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100% RENEWABLE ENERGY FOR THE UNITED KINGDOM

Authors: Philipp Diesing, Dmitrii Bogdanov, Rasul Satymov, Michael Child, Christian Breyer

LUT University, Yliopistonkatu 34, 53850 Lappeenranta, Finland

CONTENTS

[1]

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Key takeaways of the report:

- A 100% renewable energy scenario will save well over 120 billion € in achieving net zero by 2050 compared to the UK Government's strategy for net zero by 2050 – the Government pathway includes nuclear power and fossil fuels with carbon capture and storage
- A 100% renewable energy scenario will achieve net zero by 2050 with over 20% less cumulative carbon emissions compared to the UK Government pathway
- The preferred scenario is dominated by offshore wind but also includes large amounts of inter-annual energy storage to cope with fluctuations in wind power outputs within and between years
- The study finds that storing renewable energy as renewable electricity-based methane in conventional natural gas storage facilities is the most cost-effective means of inter-annual storage. The methane is converted from air captured CO2 and green hydrogen using renewable electricity
- The more onshore wind power and solar photovoltaics are used, the cheaper the path to net zero becomes
- The same assumptions for demands for energy services are used in all scenarios, and from this we can conclude that the 100% renewable energy scenarios are superior in achieving these services for lower cost and lower systemic risk compared to Government plans.

Foreword by Jonathon Porritt

COP27 was a disaster. Fossil fuel companies dominated proceedings, with their utterly duplicitous advocacy for extending their own commercial operations via the unproven, costly and hopelessly inefficient technology of Carbon Capture and Storage. It will be even worse next year with COP28 in the United Arab Emirates.

Put not your hope in these charades. As Gramsci said: “The crisis consists in the fact that the past is dying, but the future cannot yet be born.”

Our only chance of accelerating those birth pangs is to double down on making the right things happen in our own countries, whilst fighting fiercely to support poorer countries in their demand for some kind of reparation for the damage already done to them – and for the even more horrendous damage still to come.

Here in the UK we have an amazing opportunity to do our bit – by meeting all our energy needs (not just electricity) from renewables and storage by 2050. If you’re sceptical about the feasibility of that ambition level, then dig deep into this Report – and see your hope rekindled!

What’s more, it would be a massive win for citizens, with savings of well over £100bn compared to the Government’s already extremely flaky Net Zero strategy. These benefits will be particularly important to the very high percentage of our citizens already living in fuel poverty, hammered by one price hike after another.

And that really matters. Total decarbonisation of the UK economy in the next 25 years is a massive challenge. Our lifestyles will be transformed – in that all citizens will need to be active agents of change in this process. And that will only happen if people see this transformation as fair and equitable in every way.

That means putting as much emphasis on energy efficiency as on renewables and storage. Precisely because it’s such an extraordinarily ambitious challenge to get rid of all fossil fuels, every single unit of renewable energy we replace them with must be used as efficiently as possible – in our homes, our factories, our offices and retail outlets, in our transport and food production systems.

More of a revolution than a transformation!

Jonathon Porritt, Co-Founder of Forum for the Future, is an eminent writer, broadcaster and commentator on sustainable development

Summary of the report:

While the effects of the climate emergency can be observed more and more clearly through increasingly frequent extreme weather events and other climate change impacts, there is still a lack of dedicated countermeasures by decision-makers. The government of the United Kingdom (henceforth: UK) has self-committed to climate neutrality in 2050, but without initiating the essential steps and without eliminating fossil fuel-based technologies and high-risk nuclear power. However, the UK benefits from the availability of renewable energy resources, namely onshore and offshore wind, which are considered to be the best in Europe. Based on this background, this study presents several energy system transition pathways to 100% renewable energy in 2050 in high-spatial and temporal resolution, by describing the energy system of the UK in full detail from the starting point of today in five-year time steps until 2050.

In total, four scenarios were conducted:

- one scenario, called Best Policy Scenario (BPS), aimed for 100% renewable energy in 2050, with offshore wind as the main resource, limiting onshore wind and solar photovoltaics according to available land area;
- a second scenario called Inter-Annual Storage (IAS) adds on (to the BPS) required inter-annual storage needed to provide good levels of insurance against the possibilities of low-wind years;
- a third scenario (BPSplus) tested the limits of higher land area availability for onshore wind and solar photovoltaics, and where also renewable electricity-based e-fuel imports are allowed;
- finally, a fourth scenario, called Current Policy Scenario (CPS), adopted the UK Government’s strategy for net zero as published in 2020.

This Government scenario (CPS) aims for expansion of nuclear power as a key characteristic as well as use of carbon capture and storage for some fossil fuel use. In the CPS nuclear power reaches a fifth of total electricity supply in 2050. An advanced and well-established bottom-up energy system model has been applied to conduct research for the power, heat and transport sector, considering regional characteristics of the UK and using financial projections for future cost development. It should be noted that the three 100% renewable energy scenarios involve the phase out of nuclear power generation and fossil fuel use by 2050. The same levels of demand for services have been assumed in all scenarios. For the purposes of analysis (although not policy preference) substantial growth in demand for road and air transportation use is assumed in all scenarios.

Generation costs for nuclear power are based on the (so far) reported capital costs of the Hinkley C nuclear power plant, without any allowance for possible future cost increases. Costs of offshore and onshore wind and solar photovoltaics are based on current capital

costs and efficiencies, with the expectation that technical optimisation, economies of scale and technology learning will continue to reduce costs.

The results demonstrate that a 100% renewable energy system for the UK is not only technically feasible under given framework conditions, but also offers a much cheaper path towards achieving net zero in 2050 compared to the UK Government's pathway for net zero. The 100% renewable energy scenario including inter-annual storage is calculated to be 129 billion euros cheaper in total cost compared with the UK Government's pathway to achieving net zero by 2050. In addition, the 100% renewable energy scenarios reduce the quantity of carbon dioxide emitted in the period up to 2050 by over a fifth compared the Government scenario (CPS). The main trend across all 100% renewable energy scenarios is the electrification of all sectors, leading to high system efficiency and reduced primary energy demand. The increasing amount of variable renewable energy technologies leads to the establishment of a broad set of energy storage technologies, grid expansion, e-fuel production and carbon capture and utilisation measures. However, in the IAS scenario the primary energy demand is still 1717 TWh per year with the CPS being 1829 TWh, thereof high shares from fossil fuels and nuclear energy.

In grading the scenarios, a preference is given to the IAS scenario (built on BPS) involving lower land use for renewable energy (and relatively more marine renewable use) even though the BPSplus scenario would produce cheaper overall costs. The main scenario (BPS), where offshore wind will become the dominant renewable energy resource is able to reduce the Levelised Cost of Electricity (LCOE) of the electricity system from 82 €/MWh in 2020 to 43 €/MWh in 2050, while total annualised costs decrease from 79 to 68 billion €, after reaching a maximum in 2030 at 84 billion €.

As (after this) inter-annual storage is added to the system, it could be shown that methane storage is to be preferred over hydrogen storage due to the higher volumetric energy density of methane. However, if the methane is produced and stored within the UK, the resulting costs increase by 31%. Potential cost reductions can be achieved by importing sustainable methane from other countries. Further, the results show that the costs of the system can be significantly reduced if onshore wind and solar photovoltaics face less land area limitations. In this extra scenario, the LCOE in 2050 decreases to 41 €/MWh while the total annualised costs decrease to 58 billion €. This corresponds to a reduction of 16% compared to the offshore wind dominated scenario. If, in the near term, additional methane storage was built to provide much needed natural gas storage capacity in the coming years, then this would provide storage capacity that can be used over the long term for inter-annual methane storage.

The generation shares in the offshore wind dominated scenario are 44% offshore wind, 16% onshore wind, 25% solar PV (including prosumers), 11% wave energy, and 4% others. Wave power is inserted here to allow for continuing innovation in renewable energy technology. However, in this scenario more offshore wind energy will be interchangeable with this quantity of wave power at roughly similar cost if wave power does not develop so quickly. In the scenario with less land limitations the generation shares are found to be 39% solar PV (including prosumers), 31% offshore wind, 27% onshore wind, and 3% others. The current policy scenario is on a higher cost level as the main scenario with 86 billion € (b€) of annualised costs in 2050, having the highest LCOE with 74 €/MWh in 2050.

The results indicate that a 100% renewable energy system for the UK is technically feasible and economically more viable than the current policy strategy. There are plausible arguments to suggest that, with inter-annual storage, it is also more reliable than the Government's strategy. The costs of an offshore wind dominated system can be further reduced at the expense of land use for low-cost renewable generation technologies such as onshore wind and solar photovoltaics. The highest cost projections among the zero CO_2 emission options are related to a dedicated nuclear power expansion. Which pathway to go for will be one of the central challenges for policy makers and the society of the United Kingdom.

Introduction

The COVID-19 pandemic caused a historic drop in energy demand and greenhouse gas (GHG) emissions worldwide in 2020. However, successful vaccination campaigns led to relaxations in restrictions of movement. As a result, a strong increase of emissions were expected for 2021 alongside with a rise of global energy demand and gross domestic product (GDP) to pre-pandemic levels [1]. These forecasts proved to be accurate, as 2021 broke the record for annual rise of CO_2 emissions ever recorded, reaching 36.3 Gt [2].

Recently, public awareness of climate change has increased significantly 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 [3]. 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 [4].

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

To be able to address the long-term issue of global warming, the UK needs to mitigate their GHG emissions drastically by initiating a transition towards a clean and sustainable energy system, ideally based on 100% renewable energy (RE) to minimise emissions and other sustainability issues. A variety of studies presented in [8–10] indicate that only a 100% RE system can provide long-term sustainability, economic competitiveness as well as societal benefits .

The energy system's backbone of the UK is natural gas and oil, while coal is close to being phased out. In 2020, 41.9% of inland energy consumption was natural gas, followed by oil at 31.2% [11]. A huge shift can be observed in the 30 years since 1990 regarding the utilisation of coal, the share of which 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 intensive use of fossil gas and oil explains the high import dependency of 30-40% of energy supply in the last five years. The use of oil remains constant, mainly as a fuel in the transport sector [11]. The energy system structure of today is illustrated in Figure 1, showing the strong use of natural gas and fossil oil with barely developed sector coupling and almost no energy storage technologies.

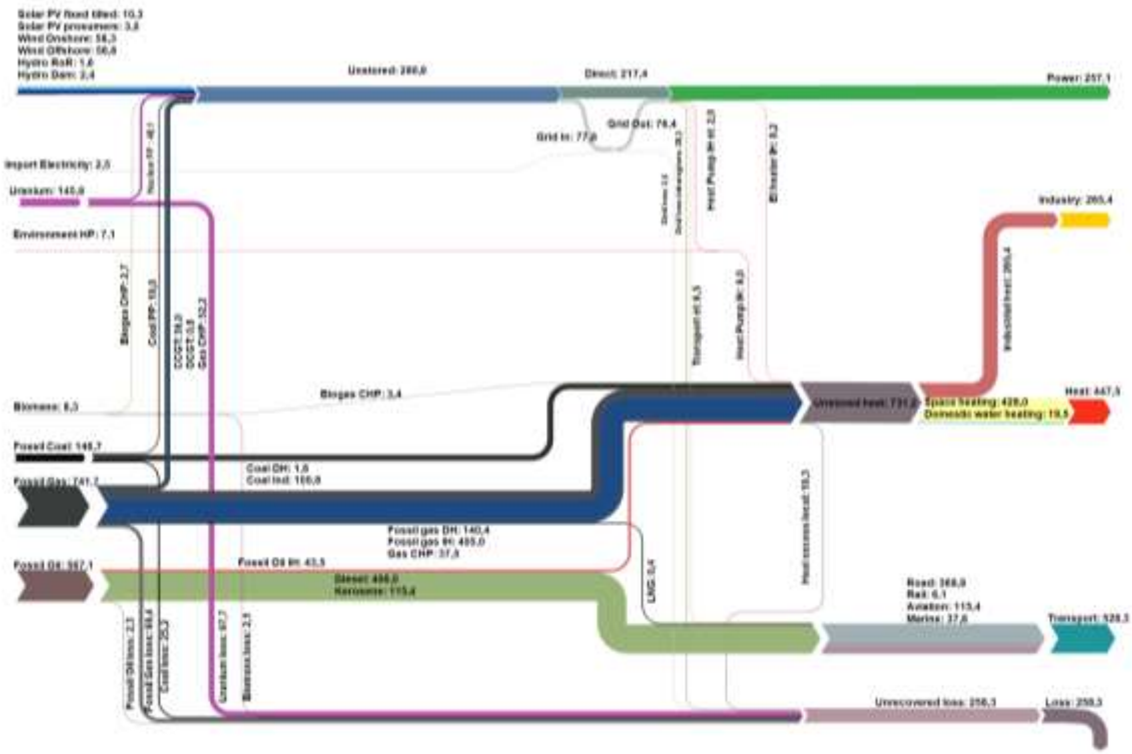

FIGURE 1: ENERGY SYSTEM OF THE UK IN 2020. ALL VALUES ARE DISPLAYED IN TWH.

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, wind power and bioenergy [11]. Furthermore, the energy intensity per household decreased by 23%, which is related to efficiency improvements for residential and commercial buildings [11].

These trends indicate that the UK government recognised the necessity for GHG emission mitigation. This development might also be driven by declining costs of RE and storage technologies [12–17]. In fact, governmental strategies 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 [18].

However, serious concerns regarding the use of those technologies and their environmental and economic effects are expressed in scientific literature [19–23]. In [24, 25] it is shown that new nuclear power technologies face strong economical obstacles. Sovacool et al. [26] state: 'We find that larger-scale national nuclear attachments do not tend to associate with significantly lower carbon emissions while renewables do'. Sovacool [27] also 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) [28]. Also, accidents with severe consequences cannot be fully avoided. The catastrophe of Fukushima initiated 100% RE studies for Japan, which challenged the necessity of nuclear power in a sustainable energy system [29, 30]. Events in France in 2022 imply that nuclear power is subject to risks of unreliability.

As an alternative, the UK has excellent on- and offshore wind energy potentials [31]. Already several decades ago, this potential was recognised and policy recommendations were derived [32]. In the first half of 2021, UK had the highest amount of installed capacity of offshore wind power worldwide with more than 10 GW [33], and the UK government pursues to quadruple the installed offshore wind capacity by 2030 [11]. Onshore wind is limited to available land area but might be even more limited by social and political acceptance [34]. The public debate on onshore wind is controversial. While new projects were blocked in 2016, in 2020 the financial restriction were lifted again for those that can gain planning consent, mainly in Scotland [35]. The resource potentials for solar energy are limited for the UK. However, previous research indicates that the resource can play a significant role for the power sector [12].

The offshore wind resource availability of the UK is the best in Europe, followed by the Republic of Ireland (henceforth: Ireland) with a cumulative technical resource potential of 8,000 TWh per year [36]. Given this vast availability of the resource, in this report, it will be assumed for the central scenario that the future energy system will be dominated by offshore wind, while onshore wind and solar energy resources are limited in terms of available land area, resulting from restricted social acceptance.

Although the wind energy potential is recognised, it is still unclear how the whole energy system with all its system components would look like if a least-cost solution is targeted. Therefore, the aim of this report is to prepare, conduct and evaluate several cost-optimised energy system transition scenarios in five-year time steps for the power, heat and transport sector until 2050 utilising the LUT Energy System Transition Model (LUT-ESTM) for the United Kingdom and evaluate the results. For this report, different scenarios are presented. Firstly, a base scenario is conducted where domestic RE generation can be supplemented by the limited import of synthetic renewable electricity-based e-fuels such as e-hydrogen and e-methane if it proves to be part of the least-cost solution. In a scenario variation, a full domestic RE supply is investigated where the import of fuels is blocked.

Furthermore, the impact of inter-annual balancing methods (extra wind capacity, inter-annual chemical storage, balancing technologies) is explored, since the annual wind yield changes significantly within different years [37]. The effect of inter-annual balancing requirements on the total system costs is then subject to discussion. One scenario discusses the limitations for land area use for solar PV and onshore wind, assuming that more area for both technologies is available, while the forced offshore wind capacity ramping is more limited, and more e-fuels imports are enabled. All scenarios that are aiming for 100% RE are compared to a current policy scenario (CPS) that describes the strategy of the UK government to reach zero GHG emissions, where the vast deployment of nuclear power and fossil CCS are an integral part of the energy system.

Data and assumptions

Energy System Representation and Future Projections

For this study, the UK and Ireland energy transitions were modelled as part of the same electricity market to simulate 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: South West, South East
	2	E - M	England: East Midlands, West Midlands
	3	E - NW	England: North West
	4	E - NE	England: North East, 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 high voltage alternating current (HVAC), and/or high voltage direct current (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 2.

FIGURE 2: SIMPLIFIED HIGH VOLTAGE POWER GRID OF THE UK AND IRELAND: CITIES WITH HIGHEST POPULATION BY SUBREGION HAVE BEEN CHOSEN AS CENTERS OF CONSUMPTION. THE INTERCONNECTION BETWEEN SUBREGIONS WERE ADOPTED FROM [38]. BLACK: HVAC. GREEN: HVDC.

The following data was collected for input:

- Weather data from a representative year for solar irradiation, precipitation, 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 divided into 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, etc.);
- Financial assumptions (capital expenditues (CAPEX), fixed and variable operational expenditures (OPEXfix, Opexvar), 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 installed 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.

The installation of new RE capacity 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 unrealistic 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.

In the main scenario, solar PV is limited to 1% of total land area demand with a power installation density of 75 MW/km^2. This leads to an upper limit for solar PV of 183 GW. Onshore wind is considered to be limited to 2% of total land area with a significantly lower power installation density of 8.4 MW/km^2. This leads to an upper limit for onshore wind of 42 GW. According to [36], 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 calculated using the method above 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 [39] and reprocessed with the REMix model by the German Aerospace Centre [40] in 0.45 x 0.45° nodal resolution. The regional FLH for wind onshore and wind offshore are shown in Figure 3. The highest wind potential can be found for Scotland and Ireland, the lowest in Southern England. The coastal regions have higher wind onshore potentials than the inland.

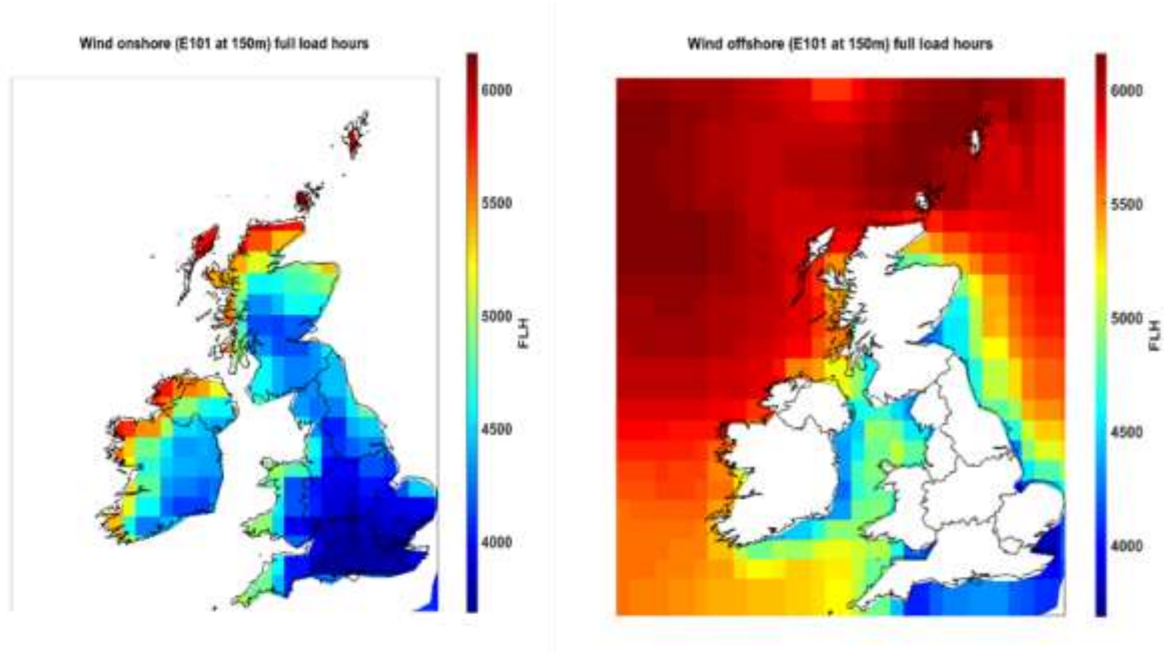

FIGURE 3: REGIONAL FLH FOR WIND ONSHORE (LEFT) AND WIND OFFSHORE (RIGHT)

Other renewable 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. This reduces the available biomass potential to biowaste, animal excrements, and sewage sludge, leading to a total potential of 11.5 TWh. Geothermal resources were obtained from [41]. An emerging energy resource is ocean energy, which has been integrated as wave power into the LUT-ESTM. The wave power potential was assumed to be 27 GW in 2050, as it is indicated by the UK government [42], which leads to a significant wave power potential especially for Scotland with the longest coastline and very high wind speeds. Tidal stream energy is another potentially substantial marine renewable energy source, but it is not part of the 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 [43], not considering altered profiles due to arising power demand for electricity-based heating and transportation, and adjusted according to governmental electricity demand forecasts 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 [44]. 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 [45] and subtracted from the overall power demand. The amount of electricity for heating in Ireland was taken from [46]. For the UK, the power demand increases from 257 TWh per year in 2020 to 333 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 [47] and visualised in Figure 4. The hourly heat demand data was used to create centralised and individual hourly heat demand profiles. The centralised heat demand includes low- and medium-temperature industrial process heat as well as district heating for individual space heating and domestic hot water demand. Individual heat demand includes residential and commercial heating systems and high-temperature industrial heat. The share of low- and medium-temperature demand for industry was found to be 62.0% and only 1.2% of space heating and domestic hot water demand is supplied by district heat [48], which indicates a barely developed heat network in the UK.

