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Chi Kong Chyong	Michael Pollitt	David M. Reiner	Carmen Li

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Russia's invasion of Ukraine has reaffirmed the importance of scaling up renewable energy to decarbonise Europe's economy while rapidly reducing its exposure to foreign fossil fuel suppliers. The question of sources of flexibility to support fully decarbonised European energy system is, therefore, becoming even more important in light of a renewable-dominated energy system. We developed and used a Pan-European energy system model to systematically assess and quantify sources of flexibility in order to meet deep decarbonization targets. We find that the electricity supply sector and electricity-based end-use technologies are crucial in achieving deep decarbonization, and that other low-carbon energy sources like biomethane, hydrogen, synthetic e-fuels, and bioenergy with carbon capture and storage will also play a role. To support a fully decarbonized European energy system by 2050, both temporal and spatial flexibility will be needed. Spatial flexibility, achieved through investments in national electricity networks and cross-border interconnections, is crucial to support the aggressive roll-out of variable renewable energy sources. Cross-border trade in electricity is expected to increase, and in deep decarbonization scenarios, the electricity transmission capacity will be larger than that of natural gas. Hydrogen storage and green hydrogen production will play a key role in providing traditional inter-seasonal flexibility, and intraday flexibility will be provided by a combination of electrical energy storage, hydrogen-based storage solutions (e.g., liquid H2 and pressurised storage), and hybrid heat pumps. The role of hydrogen networks and storage will become more important as we move towards the highest decarbonization scenario, but the need for natural gas networks and storage will decrease substantially.

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Modelling Flexibility Requirements in European 2050 Deep Decarbonisation Scenarios: The role of conventional flexibility and sector coupling options

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Russia's invasion of Ukraine has reaffirmed the importance of scaling up renewable energy to decarbonise Europe's economy while rapidly reducing its exposure to foreign fossil fuel suppliers. The question of sources of flexibility to support fully decarbonised European energy system is, therefore, becoming even more important in light of a renewable-dominated energy system. We developed and used a Pan-European energy system model to systematically assess and quantify sources of flexibility in order to meet deep decarbonization targets. We find that the electricity supply sector and electricity-based end-use technologies are crucial in achieving deep decarbonization, and that other low-carbon energy sources like biomethane, hydrogen, synthetic e-fuels, and bioenergy with carbon capture and storage will also play a role. To support a fully decarbonized European energy system by 2050, both temporal and spatial flexibility will be needed. Spatial flexibility, achieved through investments in national electricity networks and cross-border interconnections, is crucial to support the aggressive roll-out of variable renewable energy sources. Cross-border trade in electricity is expected to increase, and in deep decarbonization scenarios, the electricity transmission capacity will be larger than that of natural gas. Hydrogen storage and green hydrogen production will play a key role in providing traditional inter-seasonal flexibility, and intraday flexibility will be provided by a combination of electrical energy storage, hydrogen-based storage solutions (e.g., liquid H_2 and pressurised storage), and hybrid heat pumps. The role of hydrogen networks and storage will become more important as we move towards the highest decarbonization scenario, but the need for natural gas networks and storage will decrease substantially.

Highlights

- Central role of the electricity supply sector and electricity-based end-use technologies to meet deep decarbonization targets
- Low-carbon energy sources such as bioenergy, hydrogen, synthetic e-fuels, and CCUS plays a role in Net Zero
- Spatial flexibility is achieved through investments in national electricity networks and cross-border interconnections
- Temporal flexibility is provided by a combination of electrical energy storage, hydrogen-based storage solutions, and hybrid heat pumps
- The need for natural gas networks and storage will decrease substantially as we move towards higher decarbonization scenarios
- In Net Zero scenarios, the role of hydrogen networks and storage will become increasingly important.

Keywords
Energy system modelling, spatial flexibility, temporal flexibility, networks, intraday storage, long-duration storage, P2X, Net Zero, deep decarbonization

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Definitions and abbreviations

Blue hydrogen – hydrogen produced from fossil natural gas with CCS via steam reformation technologies (e.g., steam methane reformation (SMR) and autothermal reforming (ATR) technologies); it is a source of low-carbon hydrogen, depending on assumed captured rate of CCS;

Green hydrogen – hydrogen produced from electricity via water electrolysis; it is a source of low-carbon hydrogen, depending on carbon intensity of electricity generation. There are three kinds of electrolyser: Solid oxide electrolyser cells (SOEC); Acidic or Polymer Electrolyte Membrane (PEM); and Alkaline.

Renewable gas – biomethane (upgrading of biogas to the specification - 96% CH_4 and 3% CO_2 - allowing injection into existing gas grids). Biomethane is carbon neutral, similar to biomass for power generation. In the process of upgrading biogas, the CO_2 in the biogas is captured and either stored (negative emissions) or used to produce carbon neutral PtG and PtL;

e-gas or *power-to-gas (PtG)* – production of synthetic CH_4 (e-gas) using hydrogen and CO_2 from biomass generation or biogas upgrading to biomethane;

e-liquids or *power-to-liquid (PtL)* – production of synthetic diesel (e-liquids) using hydrogen and CO_2 from biomass generation or biogas upgrading to biomethane;

Power-to-x (P2X) – refers to both e-gas and e-liquids;

Vehicle-to-grid (V2G) – technology enabling electricity to be pushed back into the power grid that is stored in electric vehicle batteries

Diesel – refers to fossil fuel-based diesel;

Natural gas – refers to natural gas of fossil origin;

Gas network – network to transport CH_4;

H_2 network – network to transport hydrogen;

Electricity network – network to transport electricity.

Variable renewable energy (VRE) – electricity generation where the source (e.g., wind, solar) varies over time and where the energy cannot easily be stored

Electric vehicles (EVs) – vehicles that run solely on batteries, sometimes described as battery electric vehicles (BEVs)

Heavy goods vehicles (HGVs) – large goods vehicles, which in the European Union, are defined as exceeding a mass of 3500 hg

Fuel cell electric vehicles FCEV – fuel cell electric vehicle

Open cycle gas turbine (OCGT) –

Combined cycle gas turbine (CCGT) –

Combined heat and power (CHP) –

1. Introduction

In June 2021, the European Union adopted a European climate law stipulating that EU countries must cut their greenhouse gas (GHG) emissions by at least 55% by 2030, with the ultimate goal of reaching net zero (NZ) GHG emissions by 2050 (EC, 2021). At Member State (MS) level, at least 11[1] out of 27 MS adopted NZ targets in domestic legislation. These 11 MS represent more than two-thirds of EU27' GDP, GHG emissions and population (Net Zero Tracker, 2023). To support this ambitious policy target, the EC adopted a series of of strategies and initiatives including the EU Energy System Integration Strategy (EC, 2020a), the EU Hydrogen Strategy (EC, 2020b), EU Strategy on Offshore Renewable Energy (EC 2020c), the Renovation Wave (EC 2020d) and Sustainable and Smart Mobility Strategy (EC 2020e).[2]

On 24 February 2022, Russia launched a full-scale military invasion of Ukraine. In response to the worst geopolitical crisis in Europe since World War II, and in particular to ensure continued progress towards an energy transition that is both sustainable and secure, the EC published in May 2022 its RePowerEU plan (EC, 2022) setting out a series of measures and targets aiming at completely phasing out fossil fuel imports from Russia by 2027. Thus, long-term energy security (i.e., Europe's dependence on foreign energy suppliers) concern is firmly back on top of the EU's policy agenda. While the RePowerEU plan and in particular phasing out import dependence is compatible with NZ targets, the question of short-term security of supply looms larger, which reinforces our overarching question, namely, *what are the sources of flexibility to support a fully decarbonised European energy system by 2050*. This research paper seeks to address this question by developing and using a Pan-European energy system model to quantitatively assess impacts of the deep decarbonisation policy targets on Pan-European energy networks as well as storage and emerging new technologies and energy vectors. We do so by specifically looking at the role of both conventional flexibility options, such as energy network and storage capacity expansion, and also so-called "sector coupling" or "system integration" technologies, such as electrolysis to produce low-carbon hydrogen, power-to-X (P2X, electrofuels) technologies, and hybrid heat pumps.

The rest of this paper is structured as follows. In Section 2 we summarise the literature framing it in terms of sources of flexibility and their requirements in deep decarbonisation pathways. We then briefly summarise our modelling and analytical framework (with a complete model description and data inputs in Appendix 1 and 2) in Section 3. In Section 4 we present our modelling results and discuss policy and regulatory recommendations in Section 5 while the final section concludes our research.

2. Literature review on flexibility sources in deep decarbonisation scenarios

Academic literature on modelling deep decarbonisation of energy systems is abound and focuses on describing different technology pathways (see e.g., Capros et al., 2014a; Capros et al., 2014b; Capros et al., 2016; Capros et al., 2018; Capros et al., 2019; Fragkos et al., 2017; Davis et al., 2018; Weitzel et al., 2019) to serve Europe's end-use needs and explores the necessary societal changes to reach a net-zero economy (see e.g., EC 1.5 LIFE scenario in EC (2020a); Carmichael, 2019; Carmichael and Wainwright, 2020; Carmichael et al., 2020). Other studies add more complexity to the representation of emerging technologies to better understand how they affect system costs in a decarbonised economy. For example, Capros et al. (2019) model disruptive mitigation options in specific hard-to-abate industrial sub-sectors (e.g, hydrogen to produce direct reduced iron) and other emerging technologies, like direct air capture of carbon (DAC).

An important result from modelling studies (see e.g., Nijs et al., 2019; Auer et al., 2020; Rodrigues et al., 2022; see Larson et al., 2021 for the North American energy system) is that increased electrification of the European energy system using RES is a "no-regret" decision to achieve a cost-effective energy transition.

Thus, academic and regulatory community has been increasingly focusing on the costs of integrating variable renewable energy (VRE) sources into the power sector (see e.g. Ueckerdt et al., 2013; Hirth et al., 2015; Heptonstall and Gross, 2020). The European Commission (EC) stresses the importance of sources of flexibility to decarbonise the whole energy system, while ensuring supply security (see EC, 2018a, p.38); and the academic literature has discussed the flexibility needed to support the decarbonisation of the energy system through high penetration of VRE in the power sector (for a review, see e.g., Huber et al., 2014; Alizadeh et al., 2016; Kondziella et al., 2016; Cruz et al., 2018). While attention has been paid to the flexibility needs in the electricity sector, limited studies paid attention to the needs in the context of a deeply decarbonised whole energy system (see e.g., Brown et al., 2018; Evangelopoulou et al., 2019; Victoria et al., 2019; Pavičević et al., 2020; Zhu et al., 2020; Bødal et al., 2020). A more thorough analysis of flexibility needs, however, can help us leverage *sector coupling* or *energy system integration* for the benefit of system resilience and cost-effectiveness in reaching net zero.

