Offshore versus onshore: the underestimated impact of onshore wind and solar photovoltaics for the energy transition of the British Isles

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Abstract:

The British Isles, consisting of the United Kingdom and the Republic of Ireland, were investigated for a sustainable energy system transition towards 100% renewable energy in 2050. Under given framework conditions, three pathways comprising the entire energy system were investigated in 5-year time steps and hourly resolution applying an advanced energy system modelling tool and identifying the lowest cost solutions. The British Isles were structured into ten sub-national regions. Special attention was paid to the high offshore wind potential of the British Isles, as well as the limited societal acceptance for onshore wind in the United Kingdom. The results indicate that a transition to 100% renewable energy is economically more attractive than the governmental strategy that involves nuclear power and fossil carbon capture and storage. The total annualised system costs can decrease to 63 b€ and a levelised cost of electricity of 40 €/MWh if onshore wind and solar photovoltaics are allowed to be built to a higher extend. High levels of electrification and sector coupling are the main reasons for decreasing primary energy demand. The multiple risks of nuclear technology can be avoided, if dedicated action towards 100% renewable energy is taken.

Keywords:

Climate emergency, Energy system modelling, Power-to-X, Power-to-X economy, sector coupling

Nomenclature:

2W/3W – Two and three wheelers, AC – Alternating current, A-CAES – Adiabatic compressed air energy storage, b€ - billion euros, BEV – Battery electric vehicles, BPS – Best Policy Scenario, C&I – Commercial & industrial, CAGR – Compound annual growth rate, CAPEX – capital expenditures, CCGT – Combined cycle gas turbine, CCS – Carbon capture and storage, CHP – Combined heat and power, CPS – Current Policy Scenario, CSP – Concentrating solar power, DACCS - Direct air carbon capture and storage, DC – Direct current, DH – District heating, e-fuel – electricity-based fuel, FCEV – Fuel cell electric vehicle, FLH – Full load hours, GDP – Gross domestic product, GHG – Greenhouse gas emissions, GW – Gigawatt, HDV – Heavy duty vehicle, HT – High temperature, HV – High Voltage, IH – Individual heating, IPCC – Intergovernmental Panel on Climate Change, LCOC – Levelised cost of curtailment, LCOE – Levelised cost of electricity, LCOH – Levelised cost of heat, LCOT –

Levelised cost of transmission, LDV – Light duty vehicle, LNG – Liquified natural gas, LT – Low temperature, MDV – Medium duty vehicle, MT – Medium temperature, MWh – Megawatt hour, OCGT – open cycle gas turbine, OPEX – operational expenditures, PHEV – Plug-in hybrid electric vehicle, p-km – passenger kilometres, PP – Power plant, PtH – Power-to-Heat, PtX – Power-to-X, PV – Photovoltaic, RE – Renewable energy, RES – Residential, PED – primary energy demand, ROR – run-of-river, SDGs – Sustainable Development Goals, SoC – State of Charge, ST – Steam turbine, UK – United Kingdom, TES – Thermal energy storage, t-km – tonne kilometre, TWh – Terawatt hour

Highlights:

- Pathways towards climate neutrality for the British Isles have been investigated
- Two pathways that aim for 100% renewable energy are economically attractive
- Electrification of all sectors is the key for high system efficiency
- Onshore wind and solar PV are able to reduce total annualised systems costs by 20%
- The governmental strategy including nuclear power and fossil CCS shows the highest cost

1 Introduction

Recently, public awareness of climate change has increased significantly, at least partly due to extreme weather events across the globe. Moreover, the trends of continuously rising sea levels as a result of ice sheet melting are accelerating [1] while extreme events happen more frequently [2]. Compared to the last 30 years, record breaking weather events will become two to seven times more likely in the period of 2021-2050 and up to 21 times more likely in high-emission scenarios for the period of 2051-2080 [3].

The latest IPCC assessment report indicates once again that drastic greenhouse gas (GHG) mitigation pathways have to be followed resolutely to minimise the impacts of global warming such as heat waves, droughts, heavy rainfalls and floods [4]. The political framework has been clearly defined with the Paris Agreement [5] and the Sustainable Development Goals (SDGs) [6] to limit global warming at 1.5 °C compared to pre-industrial levels, alongside other urgent sustainability challenges, including a massive reduction of harmful air pollution [7].

The British Isles, consisting of the United Kingdom (henceforth: UK) and the Republic of Ireland (henceforth: Ireland), represent highly developed countries that need to mitigate their GHG emissions drastically to be compliant with the Paris Agreement. Initiating a transition towards a clean and sustainable energy system, based on 100% renewable energy (RE), can be the most promising solution, as a variety of studies presented in [8–10] indicate that a 100% RE system can provide long-term sustainability, economic competitiveness as well as societal benefits. Hundreds of studies show the benefit of 100% RE systems [10, 11], and studies on the UK and Ireland are briefly reviewed by Meschede et al. [12] and confirm this.

The energy system's backbone of both countries is natural gas for heating and electricity generation, and fossil oil for transportation. In 2020 in the UK, 41.9% of domestic energy consumption was natural gas, followed by oil at 31.2% [13]. A huge shift can be observed in the 30 years since 1990 regarding the utilisation of coal, as the share of coal in final overall energy consumption decreased from 31.3% in 1990 to 3.4% in 2020. The use of coal has mainly been substituted by natural gas and likewise through the introduction of wind power, bioenergy and waste-to-energy into the system. The high import dependency of 30-40% of primary energy supply in the last five years is due to imported fossil energy carriers [13]. The energy system structure as of today is shown in Figure 1, illustrating the utilisation of natural gas and fossil oil with barely developed sector coupling and almost no energy storage technologies.

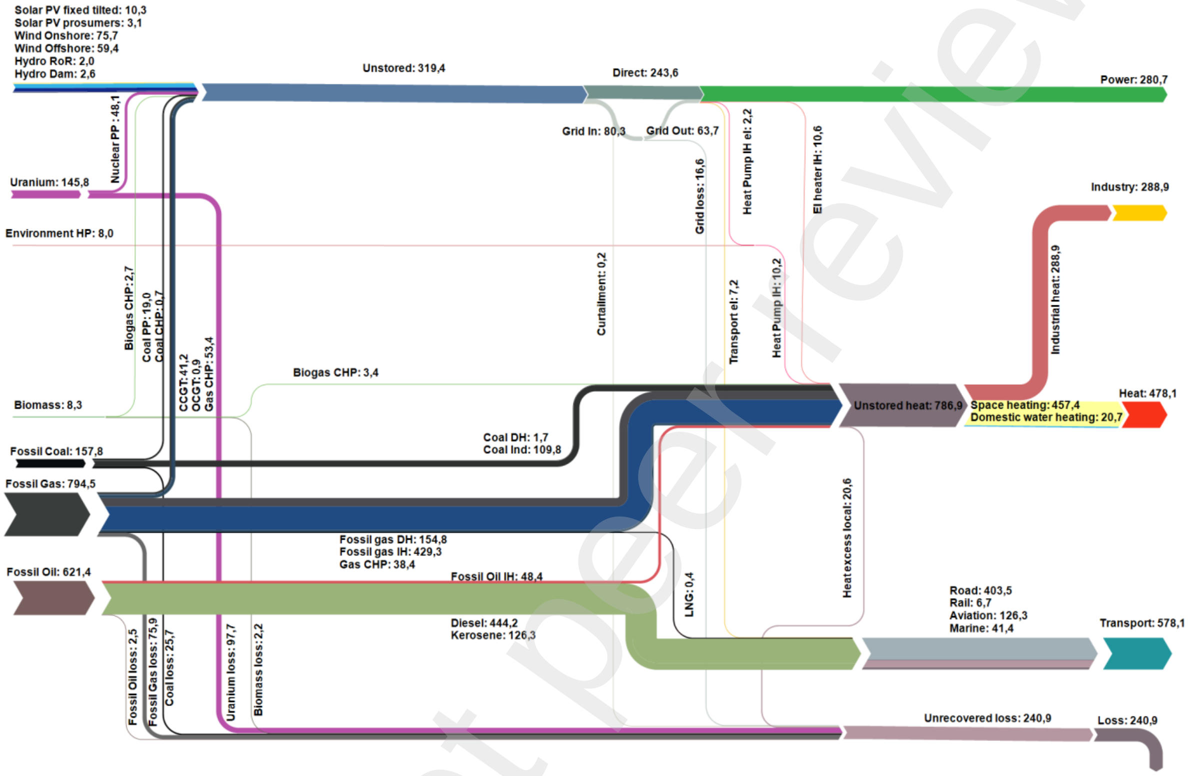

Figure 1: Energy system of the British Isles in 2020. All values are displayed in TWh.

GHG emissions of the UK are constantly decreasing and have almost halved since 1990 from 809.1 to 414.1 Mt of CO_2 equivalent. This can be explained by the use of low-carbon sources that have steadily increased from 9.4% in 2000 to 21.5% (thereof 6.6% nuclear power) in 2020 of total primary energy supply as well as the shift from coal to natural gas [13]. Furthermore, the energy intensity per household decreased by 23%, which is related to efficiency improvements for residential and commercial buildings [11]. For Ireland, the emissions remain roughly on the level of 1990 (around 30 Mt CO_{2eq}). However, emissions increased until 2006 to 44 Mt CO_{2eq}, connected to GDP growth and decreased afterwards, as the expansion of wind power accelerated [14, 15].

The development of accelerating RE expansion might not only be driven by the willingness of policy makers to fight the climate emergency but also by declining costs of RE and storage technologies [10, 16–20]. In fact, governmental strategies of the UK do not show the clear ambition to head for a 100% RE system since nuclear power as well as fossil gas and oil in combination with carbon capture and storage (CCS) are proposed as key measures to reduce emissions [21] even though these technologies are known not to lead to least cost solutions [22]. Ireland's Climate Action Plan indicates a different path that focusses on large-scale wind power without nuclear power [23].

Concerning nuclear power and fossil CCS, serious concerns regarding the use of those technologies and their environmental and economic effects are expressed in scientific literature e.g., for the climate impact of blue hydrogen [24] and nuclear power [25], regarding the nuclear technology decline [26] and further constraints for nuclear power [22, 27]. On the contrary, recent studies show that energy systems without nuclear power are possible and connected to economic benefits [28, 29]. In [30, 31] it is shown that new nuclear power technologies face strong economical obstacles. Sovacool et al. [32] analysed lifecycle emissions from nuclear power and concluded it is more vulnerable to cost overruns and construction risks compared to wind power and solar photovoltaics (PV). Moreover, accidents with severe consequences cannot be fully avoided [33]. The catastrophe of Fukushima initiated a nuclear phase-out and boosted 100% RE studies for Japan, which challenged the necessity of nuclear power in a sustainable energy system [34, 35]. Events in France in 2022 imply that nuclear power is connected to reliability issues, caused by dilapidated power plants [36], and climate change induced lack of cooling water, which can be fully overcome in a 100% RE system [37].