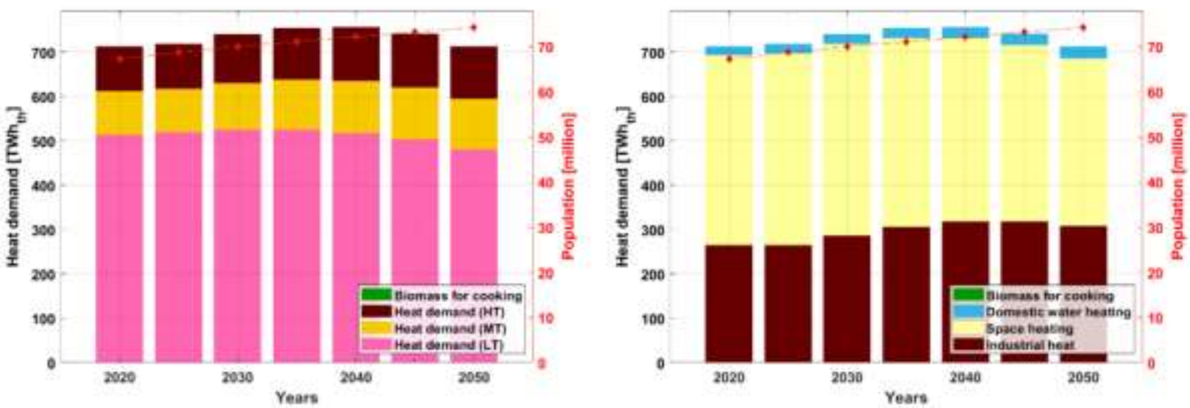

FIGURE 4: HEAT DEMAND PROJECTION UNTIL 2050 FOR DIFFERENT TEMPERATURE LEVELS (LEFT) AND END-USE (RIGHT).

Transport 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 was obtained from governmental sources for road transport [49], aviation passenger transport [50] and marine freight transport [51]. 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 5.

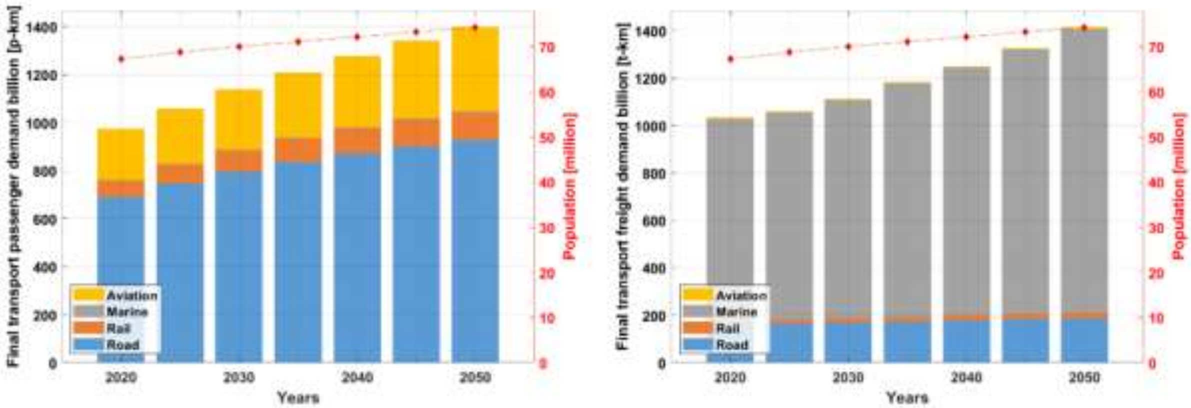

FIGURE 5: FINAL TRANSPORT DEMAND PROJECTION UNTIL 2050 FOR PASSENGER (LEFT) AND FREIGHT (RIGHT).

The power grid is modelled in a simplified way so that it represents the high voltage transmission grid structure of the current power grid. The medium and low voltage distribution grids are not modelled. For simplification, every subregion has a load centre, which is interconnected with the load centre of neighbouring subregions. Grid losses are modelled by taking the distance between load centres and type of line or cable into account, which were obtained from [52]. One default assumption of LUT-ESTM is that 70% of all power transmission happens via underground cables and 30% via overhead power lines.

Scenario variations

For this report, simulations for four 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. Three 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. 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 IAS scenario investigates the effect of maximum energy security in a 100% RE system. In this scenario inter-annual wind variabilities are tackled with additional inter-annual gas storage (hydrogen, methane) and extra wind power capacities and internal combustion generators, to reconvert stored fuel into electricity.

The BPSplus scenario investigates the effect of less area limitations for onshore renewable generation technologies, such as solar PV and onshore wind, 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 of the UK 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 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.
Best Policy Scenario – Inter-Annual-Balancing (IAS)	Same assumptions as for BPS with lifted upper limit for offshore wind, blocked imports and from 2040 an inter-annual storage is introduced to balance inter-annual wind variations. The effect of balancing methods (extra capacity, storage, balancing technologies) is investigated.
Best Policy Scenario – less restrictions (BPSplus)	Same assumptions as for BPS but available land area for onshore wind and solar PV is lifted to 3% (Scotland 4%) and 2%, respectively. More imports of e-fuels are allowed. Offshore wind installations are set to a minimum of 1 GW/yr from 2030 onwards, while higher installations are possible.
Current Policy Scenario (CPS)	According to the Energy White Paper published by the UK government [18] 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.

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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. The IAS and its implication for the overall energy system will also be discussed in more detail.

Best Policy Scenario

The BPS demonstrates the full transition for a 100% RE scenario that is dominated by offshore wind and supplemented by onshore wind, solar PV, wave power and smaller shares of hydropower and geothermal energy. Figure 6 - Figure 8 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 generation becomes the most important source of energy, contributing a share of 43.5%, or 509 TWh, of electricity generation. Solar PV capacity is higher 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 486 TWh in 2050. The highest electricity demand can be assigned to RE liquids, at 274 TWh.

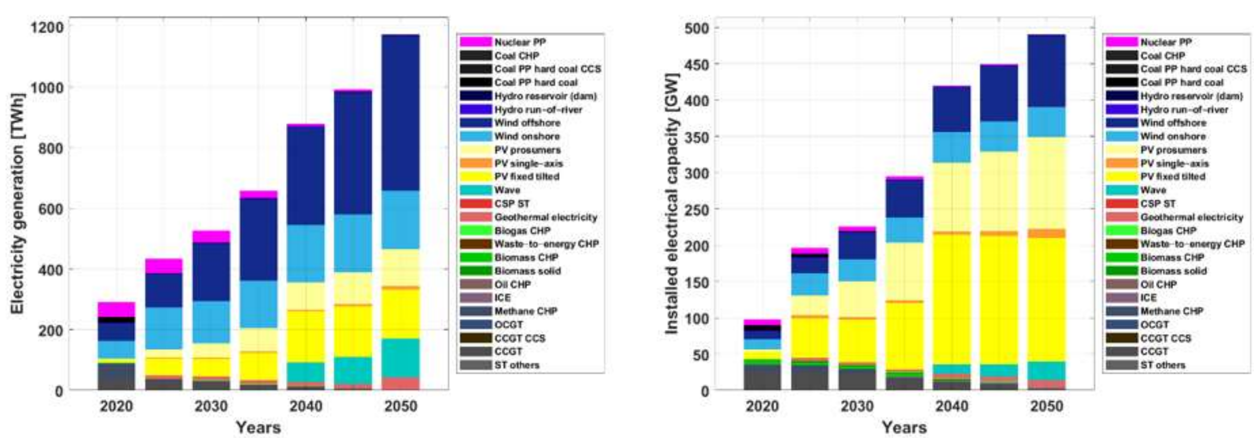

FIGURE 6: ELECTRICITY GENERATION (LEFT) AND INSTALLED ELECTRICAL CAPACITY (RIGHT) UNTIL 2050.

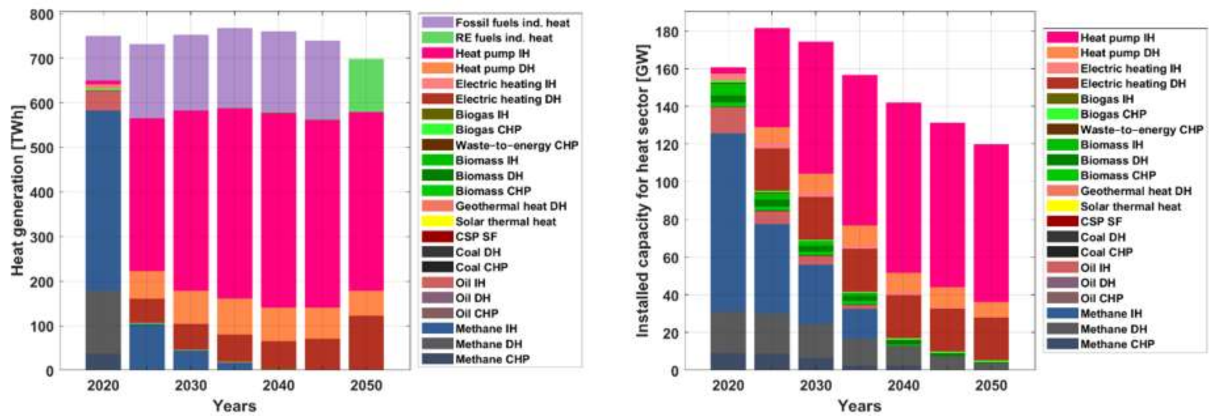

FIGURE 7: HEAT GENERATION (LEFT) AND INSTALLED HEAT CAPACITY (RIGHT) UNTIL 2050.

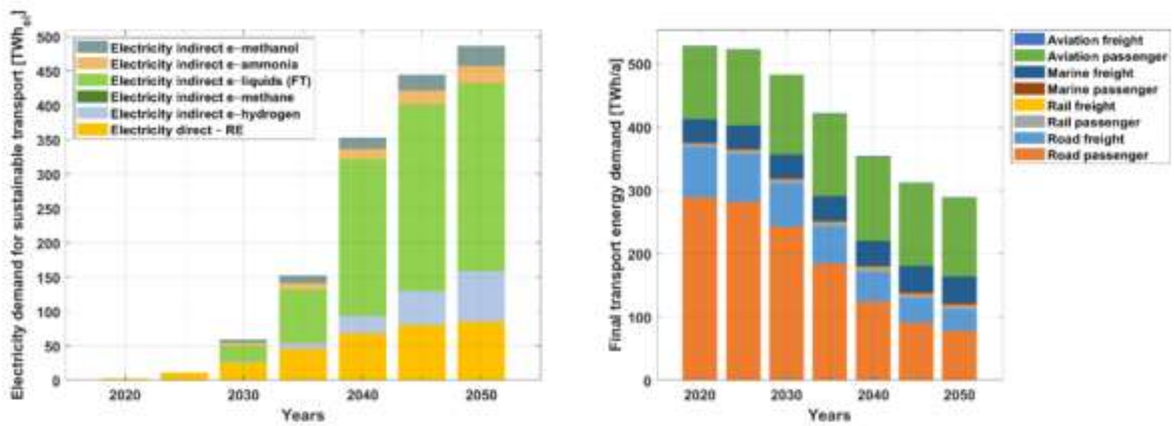

FIGURE 8: ELECTRICITY DEMAND FOR TRANSPORT (LEFT) AND FINAL TRANSPORT ENERGY DEMAND (RIGHT) UNTIL 2050.

The integration of growing shares of RE during the energy transition increases the need for energy storage utilisation. Figure 9 - Figure 11 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.

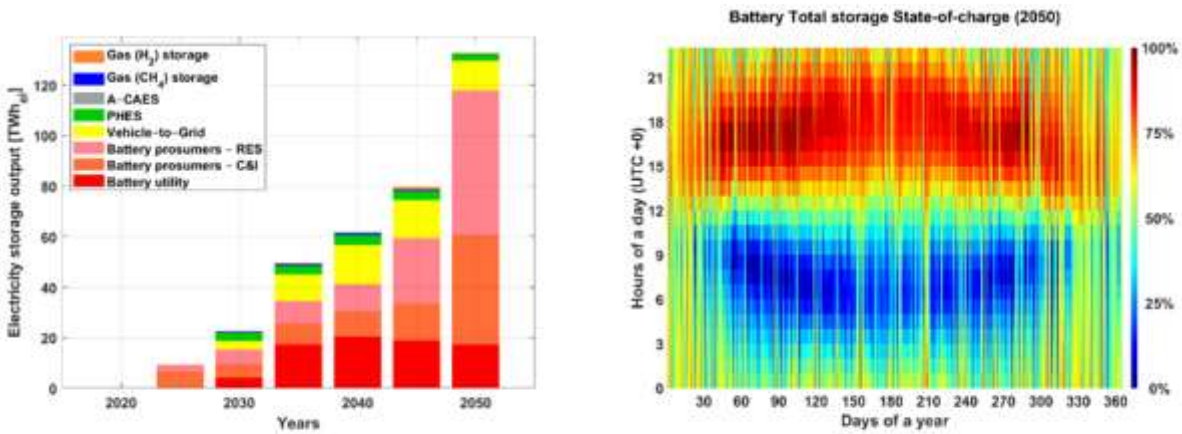

FIGURE 9: ELECTRICITY STORAGE OUTPUT UNTIL 2050 (LEFT) AND HOURLY BATTERY STORAGE STATE-OF-CHARGE IN 2050 (RIGHT).

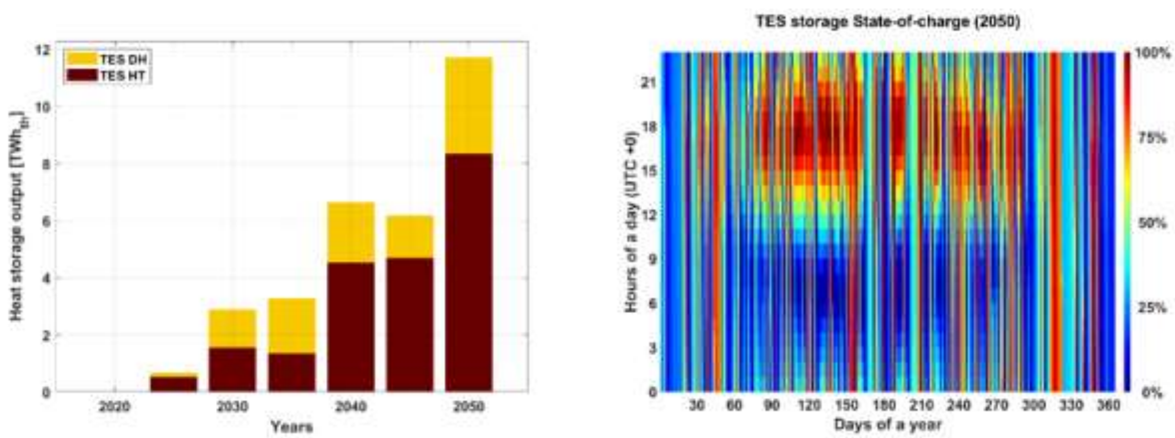

FIGURE 10: THERMAL ENERGY STORAGE OUTPUT UNTIL 2050 (LEFT) AND HOURLY HEAT STORAGE STATE-OF-CHARGE IN 2050 (RIGHT).

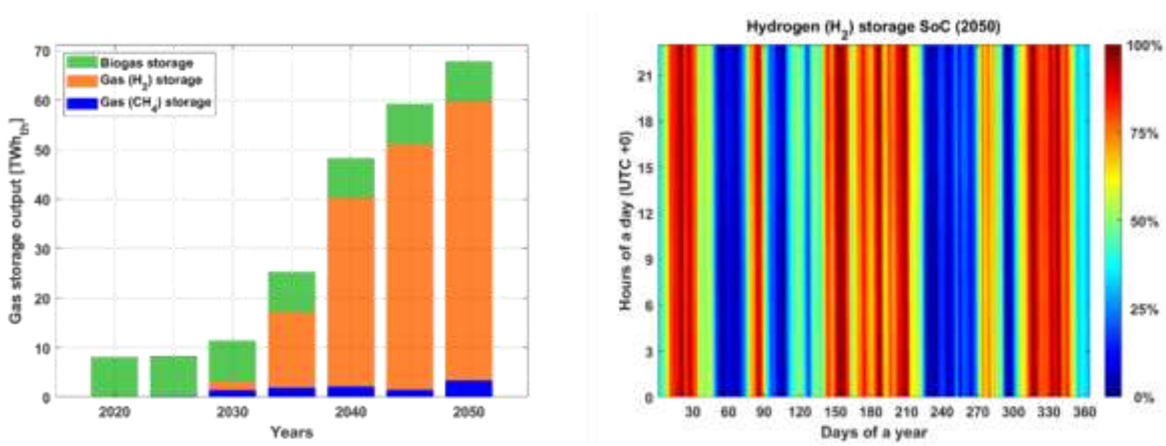

FIGURE 11: GAS STORAGE OUTPUT UNTIL 2050 (LEFT) AND HOURLY HYDROGEN STORAGE STATE-OF-CHARGE IN 2050 (RIGHT).

The battery utilisation profile 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 is used for high-temperature and district heat, mostly during evening hours in summer, but also for some days in late autumn and winter. Gas works as a seasonal storage, with the highest energy to power ratio. Hydrogen storage operates as a mid-term storage with about 5 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 12, 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.