The rest of this section, structures the review into three overarching flexibility categories: (i) spatial flexibility provided by energy networks, (ii) seasonal flexibility provided by long-duration storage, and (iii) intraday flexibility provided by a number of solutions, such as batteries, demand-side response, peak-shaving gas storage, etc.

[1] These are Germany, Sweden, France, Italy, Spain, Ireland, Portugal, Denmark, Hungary, Finland, and Luxembourg

Role of energy networks to provide spatial flexibility

The literature has appreciably explored the concept of spatial flexibility, particularly in relation to the integration of VRE resources. Integration costs of VRE are diminished by taking advantage of negative covariances between geographical locations (see e.g., Schaber et al., 2012; Malvaldi et al., 2017; Zeyringer et al., 2018) which is made possible by a high level of interconnection between European regions. Tröndle et al. (2020) analyze how Europe could reach decarbonation of its Energy system by 2050 using different geographic scales of renewable energy sources supply. The authors analyze trade-offs between geographic scale, system costs, and infrastructure needs. While sourcing renewable energy at a continental level achieves the least total cost, it also imposes a greater need for transmission infrastructure and cross-border capacity. Meanwhile, a regional-scale generation scenario reaches similar cost levels only when a continental level balancing trade is available[3].

Similarly, Neumann and Brown (2021) explore different configurations of the energy system to achieve decarbonisation of the European economy. They found that there exists a trade-off between diversifying the mix of technologies and reaching the least cost solution. The uncertainty on input cost curves was included to analyze the implications for a set of technologies[4]. Considering near-cost-optimal system configurations, they concluded about the robustness of network investments relative to the cost uncertainty of the other technologies considered. The expansion of the transmission network in Europe is the investment decision that is least sensitive to cost uncertainty as it is developed with an additional capacity of between 30% to 200% within an 8% cost-distance of the optimal solution. Hydrogen storage also appears as a vital technology: only 25% of technology mixes (scenarios) within an 8% range of the optimal solution require no long-range hydrogen storage (Neumann and Brown, 2021).

Another important factor to leverage spatial flexibility is the integration of the European energy hubs. The previous economic savings, along with efficiency gains, do not hold true when looking at specific individual countries. Electrolysers, renewables and network investments drive the German power system costs up and Norway experiences an average increase of its electricity prices after the transition (Durakovic et al., 2023). Therefore, a better alignment of national European infrastructure development strategies is necessary in order to reach a least-cost and an integrated European energy system.

Role of seasonal storage to provide temporal flexibility

The literature has also extensively examined the concept of seasonal (temporal) flexibility, particularly issues of summer and winter heat loads, the role of natural gas seasonal storage (see e.g., Chaton et al., 2008; Chaton et al., 2009), the role of long-duration electrical energy storage (see e.g., Henry et al., 2020; Ziegler et al., 2019; Albertus et al., 2020; Dowling et al., 2020; Bistline et al., 2020) and the role of power-to-gas, gas networks and storage (see e.g., Clegg and Mancarella, 2016; Blanco et al., 2018).

Fuels produced from VRE such as green hydrogen or synthetic electrofuels can supply hard-to-abate sectors such as heavy freight transport and energy-intensive industries (see e.g., Rodrigues, 2022; Amid et al., 2016; Tarkowski, 2019; Samsatli and Samsatli, 2019; Staffell et al., 2019). These technologies help to reduce emissions while providing flexibility to produce electrofuels from VRE sources in oversupply hours. Ruhnau (2022) uses a price-based electricity demand response model to analyze how electrolyzers increase the value of renewables when coupled with such systems. Runhau shows that green hydrogen can effectively and permanently halt a decline in their market value by adding flexible demand in low-price hours.

Likewise, large-scale production of green hydrogen combined with offshore wind production in the North Sea results in a significant improvement of the power system's efficiency (Durakovic et al., 2023). In a system configuration enabling large-scale production of green hydrogen, peak hour power prices plummet and traditionally low-price periods see a price increase, as electrolyzers use the cheap electricity to produce hydrogen. This suggests that electrolyzers have a stabilizing effect on the power prices. The reduced installed renewable generation capacities and lower share of electricity curtailed (dropping from currently 24.9% to 9.6% of total generation in the North Sea region) prove the improved system efficiency brought by large-scale electrolysis.

Moreover, coupling the heating and the power sector enables a much higher and more efficient utilization of renewable resources with thermal storage (Pavičević et al., 2020). Thermal storage plays a crucial role as it prevents overcapacity of thermal units and provides load shifting possibilities in a context of interlinked power and heating sectors with more P2H and CHP units.

Role of intraday storage to provide temporal flexibility

The academic literature provides studies on intraday flexibility, particularly in relation to the integration of VRE on the intraday timescale and the use of electrical energy storage to facilitate this integration (see e.g., Pudjianto et al., 2013; Steinke et al., 2013; Nijs et al., 2014; Weitemeyer et al., 2015; Zeyringer et al., 2018; Bistline et al., 2020).

Intraday variations in demand and supply can also be handled by an optimized coordination between intraday electricity-based and gas-based flexibility solutions. Felix Frischmuth et al. (2022) showed that realizing direct temporal flexibility potentials (e.g. demand-side response, storage) in different centralized and decentralized applications in the

[3] The generating scale parameter constrains the entire continental, national or regional power demand to be supplied by assets within the same geographic scope. Generating scale demands net self-sufficiency: within a year, electricity can be traded freely, as long as net annual imports reach 0; while the balancing scale defines the area in which electricity can be traded within a year.

[4] offshore and onshore wind, solar, hydrogen and battery storage, transmission networks

transport, heating and industry sector lowered the power system's flexibility options requirements. The results show a substantial decrease (-84.4%) in required battery storage capacity and a reduced electrolyzer capacity (-11.3%), proving them to be less advantageous than flexibility options in the heat, transport and industry sectors. Traditional generation technologies (such as OCGT, CCGT, CHP) are also less preferred, with a reduced installed capacity for all technologies (e.g. up to – 47.8% for OCGT).

Mandel et al. (2022) complement these findings with a study of the potential of buildings' thermal mass as heat storage. Using the thermal inertia of buildings, about 18 to 35% of residential heat pumps' energy consumption could be used for flexibility services. This flexibility yields cost savings if combined with local grid substations and reducing the need for flexibility specific investment such as electric batteries or water tank storages (for more on demand-side technologies in buildings, see e.g., Strbac et al., 2020; Elliot et al., 2020). Schledorn et al. (2022) confirm these findings: their representation of the energy system achieves a 17% cost savings when combining the thermal mass of district heating pipes (hot water) and buildings' thermal capacity for heat storage.

District heating has the advantage of multi-sources flexibility as it allows for solar thermal and direct geothermal to supply heat to buildings, offering more local and import-independent alternatives. Finally, Brown et al. (2018) optimize for a cost-optimal European energy system for a 95% reduction in carbon dioxide emissions compared to 1990 to analyze the synergies between sector temporal flexibility and spatial flexibility. They find that the cost-minimizing integration of BEV pairs well with the daily variations of solar power, while P2G (power to hydrogen or methane) and LTES (long-term thermal energy storage: large water tanks) balance seasonal variations of demand and renewables. More importantly, they showed that temporal flexibility options make a more significant contribution to the smoothing of variability from wind and solar and reduction of total system costs than using cross-border transmission (spatial flexibility).

To summarise the literature, flexibility plays a crucial role in the design, operation, and management of net zero energy systems, and that the integration of flexible technologies and operating strategies is essential for achieving a low-carbon, reliable, and least-cost energy system. Our paper contributes to this growing literature in two ways.

First, from an empirical and policy perspective, our research examines the role and interactions between traditional sources of flexibility (e.g., networks and storage) and emerging flexible sector-coupling technologies (e.g., electrolysis, P2X, and hybrid heat pumps) in deep decarbonisation scenarios. Limited studies looked at the combination of both large-scale sector-coupling technologies – electrolysis, P2X – and small-scale technologies – hybrid heat pumps – with traditional flexibility technologies.

Secondly, from the methodology perspective, our paper contribute to the modelling literature as follows:

1. We developed a statistical method (see Appendix 1.3.1) to aggregate hourly time series while capturing the essence of hourly variability of both demand and supply dynamics, in particular, generation from VRE; thus, avoiding "soft-linking" (see e.g., Zeyringer et al., 2018; Pavičević et al., 2020) between the various models with different time scales and horizons while ensuring tractability and solvability.
2. To carefully model inter-seasonal and long-duration storage in the framework of reduced time series we implement the superposition method (for details see Kotzur et al., 2018). Most of reviewed studies that uses time series aggregation methods to reduce computational cost neglect the important question of inter-seasonal storage state transition – volume of energy from one representative day to another (for details of the superposition method that we implemented, see Appendix 1.3.2).

3. Modelling Framework and Scenarios

This section outlines a short summary of our modelling framework, sensitivity analysis and describes our main scenarios.

3.1. Energy system model for net zero policy analyses

Our energy system model is a partial equilibrium, linear programming optimisation model capable of representing our modern and future energy systems in great detail. It is an economic optimisation model and hence its objective is to minimise total energy system costs comprising of capital and operational costs in the various sectors while meeting projected end-use demands and GHG emissions and other constraints specified by the user (see Figure 1). A detailed mathematical formulation of the model can be found in Appendix 1.

For this research project, the model represents 12 European market areas allowing for endogenous trade in main commodities (see Figure A. 4 in Appendix 2). The model covers **hourly dispatch** and operations of main technologies and **investment** in **capacities** of power, heat, H_2, electricity-based fuels production, end-use road transport technologies (EVs, FCEVs etc.), H_2 production, storage and networks (see Figure A. 5 in Appendix 2).

The model covers the main final consumption sectors – residential, commercial, transport and industry. For this research project we have aggregated final consumption as follows:

- Buildings sector represents final energy services demand of residential, commercial and energy use in the agriculture sectors;
- Road transport represents final energy services demand for road activities of passenger cars, public road transport and heavy goods vehicle (HGV);

- Industry represents final energy consumption in the industrial sector;
- Other transport represents final energy consumption by aviation, inland navigation and rail transport activities.

