF}_{\text{season}}$	Winter: 1.02 Summer: 0.98	[15]
HWTW	Annual Electricity Generation ^a	$G_{\text{end},i}$	10 TWh	Table 2
Hydrogen Storage	Salt Cavern Theoretical Capacity		64 Mt (2150 TWh)	[40]
	Availability Factor	AF_i	97%	[62]
	Round-trip Efficiency ^d	$\eta_{\text{H}_2 \text{ storage}}$	80%	[63]
	Minimum storage level	$S_{\text{H}_2, \text{min}}$	cushion gas (50%) plus a mandatory reserve (a two-week supply)	[39,41]
Electric Battery Storage	Installed ^b		8 GWh	[64]
	Committed ^b		26 GWh	[64]
	Availability Factor	AF_i	91%	
	Round-trip Efficiency ^e	η_i	85%	
	Minimum storage level	$S_{\text{battery}, \text{min}}$	20%	
Pumped Hydro	Installed ^b		32 GWh	[65]
	Availability Factor	AF_i	95%	
	Round-trip Efficiency ^e	η_i	80%	
	Minimum storage level	$S_{\text{pumped hydro}, \text{min}}$	0%	

^a 2023 statistics ^b 2024 view. ^c Including both installed and projects with secured funding. ^d From hydrogen injection to withdrawal. ^e From electricity charging to discharging.

4.5. Economic Assessment Sub-Model

4.5.1. No-Action Scenario

The Fossil Fuel-focused scenario is constructed as the no-action scenario to assess the economic impact of decarbonisation. This scenario mirrors the 2023 structure (Table 1), except that the small amount of coal supply is assumed to be replaced by gas and oil. Equation (14) is used to calculate annual energy generation costs for all sectors except transport and imported electricity. For transport, oil and gas prices are applied to annual

fuel consumption to derive energy costs. Imported electricity costs are calculated by applying electricity prices to annual imported volumes. The total cost calculated serves as the baseline costs, TEC_{start} , for economic benefits calculation in Equation (18).

4.5.2. Input Assumptions

The UK's official sources [66] are used for cost and economic data assumptions. The economic inputs includes wholesale commodity prices, foreign exchange rates, exchange rates, and inflation. Tables 10 and 11 presents the projections as of 2023, expressed in 2023 real prices. Cost projections for 2040 are used instead of those for 2050 to allow time for investment decisions and plant construction.

Table 10. LCOE and capacity costs assumptions. The data represent the UK Government's projections for 2040 or the nearest available year, as of 2023. All 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	
OCCGT	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 a LCOE of £46/MWh. ² Green hydrogen is produced from surplus renewables or nuclear electricity that would otherwise be curtailed; therefore, no fuel cost is assumed.

Table 11. Commodity price assumptions. The data represent the UK Government's projections for 2050 or the nearest available year, as of 2023. Currency conversion is based on the government's exchange rate forecast over the same period. All values are shown in 2023 real prices. GDP deflators are applied to remove inflation effects.

	Price GBP/MWh
Oil	41
Gas	26
Electricity	72
Biodiesel ¹	82

¹ This assumes a doubling of the oil price.

Tables 10 and 11 provide the inputs to Equations (14) and (16) for calculating the total annual energy system cost (TEC) and total investment cost (TIC), and TEC_{start} for the Fossil Fuel-focused scenario, which are subsequently applied in Equation (18) to estimate the economic benefits of each generation scenario.

5. Results and Discussion

5.1. Energy Demand Sub-Model

The sectoral useful energy demand in 2050 ($U_{end,s,i_{end}}$) calculated using Equation (1) is presented in Table 12.

5.2. Replacement Fuel Technology Sub-Model

Table 12 reports the outputs of the Replacement Fuel Technology Sub-model, showing the sectoral primary energy demand in 2050 ($D_{end,s,i_{end}}$) for electricity, hydrogen, and heat, calculated via Equations (4) and (5).

Figure 4 provides a summarised view of Table 12 by aggregating all sectors and illustrating the end-use fuel supply transition from 2023 to 2050, showing the values for D_{start} and D_{end} defined in Equations (1) and (6). Assuming maximum direct electrification, the 2050 total primary energy demand is projected to be ~1198 TWh, comprising ~1121 TWh from electricity and ~78 TWh from heat networks. The hydrogen demand is ~80 TWh (2.4 Mt), produced from ~135 TWh of electricity. Compared to 2023, electricity demand increases from ~314 TWh to 1121 TWh, representing a nearly 360% rise. In contrast, overall primary energy demand decreases from 1839 TWh to 1198 TWh, a reduction of ~35%, reflecting the lower thermal losses in a decarbonised energy system.