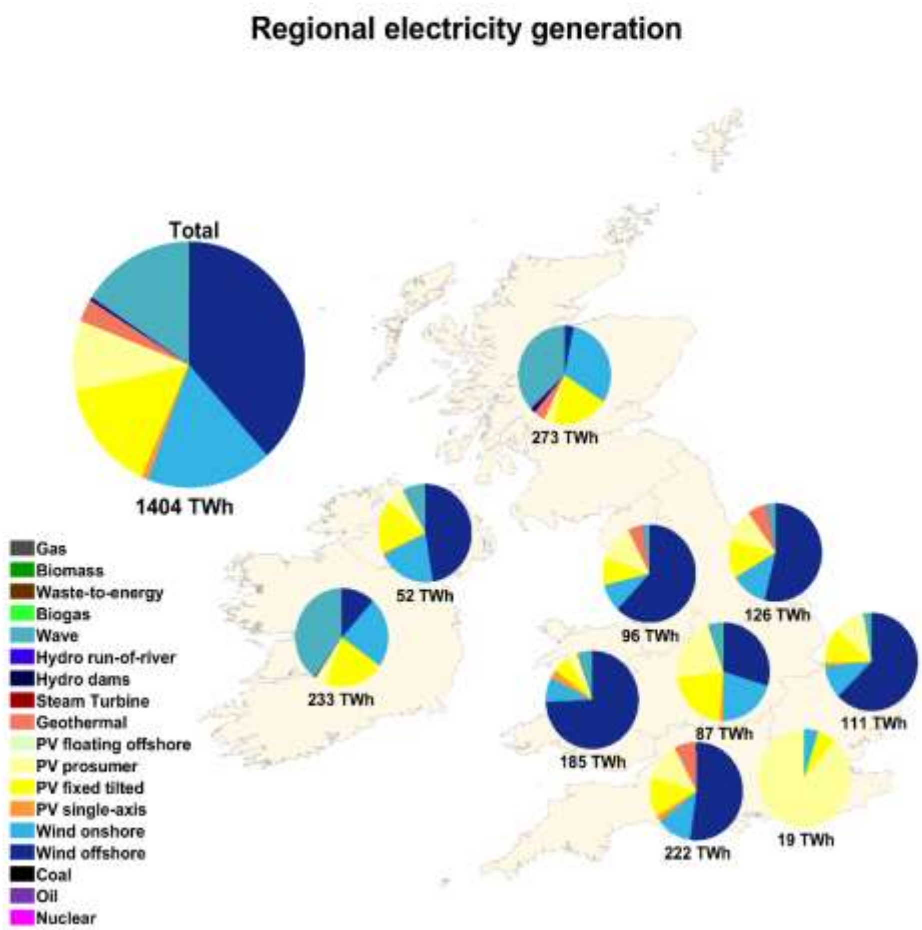

FIGURE 12: REGIONAL ELECTRICITY GENERATION IN 2050.

The energy flow of the whole energy system in 2050 is presented in Figure 13. All energy originates from RE sources, while a small part is imported. Unlike in 2020, the different sectors are strongly coupled via Power-to-heat, Power-to-mobility, Power-to-gas and Power-to-liquids. 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 fuel production than for final energy demand.

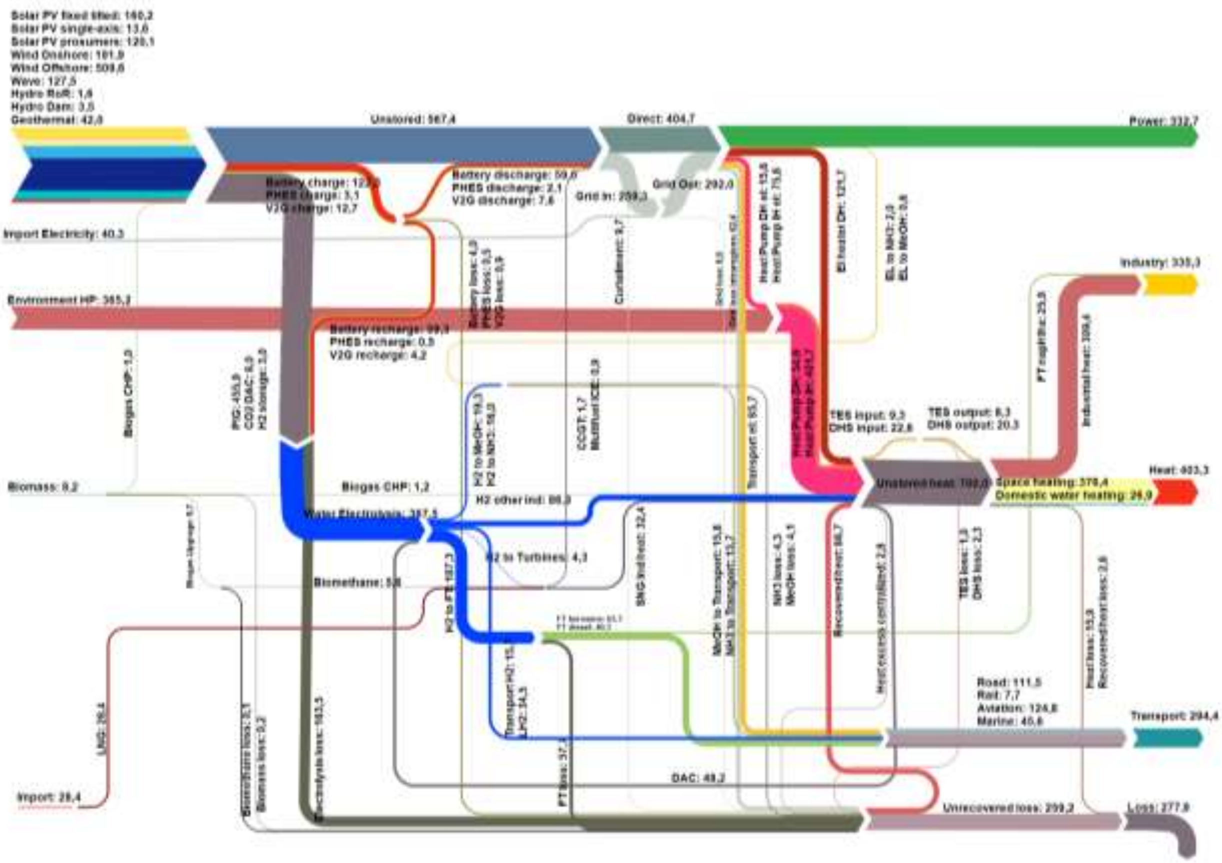

FIGURE 13: ENERGY FLOWS IN 2050 FOR THE WHOLE ENERGY SYSTEM. ALL VALUES ARE DISPLAYED IN TWH.

The electricity exchange within the regions of the UK and Ireland is illustrated in Figure 14. Strong exchange happens between Wales and London via Southern England, as Wales works as an exporter. From Southern England, electricity is transferred to London, which 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.

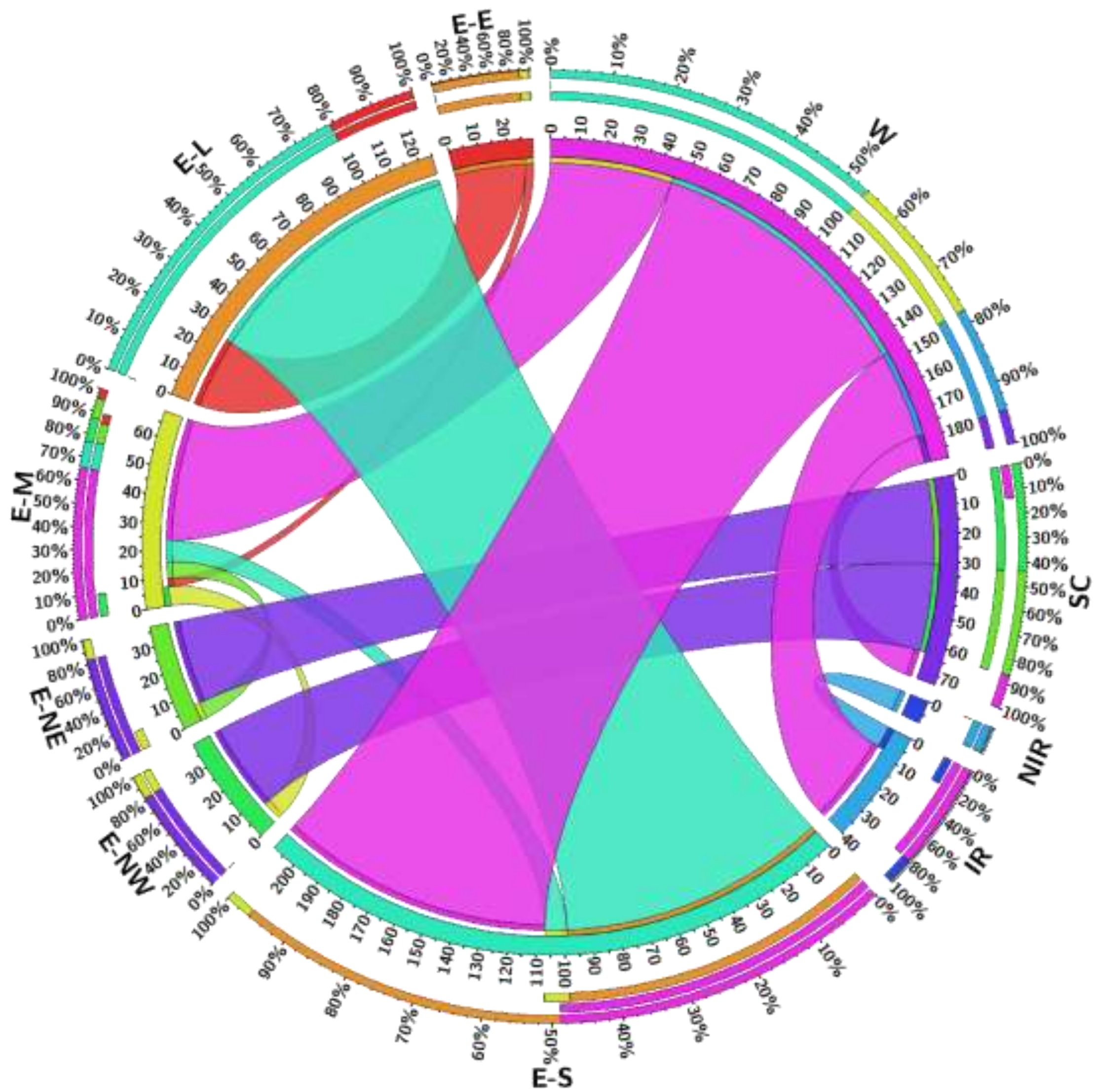

FIGURE 14: ELECTRICITY EXCHANGE WITHIN THE UK AND IRELAND IN 2050.

The development of costs over the transition is depicted in Figure 15. The levelised cost of electricity (LCOE) is significantly reduced from 90 €/MWh to 56.5 €/MWh in 2050, while the highest share originates from capital expenditures. The total annual system costs remain stable over the transition, starting from 82 b€ in 2020, reaching a maximum of 92.5 b€ in 2030 and finally declining to 81.6 b€ in 2050, with capital expenditures being responsible for the largest share.

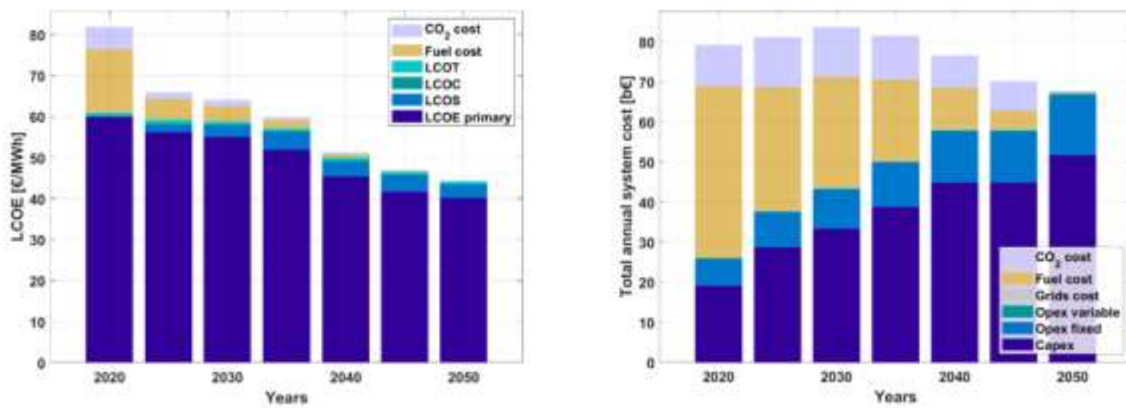

FIGURE 15: LCOE (LEFT) AND TOTAL ANNUALISED SYSTEM COSTS (RIGHT) UNTIL 2050.

CO_2 emissions decline over the transition, reaching finally zero in 2050 across all sectors, as shown in Figure 16 - Figure 18. Emissions in the power and heat sector decrease strongly at the beginning of the transition 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 sector can be decarbonised early, while high temperature industrial process heat and aviation and marine transportation require e-fuels that are only available at a later stage of the transition. The overall CO_2 emissions are substantially reduced in 2025 and in 2040, reaching zero in 2050, as shown in Figure 19. The majority of emissions originate from the heat and transport sector 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 next five years, and in 2035 more than half of today's emissions can be avoided.

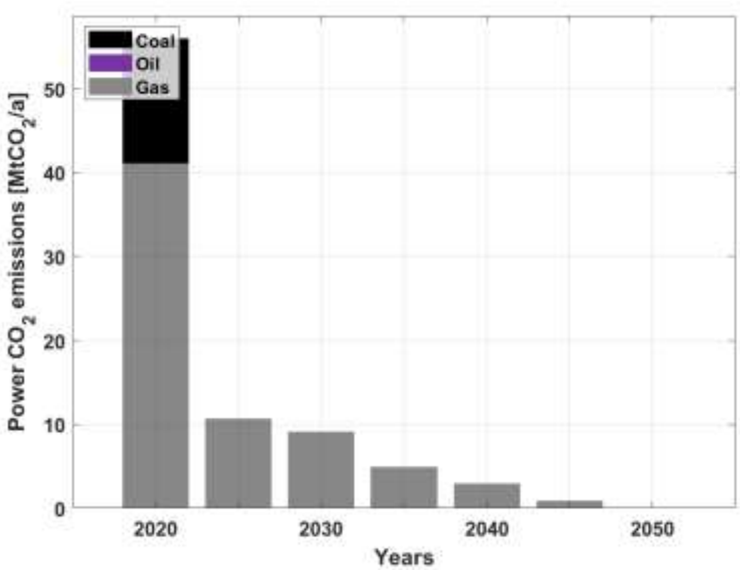

FIGURE 16: POWER SECTOR CO_2 EMISSIONS BY SOURCE UNTIL 2050.

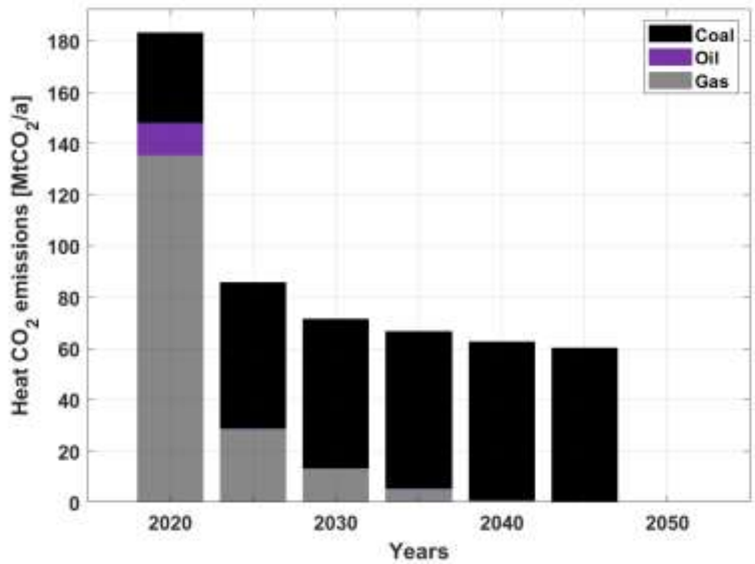

FIGURE 17: HEAT SECTOR CO_2 EMISSIONS BY SOURCE UNTIL 2050.

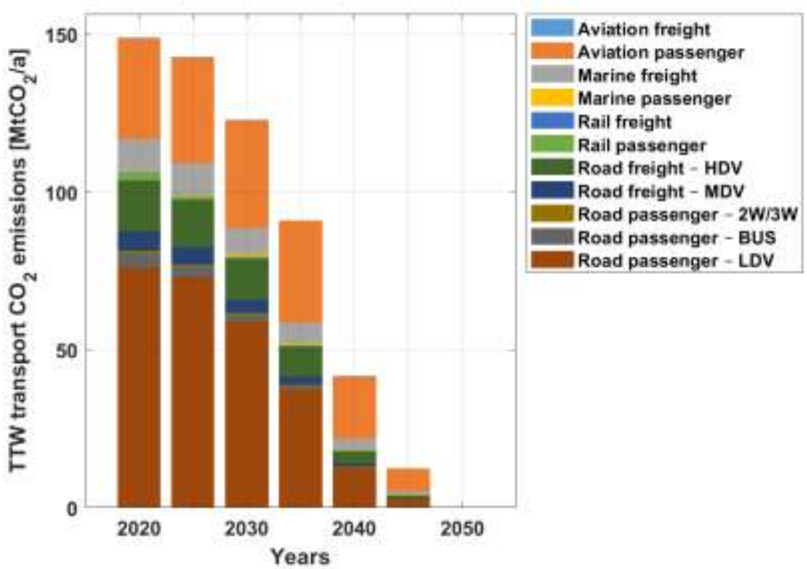

FIGURE 18: TRANSPORT SECTOR CO_2 EMISSIONS BY MODE OF TRANSPORT UNTIL 2050.

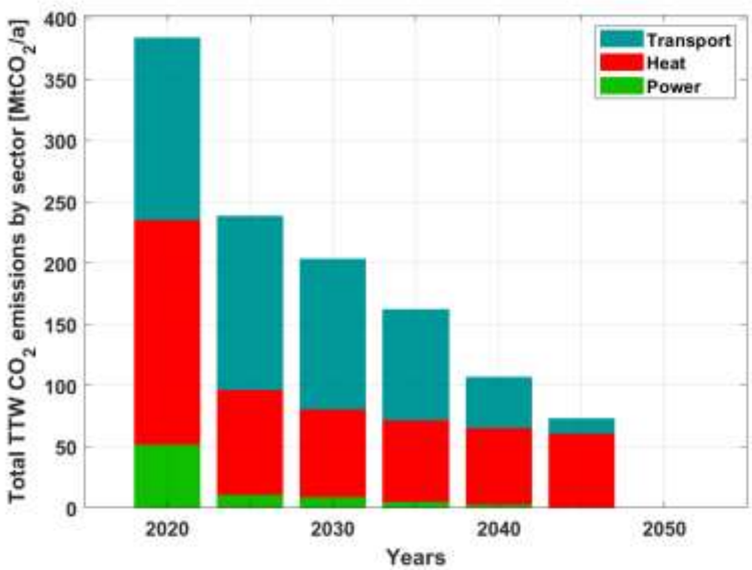

FIGURE 19: TOTAL CO_2 EMISSIONS BY SECTOR UNTIL 2050.

Inter-Annual Storage

The excellent availability of wind energy in and around the UK implies the challenge of inter-annual balancing of the energy system with an extra long-term storage that compensates for the inter-annual wind variabilities. The annual mean capacity factor of wind generation in the UK is illustrated in Figure 20 for a 33-year period from 1980 – 2012. Significant differences in wind yield can be seen there, which has a strong effect on a wind power dominated energy system. One can notice that the year 2010 with the by far lowest wind yield shows a deficit of 21% compared to an average year, such as 2005. In the highest wind yield year, 1986, the wind yield was 18% higher than in the average year.

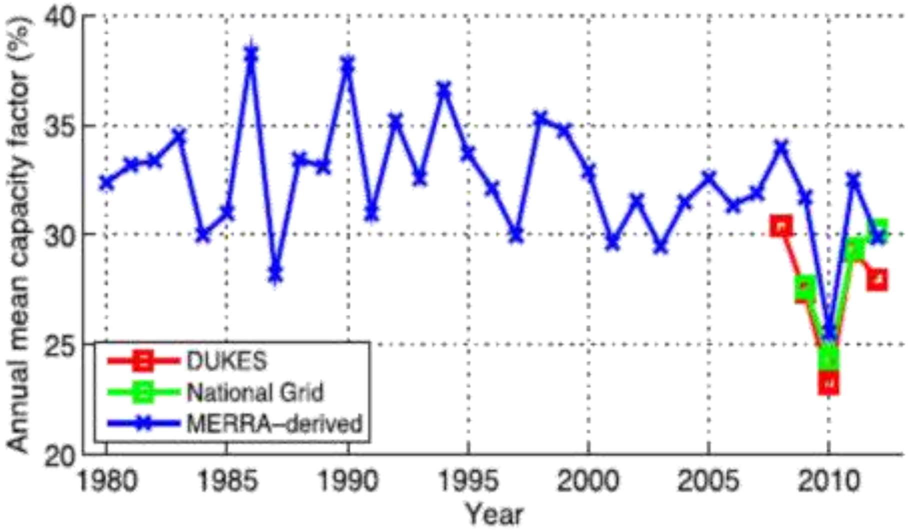

FIGURE 20: ANNUAL MEAN CAPACITY FACTOR FOR WIND GENERATION IN THE UK FROM 1980 – 2012 [37].