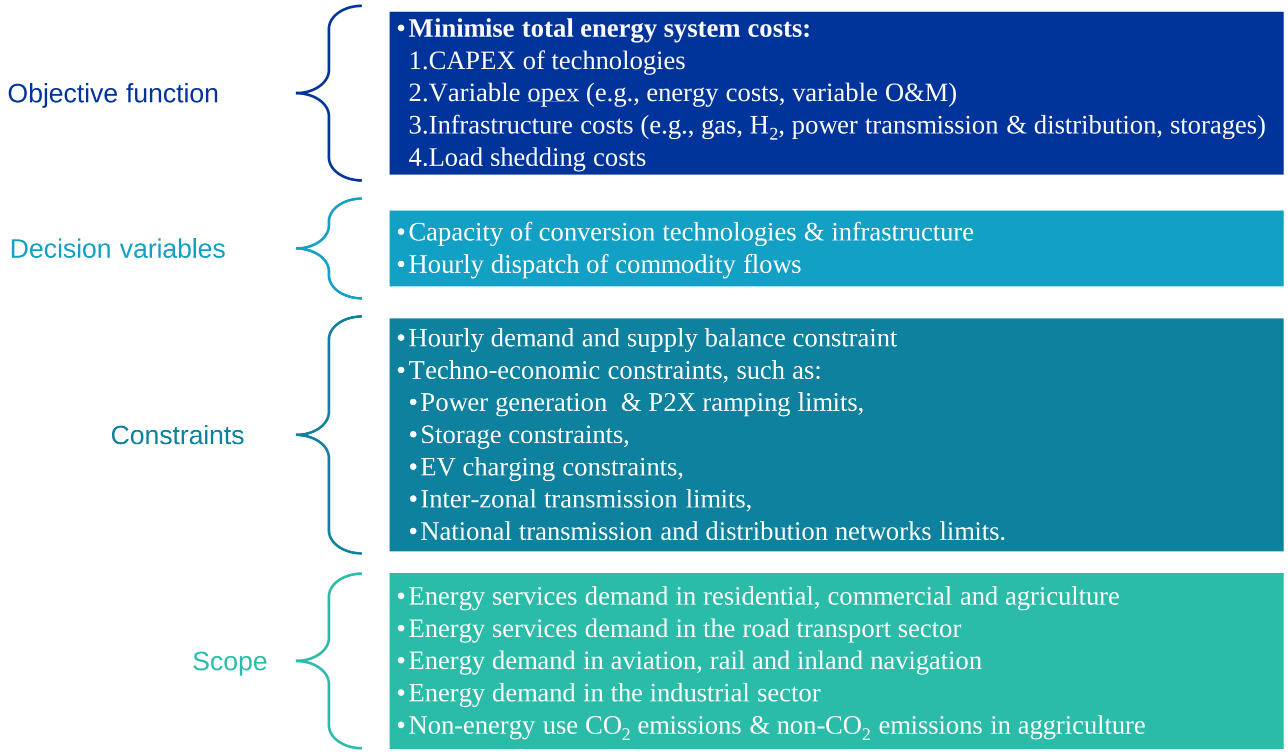

Figure 1: Energy system model for policy analyses

3.2. Baseline Scenarios

Our baseline scenario is ***Net Zero (Negative Emissions Technology Scenario) GHG emissions system by 2050***. This baseline scenario represents an ambitious GHG emissions reduction strategy – the negative emissions technology (NZ) scenario strives to achieve carbon neutrality by 2050 and it is closely aligned with the assumptions of the EC Long-Term Strategy (LTS) 1.5 TECH (EC, 2018a). Appendix 2 provides details regarding calibration to EC LTS, data inputs and assumptions. In addition to the NZ scenario, we also model another scenario, which differs along the level of GHG emissions reduction ambition. This scenario is a deep decarbonisation pathway that strives to achieve a reduction of at least 90% GHG emissions relative to 1990 level; we call this **90% Scenario**; this is closely aligned with the EC LTS COMBO scenario (EC, 2018a).

The purpose of these two scenarios is to understand the role of traditional and new sources of flexibility in meeting the ambitious decarbonisation targets. Following EC LTS (EC 2018, p.210), we assume a carbon price of €350/tCO2 in the ETS sectors in the NZ scenario and €250/tCO2 in the 90% scenario in 2050. It is worth noting that applying carbon pricing in the ETS sectors only might not lead to deep decarbonisation of other sectors such as buildings and transport sectors; therefore, in addition to the carbon pricing (in the ETS sector), we apply GHG emissions cap, in line with EC LTS assumption, for the buildings and transport sectors (see Table 1). Thus, in line with the EC LTS scenarios, there will likely by some residual emissions in the buildings and transport sectors, which will primarily be offset by negative emissions technologies (e.g., bioenergy with CCUS).

	90% Scenario	NZ Scenario
Residential	19.3	11.8
Tertiary	23	19.3
Transport	256.8	85.6

Table 1: Caps for GHG emissions in buildings and transport sectors (mn $tCO2_e$)
Source: EC (2018b,c)

Figure 2 outlines our key assumptions for prices of energy sources and capital cost of renewable and hydrogen technologies that we use in our modelling. These charts show significant uncertainties around our key assumptions. For example, natural gas price is assumed to be €30/MWh (upper right panel) in 2050, but due to the crisis in Europe related to the Russian invasion of Ukraine, natural gas prices spanned almost an order of magnitude from €30/MWh to €272/MWh between mid-2021 and late 2022. If in 2050 gas prices were to be at the high end of the recently observed price range, this would make domestically produced biomethane cost competitive. On the other hand, bioenergy availability is a key source of uncertainty and the assumed supply availability of bioenergy totalling 2,919 TWh in 2050 may seem too optimistic (upper left panel). Likewise, assumed cost reductions in wind and solar as well as hydrogen and P2X technologies may be too optimistic: for example, we have assumed cost reduction of 18% and up to 57% for wind and solar technologies (lower left panel), while for hydrogen and P2X cost reduction is assumed between 11% and up to 86% (lower right panel). Thus, to deal with these range of uncertainties we have conducted sensitivity analyses, which we discuss in the next section.

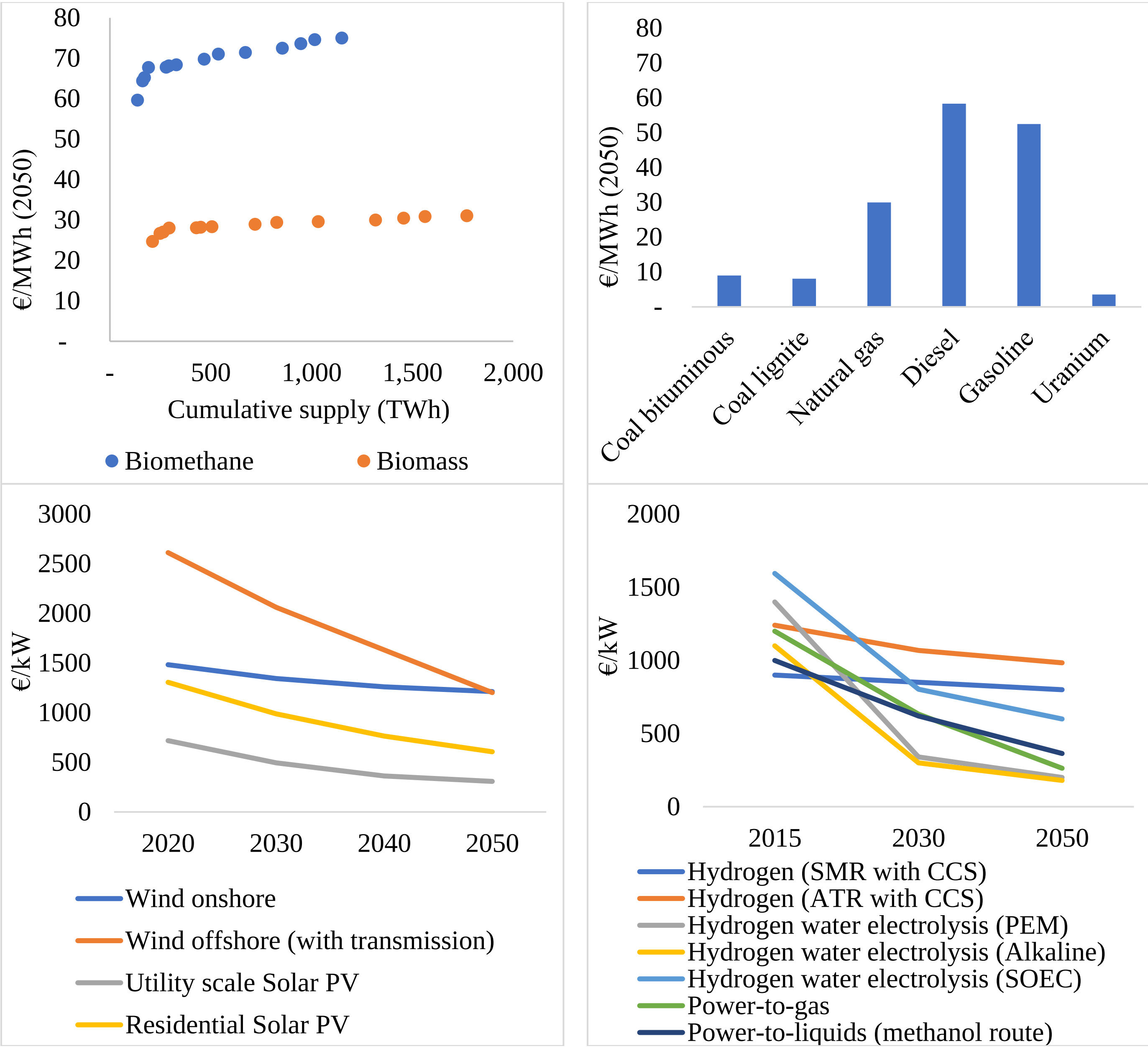

Figure 2: Cost assumptions for key technologies in the model: upper left chart – supply cost curves for bioenergy in 2050; upper right chart – prices for main energy sources in 2050; lower left chart – capital cost trend for wind and solar to 2050; lower right chart – capital cost trend for hydrogen and P2X technologies to 2050.
Source: see Appendix 2 for details about sources of these assumptions

3.3. Sensitivity analysis

In addition to the two baseline scenarios, we also carried out two sets of sensitivity analysis. The first sensitivity analysis involves modelling two additional baseline "variants" to capture uncertainties in our inputs and key assumptions (see Table 2):

1. A net zero scenario which is heavily dependent on direct electrification; we called this the **NZ-e Scenario**;
2. A net zero scenario which is heavily dependent on fossil methane, biomethane, hydrogen and negative emissions with limited reliance on direct electrification; we called this the **NZ-g Scenario**.