As an alternative, the British Isles have excellent onshore and offshore wind energy potentials [38]. Already several decades ago, this potential was recognised and policy recommendations were derived [39]. In the first half of 2021, the UK had the highest volume of installed capacity of offshore wind power worldwide with more than 10 GW [40], and the UK government pursues to quadruple the installed offshore wind capacity by 2030 [13]. Onshore wind power is limited to the available land area but might be even more limited by social and political acceptance [41]. The public debate on onshore wind power is controversial. While new projects were blocked in 2016, in 2020 the financial restrictions were lifted again for those that can gain planning consent, mainly in Scotland [42]. The resource potentials for solar energy are smaller, but also depend on available land, while the economics have reached competitiveness [16]. The offshore wind resource availability of the UK is the best in Europe, followed by Ireland with a cumulative technical resource potential of 8,000 TWh per year [43].

Although the wind energy potential is broadly recognised, it is still unclear how the whole energy system with all its system components would develop if a minimal-cost solution is pursued. Previous studies investigated the energy transition towards 100% RE for Ireland [44, 45], for Scotland [46] or for the UK as a region in Europe [47–49]. It is mentioned that the UK and Ireland can work as exporters in an interconnected European energy system [49, 50]. Other studies focused on the UK's power sector, finding that hydrogen storage is the cheapest balancing solution [51] and that excess electricity can be used for heat and transportation [52]. Williams et al. [53] investigate the generation and storage requirements for the energy system of the UK based on 95% of renewables, using biomethane and green hydrogen as balancing options for variable renewable generation. What most of these studies have in common is that they consider offshore wind power to be the main supplier of electricity (most likely due to its resource availability), with one exception that finds onshore wind power and solar PV to be preferable [54]. No study has yet investigated the full energy system transition of the British Isles with a focus on full cost optimisation and sector coupling in high temporal and spatial resolution.

This study addresses the research gap of a transition investigation of an interconnected, sector-coupled energy system of the British Isles towards 100% renewable energy in 2050. It further addresses the research gap of the impact of solar PV and onshore wind power and its performance against 1) the commonly chosen offshore wind power dominated approach and 2) the governmental strategy that aims for nuclear power and fossil CCS. Key novelties of the study are the cost compositions of the energy system with different constraints, its technological components and their interactions, leading to a novel understanding of regions with high availabilities of wind resources and moderate availability of solar resources.

2 Methods

2.1 LUT Energy System Transition Model

The LUT Energy System Transition Model (LUT-ESTM) simulates the cost-optimised transition to a given target system, such as a 100% RE system, for a specified region in five-year time-steps. The model simulates in hourly resolution and is fully described in [55] for the power sector and in [17, 56] for the entire energy system emphasising sector coupling. For this study, the model version as described in [57] was used. The input data represents the current energy system, including the power, heat, and transport sectors as well as renewable resource potentials, hourly load profiles for heat and power, and demand projections until 2050. In this study, the multi-node approach was utilised. This means that the entire region is structured into ten subregions that can exchange electricity and e-fuels.

The installation of new RE capacity in the model is limited according to the upper technical potential of a technology according to its resource availability. The installation of new RE capacity is further limited to a capacity share growth of 4% (percent points) per year to avoid unrealistically fast upscaling. The model aims to install the least cost solution: the technology with the lowest total costs is preferred over technologies with higher costs until the resource is exploited, while matching the demand profiles and seasonal variation, typically leading to a balance of solar and wind technologies due to resource complementarity [49].

The model's target function is minimising the sum of total annualised system costs as described in Equation (1). The equation uses the abbreviations: subregions (*reg,r*), technologies for generation, transmission and storage (*tech, t*), capital expenditures for technology *t* ($CAPEX_t$), capital recovery factor for technology *t* (crf_t), fixed operational expenditures for technology *t* ($OPEX_{\mathrm{fix},t}$), installed capacity for technology *t* in subregion *r* ($instCap_{t,r}$), variable operational expenditures for technology *t* ($OPEX_{\mathrm{var},t}$), total annual energy generation by technology *t* in subregion *r* ($E_{\mathrm{gen},t,r}$), ramping costs for technology *t* ($rampCost_t$) and total ramping values annually for the technology *t* in the subregion *r* ($totRamp_{t,r}$).

$$\min\left(\sum_{r=1}^{reg}\sum_{t=1}^{tech}(CAPEX_t \cdot crf_t + OPEXfix_t) \cdot instCap_{t,r} + OPEXvar_t \cdot E_{\mathrm{gen}_{t,r}} + rampC\right. \quad (1)$$

Equation (2) describes the main constraint that applies at every hour of the year to match supply and demand for power generation. It uses the abbreviations: hours (*h*), technology (*t*), all power generation technologies (*tech*), electricity generation for technology *t* ($E_{\mathrm{gen},t}$), subregion (*r*), all subregions (*reg*), imported electricity by subregion *r* ($E_{\mathrm{imp},r}$), electricity storage technologies (*stor*), discharged electricity from storage ($E_{\mathrm{stor,disch}}$), electricity demand (E_{demand}), exported electricity by subregion *r* ($E_{\mathrm{exp},r}$), electricity charged to storage ($E_{\mathrm{stor,ch}}$), excess electricity curtailed (E_{curt}) and electricity consumed by heat and transport sector (E_{other}). Similar constraints define the hourly supply and demand balances for heat, fuels and material flows.

$$\forall h\ \varepsilon\ [1,8760]\ \sum_{t}^{tech} E_{gen_t} + \sum_{r}^{reg} E_{imp_r} + \sum_{t}^{stor} E_{stor,disch_t} = E_{\text{demand}} + \sum_{r}^{reg} E_{exp_r} + \sum_{t}^{stor} E_{stor,ch_t} + E_{curt} + E_{\text{other}} \qquad (2)$$

Figure 2 shows the model scheme for the power, heat and transport sectors and how the sectors are coupled. The alternating current (AC) grid is the heart of the energy system, interconnecting all regions, all generation and storage options and all sectors. RE capacities, centralised power plants (PP) and combined heat and power (CHP) plants, electricity storage technologies, high voltage (HV) transmission lines and different modes of transport are connected to the AC grid. The AC grid satisfies the electricity demand of electricity consumers. Via HVAC and high voltage direct current (HVDC) lines and cables, electricity can be exported to neighbouring subregions while shortages can be covered by importing electricity. Power and heat sectors are coupled with power-to-heat (PtH) technologies such as heat pumps and direct electric heating. The heat demand is satisfied either centrally with heat from CHP or heat-only plants, or individually from decentralised heating systems. Thermal energy storage (TES) is used as a flexibility component in the heat sector. Power and transport sectors are coupled via the AC grid as well as via Power-to-X (PtX) components. More detailed discussion on PtH, PtX, e-fuels and sector coupling can be found in Breyer et al. [10]. Prosumers (for PV including batteries and individual heat supply) are modelled separately, divided into residential, commercial, and industrial prosumers. They can generate and store their electricity, sell excess electricity to the grid (for a defined remuneration), or buy electricity from the grid (based on the projected market price).

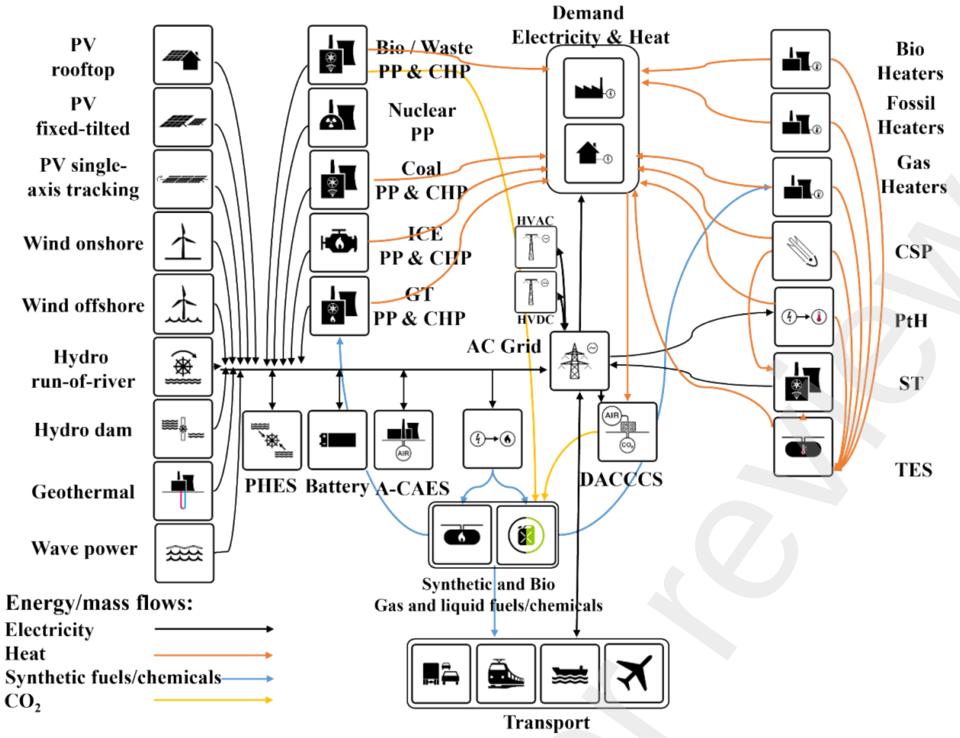

Figure 2: LUT Energy System Transition Model (LUT-ESTM) scheme for the power, heat and transport sectors [17, 55].

The LUT-ESTM integrates some industry sectors including steel, cement, aluminium, chemical industry segments [56], RE-based seawater desalination for regions with high water-stress index [58, 59], and CO_2 removal [56, 60]. Due to the scope of this study, the industry sector has not been modelled in detail, but industrial energy demand is reflected across all energy sectors and in particular with industrial process heat.

In [61] the LUT-ESTM was categorised as a bottom-up, long-term modelling tool. Furthermore, it is described as a tool that focuses on a specific sector, using the multi-node approach with high time resolution. It was rated high for resolution in time and space and in sector coupling, while it was rated medium in techno-economic detail and transparency, reaching an excellent overall assessment compared to other energy system models. LUT-ESTM is one of the two most used energy system tools for highly renewable energy system analyses [11].

2.2 Data and assumptions

For this study, the UK and Ireland energy transitions were modelled as part of the same electricity market to stress the interactions of the future energy system of both countries. Utilising a multi-node approach, the UK and Ireland have been divided into ten subregions, as described in Table 1.

Table 1: Subregions with abbreviations and administrative regions included.

	No.	Abbr.	Administrative Regions
UK & Ireland	1	E – S	England: Southwest, Southeast
	2	E – M	England: East Midlands, West Midlands
	3	E – NW	England: Northwest
	4	E – NE	England: Northeast, Yorkshire & The Humber
	5	E – L	England: Greater London

6	E – E	England: East
7	SC	Scotland
8	W	Wales
9	NIR	Northern Ireland
10	IR	Republic of Ireland

The structuring has been done according to final electricity consumption, renewable resource potentials as well as administrative constraints (to avoid splitting administrative regions). The subregions are interconnected with HVAC, and/or HVDC transmission lines and cables. The transmission lines and cables connect the predefined centres of consumption, represented as the cities with the largest population, as illustrated in Figure 3.