The core idea of inter-annual balancing is to generate more electricity from wind energy than would be necessary to supply the system for an average year and convert this with Power-to-X processes to a chemical energy carrier that is storable over a long period of time, for instance hydrogen or methane. Both options have been investigated in this study and were compared according to technical requirements and cost implications. The produced gas for storage can be accumulated when several high wind yield years occur in a row and must be resilient enough to bridge a minimum of five low wind yield years, as the 33 year period displayed above indicates, that this is the maximum period without at least one high wind yield year.

Figure 21 demonstrates how the inter-annual storage size would develop over a 33 year period. Applying the wind yield data from [37], the average year energy system is sized to charge the inter-annual storage. The amount of energy represents 4% of wind generation output (generated from 5.7% of extra wind power capacity). In better wind years the amount of e-fuel production increases as excess electricity is preserved in inter-annual storage, reaching a storage size of about 911 TWh_{CH4}.

It can be seen that even when low-yield years occur in a row, as is the case for 2010 and 2012, the storage is designed sufficiently to cover those periods. About 4% of extra, long-term storage charge can be seen as a maximum security option. If hydrogen is stored, extra electrolyser capacity is necessary for hydrogen production. Furthermore, underground storage facilities are required along with reconversion technologies such as gas turbines or internal combustion engines to convert the stored gas back to electricity. If, instead, methane is used, extra capacity for the Sabatier reaction is necessary for methanation, which includes direct air capture for CO_2 as a raw material to produce methane. This was considered as a possible option since methane has a much higher volumetric energy density than hydrogen, resulting in lower storage costs.

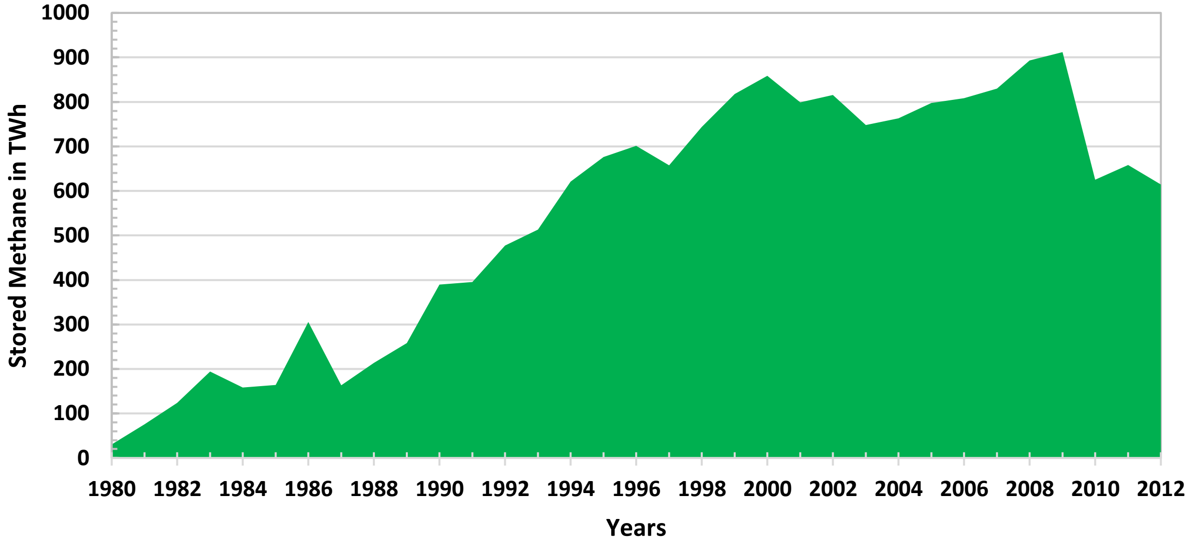

FIGURE 21: METHANE STORAGE SOC FOR AN EXEMPLARY 33-YEAR PERIOD FROM 1980 - 2012 ACCORDING TO DATA FROM [37] APPLIED TO THE UK.

For the IAS scenario, the inter-annual storage ramping was introduced in the simulation from 2040 onwards, based on the data from [37] and preliminary calculations described above. Very high storage volumes of 908 TWh_{H2} and 916 TWh_{CH4} are reached for hydrogen and methane, respectively. The storage size development is illustrated in Figure 22.

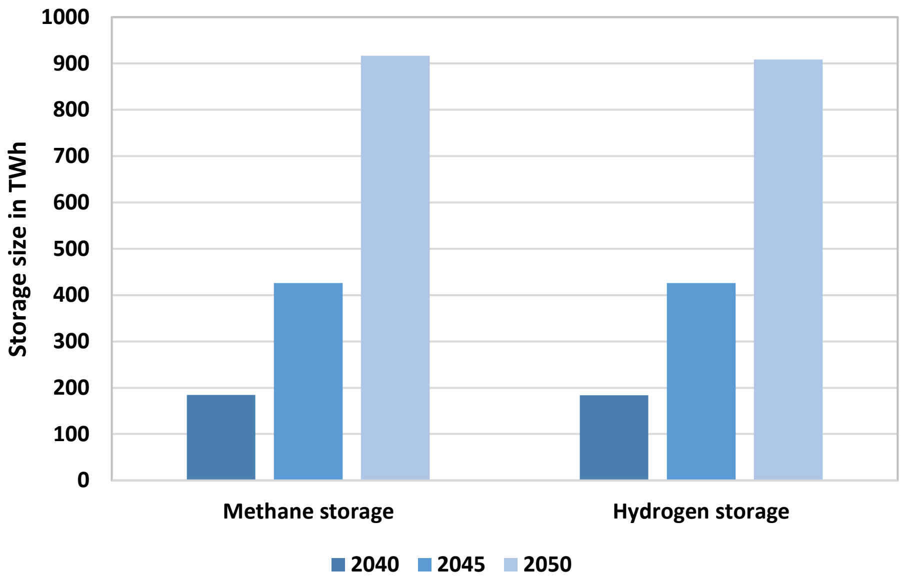

FIGURE 22: INTER-ANNUAL STORAGE SIZE FROM 2040 TO 2050 FOR HYDROGEN AND METHANE.

The design and application of an inter-annual storage has significant effects on the total annual system costs, as extra capacities for several technologies are necessary. Most importantly, huge storage facilities are needed, such as underground salt and rock caverns to store high amounts of hydrogen or methane. The simulation results are shown in Figure 23 for the cost development of the reference scenario (without inter-annual storage) against the hydrogen and methane options.

According to the latest cost numbers for both storage technologies, methane proves to be the lower cost option despite extra requirements for methane production. The total annual system costs for inter-annual hydrogen storage exceed the reference scenario costs by 67% while methane adds 31% of total annual system costs, reaching 113 b€ and 89 b€, respectively. For this reason, the methane option has been selected as the main IAS scenario.

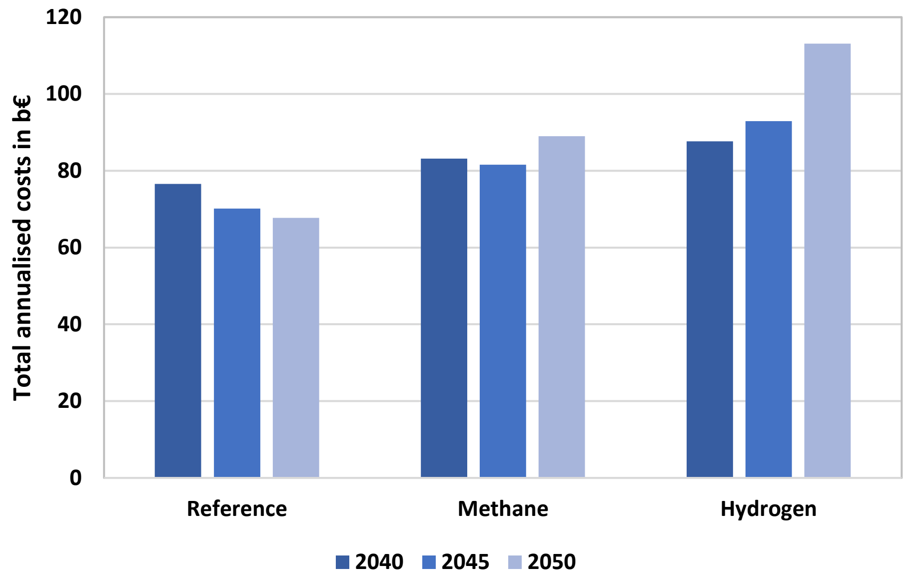

FIGURE 23: TOTAL ANNUAL SYSTEM COSTS FROM 2040 TO 2050 FOR A REFERENCE SCENARIO (WITHOUT INTER-ANNUAL STORAGE), A HYDROGEN STORAGE SCENARIO AND A METHANE STORAGE SCENARIO.

Scenario comparison

The four 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 24 for all scenarios, including environmental heat for heat pumps. The most significant differences can be seen between the CPS and the remaining scenarios, 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). It is also the scenario with the highest PED in 2050, reaching 1829 TWh. The lowest PED is achieved in the BPSplus scenario, with 1498 TWh in 2050.

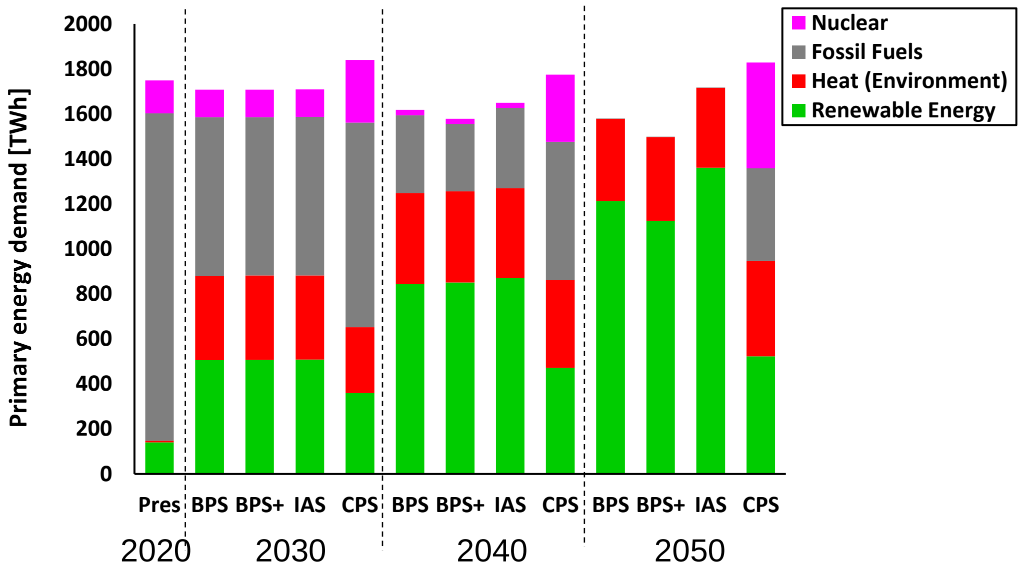

FIGURE 24: PRIMARY ENERGY DEMAND FOR ALL SCENARIOS UNTIL 2050.

The electricity generation mix, which is illustrated in Figure 25, characterizes 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 IAS and BPS, offshore wind reach shares of 45% and 38%, equivalent to 681 TWh and 510 TWh of generation, respectively. Due to less restricted land area limitations in the BPSplus scenario, onshore wind power and solar PV do have a higher importance.

Characteristic of the CPS is a high share of nuclear power at 22% of generation, which is in line with the governmental plans of nuclear power expansion. Wave power becomes important for the BPS and IAS, 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 sector. 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 are avoided.

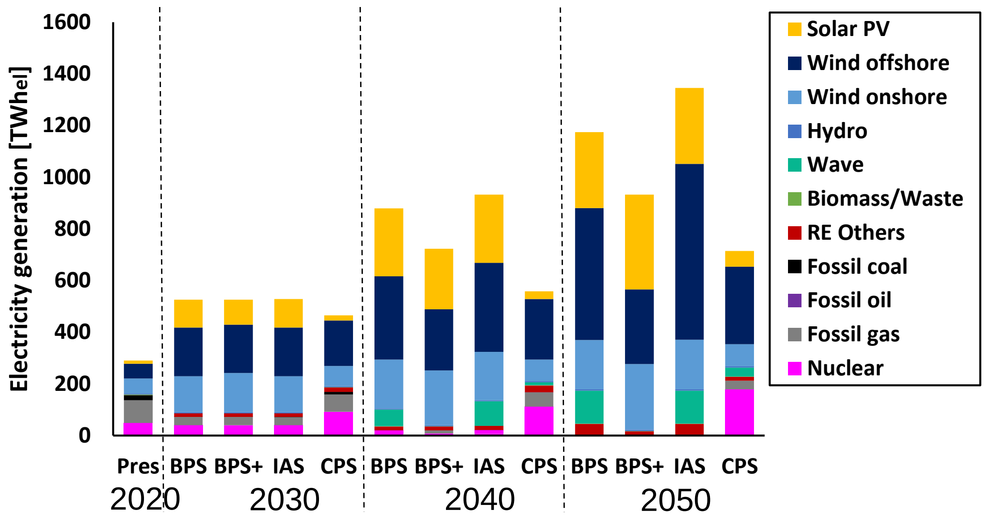

FIGURE 25: ELECTRICITY GENERATION MIX FOR ALL SCENARIOS UNTIL 2050.

All scenarios tackle the long-term goal of reaching zero CO_2 emissions in 2050. The cumulative emissions displayed in Figure 26 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 27 shows that power sector emissions are almost fully eliminated in all scenarios, while the heat and transport sectors are defossilised last. In 2030, the emissions almost halved for the 100% RE scenarios.

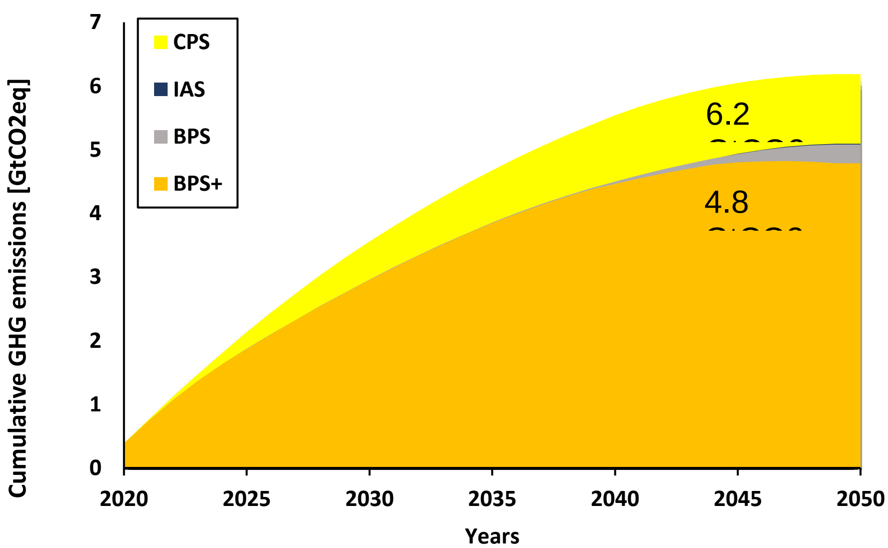

FIGURE 26: CUMULATIVE CO_2 EMISSIONS FOR ALL SCENARIOS.

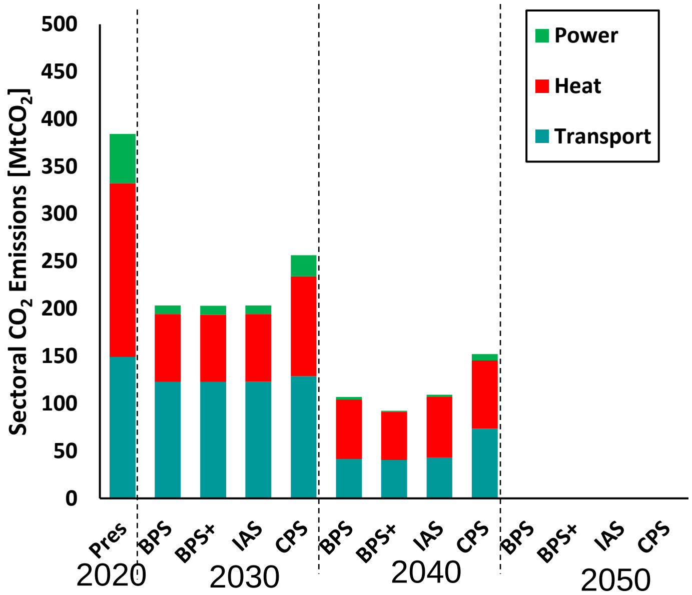

FIGURE 27: CO_2 EMISSIONS BY SECTOR FOR ALL SCENARIOS UNTIL 2050.

The different structure of the energy systems in each scenario has a strong impact on the costs. In Figure 28 it can be observed that BPS and BPSplus develop the least LCOE in 2050, declining to 43 €/MWh and 41 €/MWh, respectively. Three quarters of the LCOE originate from capital expenditures. The IAS scenario reaches an LCOE of 55 €/MWh due to extra generation, storage and balancing requirements. The LCOE of the CPS (that 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 of 74 €/MWh.

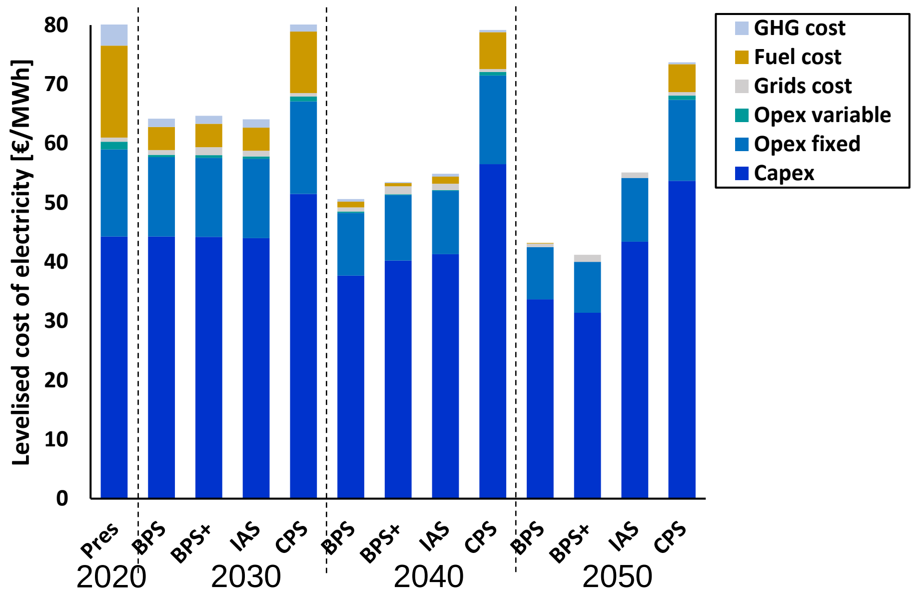

FIGURE 28: LCOE FOR ALL SCENARIOS UNTIL 2050.

Total annual system costs are illustrated in Figure 29. In the year 2050 the IAS reaches the highest total costs, at 89 b€, while the BPSplus reach the lowest, at 58 b€. The BPS reaching 68 b€ is significantly lower in cost than the CPS, at 86 b€ in 2050. The cumulative costs are highest for the CPS, resulting in 2675 b€ for the whole transition, which is even more expensive than the IAS, at 2546 b€.