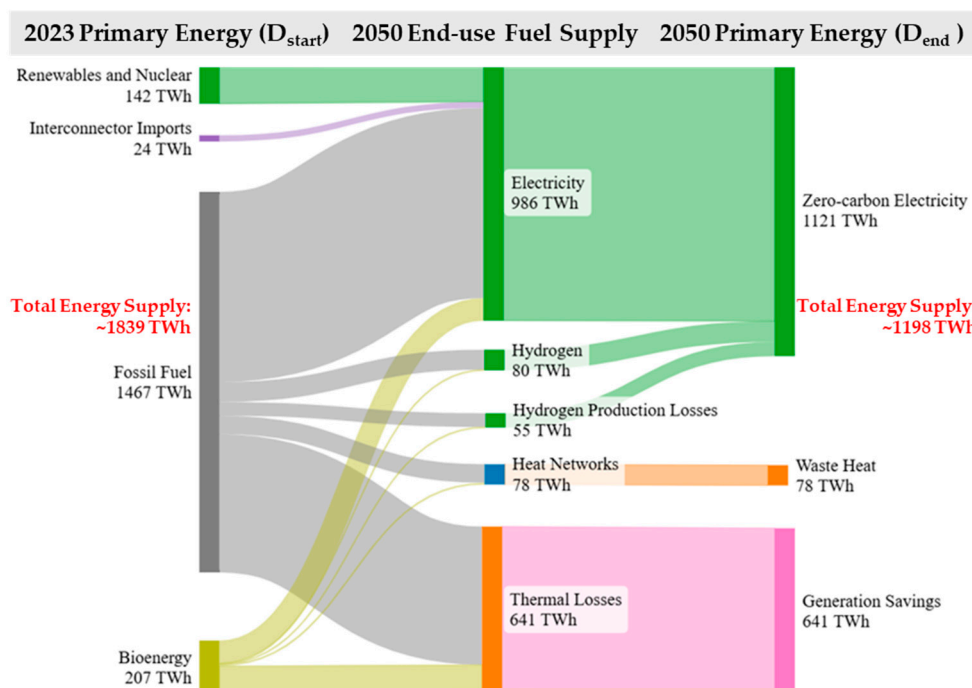


Figure 4. Illustration of fuel supply transition from 2023 to 2050. In 2050, the end-use energy demand is met through electricity, green hydrogen, and heat networks. Green hydrogen is produced from surplus zero-carbon electricity and incurs thermal loss during conversion. Heat networks utilise waste heat. As a result of decarbonisation, total primary energy demand decreases from 1839 TWh in 2023 to 1198 TWh in 2050, yielding a 641 TWh reduction in thermal losses and a consequent decrease in required generation resources. All values are reported without decimals; underlying figures are not rounded.

Table 12. Sectoral fuel supply replacement in 2050 under the Direct Electricity scenario. Repl. = replacement, H₂ = hydrogen, Heat Pumps = heat pump electricity. The aviation sector is used as an example to demonstrate the calculation. The 2023 fuel demand from oil is ~143 TWh, corresponding to ~43 TWh of useful energy based on a 30% gas turbine efficiency. In 2050, 15% aircraft are battery-electric planes and 85% hydrogen-powered, requiring ~6 TWh and ~36 TWh of useful energy, respectively. Battery-electric planes require ~9 TWh of electricity based on a 70% electrical system efficiency. Hydrogen aircraft require ~40 TWh of hydrogen, produced using ~73 TWh of electricity. This is based on 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 5) and 55% for the conversion of electricity to liquid hydrogen.

2023	Conversion Variables							2050		
Primary Energy $D_{start,s}$ TWh	Existing System Efficiency $\eta_{s,i,start}$	Useful Energy $U_{end,s,i,start}$ TWh	Replace with	Repl. Factor $R_{s,i,end}$	Repl. Useful Energy $U_{end,s,i,end}$ TWh	Repl. System Efficiency $\eta_{s,i,end}$	H ₂ Electrolyser Efficiency $\eta_{s,i,end}$	Electricity, $D_{end,s,i,end}$ TWh	H ₂ , $D_{end,s,i,end}$ TWh	Heat $D_{end,s,i,end}$ TWh
Equation (1)	Equation (1)	Equation (1)		Equation (4)	Equation (4)	Equation (5)	Equation (5)	Equation (5)	Equation (5)	Equation (5)
Coal Products:										
Power ¹	15							5		
Heat Networks	0									0
Industrial	33	60%	20	Direct Electricity	92.0%	18	100%	18		
				Hydrogen	8.0%	2	53%	5	3	
Rail	0	7%	0	Direct Electricity	95.0%	0	70%	0		
				Hydrogen	5.0%	0	30%	0	0	
Residential	3	88%	3	Direct Electricity	91.6%	3	100%	0		
				Heat Pumps	0.5%	0	311%	3		
				District Heating	8.0%	0	100%			0
Commercial and Public	0	60%	0	Direct Electricity	78.0%	0	100%	0		
				District Heating	22.0%	0	100%			0
Others incl. Agriculture	0	60%	0	Direct Electricity	78.0%	0	100%	0		
				District Heating	22.0%	0	100%			0
Losses	1	100%	1	Direct Electricity	100.0%	1	100%	1		
Oil and Petroleum Products:										
Power	5							2		
Heat Networks	1									1
Industrial	74	80%	59	Direct Electricity	92.0%	54	100%	54		

				Hydrogen	8.0%	5	53%	65%	14	9
Road Transport ²	410	Petrol 15% Diesel Car 25% Diesel Lorry 30%	81	Direct Electricity	98.7%	80	70%		115	
				Hydrogen	1.3%	1	30%	65%	6	4
Rail	7	30%	2	Direct Electricity	95.0%	2	70%		3	
				Hydrogen	5.0%	0	30%	65%	1	0
Aviation	143	30%	43	Direct Electricity	15.0%	6	70%		9	
				Hydrogen	85.0%	36	90%	55%	73	40
Shipping	9	30%	3	Direct Electricity	4.0%	0	70%		0	
				Hydrogen	96.0%	3	98%	55%	5	3
Residential	24	92%	22	Direct Electricity	91.6%	20	100%		20	
				Heat Pumps	0.5%	0	311%		0	
				District Heating	8.0%	2	100%			2
Commercial and Public	27	80%	21	Direct Electricity	78.0%	17	100%		17	
				District Heating	22.0%	5	100%			5
Others incl. Agriculture	14		11	Direct Electricity	78.0%	9	100%		9	
				District Heating	22.0%	2	100%			2
Natural Gas: Power ¹	206								102	
Heat Networks	26									26
Industrial	137	85%	116	Direct Electricity	92.0%	107	100%		107	
				Hydrogen	8.0%	9	53%	65%	27	18
Road Transport	1	25%	0	Direct Electricity	98.7%	0	70%		0	
				Hydrogen	1.3%	0	30%	65%	0	0
Residential	237	94%	223	Direct Electricity	91.6%	204	100%		204	
				Heat Pumps	0.5%	1	311%		0	
				District Heating	8.0%	18	100%			18
Commercial and Public	78	85%	66	Direct Electricity	78.0%	52	100%		52	
				District Heating	22.0%	15	100%			15
Others incl. Agriculture	11	85%	9	Direct Electricity	78.0%	7	100%		7	
				District Heating	22.0%	2	100%			2