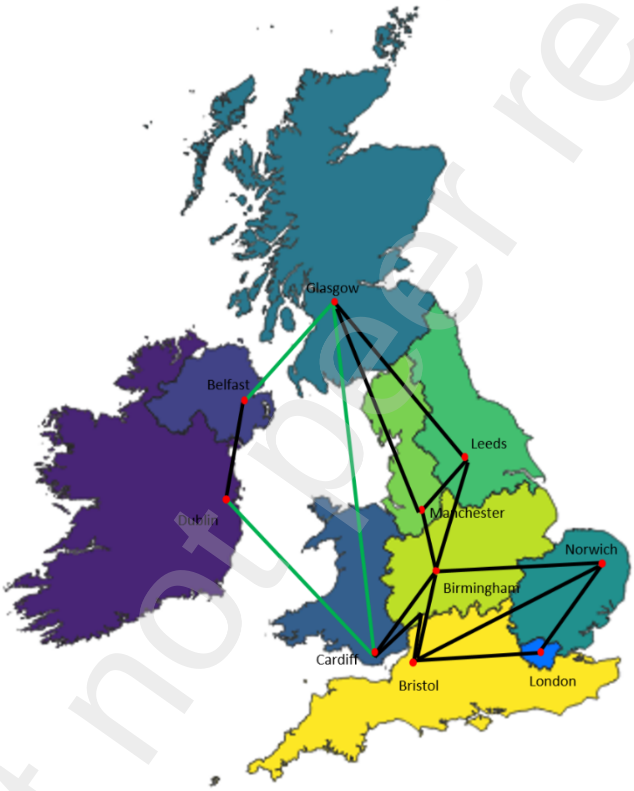

Figure 3: Simplified high voltage power grid of the UK and Ireland: Cities with highest population by subregion have been chosen as centres of consumption. The interconnection between subregions were adopted from [62]. Black: HVAC. Green: HVDC utilising sea cables.

The following data were collected for model input:

- Weather data from a representative year (2005) for solar irradiation, rivers flow rates, and wind speed distribution for nodal capacity factors and full load hours (FLH);
- Installed capacities for all technologies with their year of installation from 1960 onwards in five-year time steps;
- Sustainable bioenergy resources for biogas production (from biowaste, animal excrements and sewage sludge);
- Geothermal energy resources;
- Hourly power and heat demand for a representative year (heat demand composed by space heating (SH), domestic hot water (DHW) and industrial heat demand);

- Power and heat demand future projections in five-year time steps until 2050;
- Annual freight and passenger transport demand for road, rail, aviation and marine in passenger kilometres (p-km) and tonne kilometres (t-km) and future projections;
- Energy conversion process efficiencies for all technologies (steam turbines, gas turbines, e-fuels, etc.);
- Financial assumptions (capital expenditures (CAPEX), fixed and variable operational expenditures ($OPEX_{fix}$, $Opex_{var}$), lifetime) for all technologies and future projections in five-year time steps (the real cost basis is 2020);
- Lower and upper limits for RE resources;
- Lower limit: Currently installed capacity;
- Upper limit: Maximum installable capacity according to resource potentials;
- Centres of consumption and existing power grid data.

Population projections for all subregions are necessary as an auxiliary parameter, to split national values according to the nine subregions of the UK, and whenever regional data was not available. Data for Ireland was mostly available separately. Population projection data was taken from [63] for England, from [64] for Scotland, from [65] for Northern Ireland, from [66] for Wales, and from [67] for Ireland.

In the main scenario (BPS – see section 2.3), solar PV is limited to 1% of total land area demand with a power installation density that is growing from 91 MW/km^2 for fixed-tilted PV in 2020 to 137 MW/km^2 due to projected efficiency improvements for solar modules (that are expected to increase from the present day efficiency of around 20% to 30% in 2050 [68]), and based on a ground cover ratio of 45% for fixed-tilted solar PV and 31% for single-axis tracking, according to [69]. This leads to an upper limit for fixed-tilted solar PV of 859 GW and 589 GW for single-axis tracking. Onshore wind is considered to be limited to 2% of the total land area with a significantly lower power installation density of 8.4 MW/km^2 [70]. This leads to an upper limit for onshore wind of 53 GW. According to [43], offshore wind is abundantly available in the UK and Ireland with a range up to 2700 TWh/yr for the UK and up to 600 TWh/yr for Ireland in terms of their feasible economic potentials. In contrast, the technical potential is even higher (up to 8000 TWh/yr for UK and Ireland combined). The solar and wind resources are based on data from NASA for the year 2005 [71] and reproduced by the German Aerospace Centre [72] in 0.45 x 0.45° nodal resolution. The regional FLH for wind onshore and wind offshore are shown in Figure 4. The highest wind power potential can be found for Scotland and Ireland, the lowest in Southern England. The coastal regions have higher wind onshore potentials than the inland.

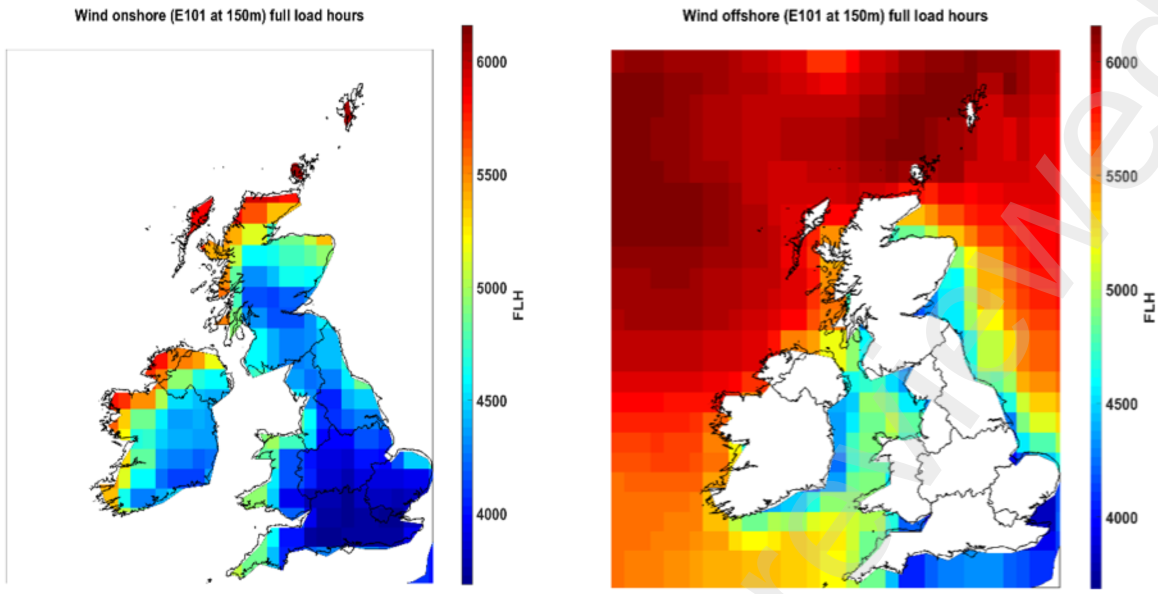

Figure 4: Regional FLH for wind onshore (left) and wind offshore (right).

Other RE resource potentials were determined in the following manner. The sustainable biomass resources were limited to waste and residues that can be converted to biogas and upgraded to biomethane. Exchange with local initiatives from the UK implied that biomass use beyond biogas may not be likely due to air pollution concerns. This reduces the available biomass potential to biowaste, animal excrements, and sewage sludge, leading to a total potential of 11.5 TWh_{th}. Geothermal resources were obtained from [73]. An emerging energy resource is ocean energy, which has been integrated as wave power into LUT-ESTM. The applied wave power potential was assumed to be 27 GW in 2050 for the UK (and 21 GW for Ireland), as indicated by the UK government [74], which leads to a significant wave power potential, especially for Scotland with the longest coastline and substantial wave energy resources. Tidal stream energy is another potentially substantial marine renewable energy source, but it is not part of LUT-ESTM.

The power demand describes the electricity demand for all electrical appliances, excluding electricity demand for heating and transportation. The hourly power demand was obtained from [75], not considering altered profiles due to arising power demand for electricity-based heating and transportation, and adjusted according to governmental electricity demand projections in five-year time steps using a median compound annual growth rate (CAGR) of 0.9% per year from different scenarios published by the UK government [76]. This data includes electricity for heating, which had to be excluded from power demand projections. Therefore, the amount of electricity used for heating was identified from [77] and subtracted from the overall power demand. The amount of electricity for heating in Ireland was taken from [44]. For the British Isles, the power demand is projected to increase from 280 TWh per year in 2020 to 363 TWh per year in 2050.

Heat demand projections until 2050 and hourly heat profiles for space heating, domestic hot water and industrial process heat demand were obtained from [78] and are visualised in Figure 5. The centralised heat demand includes low (LT)- and medium (MT)-temperature industrial process heat as well as district heating for end-users' space heating and domestic hot water demand. Individual heat demand includes residential and commercial heating systems and high

(HT)-temperature industrial heat. The share of low- and medium-temperature demand for the industry was found to be 62.0% and only 1.2% of space heating and domestic hot water demand is supplied by district heat [79], which indicates a barely developed heat network in the UK.

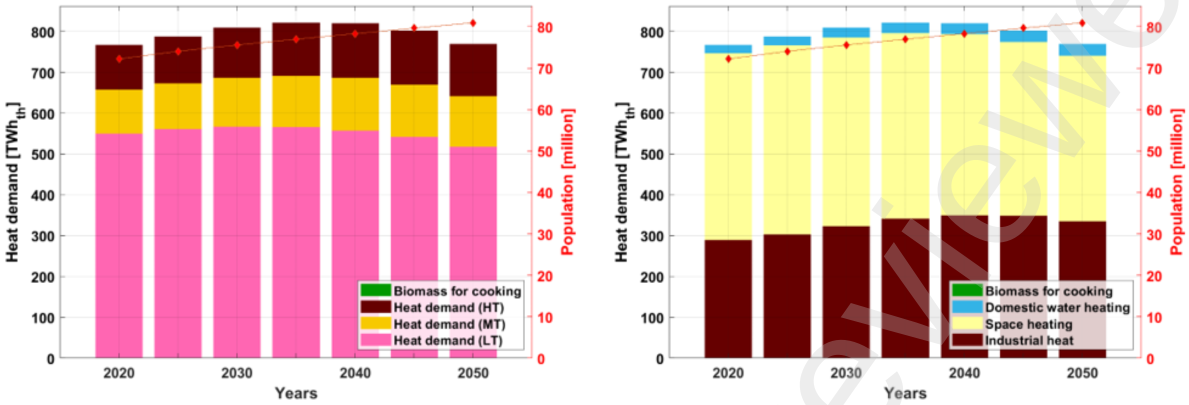

Figure 5: Heat demand projection until 2050 for different temperature levels (left) and end-use (right).