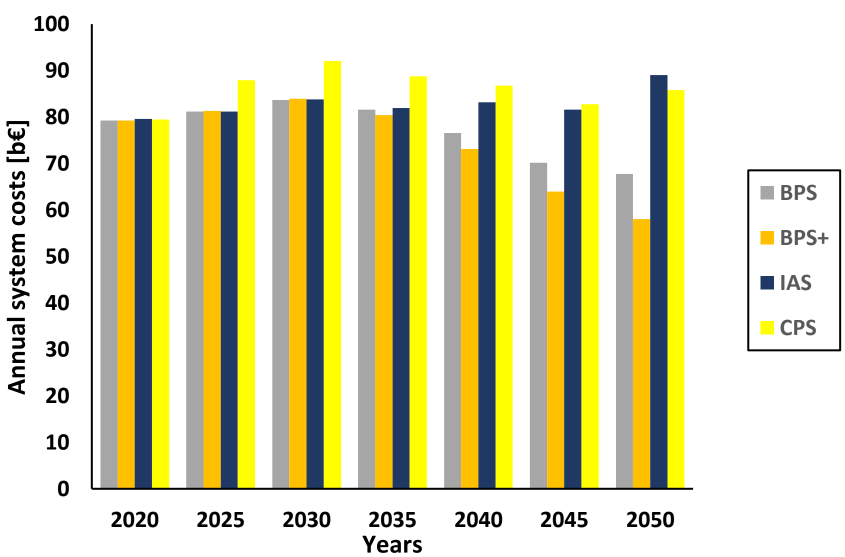

FIGURE 29: TOTAL ANNUALISED SYSTEM COSTS FOR ALL SCENARIOS UNTIL 2050.

It should be noted that the IAS scenario includes the costs of provision of around 120 GW_{el} of gas engines and gas turbines. This is needed to use stored e-methane to generate electricity during low wind periods. This is not included in the earlier Figure 6 that describes the BPS, where inter-annual storage requirements are not integrated. Costs for this extra methane-to-electricity reconversion capacity are only included in the IAS. This is one substantial reason, why total costs of the IAS scenario are higher than for the BPS.

Discussion

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 can be implemented under given framework conditions. All 100% RE scenarios are economically competitive, if not significantly cheaper than the governmental strategy for reaching zero emissions in 2050. A strong electrification of the heat and transport sector, 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, such as e-hydrogen, e-methane, e-ammonia, e-methanol, e-diesel, and e-kerosene jet fuel.

The results further show that the vast 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. This is compared to a scenario with restricted land area availability and the governmental strategy, including nuclear power and fossil CCS.

The BPS, as a central scenario of this study, relies on different sources for electricity generation, with offshore wind as the most important, supplemented 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. Those findings are consistent with studies for other countries or regions [53–55]. It should be noted, however, that for the purposes of this study the shares of offshore wind, wave power, and tidal stream generation should be regarded as potentially interchangeable. The amount of offshore wind 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 does not materialise.

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. Here, electrification competes with the use of fuels for high-temperature heat [56, 57]. 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 [58]. For long-distance marine transportation e-ammonia and e-methanol have a realistic chance of being competitive in future markets [59].

The passenger transport demand assumptions used for this study can be regarded as conservative, indicating a growth of more than 30% until 2050 and might well be lower in reality given the more sluggish rate of growth in the years prior to 2022. In this study, it could be observed that final energy demand and costs decline, even if the travel behaviour is not shaped by sufficiency concepts and behavioural change. This is mainly due to the high efficiency of BEVs along with the availability of low-cost RE resources. However, the trends during the last 27 years indicate that passenger transport demand only grew by 10% and a strong decline could be seen due to the pandemic [60]. It is uncertain how this trend may develop, but pandemic induced home working might contribute to lower transport demand. If this were the case, final energy demand for transportation would decrease even further, along with the total costs. However, the overall effects on aviation and marine transport require further research.

One of the key novelties of this study is the investigation of inter-annual balancing requirements of a 100% RE system based on a 33-weather period [37], which has not yet been discussed extensively in the scientific literature. Previous studies did acknowledge this issue [61], partly investigating the impact of those variations on the power sector [62] without discussing different storage options and other balancing requirements. In this study, it was found that a high-security option for the UK has a strong impact on the total system costs, even for the least cost option derived in this study: e-methane underground storage, produced from excess wind power in high wind yield years and reconverted to electricity with internal combustion engines in low wind yield years. For interannual storage the main cost driver is the storage itself rather than the additional balancing requirements. For this reason, methane, with its high volumetric energy density, is preferred over hydrogen.

These overall findings are consistent with Ruhnau et al. [63], who concluded for the case of Germany that the storage volume in a 100% RE system can double if the variabilities within a 35-year period are considered properly. More research is required to deeply investigate other options of inter-annual storage, however. Instead of producing e-hydrogen or e-methane from domestic RE resources, the necessary amount of gas could be imported from countries with excess RE generation in a given year. This potential cost reduction option has the major disadvantage of reproducing the import dependency that the UK faces today, and additional import infrastructure would be required. Further, other potential storage media, such as ammonia and methanol should be investigated and compared to the options discussed here: hydrogen and methane.

In addition, land use for onshore wind and solar PV and its trade-off with the total costs of the energy system are 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 is technologically feasible, its economic competitiveness is limited to some degree, due to high capital and operational expenditures of offshore wind.

The nature of the applied cost-optimisation model requires a predefined ramping of offshore wind 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-fuel production. Especially the latter is strongly affected by the source of electricity, as it consumes very high amounts of electricity due to conversion losses during water electrolysis, CO_2 direct air capture for hydrocarbon-based e-fuels and e-fuel synthesis.

This trade-off can be evaluated in detail when the central BPS is compared with the BPSplus scenario. The latter was conducted to analyse the effects on the system costs if higher dependence on e-fuels imports is tolerated and land area is subject to less restrictions for the installation of onshore wind power and solar PV. 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% of land area and raised from 2% (Scotland 2.5%) to 3% for onshore wind power (Scotland 4%), and wind offshore annual built set to a minimum of 1 GW/yr from 2030 onwards, the total annual system costs can be reduced by 15% from 68 b€ to 58 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, which again lower the costs.

Onshore wind power has a high technical and economic potential in the UK [64, 65]. However, this technology is subject to public and political opposition, being the technology with the lowest acceptance rate of all renewable technologies (52%) in Great Britain, followed by biomass combustion (47%) while offshore wind can be found on the other end of this ranking (11%) [34]. Previous studies on the energy transition of the UK naturally focused on onshore and offshore wind as the main source for RE generation [66, 67], thereby neglecting or ignoring 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 and cheap, but restricted onshore wind. With an acceptance rate of between onshore and offshore wind (25%), it might offer a solution to this dilemma, as solar PV additionally offers cheap electricity supply even with moderate resources in the UK. Due to its heavily declining costs, solar PV could thus shape the energy transition of the UK as well as it is expected to do on a global scale [12, 68].

The modelling results indicate that deep geothermal energy will contribute a rather small share (3% in 2050) in total electricity supply, mainly due to a high CAPEX that declines from 4970 to 3610 €/kW_{el} from 2020 to 2050, which is still significantly higher than for other RE technologies. However, the advantage of dispatchability can play an important role in balancing variable wind power and solar PV. As of today, geothermal utilisation is lagging in the UK compared to other European countries with comparable resources [69]. The geothermal potential according to [41] exists in Southern England, North East and North West as well as in Scotland, and it will also be used there in 2050 according to the modelling results. To realise broader deployment in reality, [69] conclude that regulatory simplifications and financial incentives are necessary in the UK.

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 [70]. Although it is not cost-competitive to other RE sources currently, it can play a role in the long-term, when the technology becomes more mature and costs decrease [71]. Based on the financial assumptions of this study for this technology [72], wave power becomes part of the energy system from 2040 onwards if solar PV and onshore wind are not available. 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 [72].

The strategy of the UK government to reach zero emissions in 2050 has recently been updated, with more focus on energy security [73] than in the report used to design the governmental strategy for this report [18]. Several attempts for decarbonisation are consistent with the requirements of a 100% RE system: hydrogen production, RE upscaling, energy storage, heat pumps and e-fuel 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 unreliability of nuclear power in France are to be compared with the potentially rather greater reliability of a 100% renewable energy system complete with a system of inter-annual storage. The results of this study indicate that 100% RE scenarios are markedly cheaper in achieving net zero by 2050 compared to the governmental plans, with savings of well in excess of 100 b€ over the period from now to 2050.

Conclusions

This study demonstrates how a sustainable transition to an emission free energy system can look like for the case of the UK with its abundant potential 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 on offshore wind power development leads to 68 b€ of total annual costs and an LCOE of 43 €/MWh in the target year 2050. This is compared to 86 b€ of total costs and an LCOE of 74 €/MWh for the governmental strategy with nuclear power as a key element. Balancing methods for inter-annual wind yield variabilities increase the costs by 31% from 68 to 89 b€ if domestically produced e-methane is used as a long-term storage medium. The cumulative costs of the preferred 100% renewable energy pathway towards achieving net zero in 2050 are 129 b€ lower than the costs of the UK Government's path to net zero by 2050. This comparison includes the inter-annual balancing costs for the 100% renewable energy. A scenario with stronger area impact caused by onshore wind power and solar PV use is able to reduce the total costs by 15% to 58 b€ and the LCOE to 41 €/MWh. All the 100% renewable energy scenarios result in carbon emissions that are over 20% lower compared to the UK Government's 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. Further, the necessity of inter-annual balancing requirements that originate from high shares of wind power implies a trade-off between energy independence on the one hand and total system costs on the other hand. Ultimately, those decisions have to be made carefully in a socio-political discourse.

Supplementary Material

LUT Energy System Transition Model

The LUT Energy System Transition Model 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 [74] for the power sector and in [15, 54] for the entire energy system. For this study, the model version described in [53] 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 split up into subregions that can exchange electricity.

The model's target function is minimising the sum of total system costs as described in the 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 ($OPEX_{fix,t}$), installed capacity for technology t in subregion r ($instCap_{t,r}$), variable operational expenditures for technology t ($OPEX_{var,t}$), total annual energy generation by technology t in subregion r ($E_{gen,t,r}$), ramping costs for technology t ($rampCost_t$) and total ramping values annually for the technology t in the subregion r ($totRamp_{t,r}$).

$$\min\left(\sum_{r=1}^{reg}\sum_{t=1}^{tech}(CAPEX_t * crf_t + OPEX_{fix,t}) * instCap_{t,r} + OPEXvar_t * E_{gen_{t,r}} + rampCost_t * totRamp_{t,r}\right) \quad (1)$$

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 ($E_{gen,t}$), subregion (r), all subregions (reg), imported electricity by subregion r ($E_{imp,r}$), electricity storage technologies (stor), discharged electricity from storage ($E_{stor,disch}$), electricity demand (E_{demand}), exported electricity by subregion r ($E_{exp,r}$), electricity charged to storage ($E_{stor,ch}$), 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.

$$\forall h \, \varepsilon \, [1{,}8760] \; \sum_{t}^{tech} E_{gen,t} + \sum_{r}^{reg} E_{imp,r} + \sum_{t}^{stor} E_{stor,disch} = E_{demand} + \sum_{r}^{reg} E_{exp,r} + \sum_{t}^{stor} E_{stor,ch} + E_{curt} + E_{other} \quad (2)$$

Figure 30 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. RE capacities, centralized PP and CHP plants, electricity storage technologies, high voltage transmission lines and different modes of transport are connected to the AC grid. The AC grid satisfies the electricity demand of electricity consumers. Via HVDC and HVAC lines and cables, excess 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. Prosumers (for PV and batteries) are modelled separately, divided into residential, commercial, and industrial prosumers. They can generate and store their own electricity, sell excess electricity to the grid (for a defined feed-in tariff), or buy electricity from the grid (market price).

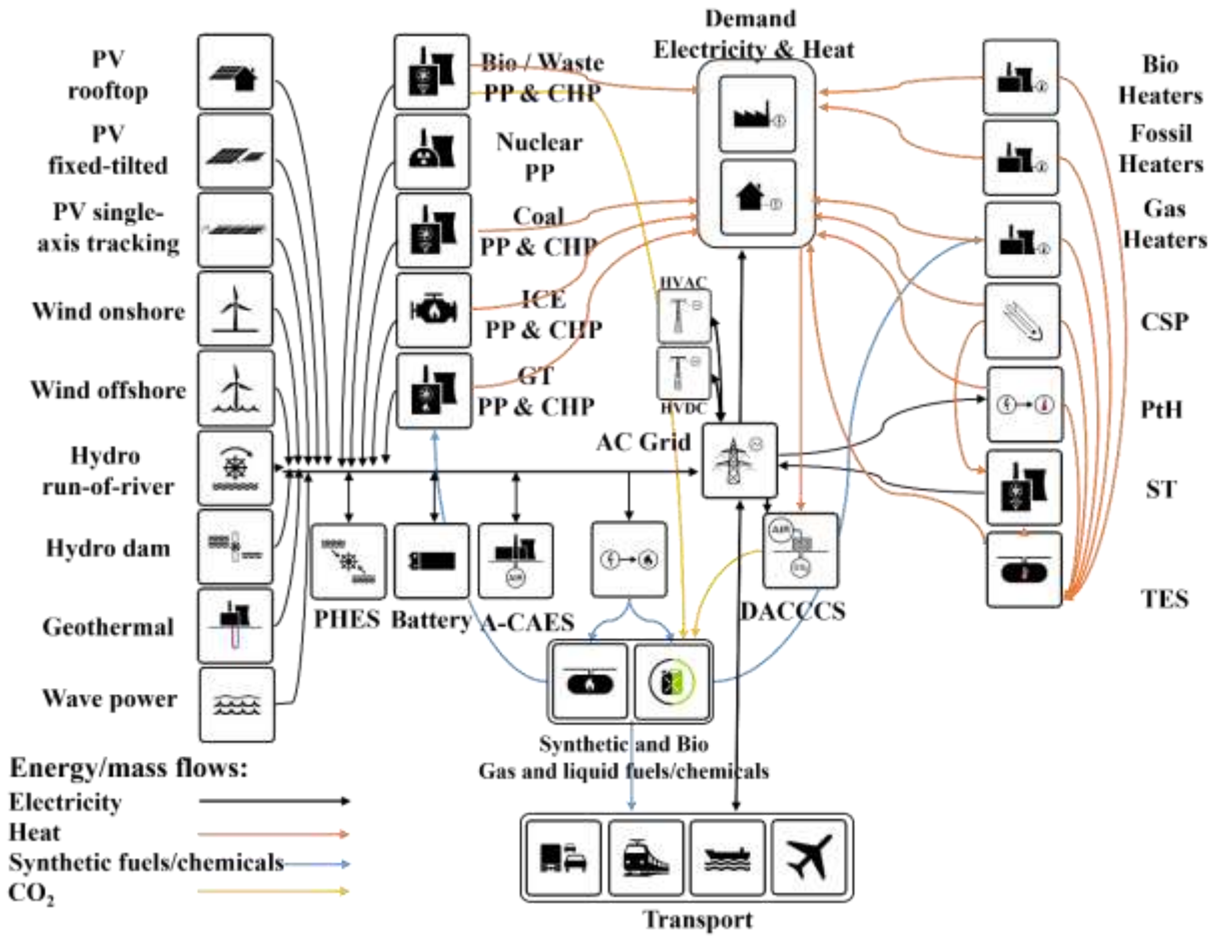

FIGURE 30: LUT ENERGY SYSTEM TRANSITION MODEL SCHEME FOR THE POWER, HEAT AND TRANSPORT SECTORS.

The LUT-ESTM is further able to integrate some industry sectors including RE-based seawater desalination for regions with high water-stress index, CO_2 removal [75, 76] as well as steel, cement, aluminium, chemical industry segments [54]. Due to the scope of this study, the industry sector has not been modelled in detail, but is reflected across all energy sectors and in particular with industrial process heat.

In [77] 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. The methodology is dispatch optimisation and single objective investment optimisation. A linear programming technique is used. 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.

Technical and financial assumptions

Appendix Table 1: Regional area in km^2 and population projections in thousands.

	Region	Area [km^2]	Population in thousands						
			2020	2025	2030	2035	2040	2045	2050
1	E - S	42,907	14,928	15,321	15,642	15,910	16,164	16,426	16,689
2	E - M	28,604	10,868	11,214	11,518	11,789	12,046	12,301	12,556
3	E - NW	14,105	7,363	7,507	7,628	7,737	7,846	7,957	8,069
4	E - NE	23,981	8,203	8,327	8,434	8,523	8,606	8,692	8,778
5	E - L	1,738	9,039	9,255	9,401	9,559	9,724	9,875	10,025
6	E - E	19,108	6,277	6,436	6,559	6,665	6,772	6,884	6,996
7	SC	79,272	5,470	5,558	5,645	5,721	5,790	5,859	5,922
8	W	20,735	3,164	3,206	3,231	3,245	3,252	3,258	3,263
9	NIR	13,874	1,911	1,943	1,962	1,974	1,985	1,994	1,996
10	IR	70,273	4,988	5,279	5,558	5,840	6,121	6,394	6,646
	Total	314,597	72,211	74,045	75,579	76,964	78,306	79,639	80,939

Appendix Table 2: Regional full load hours for variable RE technologies.

	Region	Full load hours [h]				
		PX fixed-tilted	PV single-axis	Wind onshore	Wind offshore	Hydro Run-of-River
1	E - S	1035	1118	4092	5200	2224
2	E - M	940	1000	3980	5257	2950
3	E - NW	836	877	4041	5284	2534
4	E - NE	902	963	4323	5283	3253
5	E - L	957	1009	3541	0	0
6	E - E	992	1063	4118	5233	3455
7	SC	898	964	5068	5259	2357
8	W	1025	1115	4607	5245	1815
9	NIR	912	964	4939	5273	2459
10	IR	909	958	4986	5221	3752
	Average	939	996	4612	5239	2524

Appendix Table 3: Regional annual biomass potential by category in TWh.

	Region	Annual potential [TWh]			
		Solid Biomass and waste	Wood	Wood industry waste	Local Biogas
1	E - S	9.29	9.49	0.00	2.08
2	E - M	6.75	12.86	0.00	1.62
3	E - NW	4.60	3.43	0.00	0.40
4	E - NE	5.13	6.38	0.00	1.12

5	E - L	5.62	0.03	0.00	0.31
6	E - E	3.91	7.30	0.00	1.45
7	SC	3.43	7.52	0.00	0.84
8	W	1.98	4.74	0.00	0.23
9	NIR	1.19	6.74	0.00	0.13
10	IR	3.49	7.69	0.00	3.37
	Total	45.37	66.17	0.00	11.55

Appendix Table 4: Renewable resource potentials for different scenarios and share of used potential.

Renewable Resource	Unit – upper limit	BPS	BPSplus	IAS	CPS
Wind Onshore	GW (% used)	42 (100%)	68 (80%)	42 (100%)	42 (42%)
Wind Offshore	GW (% used)	250 (39%)	250 (22%)	400 (32%)	250 (23%)
PV utility-scale	GW (% used)	183 (100%)	637 (39%)	183 (100%)	183 (15%)
PV prosumers	GW (% used)	126 (100%)	126 (100%)	126 (100%)	33 (100%)

Appendix Table 5: Annual electricity demand projections in TWh by region.

	Region	Electricity demand (excl. electricity for heat and transport) [TWh]						
		2020	2025	2030	2035	2040	2045	2050
1	E – S	55.8	58.3	60.9	63.5	66.3	69.2	72.3
2	E – M	40.7	42.5	44.4	46.3	48.4	50.5	52.7
3	E – NW	27.8	29.1	30.3	31.7	33.1	34.5	36.0
4	E – NE	31.1	32.5	33.9	35.4	37.0	38.6	40.3
5	E – L	34.7	36.3	37.9	39.5	41.3	43.1	45.0
6	E – E	23.8	24.9	26.0	27.1	28.3	29.6	30.9
7	SC	22.3	23.3	24.4	25.4	26.5	27.7	28.9
8	W	13.7	14.3	14.9	15.6	16.3	17.0	17.7
9	NIR	7.0	7.3	7.6	7.9	8.3	8.6	9.0
10	IR	23.6	24.6	25.7	26.8	28.0	29.3	30.5
	Total	280.7	293.1	305.9	319.4	333.4	348.0	363.3

Appendix Table 6: Annual space heating demand projection in TWh by region.