Table 2: Assumptions for sensitivity analysis of the NZ scenario

NZ-e key assumptions	NZ-g key assumptions
All commodity prices to be **increased** by a factor of 2 (relative to the NZ baseline costs). These commodities are coal, natural gas, biomass, biomethane, diesel, gasoline, and uranium;	All commodity prices to be **decreased** by a factor of 2 (relative to the NZ baseline costs). These commodities are coal, natural gas, biomass, biomethane, diesel, gasoline, and uranium;
Capex of wind onshore, offshore and solar PV to be **decreased** by a factor of 2 (relative to NZ baseline costs);	Capex of wind onshore, offshore and solar PV to be **increased** by a factor of 2 (relative to NZ baseline costs);
Increase the upper bound for electrification of road transport – passenger cars, public transport and HGV – to 100% (% of total vehicle stock) in 2050. Note that under the NZ baseline, the upper bound were kept in line with EC 1.5TECH (see Appendix A.2.9.);	**Decrease** the upper bound for electrification of road transport – passenger cars, public transport – down to 50% (% of total vehicle stock) while for HGV we keep the same as in the NZ baseline;
Country-specific upper bounds for wind offshore and onshore to be **increased** by a factor of 2 (relative to the NZ baseline upper bounds applied to wind offshore and onshore);	Country-specific upper bounds for biomass and biomethane availability to be **increased** by a factor of 2 (relative to the NZ baseline upper bounds applied to biomass and biomethane);
Electrification of industrial final energy demand to be **increased** to 85% compared to 60% assumed in the NZ scenario in line with 15 TECH.	Electrification of industrial final energy demand to be **capped at** 40%.

The second sensitivity analysis involves extensive modelling of changes in the costs of traditional and sector coupling technologies. While most previous academic studies of deep decarbonisation scenarios emphasise the combination of technologies and societal transformations needed to achieve these pathways (see our literature review), to date, there has been limited academic work assessing the sources of flexibility in such scenarios – We consider gas and electricity sector coupling and emerging new energy technologies that operate as both demand and supply for gas and electricity (e.g., electrolysis or hybrid heat pumps). To address this question, we begin by using our energy system model to simulate our baseline scenario and its variant, and then we conduct our sensitivity analyses (see Figure *3*). Based on our literature review, we identify the following key sources of flexibility in a deeply decarbonised energy system:

1. **Networks** – moving energy across space helping to integrate energy supply and demand sources.
2. **System integration technologies ï** such as power-to-X helping to couple the different energy sectors and enabling efficient circular energy system as well as water electrolysis technologies coupling electricity and gas sectors at the upstream level and hybrid heat pumps coupling electricity and gas at the household level.
3. **Storage** – moving energy across time helping to modulate energy demand and supply

For each of the key technologies we increase its projected cost by a small fraction and measure the impacts of these cost sensitivities on a tipping point when our energy system might switch to an alternative set of technologies. Thus, for each of the technology we listed in Figure 3, we change their projected costs by -50% to +200% from the baseline costs assumptions with the increments as shown in Table 3. Note that we consider H_2-based technologies to be immature at present and hence our range of cost sensitivities parameters applied to these set of technologies are wider; this is intended to capture a potentially wider range of outcomes of H_2-based technological innovation pathways by 2050.

For example, for the network sensitivity analysis, we have done 18 sensitivities (3 x 6) for the Net Zero Scenario and hence 18 simulations in total for this set of technologies. This analysis is performed for all key technologies we listed in Figure 3. Apart from answering our research questions, the objective of this sensitivity analysis is at least two-fold: (i) to show the robustness of the model by showing “directional” impact, and (ii) to facilitate transparency as to the model behaviour. To our best knowledge, such sensitivity analysis of key traditional flexibility and sector coupling options for modelling a net zero scenario has not been carried out systematically in the recent modelling work on energy system integration (results from this cost sensitivity analysis is reported in Appendix 3).

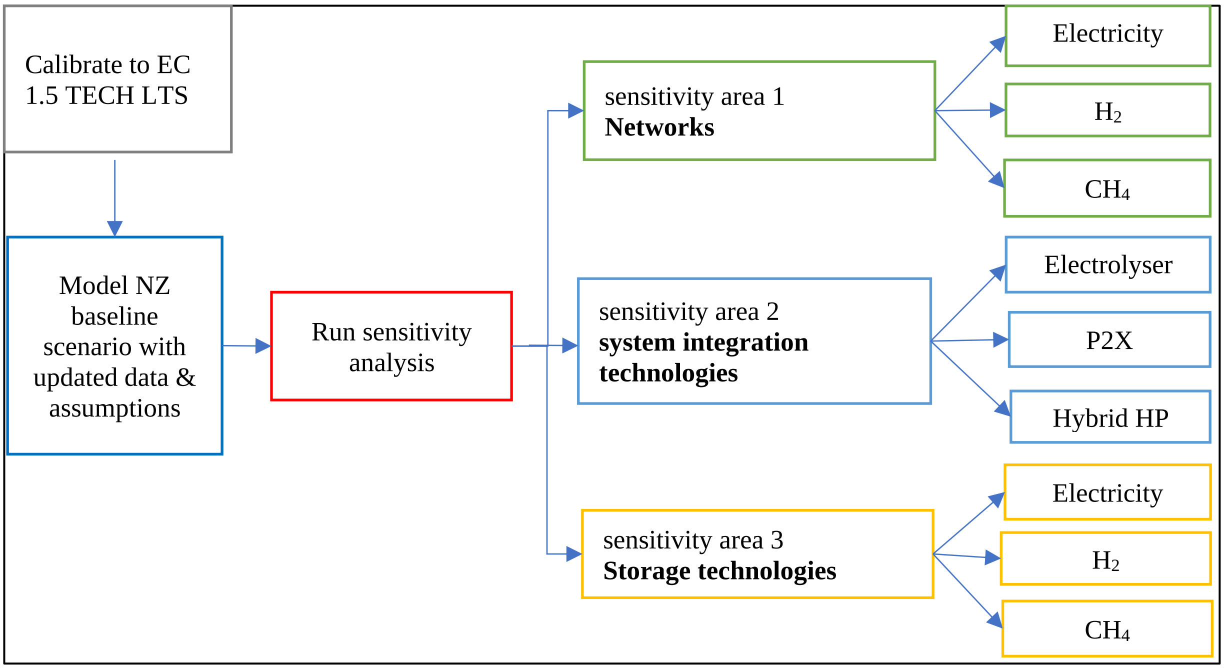

Figure 3: Research framework for sensitivity analyses

	Electricity- and CH_4-based technologies	H_2-based technologies
Sensitivity 1 (s1)	+10% (relative to the baseline cost)	+50% (relative to the baseline cost)
Sensitivity 2 (s2)	+25%	+100%
Sensitivity 3 (s3)	+50%	+200%
Sensitivity 4 (s4)	-10% (relative to the baseline cost)	-10% (relative to the baseline cost)
Sensitivity 5 (s5)	-25%	-25%
Sensitivity 6 (s6)	-50%	-50%

Table 3: Cost parameters for sensitivity analyses of traditional flexibility and sector coupling technologies

4. Modelling Results

This section starts with a brief summary of modelling results from the NZ Baseline scenario (§4.1), focusing on (i) key challenges in getting to our NZ scenario, and (ii) on results from the first sensitivity analysis – NZ-e, NZ-g and 90% scenarios. It then discusses (in §4.2) findings related to our key research question – sources of flexibility in deep decarbonisation scenarios, focusing on the differences between the NZ scenario and the 90% scenario in terms of cross-border trade, installed capacity of energy storage, sector-coupling technologies, and networks.

4.1. Reaching our deep decarbonisation scenarios by 2050

Table *4* outlines projection of final consumption and primary supply by main energy sources in the NZ scenario that we model. Our results suggest that final energy consumption reaches 8,246 TWh in 2050, which is consistent with the results obtained by the EC in its 1.5 TECH scenario (7,955 TWh in 2050). It represents 67% of final consumption in 2018. This drop in energy consumption is driven primarily by direct electrification and in uptake of more energy efficient end-use technologies in the building sector (e.g., heat pumps) and in road transport sector (e.g., EVs).

The role of electricity in our NZ Baseline

First, at the system level, the results highlight the central role of electricity in NZ GHG emissions by 2050 in the EU. In the net zero scenario electricity in the final consumption reaches 51% (for comparison, the EC 1.5TECH predicts 50%). This is a very consistent set of results with both the EC LTS result as well as with many other academic studies (see e.g., Jenkins et al., 2018).

While electricity plays a central role in our NZ scenario, it is worth mentioning the role of other low-carbon energy sources, in particular, the role of biomethane, hydrogen and P2X in final energy consumption. Together, H_2, biomethane, e-gas and fossil gas contribute around 33% of final energy consumption in 2050. To put this in the context of our current (2018) energy system and energy flow, Table 4 shows changes in final consumption and the primary supply position of electricity, CH_4 and H_2 in 2018 versus the 2050 NZ scenario. One immediate conclusion is that in terms of energy throughput requirements, the flow of CH_4 will be reduced from 2854 TWh of delivery to final consumers in 2018 to 1869 TWh in 2050, which is a reduction of 35% relative to 2018 levels; at the same time, we see a larger decrease of at least 50% in CH_4 flow at primary supply level – from 5396 TWh in 2018 down to 2672 TWh in 2050. There is no surprise in this trend because of potential decentralisation of CH_4 supply in the future as our NZ energy system will be dominated by "home grown" biomethane and synthetic gas at "local" level requiring less flow at primary supply level (or at transmission level) and hence minimising Europe's reliance on imported fossil natural gas. None of this, however, means it is any less important for the transmission nor distribution networks capability to deliver CH_4 in the NZ system; we come back to system capacity and capability below in Section 4.2.2. Further, one can see that the role of fossil gas will be reduced dramatically, from 2854 TWh to 199 TWh (just 7% of the 2018 supply level) in the structure of final consumption, while imports are expected to reduce to 907 TWh, or ca. 23% of the EU27's gas imports in 2021.