Transportation demand is divided into passenger and freight transportation demands, expressed in p-km and t-km, respectively. This is further divided into road, rail, marine and aviation transportation demand. The regional values were calculated according to the share of population for road (p-km and t-km), rail (p-km and t-km) and marine (p-km). Aviation p-km and t-km were split according to the share of total passengers landed or unloaded cargo by airport, respectively. Therefore, it was considered that most aviation traffic is done via London airports. Marine t-km was split up according to unloaded cargo by port. The transport demand projection data were obtained from governmental sources for road transport [80], aviation passenger transport [81] and marine freight transport [82]. In the absence of data for aviation freight and marine passenger transport, it was assumed that freight and passenger transport develop in the same manner for aviation and marine. The transportation demand projections are illustrated in Figure 6.

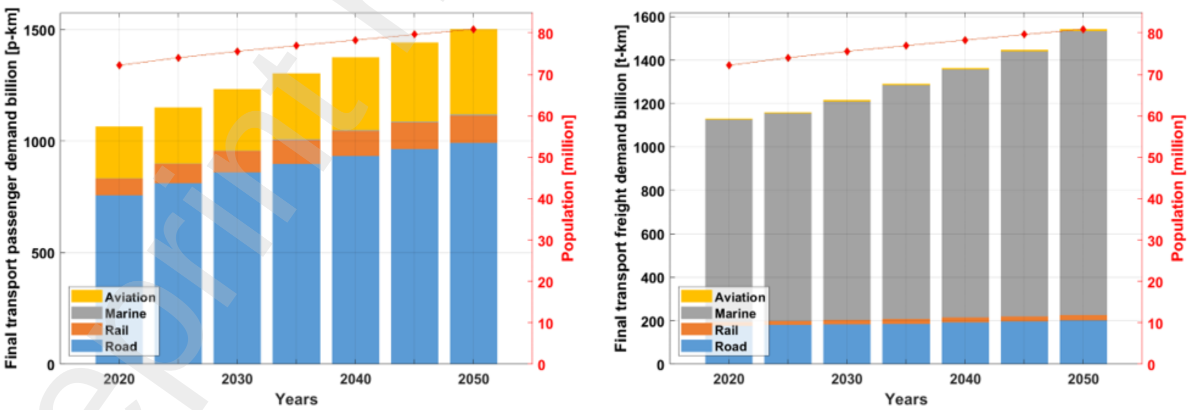

Figure 6: Final transport demand projection until 2050 for passenger (left) and freight (right).

The power grid is modelled in a simplified way so that it represents the HV transmission grid structure of the current power grid. The medium and low voltage distribution grids are not directly modelled. For simplification, every subregion has a load centre, which is interconnected with the load centre of neighbouring subregions. Grid losses in the interregional transmission grids are modelled by taking the distance between load centres and type of line or cable into account, while grid losses within regional distribution grids were obtained from [83]. One default assumption of LUT-ESTM is that 70% of all power transmission happens via underground cables and 30% via overhead power lines.

2.3 Scenario definitions

For this study, simulations for three different scenarios have been conducted. The idea behind scenario variations is to demonstrate how certain constraints can affect the overall energy system structure and costs. Two scenarios aim for the deployment of 100% RE in 2050 while one scenario adopts the governmental strategies of the UK government to reach zero GHG emissions in 2050 using significant amounts of nuclear power and fossil CCS technologies (Current Policy Scenario – CPS). The Best Policy Scenario (BPS) aspires to achieve an energy transition to 100% RE in the best of circumstances, without unnecessary delays and without counterproductive governmental actions, except for land area constraints for onshore technologies, as this is perceived as a societal consensus.

The BPSplus scenario investigates the effect of less area limitations for onshore renewable generation technologies, such as solar PV and onshore wind power, as well as a lower offshore wind forcing and higher levels of e-fuels imports. The scenarios are summarised in Table 2.

Table 2: Scenario description.

Scenario	Description
Best Policy Scenario (BPS)	The energy system will be transformed in 5-year time-steps to achieve zero CO_2 emissions and 100% RE in 2050. Using 2020 data as a starting point, fossil and nuclear power plants are phased out according to their technical lifetimes or legally approved lifetime extensions. About 2 GW/yr of offshore wind is installed until 2026, increasing to 3 GW/yr after that. Onshore wind power and solar PV are limited to 2% (Scotland 2.5%) and 1% of available land area, respectively. Biomass is limited to biogas. Imports of e-fuel are allowed, but limited to e-LNG.
Best Policy Scenario – fewer restrictions (BPSplus)	Same assumptions as for BPS but available land area for onshore wind power and solar PV is lifted to 3% (Scotland 4%) and 2%, respectively. More imports of e-fuels are allowed, including e-liquids, e-LNG, e-ammonia and e-methanol. Offshore wind power installations are set to a minimum of 1 GW/yr from 2030 onwards, while higher installations are possible, if economically attractive.
Current Policy Scenario (CPS)	According to the Energy White Paper published by the UK government [21] a scenario is created that orientates on the governmental approach to reduce GHG emissions. Vast deployment of nuclear power and fossil CCS is considered and compared in terms of costs and sustainability constraints with the Best Policy Scenarios.

3 Results

In this section, the BPS will be discussed in full detail. Subsequently, the other scenarios will be compared to the central BPS in terms of the key results for electricity and heat generation, costs and CO_2 emissions.

3.1 Best Policy Scenario

The BPS demonstrates the full transition for a 100% RE scenario that is dominated by offshore wind power and supplemented by onshore wind power, solar PV, wave power and smaller shares of hydropower and geothermal energy. Figure 7 - Figure 9 illustrate the energy transition for the power, heat and transport sectors in five-year time-steps. Electricity generation grows by a factor of 4 and is strongly linked to the electrification of heat (heat pumps), electric powertrains (battery electric vehicles) and e-fuels. Offshore wind electricity generation becomes the most important source of energy, contributing a share of 38.1%, or 537 TWh, of electricity generation in 2050. Solar PV capacity is higher, but delivers less electricity due to lower resource availability.

Heat generation shifts from natural gas boilers to heat pumps with high efficiencies for low-temperature heat, while e-fuels and direct electric heating become important for medium- and high temperature industrial heat. Electricity demand for the transport sector grows significantly to 618 TWh in 2050.

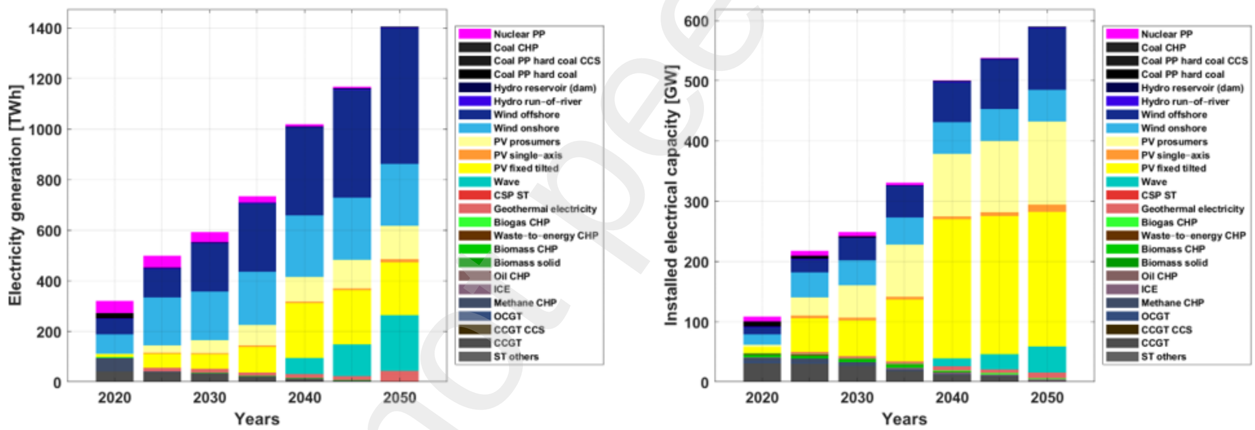

Figure 7: Electricity generation (left) and installed electrical capacity (right) until 2050.

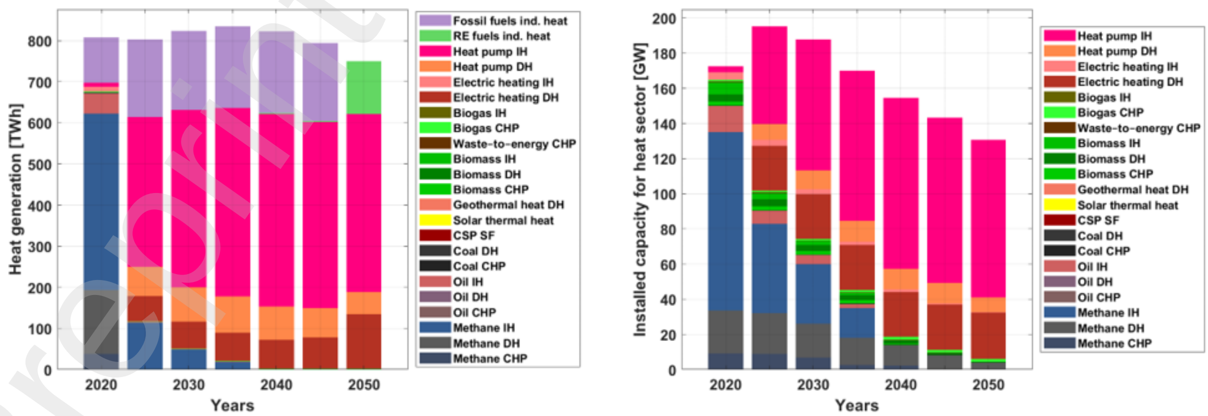

Figure 8: Heat generation (left) and installed heat capacity (right) until 2050.

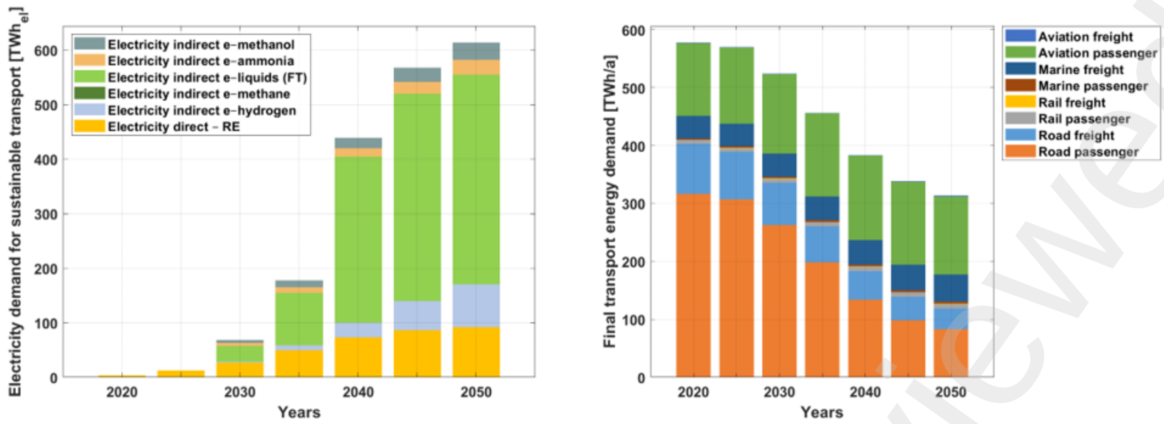

Figure 9: Electricity demand for transport (left) and final transport energy demand (right) until 2050.