	Region	Space heating demand [TWh]						
		2020	2025	2030	2035	2040	2045	2050
1	E - S	95.0	96.4	96.4	95.1	92.6	89.1	84.6
2	E - M	69.2	70.5	71.0	70.4	69.0	66.7	63.6
3	E - NW	46.9	47.2	47.0	46.2	44.9	43.2	40.9
4	E - NE	52.2	52.4	52.0	50.9	49.3	47.1	44.5
5	E - L	57.6	58.2	57.9	57.1	55.7	53.6	50.8
6	E - E	40.0	40.5	40.4	39.8	38.8	37.3	35.4
7	SC	34.8	35.0	34.8	34.2	33.2	31.8	30.0
8	W	20.1	20.2	19.9	19.4	18.6	17.7	16.5
9	NIR	12.2	12.2	12.1	11.8	11.4	10.8	10.1
10	IR	29.4	30.2	30.5	30.4	30.0	29.1	27.9
	Total	457.4	462.7	462.0	455.4	443.5	426.5	404.3

APPENDIX TABLE 7: ANNUAL DOMESTIC HOT WATER DEMAND IN TWH BY REGION.

	Region	Domestic hot water demand [TWh]						
		2020	2025	2030	2035	2040	2045	2050
1	E - S	4.3	4.6	4.9	5.2	5.5	5.8	6.0
2	E - M	3.2	3.4	3.6	3.9	4.1	4.3	4.5
3	E - NW	2.1	2.3	2.4	2.5	2.7	2.8	2.9
4	E - NE	2.4	2.5	2.7	2.8	2.9	3.0	3.2
5	E - L	2.6	2.8	3.0	3.1	3.3	3.5	3.6
6	E - E	1.8	1.9	2.1	2.2	2.3	2.4	2.5
7	SC	1.6	1.7	1.8	1.9	2.0	2.1	2.1
8	W	0.9	1.0	1.0	1.1	1.1	1.1	1.2
9	NIR	0.6	0.6	0.6	0.6	0.7	0.7	0.7
10	IR	1.1	1.3	1.5	1.6	1.7	1.8	1.9
	Total	20.7	22.1	23.5	24.9	26.2	27.5	28.8

APPENDIX TABLE 8: ANNUAL INDUSTRIAL HEAT DEMAND IN TWH BY REGION.

	Region	Industrial heat demand [TWh]						
		2020	2025	2030	2035	2040	2045	2050
1	E - S	58.9	59.1	64.1	68.6	71.3	71.6	69.5
2	E - M	42.9	43.2	47.2	50.9	53.1	53.6	52.3
3	E - NW	29.1	28.9	31.3	33.4	34.6	34.7	33.6
4	E - NE	32.4	32.1	34.6	36.8	38.0	37.9	36.6
5	E - L	35.7	35.7	38.6	41.2	42.9	43.0	41.7
6	E - E	24.8	24.8	26.9	28.8	29.9	30.0	29.1
7	SC	21.6	21.4	23.1	24.7	25.5	25.5	24.7
8	W	12.5	12.4	13.3	14.0	14.3	14.2	13.6
9	NIR	7.5	7.5	8.0	8.5	8.8	8.7	8.3

10	IR	23.5	37.8	36.3	34.3	31.8	29.2	26.5
	Total	288.9	302.9	323.5	341.1	350.3	348.3	335.9

Appendix Table 9: Annual road transport passenger demand in mil-p-km by region.

	Region	**Annual road transport passenger demand [mil p-km}**						
		2020	2025	2030	2035	2040	2045	2050
1	E - S	153510	166605	177834	187112	195355	202475	208593
2	E - M	111764	121948	130952	138651	145586	151625	156934
3	E - NW	75722	81635	86720	90992	94822	98081	100848
4	E - NE	84353	90555	95883	100242	104011	107137	109711
5	E - L	92958	100643	106885	112424	117521	121716	125299
6	E - E	64553	69988	74565	78387	81848	84855	87442
7	SC	56246	60439	64179	67282	69979	72217	74014
8	W	32540	34863	36738	38166	39303	40153	40784
9	NIR	19648	21127	22307	23219	23992	24579	24950
10	IR	65076	64712	62967	61523	61222	61876	63203
	Total	756369	812514	859031	897999	933638	964714	991778

Appendix Table 10: Annual road transport freight demand in mil t-km by region.

	Region	**Annual road transport freight demand [mil t-km}**						
		2020	2025	2030	2035	2040	2045	2050
1	E - S	36051	36964	37860	38923	40112	41329	42429
2	E - M	26247	27056	27879	28842	29893	30950	31921
3	E - NW	17783	18112	18462	18928	19470	20020	20513
4	E - NE	19810	20091	20413	20852	21356	21869	22316
5	E - L	21831	22329	22755	23386	24130	24845	25486
6	E - E	15160	15528	15874	16306	16806	17321	17786
7	SC	13209	13409	13663	13996	14369	14741	15055
8	W	7642	7735	7821	7939	8070	8196	8296
9	NIR	4614	4687	4749	4830	4926	5017	5075
10	IR	15283	14357	13405	12798	12570	12630	12856
	Total	177630	180270	182883	186801	191702	196917	201732

Appendix Table 11: Annual rail transport passenger demand in mil p-km by region.

	Region	**Annual rail transport passenger demand [mil p-km}**						
		2020	2025	2030	2035	2040	2045	2050
1	E - S	15064	17305	19634	21751	23490	24794	25658
2	E - M	10967	12666	14458	16118	17505	18567	19304
3	E - NW	7431	8479	9574	10578	11401	12011	12405
4	E - NE	8278	9406	10586	11653	12506	13120	13495
5	E - L	9122	10453	11801	13069	14131	14905	15412

6	E - E	6335	7269	8232	9112	9841	10391	10756
7	SC	5519	6278	7086	7821	8414	8843	9104
8	W	3193	3621	4056	4437	4726	4917	5017
9	NIR	1928	2194	2463	2699	2885	3010	3069
10	IR	6386	6721	6952	7152	7361	7577	7774
	Total	74222	84393	94841	104390	112261	118135	121994

APPENDIX TABLE 12: ANNUAL RAIL TRANSPORT FREIGHT DEMAND IN MIL T-KM BY REGION.

	Region	**Annual rail transport freight demand [mil t-km}**						
		2020	2025	2030	2035	2040	2045	2050
1	E - S	3441	3777	4101	4430	4680	4906	5064
2	E - M	2505	2765	3020	3283	3488	3674	3810
3	E - NW	1697	1851	2000	2154	2272	2377	2448
4	E - NE	1891	2053	2211	2373	2492	2596	2663
5	E - L	2084	2282	2465	2662	2816	2949	3042
6	E - E	1447	1587	1720	1856	1961	2056	2123
7	SC	1261	1370	1480	1593	1677	1750	1797
8	W	729	790	847	904	942	973	990
9	NIR	440	479	514	550	575	596	606
10	IR	1459	1467	1452	1457	1467	1499	1534
	Total	16956	18422	19810	21260	22368	23377	24077

APPENDIX TABLE 13: ANNUAL AVIATION TRANSPORT PASSENGER DEMAND IN MIL P-KM BY REGION.

	Region	**Annual aviation transport passenger demand [mil p-km}**						
		2020	2025	2030	2035	2040	2045	2050
1	E - S	23661	25633	27999	30365	33126	36281	39041
2	E - M	13886	15043	16432	17820	19440	21292	22912
3	E - NW	26706	28931	31602	34272	37388	40949	44064
4	E - NE	8756	9486	10362	11237	12259	13427	14448
5	E - L	105031	113783	124286	134789	147043	161047	173300
6	E - E	1617	1752	1913	2075	2264	2479	2668
7	SC	23605	25572	27933	30293	33047	36195	38949
8	W	1266	1372	1498	1625	1773	1941	2089
9	NIR	7187	7786	8504	9223	10061	11020	11858
10	IR	19930	21591	23584	25577	27902	30560	32885
	Total	231645	250949	274113	297278	324303	355189	382214

APPENDIX TABLE 14: ANNUAL AVIATION TRANSPORT FREIGHT DEMAND IN MIL T-KM BY REGION.

	Region	**Annual aviation transport freight demand [mil t-km}**						
		2020	2025	2030	2035	2040	2045	2050

1	E - S	55	56	59	63	67	72	77
2	E - M	764	785	827	884	938	1002	1074
3	E - NW	237	244	257	274	291	311	333
4	E - NE	26	27	29	31	33	35	37
5	E - L	4202	4314	4544	4860	5158	5505	5906
6	E - E	0	0	0	1	1	1	1
7	SC	116	119	125	134	142	152	163
8	W	3	3	3	4	4	4	4
9	NIR	58	59	63	67	71	76	81
10	IR	514	528	556	595	631	674	723
	Total	5977	6136	6462	6912	7336	7830	8400

APPENDIX TABLE 15: ANNUAL MARINE TRANSPORT PASSENGER DEMAND IN MIL P-KM BY REGION.

	Region	**Annual marine transport passenger demand [mil p-km}**						
		2020	2025	2030	2035	2040	2045	2050
1	E - S	695	761	839	916	1003	1102	1189
2	E - M	506	557	618	679	748	825	894
3	E - NW	343	373	409	445	487	534	575
4	E - NE	382	414	452	491	534	583	625
5	E - L	421	460	504	550	604	663	714
6	E - E	292	320	352	384	420	462	498
7	SC	255	276	303	329	359	393	422
8	W	147	159	173	187	202	219	232
9	NIR	89	96	105	114	123	134	142
10	IR	295	296	297	301	314	337	360
	Total	3425	3711	4053	4396	4795	5252	5652

APPENDIX TABLE 16: ANNUAL MARINE TRANSPORT FREIGHT DEMAND IN MIL T-KM BY REGION.

	Region	**Annual marine transport freight demand [mil t-km}**						
		2020	2025	2030	2035	2040	2045	2050
1	E - S	149191	153171	161319	172534	183133	195453	209679
2	E - M	1847	1896	1997	2136	2267	2419	2595
3	E - NW	81112	83276	87706	93804	99566	106264	113999
4	E - NE	202368	207766	218818	234031	248408	265119	284415
5	E - L	95096	97632	102826	109975	116731	124584	133651
6	E - E	65425	67170	70743	75661	80309	85712	91951
7	SC	116836	119953	126334	135117	143418	153066	164207
8	W	87872	90216	95015	101621	107864	115120	123499
9	NIR	50747	52101	54873	58688	62293	66483	71322

10	IR	80063	82199	86571	92590	98278	104889	112523
	Total	930557	955380	1006201	1076156	1142265	1219109	1307841

Appendix Table 17: Technical and financial assumptions for all technologies.

Technologies		**Units**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
PV fixed tilted PP	Capex	€/kW,el	475	370	306	237	207	184	166
	Opex fix	€/(kW,el*a)	8	7	6	5	4	4	4
	Opex var	€/kWh,el	0	0	0	0	0	0	0
	Lifetime	years	30	35	35	35	40	40	40
PV rooftop – residential	Capex	€/kW,el	1150	926	787	622	551	496	453
	Opex fix	€/(kW,el*a)	9	8	7	6	5	5	4
	Opex var	€/kWh,el	0	0	0	0	0	0	0
	Lifetime	years	30	35	35	35	40	40	40
PV rooftop – commercial	Capex	€/kW,el	758	598	502	393	345	308	280
	Opex fix	€/(kW,el*a)	9	8	7	6	5	5	4
	Opex var	€/kWh,el	0	0	0	0	0	0	0
	Lifetime	years	30	35	35	35	40	40	40
PV rooftop – industrial	Capex	€/kW,el	563	437	362	281	245	217	197
	Opex fix	€/(kW,el*a)	9	8	7	6	5	5	4
	Opex var	€/kWh,el	0	0	0	0	0	0	0
	Lifetime	years	30	35	35	35	40	40	40
PV single-axis PP	Capex	€/kW,el	523	407	337	261	228	202	183
	Opex fix	€/(kW,el*a)	9	7	6	6	5	4	4
	Opex var	€/kWh,el	0	0	0	0	0	0	0
	Lifetime	years	30	35	35	35	40	40	40
Wind onshore PP	Capex	€/kW,el	1150	1060	1000	965	940	915	900
	Opex fix	€/(kW,el*a)	23	21	20	19	19	18	18
	Opex var	€/kWh,el	0	0	0	0	0	0	0
	Lifetime	years	25	25	25	25	25	25	25
	Capex	€/kW,el	2973	2561	2287	2216	2168	2145	2130

Wind offshore PP	Opex fix	€/(kW,el*a)	85	73	66	64	62	61	61
	Opex var	€/kWh,el	0	0	0	0	0	0	0
	Lifetime	years	25	25	25	25	25	25	25
Hydro Run-of-River PP	Capex	€/kW,el	2560	2560	2560	2560	2560	2560	2560
	Opex fix	€/(kW,el*a)	77	77	77	77	77	77	77
	Opex var	€/kWh,el	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	Lifetime	years	50	50	50	50	50	50	50
Tide PP	Capex	€/kW,el	2000	2000	2000	2000	2000	2000	2000
	Opex fix	€/(kW,el*a)	40	40	40	40	40	40	40
	Opex var	€/kWh,el	0	0	0	0	0	0	0
	Lifetime	years	30	30	30	30	30	30	30
Wave PP	Capex	€/kW,el	21000	5200	2800	2300	2100	1900	1800
	Opex fix	€/(kW,el*a)	1057	221	77	58	50	46	43
	Opex var	€/kWh,el	0	0	0	0	0	0	0
	Lifetime	years	20	20	25	25	30	30	30
Concentrating Solar Heat	Capex	€/kW,el	344.5	303.6	274.7	251.1	230.2	211.9	196
	Opex fix	€/(kW,el*a)	7.9	7	6.3	5.8	5.3	4.9	4.5
	Opex var	€/kWh,el	0	0	0	0	0	0	0
	Lifetime	years	25	25	25	25	25	25	25
Geothermal Heat	Capex	€/kW,el	4970	4720	4470	4245	4020	3815	3610
	Opex fix	€/(kW,el*a)	80	80	80	80	80	80	80
	Opex var	€/kWh,el	0	0	0	0	0	0	0
	Lifetime	years	40	40	40	40	40	40	40
Water Electrolysis	Capex	€/kW,el	803	586	446	381	347	313	291
	Opex fix	€/(kW,el*a)	28.1	20.5	15.6	13.3	12.1	11.0	10.2
	Opex var	€/kWh,el	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014
	Lifetime	years	30	30	30	30	30	30	30
CO_2 direct air capture	Capex	€/(tCO_2*a)	730	481	338	281	237	217	199

	Opex fix	€/(tCO_2*a)	29.2	19.2	13.5	11.2	9.5	8.7	8
	Opex var	€/$kgCO_2$	0	0	0	0	0	0	0
	Lifetime	years	20	30	25	30	30	30	30
	CO_2 scrubbing efficiency	kWh_{el}/tCO_2	242	236	225	214	203	192	182
		kWh_{th}/tCO_2	1670	1590	1500	1393	1286	1194	1102
Methanation	Capex	€/kW,SNG,output,LHV	558	409	309	274	251	227	211
	Opex fix	€/(kW,SNG,output,LHV*a)	25.7	18.8	14.2	12.6	11.5	10.4	9.7
	Opex var	€/kWh,SNG,output,LHV	0.0017	0.0017	0.0017	0.0017	0.0017	0.0017	0.0017
	Lifetime	years	30	30	30	30	30	30	30
	Efficiency	coeff	0.778	0.778	0.778	0.778	0.778	0.778	0.778
Biogas digester	Capex	€/kW_{th}	730.61	705.95	680	652.75	631.99	608.63	589.16
	Opex fix	€/(kW_{th}*a)	29.224	28.238	27.2	26.11	25.279	24.345	23.566
	Opex var	€/kWh_{th}	0	0	0	0	0	0	0
	Lifetime	years	20	20	20	25	25	25	25
Biogas Upgrade	Capex	€/kW_{th}	290	270	250	230	220	210	200
	Opex fix	€/(kW_{th}*a)	23.2	21.6	20	18.4	17.6	16.8	16
	Opex var	€/kWh_{th}	0	0	0	0	0	0	0
	Lifetime	years	20	20	20	20	20	20	20
	Efficiency	coeff	0.98	0.98	0.98	0.98	0.98	0.98	0.98
Fischer-Tropsch unit	Capex	€/kW_{FTLiq}	947	947	947	947	852.3	852.3	852.3
	Opex fix	€/kW_{FTLiq}	28.41	28.41	28.41	28.41	25.57	25.57	25.57
	Opex var	€/kWh_{FTLiq}	0	0	0	0	0	0	0
	Lifetime	years	30	30	30	30	30	30	30
	Efficiency	coeff	0.6338	0.6338	0.6338	0.6338	0.6338	0.6338	0.6338

	Opex fix	€/kW$_{Liq}$	14.32	14.32	14.32	7.03	6.11	5.81	5.52
	Opex var	€/kWh$_{Liq}$	0	0	0	0	0	0	0
	Lifetime	years	30	30	30	30	30	30	30
	Efficiency	coeff	0.983	0.983	0.983	0.983	0.983	0.983	0.983
Steam turbine (CSP)	Capex	€/kW$_{el}$	968	946	923	902	880	860	840
	Opex fix	€/(kW$_{el}$*a)	19.4	18.9	18.5	18	17.6	17.2	16.8
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0
	Lifetime	years	25	25	25	30	30	30	30
	Efficiency	coeff	0.383	0.403	0.43	0.43	0.43	0.43	0.43
CCGT	Capex	€/kW$_{el}$	775	775	775	775	775	775	775
	Opex fix	€/(kW$_{el}$*a)	19.375	19.375	19.375	19.375	19.375	19.375	19.375
	Opex var	€/kWh$_{el}$	0.002	0.002	0.002	0.002	0.002	0.002	0.002
	Lifetime	years	35	35	35	35	35	35	35
	Efficiency	coeff	0.58	0.58	0.58	0.59	0.6	0.6	0.6
CCGT + CCS	Capex	€/kW$_{el}$	2565	2272.5	1980	1845	1710	1640	1570
	Opex fix	€/(kW$_{el}$*a)	81	72	63	58.5	54	52	50
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0
	Lifetime	years	35	35	35	35	35	35	35
	Efficiency	coeff	0.52	0.525	0.53	0.535	0.54	0.545	0.55
OCGT	Capex	€/kW$_{el}$	475	475	475	475	475	475	475
	Opex fix	€/(kW$_{el}$*a)	14.25	14.25	14.25	14.25	14.25	14.25	14.25
	Opex var	€/kWh$_{el}$	0.011	0.011	0.011	0.011	0.011	0.011	0.011
	Lifetime	years	35	35	35	35	35	35	35
	Efficiency	coeff	0.4	0.415	0.43	0.435	0.44	0.445	0.45
Int Combust Generator	Capex	€/kW$_{el}$	385	385	385	385	385	385	385
	Opex fix	€/(kW$_{el}$*a)	11.5	11.5	11.5	11.5	11.5	11.5	11.5
	Opex var	€/kWh$_{el}$	0.0047	0.0047	0.0047	0.0047	0.0047	0.0047	0.0047
	Lifetime	years	30	30	30	30	30	30	30
	Efficiency	coeff	0.3	0.3	0.3	0.3	0.3	0.3	0.3