Losses	5	100%	5	Direct Electricity	100.0%	5	100%		5	
Bioenergy and Waste:										
Power ¹	120								39	
Heat Networks	3									3
Industrial	20	80%	16	Direct Electricity	92.0%	15	100%		15	
				Hydrogen	8.0%	1	53%	65%	4	2
Road Transport	30	25%	7	Direct Electricity	98.7%	7	70%		11	
				Hydrogen	1.3%	0	30%	65%	1	0
Aviation	1	30%	0	Direct Electricity	15.0%	0	70%		0	
				Hydrogen	85.0%	0	90%	55%	1	0
Residential	15	85%	13	Direct Electricity	91.6%	12	100%		12	
				Heat Pumps	0.5%	0	311%		0	
				District Heating	8.0%	1	100%			1
Commercial and Public	15	80%	12	Direct Electricity	78.0%	9	100%		9	
				District Heating	22.0%	3	100%			3
Others incl. Agriculture	2	80%	2	Direct Electricity	78.0%	1	100%		1	
				District Heating	22.0%	0	100%			0
Other Clean Fuel Electricity ¹ :										
Onshore Wind	33								33	
Offshore Wind	50								50	
Hydro	6								6	
Solar PV	14								14	
Wave and Tidal	0								0	
Nuclear Electricity	41								41	
Others:										
Interconnector										
Electricity Import ¹	24								24	
Total Energy Demand	1839								1121	80 78

Numbers are presented up to one decimal place; underlying figures are not rounded. ¹ This refers to actual electricity generation or imports, as reported in DUKES.

² Vehicle mix by fuel type based on UK Government road traffic statistics for 2023 [46].

5.3. Energy Generation Sub-Model

Figure 5 illustrates the outputs of Equation (7) which disaggregate the projected electricity demand of ~1121 TWh (D_{end}) into an hourly demand profile.

The Energy Generation Sub-model integrates demand, generation, storage, hydrogen production and CCHT generation on an hourly interval. This calculation is demonstrated in Table A1 using a representative summer day including both electricity surplus and deficit periods. Model outputs for four generation scenarios are reported in Tables 13–16, providing statistics for two categories of resources: capacity (C_i and SC_i) and land area ($Area_i$).

In the Target-focused scenario, locally produced energy sources together generate 563 TWh of electricity, representing approximately 50% of the total electricity demand (Table 13). Meeting the shortfall with CCHTs requires nearly 32 Mt of imported hydrogen (Table 16) and more than 153 GW of CCHTs running all year-around to power the country (Table 14).

Imports accounts for around 66% of the total electricity supply (Table 13). An alternative to hydrogen imports would be to cover the shortfall with fossil fuel generation. Neither of these satisfies energy independence.

The three scenarios, Renewables-focused, Nuclear-focused, and Co-development, are all self-reliant energy scenarios. Renewables-focused requires more than quadrupling the government's targets for offshore wind, tripling onshore wind, and doubling solar capacity. Renewables supply 94% of electricity. This scenario entails the highest equipment requirements (Table 14) and hydrogen produced, although it requires slightly lower hydrogen storage, indicating better alignment between demand and electricity generated by wind. It also results in the greatest land use for solar and wind farms across all scenarios.

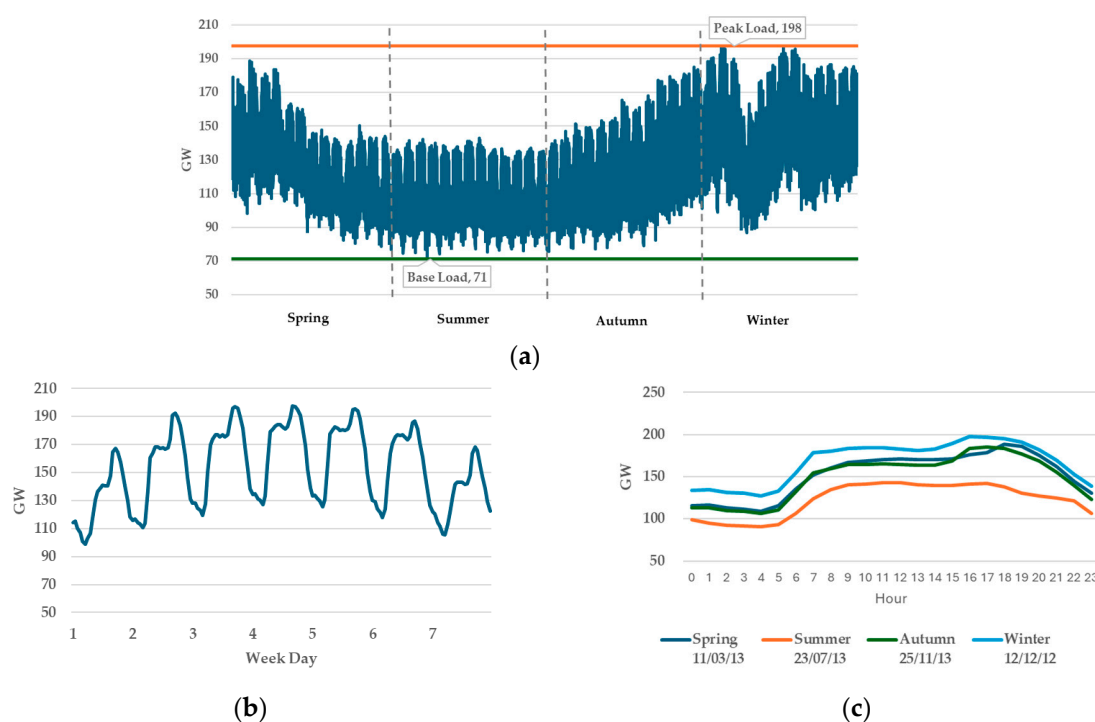


Figure 5. Hourly demand curves. (a) Year from spring to winter; (b) peak load week; (c) peak days in each season.