The integration of growing shares of RE during the energy transition increases the need for energy storage utilisation. Figure 10 - Figure 12 display various electricity, heat and gas storage technologies and their growth over the transition along with the respective hourly utilisation profiles in 2050. Different types of battery applications are the key technologies for short-term electricity storage. Electricity storage technologies are mainly stationary prosumer and utility-scale battery storage, supplemented by Vehicle-to-Grid storage, and pumped hydro energy storage.

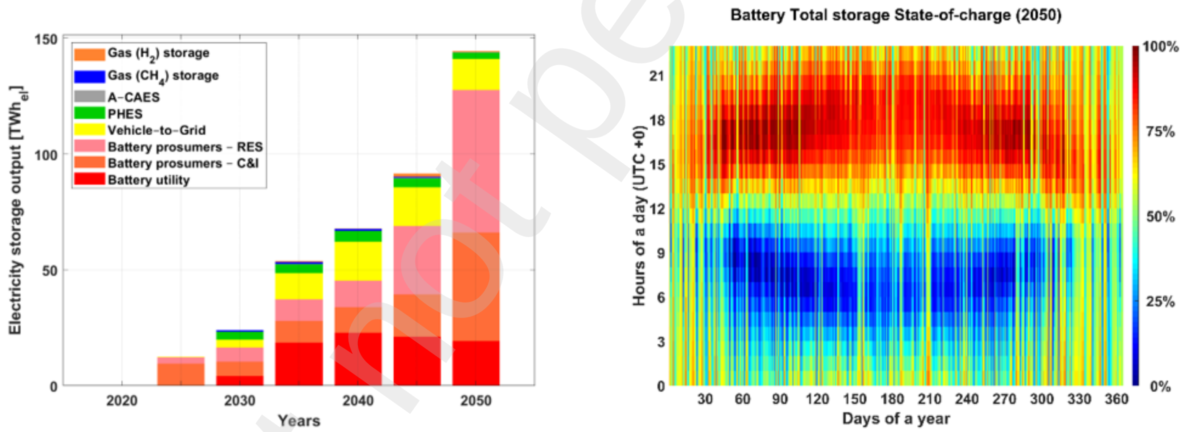

Figure 10: Electricity storage output until 2050 (left) and hourly battery storage state-of-charge in 2050 (right).

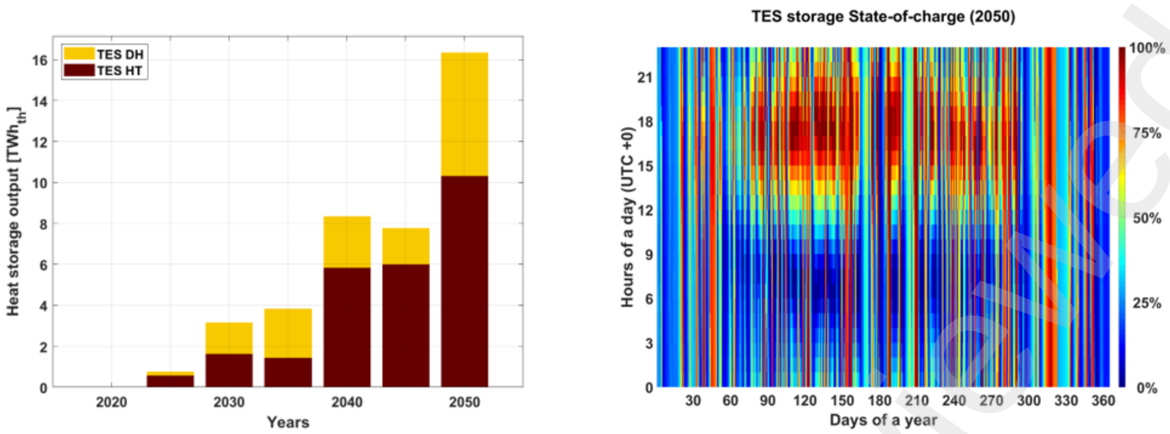

Figure 11: Thermal energy storage output until 2050 (left) and hourly heat storage state-of-charge in 2050 (right).

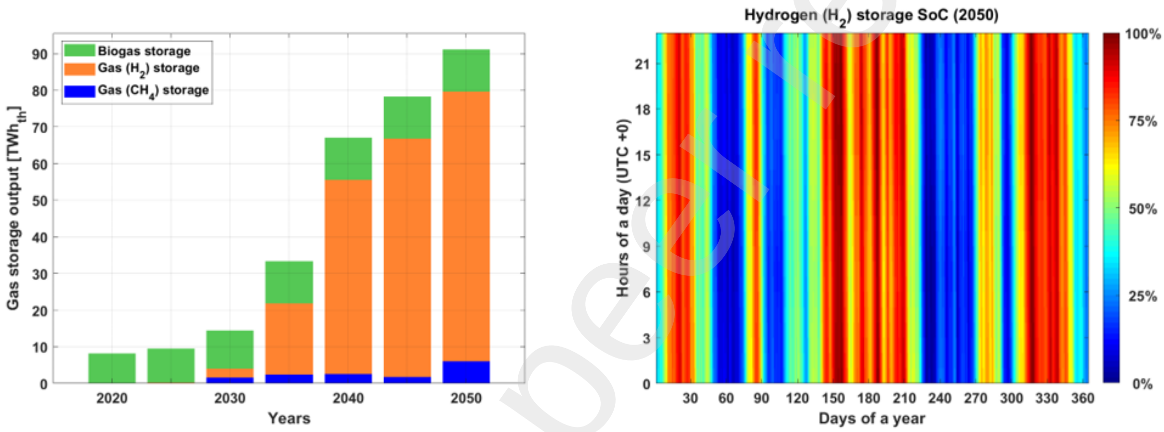

Figure 12: Gas storage output until 2050 (left) and hourly hydrogen storage state-of-charge in 2050 (right).

The battery utilisation profile (Figure 10) interacts with the solar PV generation profile from spring to autumn, when most of the solar resources are available. During winter, it shows a noticeable complementarity with the wind profile, working also as a short-term balancing technology. Heat storage (Figure 11) is used for high-temperature and district heat, mostly during evening hours in summer, but also for some days in late autumn and winter. Methane gas (Figure 12) works as a seasonal storage, with the lowest full charge cycles of 5. Hydrogen storage (Figure 12) operates as a mid-term buffer storage with about 12 full charge cycles over the year to balance energy supply and demand during low wind periods.

Regional differences in electricity generation can be seen in Figure 13, illustrating that most electricity generation happens in Scotland, and the least in London. The highest share of offshore wind can be found in Wales, while Scotland has the highest share of onshore wind and wave power. Electricity generation in London is almost fully limited to PV prosumers, while the Midlands show the highest share of utility-scale solar PV.

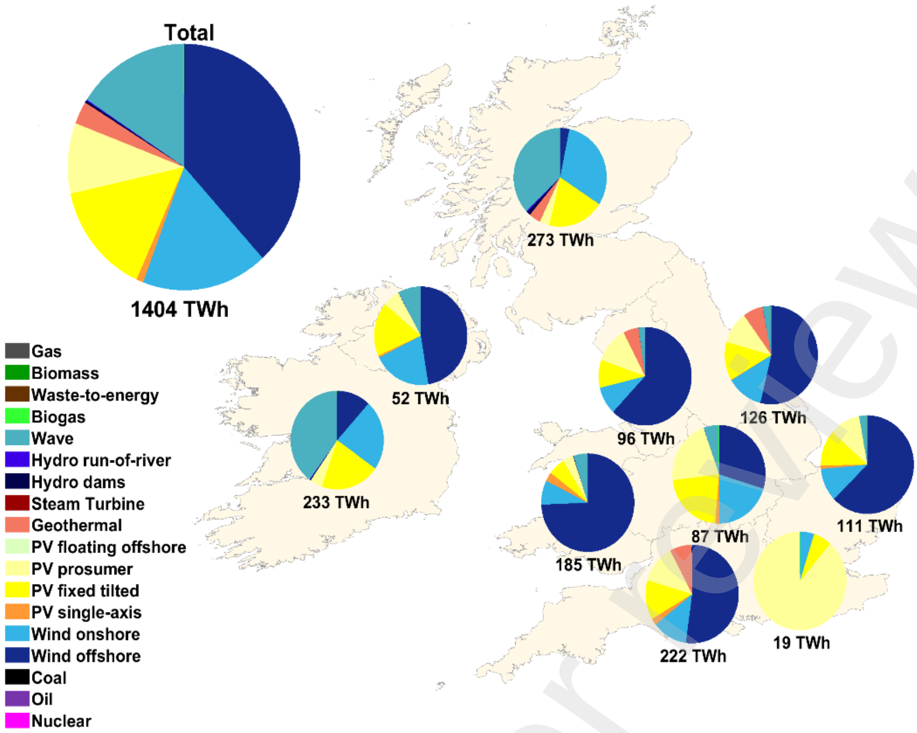

Figure 13: Regional electricity generation in 2050.

The energy flow of the whole energy system in 2050 is presented in Figure 14. All energy originates from RE sources, while a small part is imported, namely sustainable e-LNG. Unlike in 2020, the different sectors are strongly coupled via Power-to-heat, Power-to-mobility, Power-to-gas and Power-to-liquids, finally summarised best as a Power-to-X economy [84]. Various storage technologies, as well as grid utilisation and energy conversion losses can be seen in the diagram. Hydrogen is a core component of the energy system, but rather as an intermediate energy carrier for further e-fuel production than for final energy demand [84].