A second immediate conclusion we can draw is the role of the emerging H_2 energy carrier and network in 2050 – hydrogen will have a comparable role in terms of energy flow as CH_4 network; its flow to final consumption reaches ca. 50% of the flow level of CH_4 in 2050 while at primary supply level the throughput of H_2 reaches 83% of the flow level of CH_4. As we shall discuss later it is not unimaginable to have two separate networks – CH_4 and H_2 – to deliver cost optimal net zero energy system. This result is driven by the assumption that biogas (derived from wastewater treatment plans and landfill gas recovery systems) is upgraded to biomethane instead of being processed to hydrogen. Both processes are subject to great technological uncertainty, given that biomethane production today is close to zero and projected to increase to more than 1000 TWh per year in 2050. A sensitivity has been performed to explore a decarbonization pathway where bioenergy is not abundantly available (see NZ-e scenario results below)

Table 4: Changes in final consumption and primary supply of main fuels (TWh/year)

	Final Consumption		**Primary Supply**	
	2018	**NZ Scenario**	**2018**	**NZ Scenario**
Electricity	2,812	4,175	3,629	6,818
CH_4	2,854	1,869	5,396	2,672
Fossil gas	*2,854*	*199*	*5,396*	*907*
Biomethane	-	*1,059*	-	*1,150*
E-gas	-	*611*	-	*615*
Hydrogen	-	921	-	2,228

Source: 2018 data is from Eurostat

The third conclusion that we can draw is that electricity flow to final consumption needs to be scaled up by almost 50% between 2018 and 2050 to serve as the main backbone of the NZ energy system. The scale up of electricity supply is even higher – almost doubling (88%) supply increase relative to 2018 levels (6818 TWh in 2050 vs 3629 TWh in 2018). While decommissioning of energy system capacity (in this example scaling down of CH_4 supply) is a challenge on its own in terms of policy support and sunk cost recovery, the scale up of electricity generation is not a lesser challenge either - Figure 4 shows the historic trend in electricity generation in the past 30 years and what is required to achieve the NZ electricity generation target in the next 30 years. One can see that the average expansion of electricity generation over the past 30 years was ca. 26 TWh/year, with all of that expansion occurring before the 2008 financial crisis when growth was 51 TWh/year whereas since 2008 growth has been essentially flat. However, to reach the target of 6818 TWh of electricity generation by 2050 an average growth rate of 116 TWh/year from 2020-2050 would be required, which is almost *five times* the historic growth rate in generation over the past 30 years and *twice* the growth rate before the 2008 financial crisis. Further, the challenge is not just scaling up the electricity system to meet future generation level but rapidly increasing generation from a particular set of technologies.

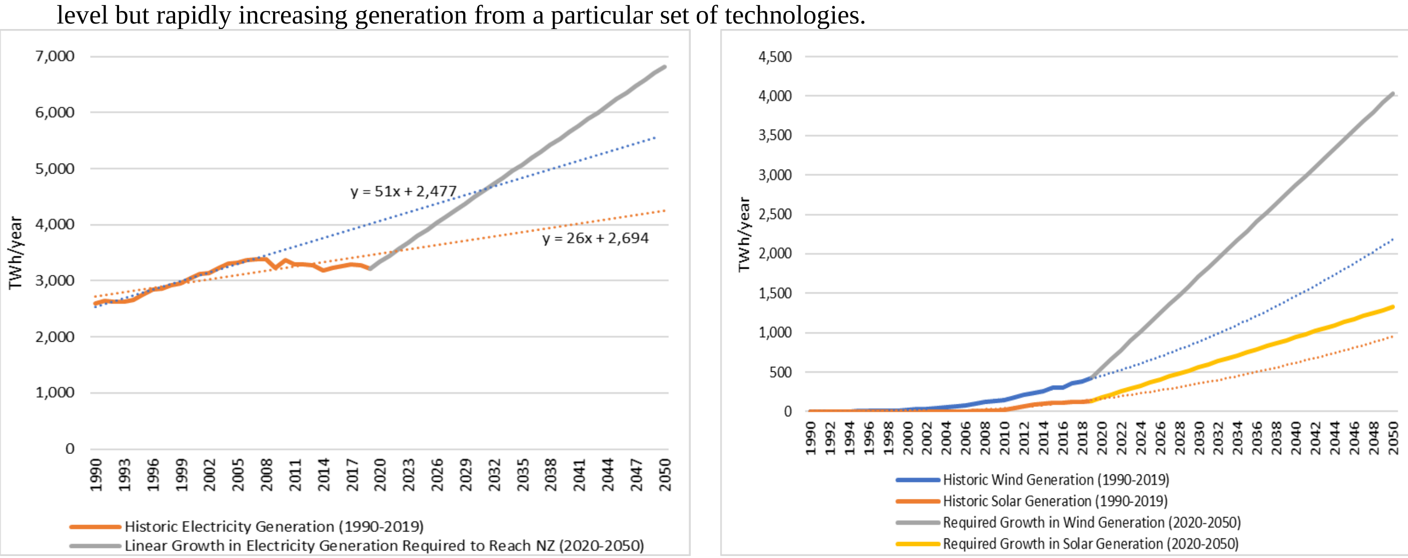

Figure 4: Expansion of Electricity Generation in EU (left panel) and Generation from Wind and Solar (right panel)
Notes: left panel - orange dotted line is linear growth fitted to 1990-2019 historic time series; blue dotted line is linear growth fitted to 1990-2008 historic time series; right panel – dotted lines are polynomial growth trends fitted to historic (1990-2019) data.

Source: historic generation data is from BP Statistical Review of World Energy (2020).

To support deep decarbonisation of European economies, our modelling suggests that European power will be decarbonised (see Figure 5). Thus, the generation mix consists of at least 78% variable renewable energy (VRE) and 12% nuclear, with hydro standing at 3% and the rest is dispatchable CCGT and biomass with CCS (with a combined share of just 7%). The NZ Scenario generation mix *is truly a zero-carbon electricity generation sector* because even fuels consumed by CCGT plants are low-carbon - they consume 95% biomethane and 5% e-gas, both of which are carbon-free fuels.

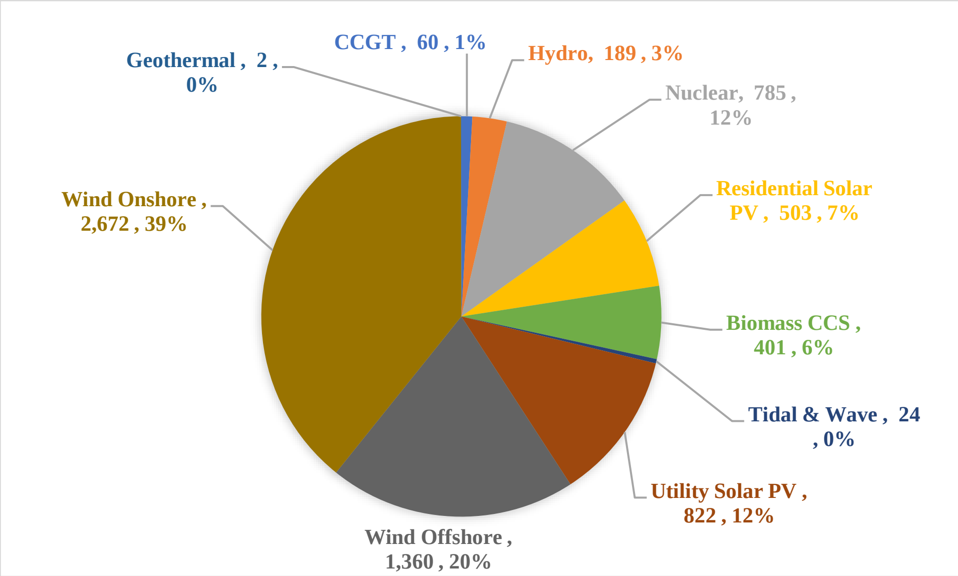

Figure 5: Generation Mix in NZ Scenario 2050
Notes: the first number is generation in GWh, second number is % in total generation

Figure 4 (right panel) shows, again, historical electricity generation from wind and solar in EU over the past 30 years (1990-2019) and the required generation trend out to 2050 to meet our NZ target. First, we see the challenge is to scale up generation from wind sources because the historic (best fit) trend would get us to more than 2,000 TWh of generation by 2050 whereas under our NZ scenario we will need more than 4,000 TWh of wind generation by 2050; that is, we need to double our historic efforts in getting wind onto the energy system. In contrast, it does not appear to be a challenge to scale up generation from solar: based on historic trend we might only miss about 300 TWh of generation (historic extrapolation suggest we might have ca. 1,000 TWh of solar generation vs 1,325 TWh that we need for the NZ scenario). Given the uncertainties around the scale and the pace of roll out of renewables technologies required to meet the NZ target, we also carried out a sensitivity analysis in which we assume a rather limited role of direct electrification (see the NZ-g scenario results below).
Nevertheless, it is worth mentioning that the EU authorities have recently reached an agreement on accelerated permitting rules for renewables[5], as part of an effort to eliminate the bloc's dependence on Russian gas by 2027 by way of faster roll-out of renewables.

The role of bioenergy and CCS in our NZ Baseline
While electricity will become a backbone of our NZ energy system, the role of bioenergy and its derivatives in delivering the NZ target in our modelling is not insignificant – bioenergy and its derivatives have a combined share of at least 32% in final energy consumption (biomethane (13%), e-gas (7%), biomass (6%), and e-liquids (5%)). Similar to the importance of supporting the tremendous scale up of investment in RES-E production (and hence transmission and distribution of electricity), the potential challenges might arise with scaling up of associated technologies for production of biomethane to the required level, in particular:

1. Proving that upgrading and methanation of biogas will work at the required scale: in 2018, only 23 TWh of biomethane was produced in the whole of EU+UK and most of this comes via upgrading of biogas produced from anaerobic digestion; to put this in the context, our NZ scenario requires 1,150 TWh of biomethane;
2. Thermal gasification is another promising technology to produce biomethane (with higher efficiency and more flexibility with feedstocks than upgrading of biogas), but not yet commercial at scale at the moment.

Therefore, the success in meeting our modelled NZ requires ambitious scale up of all key technologies from wind turbines and solar panels to ensuring sustainable bioenergy supply without negative impacts on competing land uses for other societal priorities (see subsequent analysis in this section for sensitivity analysis around these key assumptions).

[5] EU Council, REPowerEU: Council agrees on accelerated permitting rules for renewables, Press release 19 December 2022. https://www.consilium.europa.eu/en/press/press-releases/2022/12/19/repowereu-council-agrees-on-accelerated-permitting-rules-for-renewables/

In addition to the expansion of wind and solar generation as well as scaling up of supply and production of sustainable bioenergy to achieve our NZ Scenario at least cost, our modelling suggests that biomass with CCUS will have a share of 6% in the generation mix in 2050 NZ (see Figure 5) with a total installed generation capacity of 86.2 GW. Scaling up carbon capture technology (e.g., post-combustion capture technology) and associated infrastructure to the required level that will be a challenge given the limited success in large-scale demonstration of this technology so far. Nevertheless, meeting our NZ scenario in a cost-optimal way would require generation from bioenergy with CCS technology given the need for significant negative emissions. The importance of CCS in meeting net zero has been acknowledged and confirmed by the international community and academics. For example, according to the International Energy Agency's (IEA, 2020; page 13) Flagship report from September 2020: *"A net-zero energy system requires a profound transformation in how we produce and use energy that can only be achieved with a broad suite of technologies. Alongside electrification, hydrogen and sustainable bioenergy, CCUS will need to play a major role."* In that report, IEA (2020; pages 13-14) identifies four main areas where CCUS can play an important role:

- Tackling emissions from existing energy infrastructure;
- A solution for some of the most challenging emissions;
- A cost-effective pathway for low-carbon hydrogen production;
- Removing carbon from the atmosphere.