Int Combust Generator modern Multifuel	Capex	€/kW_{el}	569	553	537	522	506	491	475
	Opex fix	€/(kW_{el}*a)	6.2	6.2	6.2	6.2	6.2	6.2	6.2
	Opex var	€/kWh_{el}	0.011	0.011	0.011	0.011	0.011	0.011	0.011
	Lifetime	years	30	30	30	30	30	30	30
	Efficiency	coeff	0.47	0.47	0.47	0.47	0.47	0.47	0.47
Nuclear Power Plant	Capex	€/kW_{el}	9170	9170	9170	9170	9170	9170	9170
	Opex fix	€/(kW_{el}*a)	172.8	172.8	159.5	159.5	146.2	146.2	139.5
	Opex var	€/kWh_{el}	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025
	Lifetime	years	40	40	40	40	40	40	40
	Efficiency	coeff	0.37	0.37	0.38	0.38	0.38	0.38	0.38
Coal Power Plant	Capex	€/kW_{el}	1600	1600	1600	1600	1600	1600	1600
	Opex fix	€/(kW_{el}*a)	20	20	20	20	20	20	20
	Opex var	€/kWh_{el}	0.001	0.001	0.001	0.001	0.001	0.001	0.001
	Lifetime	years	45	45	45	45	45	45	45
	Efficiency	coeff	0.43	0.43	0.43	0.43	0.43	0.43	0.43
CHP NG Heating	Capex	€/kW_{el}	880	880	880	880	880	880	880
	Opex fix	€/(kW_{el}*a)	74.8	74.8	74.8	74.8	74.8	74.8	74.8
	Opex var	€/kWh_{el}	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024
	Lifetime	years	30	30	30	30	30	30	30
	Efficiency el	coeff	0.37	0.37	0.38	0.38	0.39	0.39	0.39
	Efficiency th	coeff	0.51	0.52	0.53	0.53	0.54	0.54	0.55
CHP Oil Heating	Capex	€/kW_{el}	880	880	880	880	880	880	880
	Opex fix	€/(kW_{el}*a)	74.8	74.8	74.8	74.8	74.8	74.8	74.8
	Opex var	€/kWh_{el}	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024
	Lifetime	years	30	30	30	30	30	30	30
	Efficiency el	coeff	0.5	0.5	0.5	0.5	0.5	0.5	0.5
CHP Coal Heating	Capex	€/kW_{el}	2030	2030	2030	2030	2030	2030	2030
	Opex fix	€/(kW_{el}*a)	46.7	46.7	46.7	46.7	46.7	46.7	46.7
	Opex var	€/kWh_{el}	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051
	Lifetime	years	40	40	40	40	40	40	40
	Efficiency el	coeff	0.43	0.44	0.45	0.45	0.46	0.47	0.47

	Efficiency he	coeff	0.41	0.42	0.43	0.44	0.44	0.45	0.45
CHP Biomass Heating	Capex	€/kW$_{el}$	3400	3300	3200	3125	3050	2975	2900
	Opex fix	€/(kW$_{el}$*a)	97.6	94.95	92.3	90.8	89.3	87.8	86.3
	Opex var	€/kWh$_{el}$	0.0038	0.0038	0.0037	0.0037	0.0038	0.0038	0.0038
	Lifetime	years	25	25	25	25	25	25	25
	Efficiency el	coeff	0.6510	0.6521	0.6532	0.6505	0.6477	0.6450	0.6422
	Efficiency th	coeff	0.295	0.2955	0.296	0.29475	0.2935	0.29225	0.291
CHP Biogas	Capex	€/kW$_{el}$	429.2	399.6	370	340.4	325.6	310.8	296
	Opex fix	€/(kW$_{el}$*a)	17.168	15.984	14.8	13.616	13.024	12.432	11.84
	Opex var	€/kWh$_{el}$	0.001	0.001	0.001	0.001	0.001	0.001	0.001
	Lifetime	years	30	30	30	30	30	30	30
	Efficiency el	coeff	0.43023	0.46512	0.5	0.52326	0.54651	0.55233	0.55814
	Efficiency th	coeff	0.34419	0.37209	0.4	0.4186	0.43721	0.44186	0.44651
Municipal Solid Waste Incinerator	Capex	€/kW$_{el}$	5630	5440	5240	5030	4870	4690	4540
	Opex fix	€/(kW$_{el}$*a)	253.35	244.8	235.8	226.35	219.15	211.05	204.3
	Opex var	€/kWh$_{el}$	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069
	Lifetime	years	30	30	30	30	30	30	30
	Efficiency el	coeff	0.71	0.71	0.71	0.71	0.71	0.71	0.71
	Efficiency th	coeff	0.26	0.26	0.26	0.26	0.26	0.26	0.26
DH Rod Heating	Capex	€/kW$_{th}$	100	100	75	75	75	75	75
	Opex fix	€/(kW$_{th}$*a)	1.47	1.47	1.47	1.47	1.47	1.47	1.47
	Opex var	€/kWh$_{th}$	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
	Lifetime	years	35	35	35	35	35	35	35
DH Heat Pump	Capex	€/kW$_{th}$	660	618	590	568	554	540	530
	Opex fix	€/(kW$_{th}$*a)	2	2	2	2	2	2	2
	Opex var	€/kWh$_{th}$	0.0018	0.0017	0.0017	0.0016	0.0016	0.0016	0.0016
	Lifetime	years	25	25	25	25	25	25	25

	COP	coeff	3.29	3.4	3.47	3.57	3.64	3.7	3.75
DH Oil Heating	Capex	€/kW$_{th}$	75	75	100	100	100	100	100
	Opex fix	€/(kW$_{th}$*a)	2.775	2.775	3.7	3.7	3.7	3.7	3.7
	Opex var	€/kWh$_{th}$	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
	Lifetime	years	35	35	35	35	35	35	35
	Efficiency	coeff	0.97	0.97	0.97	0.97	0.97	0.97	0.97
DH Coal Heating	Capex	€/kW$_{th}$	75	75	100	100	100	100	100
	Opex fix	€/(kW$_{th}$*a)	2.775	2.775	3.7	3.7	3.7	3.7	3.7
	Opex var	€/kWh$_{th}$	0.00015	0.00015	0.00015	0.00015	0.00015	0.00015	0.00015
	Lifetime	years	35	35	35	35	35	35	35
	Efficiency	coeff	0.97	0.97	0.97	0.97	0.97	0.97	0.97
DH Biomass Heating	Capex	€/kW$_{th}$	75	75	100	100	100	100	100
	Opex fix	€/(kW$_{th}$*a)	2.8	2.8	3.7	3.7	3.7	3.7	3.7
	Opex var	€/kWh$_{th}$	0.00015	0.00015	0.00015	0.00015	0.00015	0.00015	0.00015
	Lifetime	years	35	35	35	35	35	35	35
	Efficiency	coeff	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Local Rod Heating	Capex	€/kW$_{th}$	100	100	100	100	100	100	100
	Opex fix	€/(kW$_{th}$*a)	2	2	2	2	2	2	2
	Opex var	€/kWh$_{th}$	0.001	0.001	0.001	0.001	0.001	0.001	0.001
	Lifetime	years	30	30	30	30	30	30	30
Local Heat Pump	Capex	€/kW$_{th}$	780	750	730	706	690	666	650
	Opex fix	€/(kW$_{th}$*a)	15.6	15	7.3	7.1	6.9	6.7	6.5
	Opex var	€/kWh$_{th}$	0	0	0	0	0	0	0
	Lifetime	years	20	20	20	20	20	20	20
	COP	coeff	4.7	4.9	5.0	5.1	5.2	5.4	5.4
Local NG Heating	Capex	€/kW$_{th}$	800	800	800	800	800	800	800
	Opex fix	€/(kW$_{th}$*a)	27	27	27	27	27	27	27
	Opex var	€/kWh$_{th}$	0	0	0	0	0	0	0
	Lifetime	years	22	22	22	22	22	22	22

	Efficiency	coeff	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Local Oil Heating	Capex	€/kW$_{th}$	440	440	440	440	440	440	440
	Opex fix	€/(kW$_{th}$*a)	18	18	18	18	18	18	18
	Opex var	€/kWh$_{th}$	0	0	0	0	0	0	0
	Lifetime	years	20	20	20	20	20	20	20
	Efficiency	coeff	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Local Biomass Heating	Capex	€/kW$_{th}$	675	675	750	750	750	750	750
	Opex fix	€/(kW$_{th}$*a)	2	2	3	3	3	3	3
	Opex var	€/kWh$_{th}$	0	0	0	0	0	0	0
	Lifetime	years	20	20	20	20	20	20	20
Local Biogas Heating	Capex	€/kW$_{th}$	800	800	800	800	800	800	800
	Opex fix	€/(kW$_{th}$*a)	27	27	27	27	27	27	27
	Opex var	€/kWh$_{th}$	0	0	0	0	0	0	0
	Lifetime	years	22	22	22	22	22	22	22
	Efficiency	coeff	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Steam Methane Reforming	Capex	€/kW$_{H2}$	320	320	320	320	320	320	320
	Opex fix	€/kW$_{H2}$	16	16	16	16	16	16	16
	Opex var	€/kWh$_{H2}$	0	0	0	0	0	0	0
	Lifetime	years	30	30	30	30	30	30	30
	Efficiency	coeff	0.845	0.845	0.845	0.845	0.845	0.845	0.845
Battery utility-scale Storage	Capex	€/kWh$_{el}$	234	153	110	89	76	68	61
	Opex fix	€/(kWh$_{el}$*a)	3.28	2.6	2.2	2.05	1.9	1.77	1.71
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0
	Lifetime	years	20	20	20	20	20	20	20
	Round-trip	coeff	0.91	0.92	0.93	0.94	0.95	0.95	0.95
	Self-discharge	coeff	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Battery utility-	Capex	€/kW$_{el}$	117	76	55	44	37	33	30
	Opex fix	€/(kW$_{el}$*a)	1.64	1.29	1.1	1.01	0.93	0.86	0.84

scale Interface	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0
	Lifetime	years	20	20	20	20	20	20	20
Battery PV prosumer residential Storage	Capex	€/kWh$_{el}$	462	308	224	182	156	140	127
	Opex fix	€/(kWh$_{el}$*a)	5.08	4	3.36	3.09	2.81	2.8	2.54
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0
	Lifetime	years	20	20	20	20	20	20	20
	Round-trip	coeff	0.91	0.92	0.93	0.94	0.95	0.95	0.95
	Self-discharge	coeff	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Battery PV prosumer residential Interface	Capex	€/kW$_{el}$	231	153	112	90	76	68	62
	Opex fix	€/(kW$_{el}$*a)	2.54	1.99	1.68	1.53	1.37	1.36	1.24
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0
	Lifetime	years	20	20	20	20	20	20	20
Battery PV prosumer commercial Storage	Capex	€/kWh$_{el}$	366	240	175	141	121	108	98
	Opex fix	€/(kWh$_{el}$*a)	4.39	3.6	2.98	2.68	2.54	2.38	2.25
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0
	Lifetime	years	20	20	20	20	20	20	20
	Round-trip	coeff	0.91	0.92	0.93	0.94	0.95	0.95	0.95
	Self-discharge	coeff	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Battery PV prosumer commercial Interface	Capex	€/kW$_{el}$	183	119	88	70	59	53	48
	Opex fix	€/(kW$_{el}$*a)	2.2	1.79	1.5	1.33	1.24	1.17	1.1
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0
	Lifetime	years	20	20	20	20	20	20	20
Battery PV prosumer industrial Storage	Capex	€/kWh$_{el}$	278	181	131	105	90	80	72
	Opex fix	€/(kWh$_{el}$*a)	3.89	3.08	2.62	2.42	2.25	2.08	1.94
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0
	Lifetime	years	20	20	20	20	20	20	20
	Round-trip	coeff	0.91	0.92	0.93	0.94	0.95	0.95	0.95

	Self-discharge	coeff	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Battery PV prosumer industrial Interface	Capex	€/kW$_{el}$	139	90	66	52	44	39	35
	Opex fix	€/(kW$_{el}$*a)	1.95	1.53	1.32	1.2	1.1	1.01	0.95
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0
	Lifetime	years	20	20	20	20	20	20	20
PHES Storage	Capex	€/kWh$_{el}$	7.7	7.7	7.7	7.7	7.7	7.7	7.7
	Opex fix	€/(kWh$_{el}$*a)	1.335	1.335	1.335	1.335	1.335	1.335	1.335
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0
	Lifetime	years	50	50	50	50	50	50	50
	Round-trip	coeff	0.85	0.85	0.85	0.85	0.85	0.85	0.85
	Self-discharge	coeff	0.01	0.01	0.01	0.01	0.01	0.01	0.01
PHES Interface	Capex	€/kW$_{el}$	650	650	650	650	650	650	650
	Opex fix	€/(kW$_{el}$*a)	0	0	0	0	0	0	0
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0
	Lifetime	years	50	50	50	50	50	50	50
A-CAES Storage	Capex	€/kWh$_{el}$	35	32.6	31.1	30.3	29.8	27.7	26.3
	Opex fix	€/(kWh$_{el}$*a)	0.5	0.5	0.5	0.5	0.5	0.4	0.4
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0
	Lifetime	years	55	55	55	55	55	55	55
	Round-trip	coeff	0.59	0.65	0.70	0.70	0.70	0.70	0.70
	Self-discharge	coeff	0.01	0.01	0.01	0.01	0.01	0.01	0.01
A-CAES Interface	Capex	€/kW$_{el}$	600	558	530	518	510	474	450
	Opex fix	€/(kW$_{el}$*a)	0	0	0	0	0	0	0
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0
	Lifetime	years	55	55	55	55	55	55	55
Hydrogen Storage	Capex	€/kWh$_{th}$	0.24	0.24	0.24	0.24	0.24	0.24	0.24
	Opex fix	€/(kWh$_{th}$*a)	0.0096	0.0096	0.0096	0.0096	0.0096	0.0096	0.0096
	Opex var	€/kWh$_{th}$	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001

	Lifetime	years	30	30	30	30	30	30	30
	Round-trip	coeff	1	1	1	1	1	1	1
	Self-discharge	coeff	0	0	0	0	0	0	0
Hydrogen Storage Interface	Capex	€/kW_{th}	100	100	100	100	100	100	100
	Opex fix	€/(kW_{th}*a)	4	4	4	4	4	4	4
	Opex var	€/kW_{th}	0	0	0	0	0	0	0
	Lifetime	years	15	15	15	15	15	15	15
CO_2 Storage	Capex	€/ton	142	142	142	142	142	142	142
	Opex fix	€/(ton*a)	9.94	9.94	9.94	9.94	9.94	9.94	9.94
	Opex var	€/ton	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
	Lifetime	years	30	30	30	30	30	30	30
	Round-trip	coeff	1	1	1	1	1	1	1
	Self-discharge	coeff	0	0	0	0	0	0	0
CO_2 Storage Interface	Capex	€/ton/h	0	0	0	0	0	0	0
	Opex fix	€/(ton/h*a)	0	0	0	0	0	0	0
	Opex var	€/ton	0	0	0	0	0	0	0
	Lifetime	years	50	50	50	50	50	50	50
Gas Storage	Capex	€/kWh_{th}	0.05	0.05	0.05	0.05	0.05	0.05	0.05
	Opex fix	€/(kWh_{th}*a)	0.001	0.001	0.001	0.001	0.001	0.001	0.001
	Opex var	€/kWh_{th}	0	0	0	0	0	0	0
	Lifetime	years	50	50	50	50	50	50	50
	Round-trip	coeff	1	1	1	1	1	1	1
	Self-discharge	coeff	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Gas Storage Interface	Capex	€/kW_{th}	25.8	25.8	25.8	25.8	25.8	25.8	25.8
	Opex fix	€/(kW_{th}*a)	31	31	31	31	31	31	31
	Opex var	€/kW_{th}	36.2	36.2	36.2	36.2	36.2	36.2	36.2
	Lifetime	years	41.4	41.4	41.4	41.4	41.4	41.4	41.4

	Efficiency	coeff	46.6	46.6	46.6	46.6	46.6	46.6	46.6
District Heat Storage	Capex	€/kWh$_{th}$	40	30	30	25	20	20	20
	Opex fix	€/(kWh$_{th}$*a)	0.6	0.45	0.45	0.375	0.3	0.3	0.3
	Opex var	€/kWh$_{th}$	0	0	0	0	0	0	0
	Lifetime	years	25	25	25	30	30	30	30
	Round-trip	coeff	0.9	0.9	0.9	0.9	0.9	0.9	0.9
	Self-discharge	coeff	0.01	0.01	0.01	0.01	0.01	0.01	0.01
District Heat Storage Interface	Capex	€/kW$_{th}$	0	0	0	0	0	0	0
	Opex fix	€/(kW$_{th}$*a)	0	0	0	0	0	0	0
	Opex var	€/kW$_{th}$	0	0	0	0	0	0	0
	Lifetime	years	25	25	25	30	30	30	30
HVDC Transmission Line	Capex	€/(kW*km)	0.9233	0.9233	0.9233	0.9233	1.0467	1.0467	1.0467
	Opex fix	€/(kW*km)	0.0015	0.0015	0.0015	0.0015	0.0019	0.0019	0.0019
	Opex var	€/(kWh*km)	0	0	0	0	0	0	0
	Lifetime	year	50	50	50	50	50	50	50
	Efficiency	coeff	0.934	0.934	0.934	0.934	0.984	0.984	0.984
HVDC Transmission Line (Cable)	Capex	€/(kW*km)	1.2333	1.2333	1.2333	1.2333	1.3667	1.3667	1.3667
	Opex fix	€/(kW*km)	0.0012	0.0012	0.0012	0.0012	0.0014	0.0014	0.0014
	Opex var	€/(kWh*km)	0	0	0	0	0	0	0
	Lifetime	year	50	50	50	50	50	50	50
	Efficiency	coeff	0.934	0.934	0.934	0.934	0.984	0.984	0.984
HVDC Transmission Line (Overhead)	Capex	€/(kW*km)	0.2	0.2	0.2	0.2	0.3	0.3	0.3
	Opex fix	€/(kW*km)	0.002	0.002	0.002	0.002	0.003	0.003	0.003
	Opex var	€/(kWh*km)	0	0	0	0	0	0	0
	Lifetime	year	50	50	50	50	50	50	50

	Efficiency	coeff	0.934	0.934	0.934	0.934	0.984	0.984	0.984
HVAC Transmission Line	Capex	€/(kW*km)	0.4576	0.4576	0.4576	0.4576	0.4576	0.4576	0.4576
	Opex fix	€/(kW*km)	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029
	Opex var	€/(kWh*km)	0	0	0	0	0	0	0
	Lifetime	year	50	50	50	50	50	50	50
	Efficiency	coeff	0.906	0.906	0.906	0.906	0.906	0.906	0.906
Converter Station	Capex	€/(kW)	150	150	150	150	180	180	180
	Opex fix	€/(kW)	1.5	1.5	1.5	1.5	1.8	1.8	1.8
	Opex var	€/(kWh)	0	0	0	0	0	0	0
	Lifetime	year	50	50	50	50	50	50	50
	Efficiency	coeff	0.986	0.986	0.986	0.986	0.986	0.986	0.986

APPENDIX TABLE 18: FUEL AND CO_2 EMISSION PRICES IN €/MWH AND €/TCO_2.

Component	Unit	2020	2025	2030	2035	2040	2045	2050
Coal	€/MWh_{th}	7.7	8.4	9.2	10.2	11.1	11.1	11.1
Oil	€/MWh_{th}	35.24	39.82	44.40	43.94	43.48	43.48	43.48
Natural gas	€/MWh_{th}	22.2	30	32.7	36.1	40.2	40.2	40.2
CO_2 emissions	€/tCO_{2eq}	28	52	61	68	75	100	150

APPENDIX TABLE 19: CO_2 EMISSIONS BY FUEL.

Fuel	CO_2 emissions [tCO_2/MWh_{th}]
Coal	0.389
Oil	0.387
Natural gas	0.283

APPENDIX TABLE 20: INSTALLED ELECTRICAL CAPACITY UNTIL 2050.

Installed electrical capacity [GW]	2020	2025	2030	2035	2040	2045	2050
ST others	0	0	0	0	0	0.1	0
CCGT	27.4	26.7	23.6	15.4	9.3	8.1	1.3

CCGT CCS	0	0	0	0	0	0	0
OCGT	1.7	1.3	0.9	0.4	0.3	0.2	0.2
Methane CHP	6.4	6.3	4.8	1.7	1.6	0.2	0
ICE	0.3	0.2	0.1	2	2	2	2
Oil CHP	0	0	0	0	0	0	0
Biomass solid	0	0	0	0	0	0	0
Biomass CHP	4.8	4.7	4.5	4.2	1.3	0	0
Waste–to–energy CHP	1.1	1	0.8	0.8	0.7	0.4	0
Biogas CHP	1.3	1.2	0.9	1.2	1.4	1.2	1.1
Geothermal electricity	0	3.3	3.3	3.3	6.7	6.7	10
CSP ST	0	0	0	0	0	0	0
Wave	0	0	0	0	12.5	17.5	24.7
PV fixed tilted	10.4	54.7	58	91.5	179	176.8	170.8
PV single–axis	0	4.2	4.2	4.2	4.2	6.5	12.5
PV prosumers	3	27.2	49.1	79.2	95.2	109.2	126.2
Wind onshore	13.9	30.8	30.8	34.7	42	42	42
Wind offshore	10.8	20.8	35.8	50.8	61.3	76.1	97.2
Hydro run–of–river	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Hydro reservoir (dam)	1	1	1	1	1	1	1.5
Coal PP hard coal	7.4	4.4	1.3	0	0	0	0
Coal PP hard coal CCS	0	0	0	0	0	0	0
Coal CHP	0	0	0	0	0	0	0
Nuclear PP	7.8	7.8	6.5	4	1.3	1.3	0
Total	98	196.3	226.3	295.1	420.5	450	490.2

APPENDIX TABLE 21: ELECTRICITY GENERATION UNTIL 2050.