Table 13. Scenario comparison of energy generation in 2050. Off. W. = offshore wind, On. W. = on-shore wind, H₂ Imp. = hydrogen import, HWTW = hydro, wave, tidal, and non-bio-degradable waste, Cap. = capacity, Elec. = electricity, Load = load factor.

	Co-Development					Target-Focused			Renewables-Focused			Nuclear-Focused		
	Cap. Ci GW	Elec., G _{end,i} TWh	Elec. %	Load %	Area Area _i km ²	Cap. Ci GW	Elec., G _{end,i} TWh	Area Area _i km ²	Cap. Ci GW	Elec. G _{end,i} TWh	Area Ar- ea _i km ²	Cap. Ci GW	Elec. G _{end,i} TWh	Area Area _i km ²
Off. W.	119	555	42%	53%	28,481	50	234	12,000	211	988	50,690	28	131	6720
On. W.	29	65	5%	26%	5593	29	65	5593	87	196	16,779	20	45	3857
Solar	70	65	5%	11%	12,141	70	65	12,141	140	130	24,281	24	22	4162
Nuclear	81	638	48%	90%		24	189		10	79		140	1099	
HWTW		10	1%				10			10			10	
H ₂ Imp.		0	0%				1071			-			-	
Total	299	1333	100%		46,214	173	1634	29,733	448	1402	91,750	212	1308	14,740

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

Table 14. Scenario comparison of electrolyser, CCHT, and electricity grid capacity in 2050. Cap. = capacity, Uti'n = utilisation ratio, Op. Hr = % of operating hours in a year.

	Co-Development			Target-Focused			Renewables-Focused			Nuclear-Focused		
	Cap. Ci GW	Uti'n	Op. Hr	Cap. Ci GW	Uti'n	Op. Hr	Cap. Ci GW	Uti'n	Op. Hr	Cap. Ci GW	Uti'n	Op. Hr
Electrolyser	107	31%	77%	8	0%	0%	189	24%	72%	81	35%	81%
CCHT	81	9%	23%	153	79%	100%	114	13%	28%	55	8%	19%
Grid	225			198			308			198		

Table 15. Scenario comparison of storage capacities in 2050. H₂ = hydrogen, Elec. = electricity, Cap. = capacity.

	Co-Development			Target-Focused			Renewables-Focused			Nuclear-Focused		
	Cap. SC _i GWh	Storage Level Mean Max		Cap. SC _i GWh	Storage Level Mean Max		Cap. SC _i GWh	Storage Level Mean Max		Cap. SC _i GWh	Storage Level Mean Max	
H ₂	108,588	79%	100%	2,141,732	74%	100%	108,258	79%	100%	110,433	78%	100%
Elec. Battery	26	76%	100%	26	20%	20%	26	73%	100%	26	82%	100%
Pumped Hydro	32	72%	100%	32	0%	0%	32	67%	100%	32	80%	100%

Table 16. Scenario comparison of hydrogen production, import, and export in 2050. H₂ = hydrogen.

	Co-Development	Target-Focused	Renewables-Focused	Nuclear-Focused
	kt	kt	kt	kt
H ₂ Produced	4767	1	6778	4026
H ₂ Import	-	31,997	-	-
H ₂ Export	2	1	2	2

Energy security remains a concern in Renewables-focused. With nuclear power providing less than 14% of base load needs, the system is highly exposed to weather variability. A sudden cold spell could lead to power shortage. Increasing nuclear capacity would mitigate this risk.

In Nuclear-focused, nuclear power supplies 84% of electricity. A high level and stable power supply reduces the need for supporting equipment. Electrolysers operate 81% of hours in the year and have the highest utilisation rate among all three scenarios (Table

14). This shows that electrolyzers act as a good buffer to nuclear power plants in periods of low demand. The remaining high demand periods are supported by CCHTs.

In Co-development, ~81 GW of nuclear power supplies the base load demand, ensuring electricity system stability and contributing 48% of total electricity. This is followed by 41% from ~119 GW of offshore wind, and 5% each from ~29 GW of onshore wind and ~70 GW of solar. The daily average generation and demand patterns for each season are shown in Figure A1 in the Appendix A.

Over 107 GW of electrolyzers operate for 77% of hours in the year to produce ~4.8 Mt of green hydrogen. During the remaining hours, over 81 GW of CCHTs provide flexible power to meet generation shortfalls. About 3.2 Mt of hydrogen storage capacity (~109 TWh) is required, representing only 5% of the total salt cavern capacity projected by Williams et al. [40]. All storage types reach a maximum storage level of 100% (Table 15). The mean level is highest for hydrogen storage. The dual roles of hydrogen storage in meeting both daily hydrogen demand and electricity demand contribute to its higher utilisation compared to the other two.

A land area of ~12 thousand km² would be needed for solar and ~6 thousand km² for onshore wind, equivalent to around 85% of the land area of Wales. For offshore wind, over 28 thousand km² maritime area would be required, representing approximately 3% of the total UK sea areas.