To conclude, without doubt, the energy system faces three challenges (i) scaling up the electricity system (e.g., networks) to meet the overall level of expected electricity generation and bioenergy supply, (ii) scaling up carbon neutral generation sources, while (iii) at the same time decommissioning of carbon intensive generation assets.

Moving from the 90% GHG emissions reduction scenario to our NZ scenario

Table 8 compares final energy consumption structure in the NZ and 90% scenarios. First, we can see that biomethane supports decarbonisation: its share stays roughly the same at 12-13% in the final energy consumption, irrespective of GHG emissions reduction target being either 90% or net zero. Hydrogen plays a more prominent role in the final consumption when we need to achieve the net zero target, as its share increases from 3% under the 90% GHG emissions reduction scenario to 11%, predominantly to serve road transport demand.

Overall, allowing for some residual GHG emissions to remain in the system under the 90% reductions target, we still see at least 12% of gasoline and diesel in the final consumption mix, predominantly to serve the road transport demand. Therefore, these results do suggest that residual GHG emissions are indeed focused in hard-to-abate sectors like transport. One can see that, for example, in the 90% GHG reductions scenario there are 56 mn gasoline cars and 5.9 mn diesel cars (see Table 5) but in the net zero scenario we only have 8.4 mn gasoline cars while the rest switched to gas mobility (running on biomethane and carbon-neutral e-gas); similarly, the switch between gas mobility and H_2-driven and electricity-based HGVs also happens between 90% and net zero scenarios, suggesting sensitivity of low carbon solutions in the HGV sector.

Table 5: Road vehicle stock in NZ and 90% Scenarios (million vehicles)

	NZ Scenario	**90% Scenario**
Diesel Cars	0.00	5.86
EV Cars	204.30	204.30
EV HGV	0.92	0.01
EV Public Transport	0.68	0.68
FCEV Cars	0.00	0.00
FCEV HGV	7.60	0.00
FCEV Public Transport	0.13	0.15
Gas Cars	42.71	0.00
Gas HGV	3.38	6.23
Gasoline Cars	8.36	56.34
Total	**268.09**	**273.58**

If we compare (see Table 10) the electricity generation mix in the two deep decarbonisation scenarios we see that is largely similar with the exception that fuels consumed by CCGT plants are low-carbon under the net zero scenario - they consume 95% biomethane and 5% e-gas, both of which are carbon free fuels. However, under the 90% emissions reduction scenario the fuel mix for CCGTs consists of 90% fossil natural gas and 10% e-gas. Obviously, allowing for some residual GHG emissions in the system (10%) would permit some plants, as back-up power sources, to run on fossil fuels. Further, under the net zero scenario, electricity generation increases by 7.3% in absolute terms; therefore, deeper decarbonisation pushes further electricity generation for both direct electrification of end-use sectors as well as in transformation sectors, in particular the usage of electricity to produce hydrogen and synthetic fuels.

Table 6 shows electricity consumption by activities for both baselines – while growth in the final consumption is ca. 2% between the net zero and the 90% GHG reduction scenario, the major growth in electricity consumption is in the transformation sector – we see 17% growth in electricity consumption in the net zero scenario compared to the 90% GHG reduction scenario, primarily to produce more green H_2. This suggests an important role for green H_2 in the net zero scenario to further decarbonise the energy system where direct electrification is less suitable. What is also interesting to note is that under the net zero scenario we see uptake of less mature electrolysis technologies (and more costly) such as solid oxide electrolyser cell (SOEC) which is expected to be more efficient than the alkaline technology. Therefore, pushing our system towards net zero GHG emissions target seems to suggest a need for more technological efficiency in green H_2 production, perhaps, due to limited availability of incremental renewables capacity or costly incremental expansion of the electricity system.

Table 6: Electricity consumption (TWh) by end-use activities in NZ and 90% Scenarios

	NZ Scenario		**90% Scenario**	
	Consumption	Shares in total	Consumption	Shares in total
Transformation	2,085	33%	1,780	30%
Electrolysis Alkaline	1,910	31%	1,780	30%
Electrolysis PEM	0	0%	0	0%
Electrolysis SOEC	150	2%	0	0%
Direct Air Capture	25	0%	0	0%
Final Consumption	4,175	67%	4,093	70%
Buildings	2,063	33%	2,079	35%
Industry	1,381	22%	1,351	23%
Transport Cars	507	8%	507	9%
Transport Public	35	1%	35	1%
Transport HGV	60	1%	0	0%
Transport Other	129	2%	120	2%
Total	6,260	100%	5,873	100%

Table 7 outlines projected GHG emissions, storage and utilization in the two baseline scenarios. First, one can see that removing the residual 10% emissions (i.e., reaching the net zero target) requires a four-fold increase in permanent CO_2 sequestration, of which at least more than half is negative emissions, relative to the level of sequestration under the 90% reduction target scenario. Under the net zero scenario, the emissions are higher in the transformation sector, predominantly from the residual emissions in the process of blue H_2 productions from advanced gas reformers as well as from burning bioenergy.

It is worth mentioning an interesting result that CO_2 utilization for production of synfuels are higher under the 90% scenario than under the net zero baseline. The main reason for this is higher economic value of having more negative emissions in the net zero scenario, i.e., production of carbon neutral synfuels competes with alternative use (permanent sequestration) of CO_2 from bioenergy to create supply of CO_2 emissions permits. Looking at the results in Table 7 we can see that increment of negative emissions (252,692 less 20,676 ktCO2e) accounts for about 41% of total residual CO_2 emissions in the 90% reduction scenario – therefore, achieving the net zero target requires essentially abating another 59% of the 572,652 ktCO_{2e} which was achieved with a combination of higher direct electrification as well as higher usage of H_2 and renewable gases.

Finally, we calibrated our input dataset to the EC LTS and therefore for the 90% scenario we used EC LTS's overall GHG emissions – 620,100 ktCO2e (line [9] in Table 7) as the emissions cap in our modelling of that scenario. But one can see that the constraint was not binding as our total projected emissions under the 90% reduction scenario is 572,652 ktCO2e (vs 620,100 ktCO2e); that said, if we compare our projected total residual emissions with the 1990 level then this projection is ca. 10.6% of the 1990 level; therefore, it is unclear why the EC LTS COMBO has GHG emissions which is 11.46% of the 1990 level. Finally, EC's 1.5 TECH is actually not a net zero scenario – it is a scenario that achieves 99.5% reduction of CO_{2e} emissions over 1990 level (see EC LTS, p. 198).

Table 7: GHG emissions balance in the NZ and 90% Scenarios, mtCO2e

		NZ Scenario	**90% Scenario**
[1]	**Stock Change**	-406.2	-100.3
[1.1]	Underground storage: non neutral emissions	-153.5	-79.6
[1.2]	Underground storage: negative emissions	-252.7	-20.7
[2]	**Transformation**	612.0	457.4
[3]	**CO_2 utilization**	-229.4	-276.3
[4]	**Final Consumption**	510.9	822.1
[4.1]	Buildings	173.5	171.1
[4.2]	Industry	109.8	175.6
[4.3]	Transport Cars	79.8	76.2
[4.4]	Transport Public	0.0	0.0
[4.5]	Transport HGV	69.3	255.8
[4.6]	Transport Other	78.5	143.5
[5]	**CO_2 neutral emissions**	-518.0	-427.2
[6]	**LULUCF CO_2 emissions**	-306.6	-240.5
[7]	**Non CO_2 emissions**	337.4	337.4

[8]	**TOTAL 2050 (this research)**	0.0	572.7
[9]	**TOTAL 2050 (EC LTS)**	26.1	620.1
[10]	**TOTAL 1990***	5408.8	

Notes: [8]=[1]+[2]+[3]+[4]+[5]+[6]+[7]; * Total CO2e, including indirect CO_2, with land use, land-use change and forestry.

Don't Put All Eggs in One Basket

We can see from our modelling results that meeting net zero requires the roll out of multiple new technologies at scale with a wide range of uncertainties around their costs and associated resource availability. Therefore, the model results are highly dependent on assumptions regarding availability (and costs) of these key technologies. For example, availability of negative emissions has been long recognised as a source of controversy, as discussed by Anderson and Peters (2016) and by Fuss et. al. (2014). Ultimately, the volume of negative emissions available will inevitably depend on accounting methodologies, sustainability of the biomass feedstock, acceptability of biomass use at scale. Thus, to understand how these key sources of uncertainties could drive our results, we model two net zero variants with a wide range of key parameters representing these uncertainties (see Section 3.3. for more details).

Thus, this section summarises key drivers of electrification and gasification of the energy system under the net zero GHG emissions target by 2050. Table 8 outlines structures of the final energy consumption in the two NZ variants that we modelled as a result of changing key assumptions of the NZ baseline (see Table 2). As we would expect the set of 3 key dimensions that we vary produces a wide range of results in terms of share of electricity (electrification of final demand) in final consumption – from **36% (NZ-g) to 68% (NZ-e)**:

1. Future evolution of commodity prices, including importantly prices of fossil gas and bioenergy **and** availability of sustainably sourced bioenergy;
2. Investment costs of wind and solar technologies **and** resource availability;
3. Technological innovation in industrial processes allowing further direct electrification of industrial demand and further innovation in road transport modes and supporting infrastructure to allow higher uptake of EVs in all road segments.

Table 8: Final Energy Consumption (TWh) in the NZ Scenario and its Variants (NZ-e and NZ-g)

	NZ Scenario		**NZ-e Scenario**		**NZ-g Scenario**		**90% Scenario**	
	Final Consumption	Shares in total	Final Consumption	Shares in total	Final Consumption	Shares in total	Final Consumption	Shares in total
Biomethane	1,059	13%	359	4%	1,936	22%	1,040	12%
E-gas	611	7%	191	2%	597	7%	647	8%
Electricity	4,175	51%	5,402	68%	3,229	36%	4,093	49%
Hydrogen	921	11%	677	8%	731	8%	210	3%
Natural gas	199	2%	152	2%	199	2%	323	4%
Gasoline	45	1%	0	0%	35	0%	305	4%
Diesel	290	4%	332	4%	300	3%	661	8%
Biomass	517	6%	227	3%	517	6%	508	6%
E-liquids	429	5%	645	8%	1,399	16%	582	7%
Total	**8,246**	**100%**	**7,985**	**100%**	**8,943**	**100%**	**8,369**	**100%**

Results of the final consumptions structure reveal some interesting insights:

1. While electricity shares swing from 36-68%, we can also see that the role of biomethane swing from 4-22%, suggesting that the role of biomethane in final consumption is much more sensitive to our key set of assumptions than electricity; similar conclusion applies to synthetic fuels (e-gas and e-liquids) as their shares varies widely from 5-16% for e-liquids to 2-7% for e-gas;
2. The role of hydrogen, although marginal at 8-11%, is very stable in final consumption structure, suggesting its prominent importance in delivering net zero target; this result seem to suggest that hydrogen is simply insensitive to such a wide variations in key input assumptions. Similar conclusions apply to other very marginal fuels which are quite insensitive to changes in key inputs – fossil gas, gasoline, diesel, biomass.