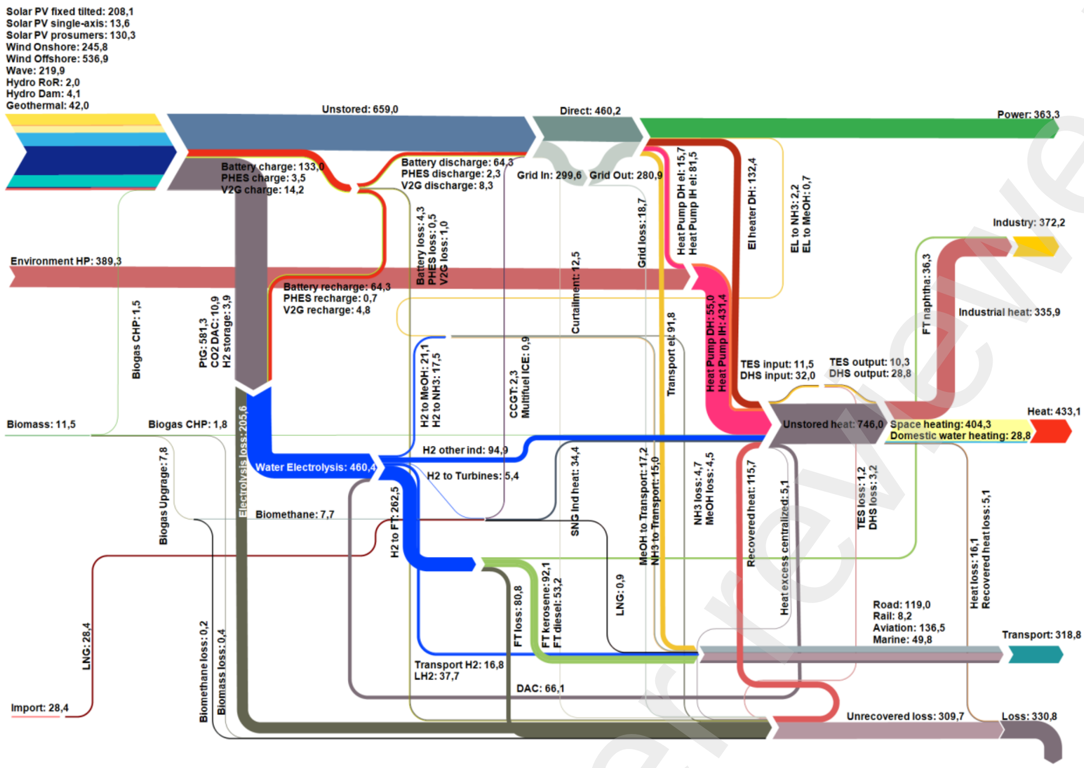

Figure 14: Energy flows in 2050 for the whole energy system. All values are displayed in TWh.

The electricity exchange within the regions of the UK and Ireland is illustrated in Figure 15. Strong exchange happens between Wales and London via Southern England, as Wales acts as an exporter. London is also supplied by the East of England. Wales also exchanges electricity with the Midlands and Ireland, while Scotland exports electricity to the North of England.

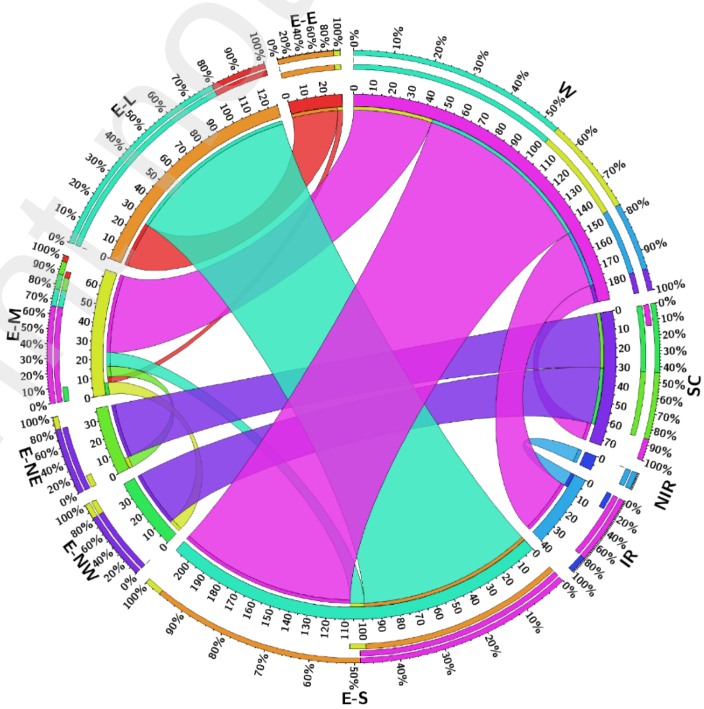

Figure 15: Electricity exchange within the UK and Ireland in 2050.

The development of costs over the transition is depicted in Figure 16. The levelised cost of electricity (LCOE) is significantly reduced from 80.2 €/MWh in 2020 to 42.8 €/MWh in 2050, while the highest share originates from capital expenditures. The total annualised system costs remain almost stable over the transition, starting from 85.8 b€ in 2020, reaching a maximum of 90.9 b€ in 2030 and finally declining to 78.6 b€ in 2050, with capital expenditures being responsible for the largest share.

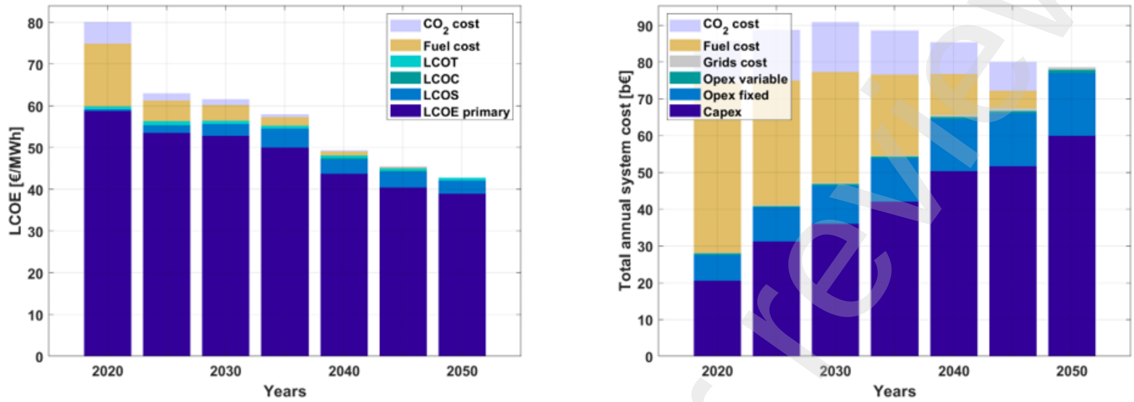

Figure 16: LCOE (left) and total annualised system costs (right) until 2050.

CO_2 emissions decline over the transition, finally reaching zero in 2050 across all sectors, as shown in Figure 17. Emissions in the power and heat sectors decrease strongly at the beginning of the considered period due to the ramping of wind power and heat pumps, substituting natural gas based power and heat generation. Large shares of the power and heat sectors can be decarbonised early, while high temperature industrial process heat and aviation and marine transportation require e-fuels that are available at larger volumes at a later stage of the transition. The overall CO_2 emissions are substantially reduced in 2025 and 2040, reaching zero in 2050, as shown in Figure 17 (bottom right). The majority of emissions originate from the heat and transport sectors, where natural gas and fossil oil are used as fuels. With the immediate and determined initiation of the energy transition, the amount of emitted CO_2 can be reduced by 36% in the near term, and in 2035 more than half of today's emissions can be avoided.

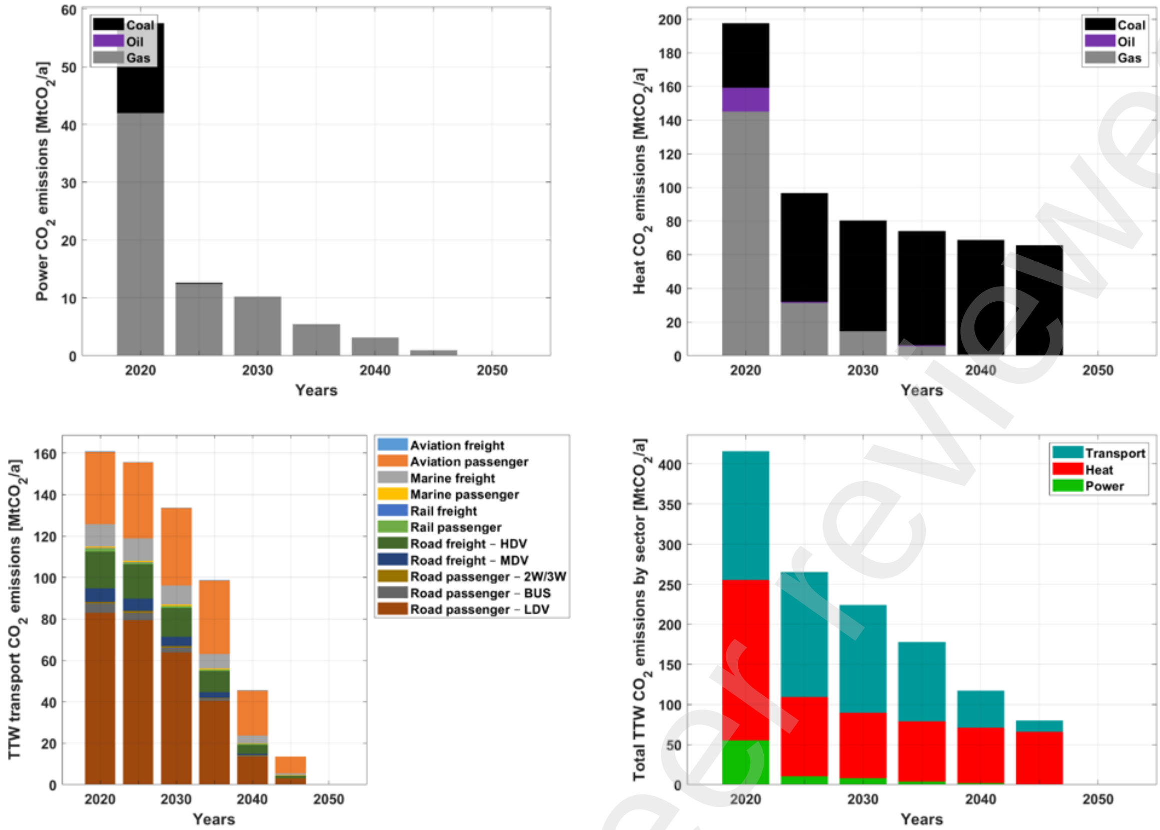

Figure 17: CO_2 emissions for the power sector (top left), heat sector (top right), transport sector (bottom left), and all sectors (bottom right).

3.2 Scenario Comparison

The three scenarios differ mainly in terms of the electricity generation mix, which has a strong effect on the total costs of the energy system. Primary energy demand (PED) is presented in Figure 18 for all scenarios, including environmental heat for heat pumps. The most significant differences can be observed between the CPS and the BPS and BPSplus, since the CPS uses nuclear power for power generation and a large share of fossil fuels (for heat and transport) even in 2050. The remaining emissions are removed by direct air carbon capture and storage (DACCS), as introduced to LUT-ESTM in [56, 60] and conceptually also suggested by Lux et al. [85]. It is also the scenario with the highest PED in 2050, reaching 1984 TWh. The lowest PED is achieved in the BPSplus scenario, with 1659 TWh in 2050.