In summary, the energy model highlights substantial capacity shortfalls in Target-focused and system reliability concerns in Renewables-focused. It also demonstrates the critical role of CCHTs across all scenarios. However, this model does not clearly distinguish between Nuclear-focused and Co-development, as both meet baseload demand with nuclear power, providing energy security. Cost comparison is therefore necessary to further differentiate between them.

5.4. Economic Assessment Sub-Model

Table 17 presents the results of Equations (14) and (16) and illustrates the outputs of Equation (18). Owing to the lower generation costs of renewables relative to nuclear, Renewables-focused yields the greatest annual energy cost savings relative to the benchmark Fossil Fuel-focused. Its main limitation, however, is reduced system reliability as identified in the energy model. Notably, nearly one-quarter of total investment is directed to electrolyzers and CCHTs (Table 17), reflecting the substantial supporting infrastructure required for renewables-based systems.

Table 17. Scenario comparison of energy costs in 2050. Off. W. = offshore wind, On. W. = onshore wind, HWTW = hydro, wave, tidal, and non-bio-degradable waste, H₂ Elec. = hydrogen electrolysis, H₂ Stor. = hydrogen storage, Ene. Gen. = energy generation, Ene. Cost = energy cost, Add. Cap. = additional capacity, the difference between the target installed capacity and committed capacity (Equation (16)), Inv. = investment for the additional capacity.

	Co-Development				Target-Focused				Renewables-Focused				Nuclear-Focused			
	Ene. Gen. G _{end,i}	Ene. Cost TEC	Add. Cap.	Inv. TIC	Ene. Gen. G _{end,i}	Ene. Cost TEC ³	Add. Cap.	Inv. TIC	Ene. Gen. G _{end,i}	Ene. Cost TEC	Add. Cap.	Inv. TIC	Ene. Gen. G _{end,i}	Ene. Cost TEC	Add. Cap.	Inv. TIC
	TWh	GBP bn	GW ²	GBP bn	TWh	GBP bn	GW ²	GBP bn	TWh	GBP bn	GW ²	GBP bn	TWh	GBP bn	GW ²	GBP bn
Off. W.	555	31	91	225	234	13	22	55	988	55	183	455	131	7	0	-
On. W.	65	3	9	13	65	3	9	13	196	8	67	93	45	2	0	-
Solar	65	2	46	13	65	2	46	13	130	4	116	33	22	1	0	-

Nu- clear	638	64	71	399	189	19	14	78	79	8	0	-	1099	111	130	728
HWT W	10	1	-	-	10	4	-	-	10	7	-	-	10	8	-	-
H ₂ Elec.	160	11	107	81	0	0	8	6	227	15	189	143	135	9	81	62
CCHT	34	0	81	56	558	7	153	105	68	1	114	78	21	0	55	38
H ₂ Stor. ¹			109 TWh	104			2142 TWh	2046			108 TWh	103			110 TWh	105
Total	1526	112		891	1121			2316	1697	99		906	1464	138		933

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. ³ Does not include imported electricity, therefore total cost is not comparable with other scenarios.

Despite requiring far fewer electrolyzers and CCHTs and offering a more reliable system than Renewables-focused, Nuclear-focused is the most investment-intensive due to the high capital costs of nuclear plants.

By balancing nuclear and renewables in the system, Co-development achieves the lowest capital investment. With an estimated £891 billion investment, it delivers ~£56 billion savings (~33% reduction) in annual energy costs compared to the current fossil fuel-based structure (Figure 6).

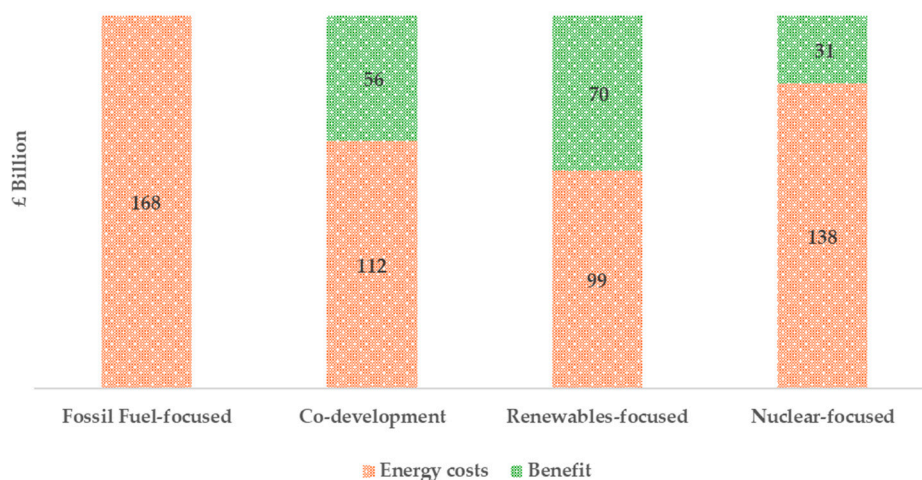


Figure 6. Annual energy costs by scenario. All numbers are presented without decimals and the underlying calculations are not rounded. The figure illustrates the results of Equation (18), indicating that decarbonisation brings economic benefits compared to a fossil fuel-based energy system.

5.5. Additional Analyses

According to Equations (1) and (5), the 2050 primary energy demand is positively related to the efficiencies of carbon-emitting technologies but inversely related to those of zero-carbon technologies. Sensitivity analyses varying these efficiencies show that the conclusion regarding primary energy demand reduction from decarbonisation remains supported. Transport is the largest fossil fuel consumer. Even with a 15 percentage point increase in the efficiencies of carbon-emitting road, rail, and shipping engines—a level that is highly unlikely as a national average, the resulting demand reduction remains around 30%. Changes in other efficiency ratios within plausible ranges have a limited effect on national energy demand unless the fuel supply mix shifts to increase the share of more efficient technologies. In such cases, separate studies considering different

technology deployment and their drivers would be required. For example, Gao et al. [45] developed a heat pump scenario representing widespread deployment of residential heat pumps. They found an additional 5% reduction in the total primary energy demand compared with the Direct Electricity scenario in this study.