The fact that direct usage of hydrogen in final consumption sectors is not sensitive to our key inputs does not mean that its supply volume does not change in the NZ energy system as we move from one extreme to another one (from NZ-e and NZ-g). We can see changes in primary supply of all fuels and commodities in Table 9. Hydrogen supply volume changes by almost a factor of two between the two NZ extremes. What is interesting to note in the NZ-g variant is that the primary supply volume of CH_4 (fossil gas, biomethane and e-gas) totals 7,049 TWh – this is 31% higher than the supply volume in 2018. Thus, in this hypothetical NZ-g variant not only we meet the GHG reduction target but we might also see an expansion of CH_4 supply sector – of this CH_4 supply volume, 41% is carbon neutral (renewable) gas while the rest is imported fossil gas to generate blue hydrogen. Given the current context and political will to eliminate imports of fossil gas such an increase in supply and imports of natural gas in the NG-g seems implausible.

Table 9: Primary Supply (TWh) Mix in the NZ Scenario and its Variants (NZ-e and NZ-g) in 2050

	NZ Scenario		NZ-e Scenario		NZ-g Scenario	
	Supply	Shares in total	Supply	Shares in total	Supply	Shares in total
Biomethane	1,150	8%	359	3%	2,300	12%
E-gas	615	4%	191	1%	600	3%
Electricity	6,818	48%	8,309	63%	4,176	21%
Hydrogen	2,228	16%	1,743	13%	3,232	16%
Natural gas	907	6%	152	1%	4,149	21%
Gasoline	45	0%	0	0%	35	0%
Diesel	290	2%	332	3%	300	2%
Biomass	1,769	12%	1,375	10%	3,538	18%
E-liquids	429	3%	645	5%	1,399	7%
Total	14,251	100%	13,107	100%	19,729	100%

As we might also expect, these two extreme NZ variants produce diametrically opposite results in terms of hydrogen supply sources and technology reliance (see Figure 6) – in the NG-g variant due to our assumption of low energy commodity prices (both bioenergy and fossil) as well as abundance of bioenergy (to offset residual emissions from blue hydrogen production via ATR-CCS route) 90% of hydrogen production comes from gas ATR-CCS route (blue hydrogen). The fact that we still see 10% of green hydrogen in this very aggressive gas NZ scenario suggests a robust competitive position of green hydrogen even in such an unfavourable set of electricity assumptions (high costs of wind generation and very low cost of gas commodity and abundance of negative emissions to offset residual GHG emissions).
Similarly, if we look at another extreme (NG-e) we see that hydrogen is in fact 100% produced from electricity (green hydrogen) and this reinforces our conclusion that blue hydrogen is very sensitive to:

1. Fossil gas commodity prices;
2. Availability of bioenergy with CCS (negative emissions) to offset the residual emissions from ATR-CCS in the context of binding net zero constraint.

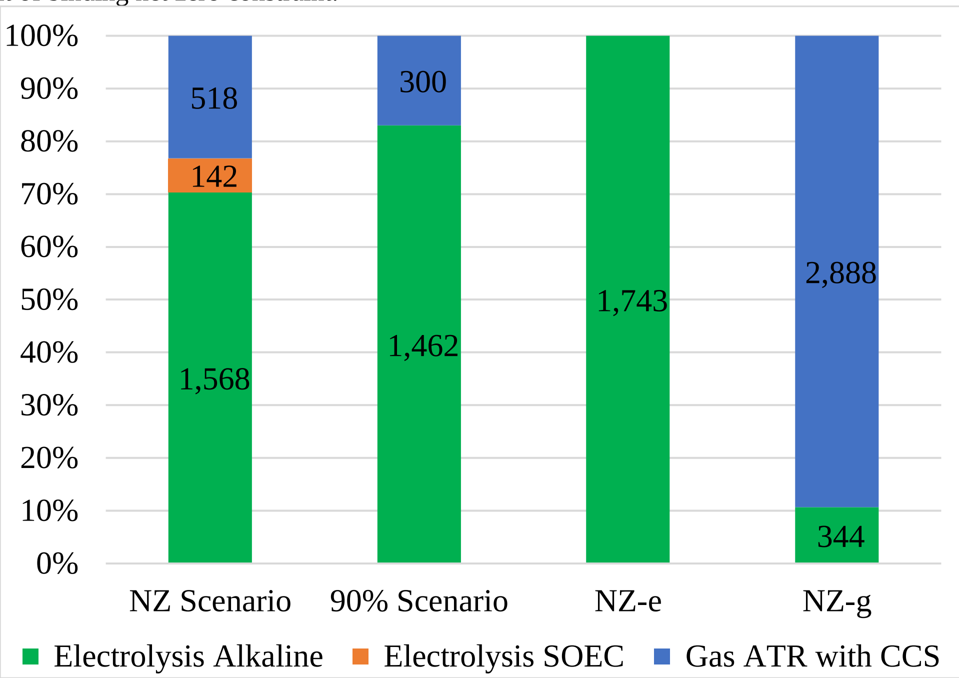

Figure 6: Supply Volumes and Market Share of Green and Blue H_2 in the Baseline Scenarios and its Variants in 2050
Note: numbers in the chart represent production of H_2 in TWh/year.

Coming back to the role of electricity in delivering NZ, we can conclude that even in the extreme gasification scenario (NZ-g) we should still expect the electricity supply industry to grow (albeit of course marginally) by at least 15% compared to 2018, while under the electrification extreme (NZ-e) the electricity supply should expand by a factor of 2.3. Indeed, if we look at the electricity generation mix under the extreme electrification scenario (see Table 10) we should expect that at least 85% of electricity supply coming from VRE (wind and solar) with the other 10% coming from nuclear and dispatchable renewables (e.g, hydro). However, what is striking, is that even in this highly electrified scenario, we still see ca. 4% of generation coming from biomass CCS suggesting that to meet NZ even with 90% zero carbon electricity we need negative emissions to offset GHG emissions in hard-to-abate sectors such as aviation and industrial processes. That is, even with such relatively unfavourable assumptions (high cost of bioenergy and its low availability coupled with low cost of VRE and its high availability) it is still cost optimal to have some negative emissions to reach NZ under high electrification pathway.

Table 10: Electricity Generation (TWh) Mix in the Baseline Scenarios and its Variants (NZ-e and NZ-g) in 2050

	NZ Scenario		NZ-e Scenario		NZ-g Scenario		90% Scenario	
	Generation	Shares in total	Generation	Shares in total	Generation	Shares in total	Generation	Shares in total
CCGT	60	1%	0	0%	231	6%	67	1%
Hydro	189	3%	94	1%	274	7%	242	4%
Nuclear	785	12%	763	9%	806	19%	790	12%
Residential Solar PV	503	7%	523	6%	503	12%	453	7%
Biomass	0	0%	0	0%	265	6%	17	0%
Biomass CCS	401	6%	367	4%	754	18%	301	5%
Tidal & Wave	24	0%	0	0%	36	1%	24	0%
Utility Solar PV	822	12%	281	3%	251	6%	733	12%
Wind Offshore	1,360	20%	2,180	26%	639	15%	1,122	18%
Wind Onshore	2,672	39%	4,100	49%	413	10%	2,601	41%
Geothermal	2	0%	1	0%	3	0%	3	0%
Total	**6,818**	**100%**	**8,309**	**100%**	**4,176**	**100%**	**6,353**	**100%**

Abstracting away from the details of the modelling results from these two extreme NZ scenarios one key policy conclusion emerges. While the future commodity prices are so uncertain to predict and largely out of our control, the four other key areas are largely in our hands – such as investing in R&DD to drive down costs and increasing availability of low-carbon energy resources and new end-use technologies. Thus, policy support at early stage for all key set of technologies that could jointly deliver us NZ should be pursued at early stage and none should be excluded if we are to achieve the NZ target at least cost while tackling many uncertainties on our way to the target.

4.2. Sources of Flexibility in the Net Zero and 90% Scenarios

This section presents our results regarding flexibility source to deliver deep decarbonisation scenarios. We start with examining the role of networks and cross-border trade (Spatial Flexibility) and then the role of storage technologies to provide temporal flexibility. The section ends with a discussion on the role of "new" energy sources and technologies in providing flexibility.

4.2.1. Spatial Flexibility

Table 11 outlines historic 2018 and cross-border trade in electricity, CH_4 and low carbon H_2 in our scenarios in 2050. The first conclusion to highlight is that the trend in electricity cross-border is in line with observed historic trends– as we electrify our economies, the role of cross-border also increases: the share of total trade in final consumption at least doubles in our decarbonisation scenarios relative to 2018 (56% in NZ and 51% in 90% Scenario vs 27% in 2018). Importantly, it should be noted that while final consumption increases between 47-50% the total electricity trade in 2050 increases by ca. 176-207% (i.e., by a factor of 2.7-3) compared to total trade in 2018. This highlights the importance of cross-border electricity trade and market rules to complete EU's single market for electricity trading in deep decarbonisation scenarios. Electricity cross-border trading will increase by 11% in NZ compared to 90% Scenario, while electricity consumption will only rise by 2%.

Table 11: Electricity, CH_4 and H_2 cross-border trade 2018 and NZ 2050 and 90% Scenario

	2018		NZ Scenario			90% Scenario		
	Electricity	CH_4	Electricity	CH_4	H_2	Electricity	CH_4	H_2
Import	394	5,016	1,168	1,190	25	1049	998	0
Export	366	954	1,168	283	25	1049	170	0
Final consumption	2,784	5,327	4,175	1,869	921	4093	2011	210
% in final consumption*	27%	112%	56%	79%	5%	51%	58%	0%

Source: 2018 data is from Eurostat.
Notes: *Share of trade in final consumption was calculated as sum of imports and exports divided by final consumption.

While the picture for the electricity cross-border trading and interconnection capacity requirements in our scenarios is in line with the rest of modelling results, confirming the growing importance of cross-border trading going forward, the status of cross-border trade in CH_4 is quite different from the 2018 status. We can see that the total trade in CH_4 reduces by a factor of at least 4 in the NZ and 5 in the 90% scenario. This is mainly due to the reduced requirement to import fossil gas from non-EU countries. It is worth noting that there is slightly higher CH_4 cross border trade in the NZ scenario compared to the 90% scenario because of higher hydrogen requirements to meet the net zero target. This higher hydrogen demand, in turn, increases the need for feedstock natural gas. Secondly, if we disregard fossil gas imports (totalling ca. 907 TWh) then the share of cross-border trade in biomethane and e-gas (the two fuels that are produced at “home”) is quite marginal – 30% of final CH_4 consumption and is only a *quarter* of the value of cross-border electricity trade in NZ 2050. This is a complete reversal of the 2018 situation when we saw that cross-border trade (mainly due to huge import value) in gas exceeded that of electricity by a factor of 7 at least. In our scenarios, total cross-border trade in electricity exceed that of CH4 by a factor of 2. It is interesting to note that cross-border trading in CH_4 is 26% higher in the NZ scenario than in the 90% scenario, while the share of CH_4 in the final consumption is 7% less. An increase in CH_4 cross-border trading in the NZ scenario relative to the 90% scenario is because of higher requirements for low-carbon hydrogen production from steam reformers.