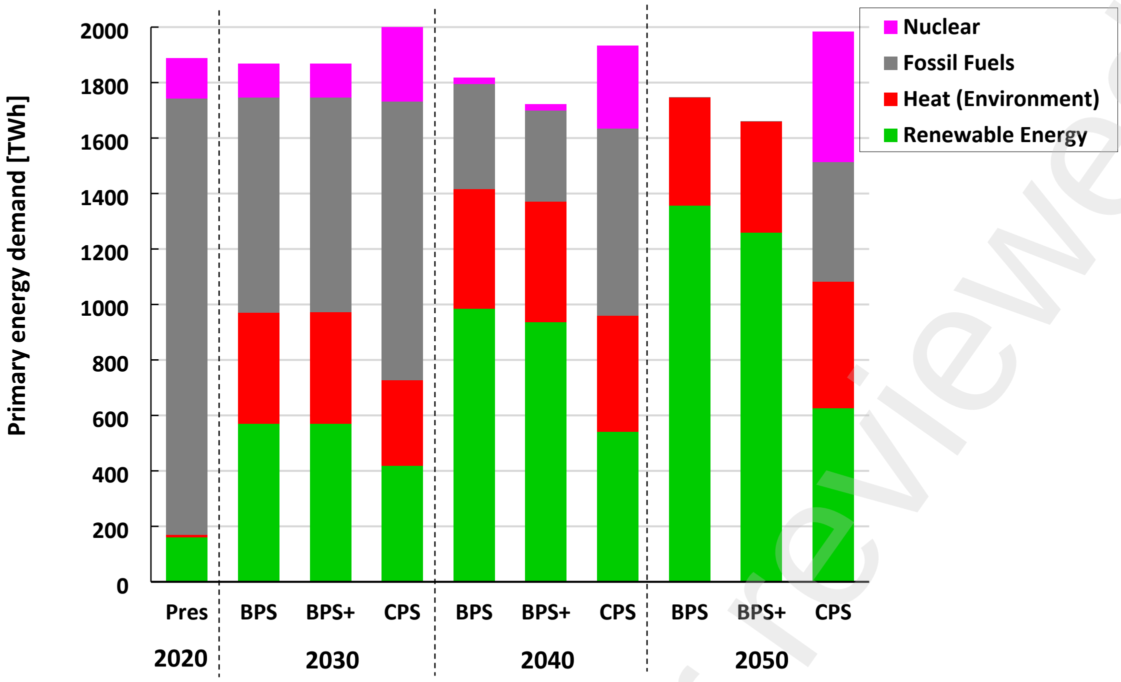

Figure 18: Primary energy demand for all scenarios until 2050.

The electricity generation mix, which is illustrated in Figure 19, characterises the intrinsic features of each scenario. Offshore wind as the main source of RE is consistent across all scenarios, except for the BPSplus, where solar PV reaches the highest share at 37% of total generation. In the BPS, offshore wind reaches a share of 38%, equivalent to 537 TWh of generation. Due to less restricted land area limitations in the BPSplus scenario, onshore wind power and solar PV do have a higher relevance.

Characteristic of the CPS is a high share of nuclear power at 22% of generation in 2050, which is in line with the governmental plans of nuclear power expansion. Wave power becomes important for the BPS while it does not play a significant role for CPS and BPSplus. Huge differences can further be seen in the amount of electricity generated in each scenario. The CPS has the lowest amount of electricity generated due to lower electrification levels of the heat and transport sectors. In the BPSplus, more e-fuels are imported, from which it follows that less electricity has to be generated domestically and also contributes to lower PED as losses in e-fuels production are avoided in UK and Ireland.

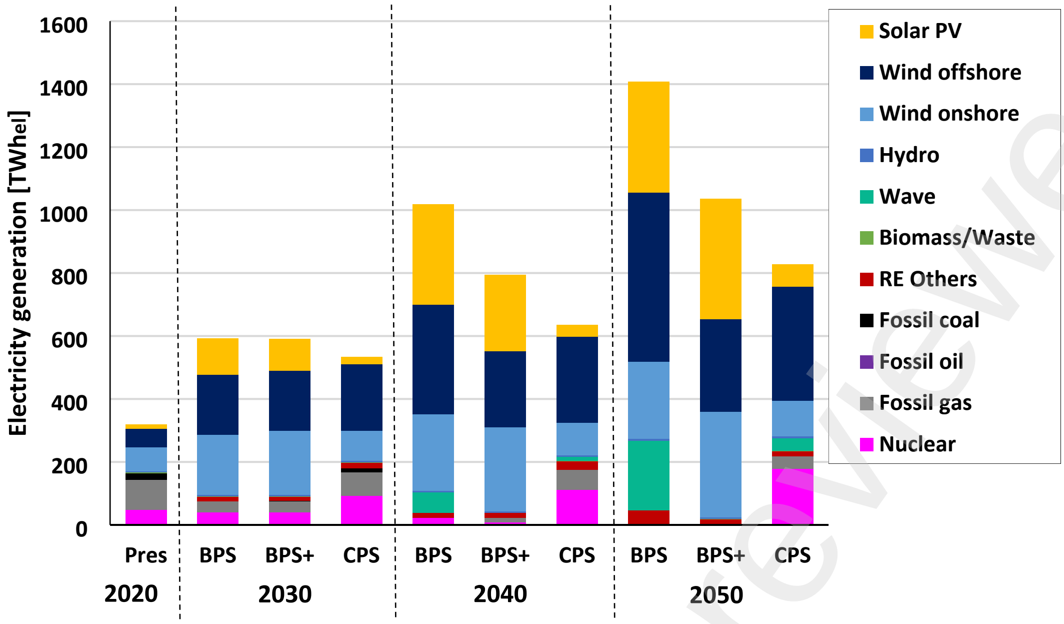

Figure 19: Electricity generation mix for all scenarios until 2050.

All scenarios tackle the long-term goal of reaching zero CO_2 emissions in 2050. The cumulative emissions displayed in Figure 20 (left) show that over the whole transition period, the CPS releases more emissions than the other scenarios. By applying governmental strategies, the transition takes place more slowly. The remaining scenarios do not differ to a great extent, although in the BPSplus, the least amount of cumulative CO_2 is emitted. Figure 20 (right) shows that power sector emissions are almost fully eliminated early in all scenarios, while the heat and transport sectors are defossilised last. In 2030, the emissions are almost halved for the 100% RE scenarios.

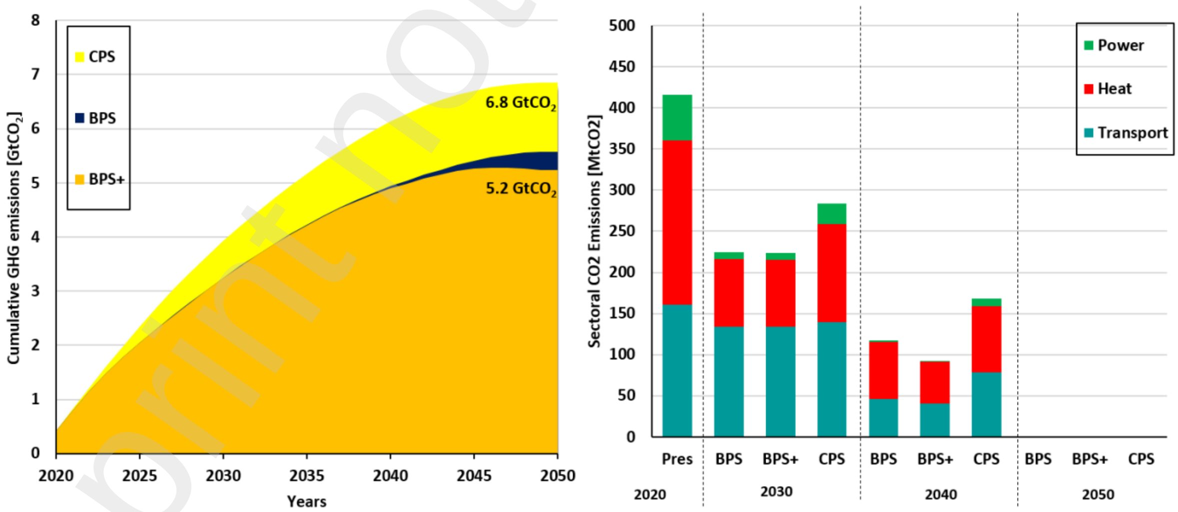

Figure 20: Cumulative (left) and sectoral CO_2 emissions (right) in $GtCO_2$ for all scenarios during the transition.

The different structure of the energy systems in each scenario has a strong impact on the costs. In Figure 21 (left) it can be observed that the BPS and BPSplus enable the least LCOE in 2050, declining to 41 €/MWh and 40 €/MWh, respectively. Three quarters of the LCOE originates from capital expenditures. The LCOE of the CPS, which does not fully phase out fossil and nuclear fuels, further shows a small share of fuel costs as part of the composition, reaching the highest LCOE among all scenarios at 70 €/MWh. Total annualised system costs are illustrated in Figure 21 (right). In the year 2050, the CPS reaches the highest total costs, at 93 b€, while the BPSplus reach the lowest, at 63 b€. The BPS, reaching 79 b€, is lower in cost than the CPS. The cumulative costs are highest for the CPS, resulting in 2934 b€ for the whole transition, compared to 2676 b€ for the BPS and 2570 b€ for the BPSplus.

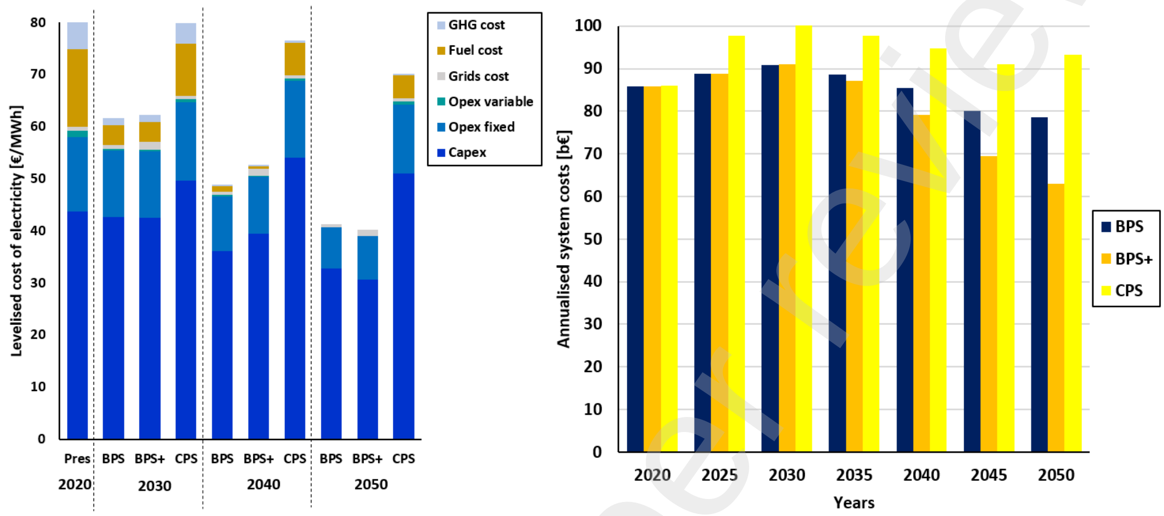

Figure 21: LCOE (left) and total annualised system costs (right) for all scenarios until 2050.