This study also explored the resource requirements for developing a hydrogen export economy. Increasing the offshore wind capacity by 50 GW from Co-development enables nearly 5 Mt of hydrogen exports. This would require ~12 thousand km² of additional sea area, along with ~43 GW of extra electrolyser and grid capacity each. Enabling exports reduces hydrogen storage needs to ~0.5 Mt (~18 TWh). However, over 67 GW of CCHTs would still work 10% of hours in the year. Eliminating CCHTs completely would require 1439 GW of offshore wind, occupying around 345 thousand km² of sea area. This is close to 40% of the total UK maritime zone and more than the seabed area currently managed by the Crown Estate.

5.6. Discussion

Applying EDRA to the UK case study highlights key insights for the country's decarbonisation strategy. First and foremost, the principal challenge lies in delivering the required magnitude of resources within the prescribed timeframe. Under Co-development, this would entail annual installation rates exceeding 3 GW of nuclear and nearly 5 GW of offshore wind, alongside unprecedented infrastructure upgrades within 25 years. This is further complicated by reliance on immature technologies and land-use constraints, underscoring the difficulty of the 2050 target and the importance of demand reduction and efficiency-enhancing innovation to ease resource pressures. This implies a potentially longer energy transition, in which case carbon removal technologies may play a role, supporting the transition pathways proposed by Climate Change Committee and National Grid ESO using TIMES [5,8].

Comparison of the current and end-state energy systems through fuel substitution highlights the substantial reduction in thermal losses achieved by clean energy systems relative to fossil fuel-based systems, lending strong support to decarbonisation. Notably, EDRA reaches the same conclusions as the more complex TIMES modelling framework [5,8].

The analysis further identifies substantial resource requirements for supporting infrastructure such as electrolysers, CCHTs, and grid networks. This finding is consistent with the Libyan studies [13,14], while extending them by demonstrating that such requirements are greater for wind or solar-based systems than for nuclear-based ones, representing a methodological advancement.

In addition, the results highlight the importance of evaluating total system costs alongside installed capacities and land-use when determining system configurations. The high generation costs associated with nuclear power may constrain its deployment despite its reliability advantages. Conversely, while solar and wind benefit from lower generation costs, their greater reliance on supporting equipment can offset these advantages at the system level. In this respect, the present study extends earlier applications of the end-state resource analysis method [13–15] by providing a more comprehensive assessment of system-wide resource and cost implications.

Overall, the findings demonstrate that end-state resource analysis combined with scenario modelling can effectively identify structural challenges in a decarbonised energy system design, revealing policy implementation constraints and highlighting areas for policy intervention.

Beyond methodology, the results also inform several system planning considerations. First, high nuclear generation costs may limit its broad deployment despite its high

reliability. Nevertheless, achieving system reliability may require nuclear to constitute nearly half of the generation mix to meet baseload energy needs.

Second, CCHTs may play a crucial role in future energy systems, providing backup and supporting grid stability. They may remain necessary even in a hydrogen-export economy. Safety risks associated with hydrogen infrastructure are equally critical and must be addressed through strong regulation, effective safety management, and proper equipment across processing stages.

Thirdly, without relying on energy imports, the need for underground hydrogen storage may be small due to the close alignment between production and consumption cycles. For illustration, it could be less than 5% of the UK's theoretical salt cavern capacity estimated by Williams et al. [40].

Finally, this study supports offshore wind as the primary renewable technology for the UK, given its high energy output and strong alignment with the nation's seasonal demand profile. This alignment also reduces energy storage needs.

Limitations

Given the inherent uncertainty in long-term energy system modelling, EDRA is not intended to produce a single deterministic quantitative solution, but rather to indicate the order of magnitude of resource requirements for an initial strategic evaluation. It is, therefore, complementary to rather than a substitute for advanced modelling tools. In areas requiring complex system optimisation or developing time-series transitional pathways, more resource-intensive tools such as TIMES are necessary.

A further limitation concerns cost coverage. Due to the data availability constraints, this study focuses primarily on generation costs, while other components, such as grid reinforcement, hydrogen pipeline retrofits, and energy storage, are excluded. Consequently, the reported costs should be regarded as lower-bound estimates within the broader range of decarbonisation costs. Nevertheless, this study reaches the same conclusion as the UK Government's Carbon Budget [5], based on the TIMES model, that decarbonisation can deliver long-term economic benefits despite trillion pound-scale upfront investments.

The limited cost coverage may also affect the interpretation of the cost advantage of renewables relative to nuclear generation. Renewables-dominated systems require substantially greater grid capacity and hydrogen conversion infrastructure than nuclear-driven alternatives. Therefore, including electricity and hydrogen network costs would increase the system costs of renewables, highlighting the need for further work on comprehensive system cost comparisons.

The assumption of static useful energy demand throughout the study period presents another limitation, as future demand may increase due to widespread energy-intensive technologies such as data centres [42]. Any substantial increase in demand would further exacerbate the resource constraints identified in this study.

6. Conclusions

This study develops the EDRA framework for evaluating country-level decarbonisation strategies. Comprising four sub-models and employing scenario modelling and optimisation, EDRA estimates technical, geographical, and financial resource requirements associated with full national decarbonisation. It provides a simplified yet comprehensive approach for researchers and industry practitioners to contrast and evaluate resource availability for decarbonised systems, thereby identifying policy challenges and priority areas for intervention. It also serves as an early-stage feasibility screening tool prior to conducting complex whole-system modelling.