Electricity generation [TWh]	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
ST others	0	0	0	0	0	0	0
CCGT	36	35	31	19	12.1	5.4	0.2
CCGT CCS	0	0	0	0	0.1	0	0
OCGT	0.8	0.6	0.4	0.2	0.1	0.1	0
Methane CHP	52.2	0.1	0.1	0.1	0.1	0.1	0
ICE	0	0	0	0.5	0.4	0.2	0.1
Oil CHP	0	0	0	0	0	0	0
Biomass solid	0	0	0	0	0	0	0
Biomass CHP	0	0	0	0	0	0	0

Waste–to–energy CHP	0	0	0	0	0	0	0
Biogas CHP	2.7	0.9	0.8	0.8	1	1	1
Geothermal electricity	0	13.9	13.9	13.9	14	14	42
CSP ST	0	0	0	0	0	0	0
Wave	0	0	0	0	64.2	90	127.5
PV fixed tilted	10.3	53.8	57.2	89.9	168.5	166.2	160.2
PV single–axis	0	4.7	4.7	4.7	4.7	7.2	13.6
PV prosumers	3	25.9	47	75.2	90.3	103.8	120.1
Wind onshore	58.3	138.3	139.6	157.7	189.6	191.9	191.9
Wind offshore	56.6	109.1	187.7	266.8	322.2	399.6	509.6
Hydro run–of–river	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Hydro reservoir (dam)	2.4	2.4	2.4	2.4	2.4	2.4	3.5
Coal PP hard coal	19	0	0	0	0	0	0
Coal PP hard coal CCS	0	0	0	0	0	0	0
Coal CHP	0	0	0	0	0	0	0
Nuclear PP	48.1	48.1	40.1	24.4	7.7	7.7	0
Total	291	434.4	526.5	657.2	879	991.2	1171.3

APPENDIX TABLE 22: HEAT GENERATION UNTIL 2050.

Heat generation [TWh]	2020	2025	2030	2035	2040	2045	2050
Methane CHP	37.5	0	0.1	0	0.1	0	0
Methane DH	140.4	0	0	0.2	0.3	0.2	0.1
Methane IH	405	103.7	44.2	16.4	0	0	0
Oil CHP	0	0	0	0	0	0	0
Oil DH	0	0	0	0	0	0	0
Oil IH	43.5	1.3	0.4	0.9	0	0	0
Coal CHP	0	0	0	0	0	0	0
Coal DH	1.6	0.3	0.1	0.1	0.1	0	0
CSP SF	0	0	0	0	0	0	0
Solar thermal heat	0	0	0	0	0	0	0
Geothermal heat DH	0	0	0	0	0	0	0
Biomass CHP	0	0	0	0	0	0	0
Biomass DH	0	0	0	0	0	0	0
Biomass IH	0.1	0	0	0	0	0	0
Waste–to–energy CHP	0	0	0	0	0	0	0
Biogas CHP	3.4	1.1	1	1	1.3	1.2	1.2

Biogas IH	0	0	0	0	0	0	0
Electric heating DH	0	53.9	57.7	61.7	63.5	69.8	121.7
Electric heating IH	9.2	0	0	0	0	0	0
Heat pump DH	0	61.4	74.5	80.3	76.1	69.7	54.9
Heat pump IH	9	343.9	404.6	428	437	421.8	401.7
RE fuels ind. heat	0	0	0.3	0.2	1.7	1.5	119.2
Fossil fuels ind. heat	100.8	165.5	170.2	178.3	180.7	174.6	0.1
Total	750.5	731.1	753.1	767.1	760.8	738.8	698.9

APPENDIX TABLE 23: INSTALLED HEAT CAPACITY UNTIL 2050.

Installed capacity for heat sector [GW]	2020	2025	2030	2035	2040	2045	2050
Methane CHP	9	8.8	6.7	2.3	2.3	0.3	0
Methane DH	22.1	21.4	17.9	14.3	10.7	7.2	3.6
Methane IH	94.6	47.3	31.5	15.8	0	0	0
Oil CHP	0	0	0	0	0	0	0
Oil DH	0	0	0	0	0	0	0
Oil IH	14	7	4.7	2.3	0	0	0
Coal CHP	0	0	0	0	0	0	0
Coal DH	0.2	0.2	0.2	0.1	0.1	0.1	0
CSP SF	0	0	0	0	0	0	0
Solar thermal heat	0	0	0	0	0	0	0
Geothermal heat DH	0	0	0	0	0	0	0
Biomass CHP	2.2	2.1	2	1.9	0.6	0	0
Biomass DH	3.8	3.8	3.2	2.5	1.9	1.3	0.6
Biomass IH	6.4	3.2	2.1	1.1	0	0	0
Waste–to–energy CHP	0.4	0.4	0.3	0.3	0.3	0.1	0
Biogas CHP	1	1	0.7	0.9	1.1	0.9	0.9
Biogas IH	0	0	0	0	0	0	0
Electric heating DH	0	22.8	22.8	22.8	22.8	22.8	22.8
Electric heating IH	3.8	3.2	2.5	1.9	1.3	0.6	0
Heat pump DH	0	7.8	9.7	10.5	10.6	10.6	8.3
Heat pump IH	3.3	52.6	70	80	90.5	87.5	83.7
Total	160.8	181.6	174.3	156.7	142.2	131.4	119.9

APPENDIX TABLE 24: FINAL TRANSPORT ENERGY DEMAND UNTIL 2050.

Final transport energy demand [TWh/a]	2020	2025	2030	2035	2040	2045	2050
Road passenger	289.3	282.5	243.1	184.8	124.9	91.9	78.2

Road freight	79.5	75.4	67.7	57.8	46.3	38	33.3
Rail passenger	5.5	6	6.4	6.8	7	7.1	7
Rail freight	0.7	0.7	0.7	0.7	0.7	0.7	0.6
Marine passenger	2.1	2.3	2.4	2.5	2.7	2.9	3.1
Marine freight	35.7	35.9	36.4	37.8	38.9	40.4	42.5
Aviation passenger	114.6	120.2	125.6	130.8	132.7	130.7	124
Aviation freight	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Total	528.2	523.8	483.1	422	354	312.5	289.5

APPENDIX TABLE 25: ELECTRICITY DEMAND FOR SUSTAINABLE TRANSPORT UNTIL 2050.

Electricity demand for sustainable transport [TWh_{el}]	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Electricity direct – RE	3	11.3	24.7	45.8	68.2	80.9	85.7
Electricity indirect e–hydrogen	0	0	1.5	8.4	25.1	48.9	72.5
Electricity indirect e–methane	0	0	0	0	0	0	0
Electricity indirect e–liquids (FT)	0	0	23.8	77.6	228.6	271.6	274.3
Electricity indirect e–ammonia	0	0.1	4.2	9.8	14.4	19.8	24.8
Electricity indirect e–methanol	0	0.1	4.9	11.6	17.1	23.7	28.9
Total	3	11.5	59.1	153.2	353.4	444.9	486.2

APPENDIX TABLE 26: ELECTRICITY STORAGE OUTPUT UNTIL 2050.

Electricity storage output [TWh_{el}]	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Battery utility	0	0.1	4.2	17.3	20.5	19	17.4
Battery prosumers – C&I	0	6.5	5.3	8.5	10.1	14.8	43.3
Battery prosumers – RES	0	2.6	5.8	8.8	10.6	25.6	57.1
Vehicle–to–Grid	0	0.1	3.3	10.5	15.4	15.1	11.8
PHES	0	0	3.1	3.4	4	3.4	2.6
A–CAES	0	0	0	0	0.1	0.1	0.1
Gas (CH_4) storage	0	0	0.5	0.7	0.6	0.5	0
Gas (H_2) storage	0	0	0	0.3	0	1.2	0.3
Total	0	9.3	22.2	49.5	61.3	79.7	132.6

APPENDIX TABLE 27: HEAT STORAGE OUTPUT IN 2050.

Heat storage output [TWh$_{th}$]	2020	2025	2030	2035	2040	2045	2050
TES HT	0	0.5	1.5	1.3	4.5	4.7	8.3
TES DH	0	0.2	1.3	1.9	2.1	1.5	3.4
Total	0	0.7	2.8	3.2	6.6	6.2	11.7

APPENDIX TABLE 28: GAS STORAGE OUTPUT UNTIL 2050.

Gas storage output [TWh$_{th}$]	2020	2025	2030	2035	2040	2045	2050
Gas (CH_4) storage	0	0.2	1.3	1.9	2.1	1.5	3.4
Gas (H_2) storage	0	0	1.9	15.2	38.1	49.6	56.3
Biogas storage	8.2	8.2	8.2	8.2	8.1	8.1	8.2
Total	8.2	8.4	11.4	25.3	48.3	59.2	67.9

APPENDIX TABLE 29: LCOE BY COMPONENT UNTIL 2050 FOR THE BPS.

LCOE [€/MWh]	2020	2025	2030	2035	2040	2045	2050
Capex	44.3	44.2	44.3	43.2	37.7	35.1	33.7
Opex fixed	14.7	13.5	13.4	12.9	10.6	9.8	8.8
Opex variable	1.3	0.5	0.4	0.3	0.2	0.2	0
Grids cost	0.7	1	0.8	0.7	0.7	0.6	0.6
Fuel cost	15.5	5.1	3.9	2.0	1.0	0.4	0.1
CO_2 cost	5.4	1.7	1.4	0.8	0.4	0.2	0
Total	81.9	66	64.2	59.9	50.6	46.3	43.2

APPENDIX TABLE 30: TOTAL ANNUAL SYSTEM COSTS BY COMPONENT UNTIL 2050 FOR THE BPS.

Total annual system cost [b€]	2020	2025	2030	2035	2040	2045	2050
Capex	19.1	28.7	33.3	38.7	44.8	44.9	51.6
Opex fixed	6.5	8.6	9.6	10.9	12.6	12.5	14.7
Opex variable	0.5	0.3	0.4	0.4	0.5	0.6	0.7
Grids cost	0.1	0.3	0.3	0.3	0.5	0.5	0.7
Fuel cost	42.7	30.9	27.6	20.2	10.2	4.4	0
CO_2 cost	10.4	12.4	12.4	11.0	8.0	7.3	0
Total	79.3	81.2	83.6	81.5	76.6	70.2	67.7

APPENDIX TABLE 31: POWER SECTOR CO_2 EMISSIONS UNTIL 2050.

Power CO_2 emissions [$MtCO_2$/a]	2020	2025	2030	2035	2040	2045	2050

Gas	41.1	10.7	9.1	4.9	2.9	0.9	0
Oil	0	0	0	0	0	0	0
Coal	14.9	0	0	0	0	0	0
Total	56	10.7	9.1	4.9	2.9	0.9	0

APPENDIX TABLE 32: HEAT SECTOR CO2 EMISSIONS UNTIL 2050.

Heat CO_2 emissions [$MtCO_2/a$]	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Gas	135.3	28.5	13.1	5.2	0.7	0.3	0
Oil	12.8	0.4	0.1	0.3	0	0	0
Coal	35.2	56.9	58.4	61.2	62	59.9	0
Total	183.3	85.8	71.6	66.7	62.7	60.2	0

APPENDIX TABLE 33: TRANSPORT SECTOR TTW CO_2 EMISSIONS UNTIL 2050.

TTW CO_2 emissions - road [$MtCO_2/a$]	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Road passenger – LDV	76.2	73.1	59	37.6	12.6	2.7	0
Road passenger – BUS	4.3	3.3	2.1	1	0.3	0.1	0
Road passenger – 2W/3W	0.9	0.7	0.6	0.4	0.2	0	0
Road freight – MDV	6.1	5.4	4.2	2.6	0.8	0.2	0
Road freight – HDV	16.2	15.2	13	9.5	3.9	0.9	0
Total	103.7	97.7	78.9	51.1	17.8	3.9	0

APPENDIX TABLE 34: TOTAL TTW CO_2 EMISSIONS BY SECTOR UNTIL 2050.

Total TTW CO_2 emissions by sector [$MtCO_2/a$]	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Power	51.9	10.7	9.2	4.8	2.8	0.8	0
Heat	183.3	85.8	71.6	66.7	62.7	60.2	0
Transport	149	142.5	122.8	90.9	41.5	12.4	0
Total	384.2	239	203.6	162.4	107	73.4	0

APPENDIX TABLE 35: STORAGE SIZE IAS FROM 2040 TO 2050.

Storage size IAS [TWh]	**2040**	**2045**	**2050**
Methane storage	184.3	426.3	916.5
Hydrogen storage	184.2	426.3	908.2

Appendix Table 36: Total annual system costs IAS until 2050.

Total ann. Cost [b€]	2040	2045	2050
Reference	93.6	90.1	91.9
Methane	96.0	95.8	104.8
Hydrogen	100.4	107.2	129.0

Appendix Table 37: Primary Energy Demand for all scenarios until 2050.

PED [TWh]	Scenario	Renewable Energy	Heat (Environment)	Fossil Fuels	Nuclear	Total
2020	Pres	140.5	7.1	1455.6	145.8	1748.9
2030	BPS	506.3	373.8	705.7	121.4	1707.3
	BPS+	507.1	375.2	703.5	121.4	1707.1
	IAS	508.7	374.1	704.6	121.4	1708.8
	CPS	359.9	292.4	909.5	278.7	1840.4
2040	BPS	846.0	402.4	346.1	23.2	1617.6
	BPS+	851.4	405.1	298.6	23.2	1578.3
	IAS	870.2	400.5	355.7	23.2	1649.7
	CPS	471.7	389.2	615.3	297.8	1774.0
2050	BPS	1213.0	365.2	0.2	0.0	1578.4
	BPS+	1124.9	372.7	0.1	0.0	1497.7
	IAS	1360.6	356.0	0.2	0.0	1716.8
	CPS	522.2	424.9	411.9	469.7	1828.6

Appendix Table 38: Electricity supply mix for all scenarios until 2050.

Electricity [TWh]	Scenario	Solar PV	Wind onshore	Wind offshore	Hydro	Wave	Biomass/ Waste	RE Others	Fossil coal	Fossil oil	Fossil gas	Nuclear
2020	Pres	13.4	58.3	56.6	3.9	0.0	2.7	0.0	19.0	0.0	89.0	48.1
2030	BPS	108.8	139.6	187.7	4.0	0.0	0.8	13.9	0.0	0.0	31.5	40.1
	BPS+	96.1	151.8	187.4	3.9	0.0	0.8	13.9	0.0	0.0	31.5	40.1
	IAS	111.1	139.7	187.6	4.0	0.0	0.8	13.9	0.0	0.0	31.5	40.1
	CPS	18.9	78.5	176.1	4.0	0.0	0.8	17.7	9.8	0.0	66.9	92.0
2040	BPS	263.5	189.6	322.2	4.0	64.2	1.0	14.9	0.0	0.0	12.6	7.7

	BPS+	234.2	212.0	237.0	4.0	0.0	1.0	15.1	0.0	0.0	12.5	7.7
	IAS	263.5	187.2	344.8	4.0	95.0	1.0	16.0	0.0	0.0	13.2	7.7
	CPS	30.2	83.3	234.5	4.0	11.2	1.0	26.7	0.0	0.0	55.8	111.7
2050	BPS	294.0	191.9	509.6	5.1	127.5	1.0	42.9	0.0	0.0	1.9	0.0
	BPS+	366.7	254.6	289.4	4.0	0.0	1.0	15.1	0.0	0.0	1.8	0.0
	IAS	294.0	191.9	681.0	5.1	127.5	1.0	43.3	0.0	0.0	2.2	0.0
	CPS	60.7	86.4	299.1	4.0	35.0	1.0	15.3	0.0	0.0	34.0	178.5

APPENDIX TABLE 39: CO_2 EMISSIONS FOR ALL SCENARIOS UNTIL 2050

CO_2 Emissions [$MtCO_2$]	2020	2025	2030	2035	2040	2045	2050
CPS	386	326	257	203	152	69	0
IAS	377	239	203	162	109	79	0
BPS	384	239	204	162	107	73	0
BPS+	384	238	203	160	92	33	0

APPENDIX TABLE 40: CO_2 EMISSIONS BY SECTOR FOR ALL SCENARIOS UNTIL 2050.

CO_2 [$MtCO_2$]	Scenario	Power	Heat	Transport
2020	Pres	51.9	183.3	149
2030	BPS	9.2	71.6	122.8
	BPS+	9.2	71	122.8
	IAS	8.9	71.2	123.2
	CPS	22.3	105.4	128.9
2040	BPS	2.8	62.7	41.5
	BPS+	0.9	51.1	40.4
	IAS	2.4	63.7	43.1
	CPS	7	71.9	73.4
2050	BPS	0	0	0
	BPS+	0	0	0
	IAS	0	0	0
	CPS	0	0	0

APPENDIX TABLE 41: LCOE FOR ALL SCENARIOS UNTIL 2050.

LCOE	Scenario	Capex	Opex fixed	Opex variable	Grids cost	Fuel cost	GHG cost	Total
		[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]
2020	Pres	44.3	14.7	1.3	0.7	15.5	5.4	81.9
2030	BPS	44.3	13.4	0.4	0.8	3.9	1.4	64.2
	BPS+	44.2	13.4	0.4	1.4	3.9	1.4	64.7
	IAS	44.0	13.4	0.4	1.0	3.9	1.4	64.1
	CPS	51.5	15.6	0.8	0.6	10.4	3.9	82.8
2040	BPS	37.7	10.6	0.2	0.7	1.0	0.4	50.6
	BPS+	40.2	11.1	0.1	1.4	0.5	0.2	53.5
	IAS	41.3	10.7	0.1	1.1	1.2	0.5	54.9
	CPS	56.5	15.0	0.6	0.5	6.2	0.4	79.2
2050	BPS	33.7	8.8	0	0.6	0.1	0	43.2
	BPS+	31.4	8.6	0	1.2	0	0	41.2
	IAS	43.4	10.8	0	0.9	0	0	55.1
	CPS	53.7	13.7	0.7	0.6	4.7	0.3	73.7

APPENDIX TABLE 42: CAPITAL EXPENDITURES. TOTAL ANNUAL SYSTEM COSTS AND CUMULATIVE COSTS BY SCENARIO UNTIL 2050.

Costs [b€]	Scenario	2020	2025	2030	2035	2040	2045	2050
Capex	BPS	162.1	249.2	309.0	385.4	472.4	493.1	557.3
Total Annual	BPS	79.3	81.2	83.7	81.6	76.6	70.2	67.7
Cumulative	BPS	79.3	477.6	885.9	1302.2	1705.2	2081.5	2429.9
Capex	BPS+	162.1	252.3	311.6	357.7	383.9	397.0	400.2
Total Annual	BPS+	79.3	81.3	83.9	80.5	73.1	64.0	58.1
Cumulative	BPS+	79.3	477.7	886.9	1303.1	1698.0	2054.3	2368.2
Capex	IAS	162.0	249.2	310.8	388.8	528.6	589.0	774.0
Total Annual	IAS	79.6	81.2	83.8	82.0	83.2	81.6	89.0
Cummulative	IAS	79.6	479.3	887.9	1305.0	1716.1	2130.5	2545.9
Capex	CPS	162.1	195.3	310.4	367.2	424.5	472.4	544.6
Total Annual	CPS	79.5	87.9	92.1	88.7	86.8	82.7	85.8
Cumulative	CPS	79.5	485.3	929.1	1386.1	1827.9	2257.7	2674.5

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