4 Discussion

4.1 General implications for the energy transition

The results of this study demonstrate how several cost-optimised energy transitions from the current fossil fuel-based to a 100% RE system in the UK and Ireland can be implemented under given framework conditions. Both 100% RE scenarios (BPS, BPSplus) are economically competitive, and significantly cheaper than the governmental strategy (CPS) for reaching zero emissions in 2050. Strong electrification of the heat and transport sectors, leading to a more efficient, flexible, and sector-coupled energy system emerges as a fundamental requirement of a sustainable transition. The power sector transformation can be achieved to a great extent by 2030, while the heat and transport sectors require the extensive deployment of e-fuel production [86, 87] such as e-hydrogen, e-methane, e-ammonia, e-methanol, e-diesel, and e-kerosene jet fuel.

The results further show that the expanded use of low-cost renewable generation technologies such as onshore wind power and solar PV are able to lower the total costs of the energy system significantly (BPSplus). This is compared to a scenario with restricted land area availability (BPS) and the governmental strategy (CPS), including nuclear power and fossil CCS. The BPS, as the central scenario of this study, relies on different sources for electricity generation, with offshore wind as the most important, complemented by solar PV and onshore wind but also hydropower, wave power, geothermal energy and the utilisation of biogas from organic residues. The strongly electrified heat sector uses highly efficient heat pumps for domestic hot water and space heating that are partly supplied by decentralised rooftop PV. The rapid upscaling of heat pumps in this study is a result of the cost optimisation character of the applied model and may happen more slowly in reality.

For hard-to-abate applications, especially in the steel, glass or cement industry, higher temperatures of heat up to 1600°C are required that cannot be provided by heat pumps. Thus, other technologies like direct electric heating and the combustion of e-fuels, such as e-hydrogen or e-methane, are important measures. Hydrogen is projected as the default iron ore reduction feedstock [88, 89]. Direct electric heating competes with the use of fuels for high-temperature heat [90, 91]. In the transport sector, direct electrification is to be preferred over fuel use whenever possible, since conversion losses can be avoided, thereby leading to higher efficiency and lower costs. This becomes very important for the road and rail transport modes, while marine and aviation will be partly dependent on combustible fuels, which are produced from hydrogen and captured CO_2 [92]. For long-distance marine transportation, e-ammonia and e-methanol have a realistic chance of being competitive in future markets [93].

The results for the UK and for Ireland show several similarities. The heat and the transport sectors as well as energy storage roughly rely on the same technologies in all scenarios: battery storage for short-term storage, heat pumps for individual heating and BEVs for passenger transportation. Differences can be found mostly for the electricity generation mix, as Ireland's main source of electricity is wave power in the BPS (UK: mostly offshore wind power), onshore wind power in the BPSplus (UK: solar PV or offshore wind power), and offshore wind power in the CPS (UK: nuclear power). From all subregions in the UK, Scotland is the one with a structure very close to Ireland, most likely due to similar resource availabilities, land area and comparable energy service demands. Nuclear power is not part of governmental plans in Ireland and therefore not imposed in the CPS.

The overall findings of this study are consistent with studies for sector coupling and smart energy systems [94, 95] as well as for the energy transition of other countries [56, 96]. It should be noted, however, that for the purposes of this study the shares of offshore wind, wave power, and maybe tidal stream generation should be regarded as potentially interchangeable. The amount of offshore wind electricity generation can be extended to fulfil the quantity projected from wave power. This could be the case if the possibility of a medium term rapid technical optimisation in wave power technology [97] does not materialise.

Green hydrogen becomes a key component in a fully renewable energy system, but not necessarily for final energy use. Instead, green hydrogen may work as an intermediate product for the conversion to a variety of e-fuels. Therefore it should be considered as important but not as the most characteristic element of a future Power-to-X economy [84] that also comprises electricity-based mobility and heat as well as the substitution of fuels for primary energy supply. The downstream applications for green hydrogen derivates are vast, such as e-ammonia (as a fuel or for fertilizers) [98], e-methanol (as a fuel or as a basic chemical for the chemical industry) [99] or Fischer-Tropsch fuels [100] as they all necessarily rely on hydrogen. While some direct uses for hydrogen are very realistic (e.g., for green steel), it may not serve as silver bullet for all end-use applications.

Moreover, the nature of the applied cost-optimisation model requires a predefined ramping of offshore wind power to realistically represent its development as the model would naturally prefer lower-cost technologies. As energy systems with high shares of renewables tend to have high levels of electrification, the electricity generation mix is one of the most important aspects for the evaluation of the energy system, as it strongly influences other sectors as well as energy storage, grid utilisation and e-fuels production. Especially the latter is strongly affected by the source of electricity, as it requires substantial amounts of electricity due to conversion losses during water electrolysis, CO_2 direct air capture for hydrocarbon-based e-fuels and e-fuel synthesis.

The study is subject to some limitations. Although the modelling has been done in high temporal resolution on an hourly scale, the modelling results do not approach energy system characteristics that occur below this time resolution, e.g., on a second- or minute-scale, but these are assumed to be balanced with battery storage with smart inverters. Adequate capacity of short term storage is installed in all scenarios. This study has not addressed the interconnection between the British Isles and Europe, as this has already been done in [49, 50]. However, more research is needed to further understand the interconnections between subregions of the British Isles and other European countries. Due to the characteristic of a wind power dominated energy system in the British Isles, the effects of inter-annual wind variations have not yet been investigated but should be subject to further research.

The energy transition has to be implemented regionally, since PV systems, heat pumps, battery systems and electric vehicles in particular are connected to low- and medium-voltage grids. These must be designed accordingly and extended with communication technology to implement vehicle-to-grid and demand-side-management concepts. Distribution grids have not been modelled in this study. While electrical energy can also be transported efficiently over long distances, as shown, heat must be provided more locally. Different regional conditions lead to different supply concepts (district heating if industrial waste heat is available, central heat pumps, or individual heat pumps). Other investigation tools need to be developed for these local investigations for instance, power system calculations in a higher detail or multi-energy system models for distribution grids [101].

4.2 Onshore versus offshore energy supply

Onshore wind power has a high technical and economic potential in the British Isles [102, 103]. However, this technology is subject to public and political opposition, being the technology with the highest rejection rate of all RE technologies (52%) in Great Britain, followed by biomass combustion (47%) while offshore wind power can be found on the other end of this ranking (11%) [41]. Previous studies on the energy transition of the British Isles naturally focused on onshore and offshore wind power as the main source for RE generation [50, 52], thereby neglecting the role of solar PV. From an acceptance point of view, solar PV is discussed less controversially and might offer a compromise between expensive but accepted offshore wind power and low-cost, but restricted onshore wind power. With a rejection rate between onshore and offshore wind power (25%), solar PV might offer a solution to this dilemma, as solar PV additionally offers a competitive electricity supply even with moderate resources in the British Isles [16]. Due to its continued declining costs, solar PV could thus shape the energy transition of the British Isles as it is expected to do on a global scale [104, 105].

Being subject of future discussions, land use for onshore wind power and solar PV and its trade-off with the total costs of the energy system is one of the big decisions that society has to make in the years to come. While the results of the central BPS demonstrate that an option with low area impact and high utilisation of offshore wind power is technologically feasible, its economic competitiveness is limited to some degree, due to the high capital and operational expenditures of offshore wind power.

The trade-off between land area availability and system costs can be evaluated in detail when the central BPS is compared with the BPSplus scenario. Modelling results show that a high share of the lifted upper potential for both technologies is utilised that consequently leads to lower costs. If the land area availability for solar PV is doubled from 1% to 2% and raised from 2% (Scotland 2.5%) to 3% for onshore wind power (Scotland 4%), and offshore wind power annually built set to a minimum of 1 GW/yr from 2030 onwards, the total annualised system costs can be reduced by 20% from 79 b€ to 63 b€.

The BPSplus can be seen as a "testing-the-limits-scenario" in which also energy independence is softened, by allowing higher imports of e-fuels (155 TWh for BPSplus in 2050, compared to 29 TWh in the BPS), which again lowers the costs. The imported e-fuels in the BPS are solely e-methane, while in the BPSplus, 83% of the imported fuels are Fischer-Tropsch fuels (mainly e-kerosene jet fuel) and 17% e-methane. The import dependency in the BPS is very low with only 2% of total PED compared to 12% in the BPSplus.

Wave power (along with other forms of ocean energy) is a source of energy that has the potential to become important for future energy systems [106]. Although it is not yet cost-competitive to other RE sources, it can play a role in the long-term, when the technology becomes more mature and costs decrease [107]. Based on the financial assumptions of this study for this technology [108], wave power becomes part of the energy system from 2040 onwards if solar PV and onshore wind power are not anymore available due to area restrictions. This indicates that wave power should be considered as a form of clean energy generation not only if other sources are limited due to societal constraints, but also if land area is geographically unavailable, for example on smaller islands and archipelagos. For example, the future impact of wave power on islands has recently been investigated for the case of the Maldives [108]. Energy supply diversity is increasingly noticed as a means for overall energy system resilience and needs to be considered in the societal discourse as an important aspect in addition to the low-cost objective for energy systems [22].

4.3 Nuclear energy and fossil CCS

The strategy of the UK government to reach zero emissions in 2050 has recently been updated, with more focus on energy security [109] than in the report used to design the governmental strategy for this report [21]. Several attempts at decarbonisation are consistent with the requirements of a 100% RE system: hydrogen production, RE upscaling, energy storage, heat pumps and e-fuels use for marine and aviation transportation. However, the key message of the governmental plans has barely changed. Nuclear power remains central to governmental plans for decarbonisation (even for hydrogen production, being called pink hydrogen), fully neglecting nuclear power induced risks, high costs, unsolved repository questions and lock-ins of the current energy system structure. The recent problems of the unreliability of nuclear power in France [110] are to be compared with the potentially greater reliability of a 100% renewable energy system complete with a system of inter-annual storage. A public discussion is lacking on the military dimension of governmentally forced civil nuclear power [111] that would not have any market chance without massive governmental subsidies. The results of this study indicate that 100% RE scenarios can be markedly cheaper in achieving net zero emissions by 2050 compared to the governmental plans.

5 Conclusion

This study demonstrates what a sustainable transition to a CO_2 emission free energy system can look like for the case of the UK and Ireland with their abundant potentials for wind power. A well-established energy system model has been used to simulate a cost-optimised transition to a carbon neutral energy system for given constraints.

A scenario with low land area impact and priority of offshore wind power development leads to 79 b€ of total annualised costs and a levelised cost of electricity of 41 €/MWh in the target year 2050. This is compared to 93 b€ of total costs and a levelised cost of electricity of 70 €/MWh for the governmental strategy with nuclear power and fossil carbon capture and storage as key elements. A scenario with stronger area impact caused by onshore wind power and solar photovoltaic use is able to reduce the total costs by 20% to 63 b€ and the levelised cost of electricity to 40 €/MWh. Both 100% renewable energy scenarios result in CO_2 emissions that are over 20% lower compared to the governmental pathway to net zero by 2050.

The obtained results demonstrate that a dedicated pathway to 100% renewable energy should be considered as the number one option, as it avoids nuclear power induced risks and transition delays due to lock-in effects, while significantly reducing the costs. Within this path towards 100% renewables, a compromise between land area impact and total system costs must be found. Ultimately, those decisions have to be made carefully in a socio-political discourse.

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Appendix

The supplementary material can be found:

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