Applying EDRA to the UK, the study concludes that achieving full decarbonising while meeting three policy objectives, namely, net-zero, energy independence, and energy security, would require more than triple the current nuclear target, over double the off-shore wind target, and more than 400 GW of electrolyzers, CCHTs and electricity grid. The footprints for wind and solar could cover around 85% of the land area of Wales and 3% of the UK's total sea territory. More than £891 billion investment would also be required. Achieving such resource deployment with a 25-year timeframe presents a significant policy challenge. Nevertheless, decarbonised systems could reduce primary energy demand by over 30%, leading to ~33% savings in annual energy generation costs compared to the current fossil fuel-based system.

Accordingly, the primary policy recommendation for the UK Government is to prioritise measures that reduce energy demand, thereby lowering resource requirements and improving the feasibility of achieving policy objectives. Net-zero by 2050, energy independence, and energy security are all critical goals. However, attaining them is less likely without substantial demand reduction. In light of the roles of different levels of government, the following recommendations are proposed.

At the central government level, policies should focus on reducing energy demand through demand-side management initiatives and the deployment of efficiency-enhancing technologies. In this context, accelerating heat pump deployment represents a high-priority measure. At the institutional level, governmental organisations should support these efforts through incentives, training, and community engagement to promote energy-efficiency practices. Globally, international collaboration on technology development and knowledge sharing is essential to enable governments to jointly advance low-carbon strategies.

As a data-driven model, EDRA benefits from broader application which can enhance its generalisability. Future work is therefore recommended to apply EDRA to multiple countries and a wider range of technology adoption scenarios. In addition, future studies should address the limitations of this work by extending the cost analysis to include additional components, such as grid network investments and energy storage costs. Further research many also examine the impacts of climate change on energy demand profiles, as well as potential demand growth driven by data centre expansion.

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Abbreviations

The following abbreviations are used in this manuscript:

Area _i	land or sea area required for technology i
Area Factor _i	area required per unit of installed capacity.
AF _{solar}	solar farm availability factor

AF_{wind}	wind farm availability factor
AF_i	plant availability factor of technology i
C_{CCHT}	available CCHT capacity
$C_{electrolyser}$	available electrolyser capacity
C_{grid}	available electricity grid capacity
C_i^{comm}	committed installed capacity including projects that are in operation, under construction or with secured finance for technology i
C_i	installed capacity of technology i
CC_i	capacity cost of technology i
$d_{end,h}$	energy demand at hour h at the end-state year
D_{end}	total primary energy demand at the end-state year
$D_{end,s,i_{end}}$	primary energy demand for the end-state year technology i in sector s
$D_{start,s}$	total primary energy demand in sector s at the start year
Economic Benefits	difference between total annual energy system costs between the end-state year and the start year.
$g_{h,nuclear}$	nuclear electricity at hour h
$g_{h,solar}$	solar electricity generated at hour h
$g_{h,wind}$	onshore or offshore wind electricity at hour h
G_{end}	total energy generation at the end-state year
$G_{end,i}$	total energy generation at the end-state year for technology i
$g_{end,h}$	total energy generation at hour h at the end-state year
$g_{h,i}$	electricity generated at hour h by technology i
h	the hour
$H_2 \text{ Export}_h$	hydrogen exported at hour h
$H_2 \text{ for Powering CCHT}_h$	hydrogen used to power CCHT at hour h
$H_2 \text{ Produced}_h$	hydrogen produced at hour h
$H_2 \text{ Stored}_h$	hydrogen stored at hour h
k_s	demand growth ratio between the start year and the end-state year in sector s
$LCOE_i$	levelised cost of energy of technology i
$LF_{h,i}$	the hourly load factor of technology i
$R_{s,i_{end}}$	the fraction of fuel supplied by technology i in sector s at the end-state year, representing the replacement factor
S_{end}	total storage capacity
$S_{battery}$	available capacity of electric battery storage
S_{H_2}	available capacity of underground hydrogen storage
$S_{H_2,min}$	minimum storage level for underground hydrogen storage
S_i	available capacity of storage technology
$S_{i,min}$	minimum storage level for technology i
$S_{pumped hydro}$	available capacity of pumped hydro storage
SC_{H_2}	installed capacity of underground hydrogen storage.
SC_i	installed capacity of storage i
SF_{season}	nuclear power plant seasonal availability adjustment factor for each season
Solar Radiation $_h$	solar radiation at hour h
Storage Level $_{i,h}$	storage level for storage technology i at hour h
U_{end}	total all-sector useful energy demand at the end-state year
$U_{end,s}$	total useful energy demand at the end-state year in sector s
$U_{end,s,i_{end}}$	total useful energy demand at the end-state year associated with the end-state year fuel supply technology i in sector s
$U_{end,s,i_{start}}$	total useful energy demand at the end-state year associated with the start-year fuel supply technology i in sector s
TEC	total annual energy system cost
TEC_{end}	total annual energy system cost at the end-state year
TEC_{start}	total annual energy system cost at the start year
TIC	total investment cost of an energy system
Wind Power $_h$	wind power at hour h
η_{CCHT}	CCHT efficiency
$\eta_{electrolyser}$	electrolyser efficiency

$\eta_{H_2 \text{ storage}}$	underground hydrogen storage round-trip efficiency from injection to withdrawal
η_i	Electric battery or pumped hydro storage round trip efficiency from charging to discharging
$\eta_{s,i_{\text{end}}}$	efficiency of the end-state year technology i in sector s
$\eta_{s,i_{\text{start}}}$	efficiency of the start-year fuel supply technology i in sector s
GW	gigawatt
GWh	gigawatt hour
km ²	square kilometre
kt	kilotonne
m	metre
m/s	meter per second
Mt	megatonne
MW	Megawatt
t	tonne
TWh	terawatt hour
W/m ²	Watt per square metre
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
ESOM	Energy System Optimisation Model
LCOE	Levelised Cost of Energy
OCGT	Open Cycle Gas Turbine
TIMES	The Integrated MARKAL-EFOM System

Appendix A

This table presents the power and energy calculation based on hourly data from a selected summer day featuring both electricity surplus and deficit periods. There are two types of daily demand: Daily Electricity Demand and Daily Hydrogen Demand. In the 4 o'clock row, 104 GWh of electricity is produced, meeting the 93 GWh Daily Electricity Demand (Step 1). The 11 GWh surplus is converted into 203 tonnes of hydrogen (Step 2), with an additional 13 tonnes of hydrogen withdrawn from underground caverns to satisfy the remaining Daily Hydrogen Demand (Step (3)). At 5 o'clock, electricity produced is less than the 106 GWh Daily Electricity Demand. As a result, 1 GWh is first discharged from battery storage (Step (1)). Since pumped hydro has no stored energy (Step (2)), the remaining electricity is produced by CCHTs through withdrawing 4 tonnes of hydrogen from caverns (Step (4)). At 8 o'clock, the Daily Electricity Demand increases to 140 GWh, exceeding generation of 117 GWh and creating a 23 GWh shortfall. With no stored electricity available from battery storage nor pumped hydro, CCHTs supply the deficit by combusting 1115 tonnes of hydrogen withdrawn from caverns (Step (4)). This operation requires 23 GW of available CCHTs capacity. Meanwhile, 467 tonnes of hydrogen is withdrawn to meet the Daily Hydrogen Demand (Step (3)). As a result, the hydrogen storage level decreases by a total of 1582 tonnes to 2,478,741 tonnes compared to the previous hour.



Figure A1. Co-development scenario: Average hourly demand and generation in each season. On average, electricity generation exceeds demand except for a short window of up to 5 h on winter evenings.

Table A1. Co-development: summer peak demand day energy panorama in 2050. Hr = hour, Elec. = electricity, Pro'd = produced, H₂ = hydrogen, H₂ Exp'd = hydrogen exported, Avai. Elec'ser Cap. = available electrolyser capacity, Avai. CCHT Cap. = available CCHT capacity, Avai. Grid Cap. = available grid capacity.

Electricity Surplus																			Energy Deficit								
Step 1																			Step 2	Step 3	Step 4	Step 5	Step 5	Step (1)	Step (2)	Step (3)	Step (4)
Hr	Elec. Pro'd	Daily Elec. De-mand	Daily H2 De-mand	Daily Elec. Demand from elec. Pro'd	Daily H2 Demand from Elec. pro'd	Elec. Charged in Battery	Elec. Charged to Pumped Hydro	H2 pro'd	H2 In-jected into Cavern	Elec. Dis-charged from Battery	Elec. Discharged from Pumped Hydro	H2 With-drawn from Cavern for Daily H2 De-mand	H2 Withdrawn from Cavern for CCHT	H2 Stored	H2 Exp'd	Avai. Elec'ser Cap.	Avai. CCHT Cap.	Avai. Grid Cap.									
	GWh	t		GWh	t	GWh	GWh	t	t	GWh	GWh	t	t	t	t	GW	GW	GW									
0	105	95	219	95	185	-	-	-	-	-	-	38	-	2,482,926	-	10	-	105									
1	104	92	212	92	212	1	-	-	-	-	-	-	-	2,482,926	-	11	-	103									
2	104	91	210	91	210	2	-	-	-	-	-	-	-	2,482,926	-	11	-	102									
3	104	91	210	91	210	2	-	-	-	-	-	-	-	2,482,926	-	11	-	102									
4	104	93	215	93	203	-	-	-	-	-	-	13	-	2,482,913	-	10	-	104									
5	105	106	245	105	-	-	-	-	-	1	-	270	4	2,482,639	0	-	0	106									
6	109	124	285	109	-	-	-	-	-	4	-	365	517	2,481,757	-	-	11	124									
7	114	134	310	114	-	-	-	-	-	-	-	440	994	2,480,323	0	-	21	134									
8	117	140	323	117	-	-	-	-	-	-	-	467	1115	2,478,741	0	-	23	140									
9	122	142	327	122	-	-	-	-	-	-	-	456	969	2,477,315	0	-	20	142									
10	128	143	329	128	-	-	-	-	-	-	-	431	692	2,476,192	0	-	14	143									
11	137	143	330	137	-	-	-	-	-	-	-	391	284	2,475,517	0	-	6	143									
12	148	140	323	140	141	-	-	-	-	-	-	201	-	2,475,316	0	7	-	148									
13	158	140	322	140	322	1	-	-	-	-	-	-	-	2,475,316	-	17	-	156									
14	161	140	322	140	322	4	-	-	-	-	-	-	-	2,475,316	-	17	-	157									
15	158	142	326	142	326	0	-	-	-	-	-	-	-	2,475,316	-	17	-	158									
16	153	142	327	142	224	-	-	-	-	-	-	114	-	2,475,202	0	12	-	153									
17	146	138	319	138	146	-	-	-	-	-	-	191	-	2,475,011	0	8	-	146									
18	140	131	302	131	178	-	-	-	-	-	-	136	-	2,474,875	0	9	-	140									
19	134	128	294	128	135	-	-	-	-	-	-	174	-	2,474,701	-	7	-	134									

20	129	125	288	125	74	-	-	-	-	-	-	236	-	2,474,465	0	4	-	129
21	124	121	280	121	59	-	-	-	-	-	-	243	-	2,474,222	0	3	-	124
22	124	107	246	107	246	4	-	-	-	-	-	-	-	2,474,222	-	13	-	119
23	123	98	225	98	225	8	-	-	-	-	-	-	-	2,474,222	-	12	-	109
	3050	2946	6789	2845	3418	22	-	-	-	5	-	4165			3			

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

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