Lastly, we can also conclude that the role of cross-border in H_2 might be limited in our NZ scenario (see Table 11), for quite similar reasons to the one we see for cross-border trade of natural gas – the fact that H_2 is locally produced (predominantly from electricity – see **Error! Reference source not found.**) in every EU country and the fact that local energy systems can self-balance using a combination of end-use and grid-scale flexibility solutions (see next two sections), cross-border capacity might be less needed to balance the fluctuations in supply and demand for H_2.

Turning to the modelling results for the transmission capacity at regional level, the current European gas (CH_4) system’s capability is at least *three and a half times larger* than its electricity counterpart (see Figure 7). Nevertheless, in both the NZ and 90% scenarios, as the result of dramatic system changes (discussed above), the capability of the two systems will change dramatically:

1. We will see a reversal in the relative size of gas and electricity networks. Electricity transmission capacity will be 13-26% larger than the CH_4 transmission capacity in 2050; in fact, electricity transmission capacity expands by a factor of 2.8-3 relative to 2018 and is just 13-19% smaller than the CH_4 system in 2018;
2. That said, at the distribution level, we see that the CH_4 distribution network capability is similar to transmission (e.g., in NZ scenario, there is 1,118 GW of CH_4 distribution capacity vs. 1,134 GW transmission capacity) capability; further, CH_4 distribution network is ca. 30-36% larger than the electricity distribution network;
3. Both CH_4 transmission and distribution networks are 30% smaller than today’s CH_4 system capacity.

Further, our modelling results describe that the emergence of H_2 transmission and distribution networks but the size of those networks are small compared to CH_4 – transmission for H_2 is 32-40% of the CH_4 transmission capacity by 2050, while at distribution level the H_2 network is just 4-21% of the CH_4 distribution network. This can be explained by the fact that H_2 transmission is served to manage fluctuations in green H_2 production while a small H_2 distribution network is mainly to serve transport and industry sector demand. It is interesting also to note that the combined transmission capacity of the CH_4 and H_2 systems is 1,594 GW, whuch is just 2% smaller than the CH_4 system capacity in 2019. Also, the CH_4 network capacity does not change dramatically between NZ and 90% scenarios, whereas electricity and H2 networks see an increase (notably, H_2 distribution capacity 49 GW in the 90% scenario but is almost five times larger (239 GW) in the NZ scenario). Thus, the flexibility provided by the electricity and H_2 networks will become important, as we move from 90% GHG reduction scenario to net zero.

Further, several important conclusions can be made:

1. while in terms of energy throughput (flow), both CH_4 distribution and transmission system might see a reduction of at least 35% and 50% compared to the current situation (2018), the overall network capacity needed to meet peak demand during wintertime in our scenarios will be just 30% less compared to today. We consider this potential divestment to be sensible, especially in the context of the size of today’s CH_4 network, which is largely oversized in anticipation of (wrong) growth in gas demand (see Chyong, 2019).
2. The 30% divestment in CH_4 system capability may largely be due to reduced requirement for imports of fossil gas from non-EU countries, which in the current context of Russia’s invasion of Ukraine is fully politically acceptable.
3. While (1) is applicable largely to CH_4 transmission we see that at the distribution level CH_4 network capability is important due to the provision of ramping requirements coming from the heat load (hybrid heat pumps running on biomethane).
4. Since the electricity system grows both in terms of energy flow as well as in terms of capacity regulatory provision to support efficient expansion of both transmission and distribution capacity will become important as we increasingly rely on electricity system to decarbonise.

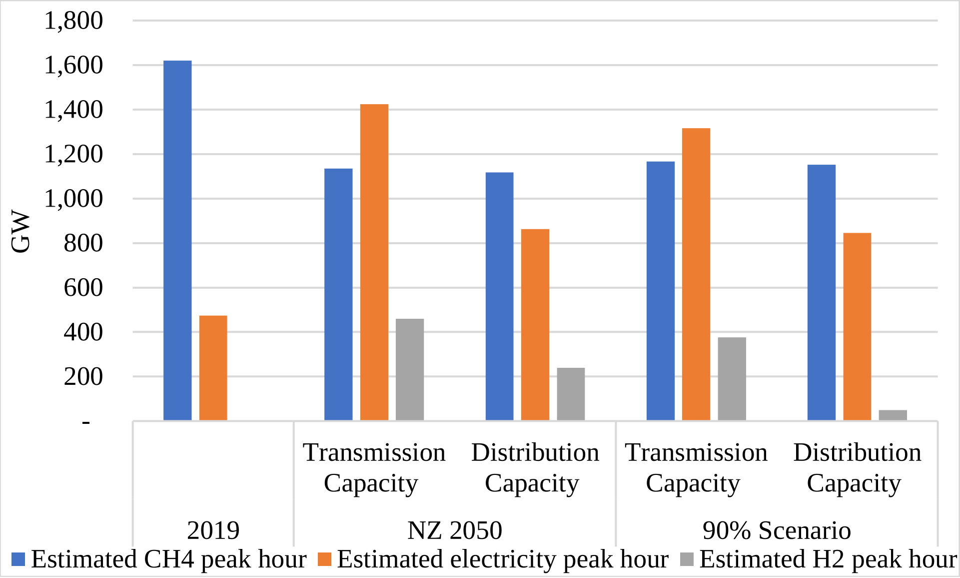

Figure 7: Estimated Electricity, CH_4 and H_2 network capacity (based on peak hour flow) for Europe
Source: 2019 is from ENTSO-E and ENTSO-G.

4.2.2. Temporal Flexibility

In Section 2 we made a distinction between inter-seasonal and intra-day flexibility requirements in moving to a carbon neutral energy system. Table 12 outlines modelling results for storage system capacity for electricity, H_2 and CH_4 in our scenarios. It is clear that inter-seasonal flexibility in the NZ scenario is provided by CH_4 long-duration storage (traditional underground gas storage).

Table 12: Electricity, CH_4 and H_2 Storage Capacity in NZ 2050 and 90% Scenario

	NZ baseline			**90% Scenario**		
	Electricity	H_2	CH_4	Electricity	H_2	CH_4
Volume, GWh	461	8306	272,735	469	463	311,002
Power, GW	99	671	334	106	463	381
Average storage duration, hours	**5**	**12**	**816**	**4**	**1**	**816**

Given the reduced requirement for CH_4 in the buildings sector (predominantly for heat load), less inter-seasonal storage capacity will be required in our scenarios. Thus, currently, in terms of CH_4 storage volume needed to move energy from summer to winter season will reduced by a factor of 4 (existing storage volume of 1,117 TWh in 2021 to 272.7 TWh in NZ scenario and 311 TWh in 90% scenario). Comparing results between the two scenarios, we see a large increase in H_2-based storage capacity – H_2-based storage duration increases from 1 hour to 12 hours in NZ scenario, suggesting that requirement for medium range storage will be fulfilled by hydrogen storage. At the same time, capacity of both electricity and CH4-based storage is lower in the 90% scenario compared to the NZ scenario. This can be explained by both the increase in H_2-based storage as well as electricity networks (see previous section).

While CH_4 seasonal storage serves seasonal variations in energy demand in buildings, green H_2 production serves as a "virtual" seasonal storage to manage seasonal variations in VRE production, especially solar output. Figure 8 shows how green H_2 production follows closely the monthly solar generation. Green H_2 is indeed an important sector coupling technology helping to efficiently integrate VRE.

When it comes to intraday flexibility in our scenarios it is delivered by a combination of:

1. electrical energy storage: both traditional storage solutions like hydro-based electrical storage and generation as well as new forms of intraday flexibility – V2G from EVs and electrical energy battery storage;
2. from H_2-based intraday storage solutions, like pressurised H_2 tanks and liquid H_2 storage technologies.
3. And, hybrid heat pumps which allow for greater system flexibility associated with within day ramping requirements to meet heat loads

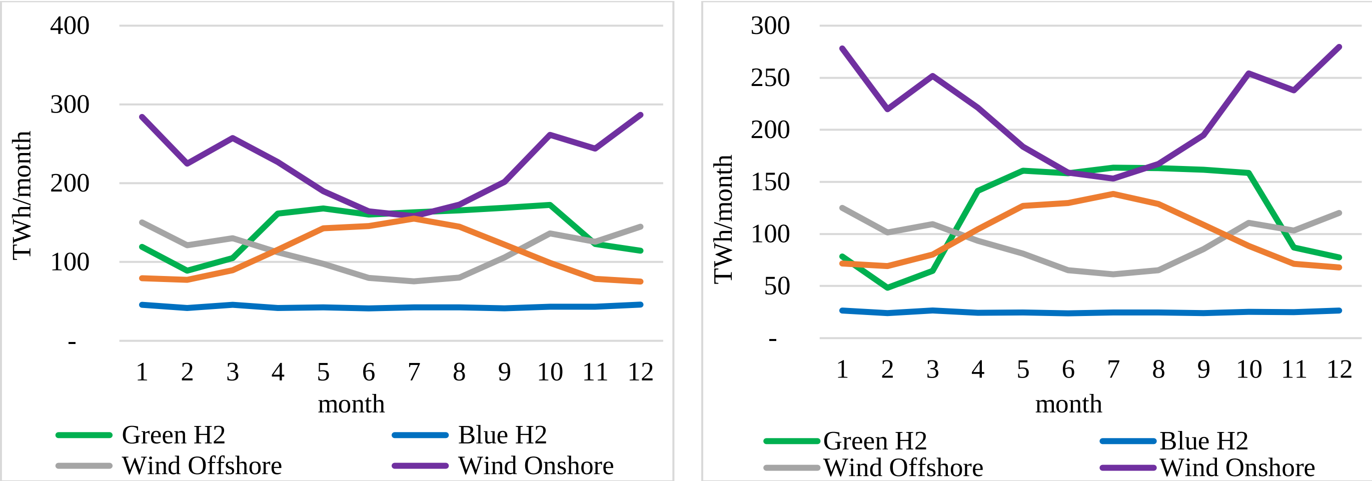

Figure 8: Monthly H_2 production and outputs from wind and solar in NZ (left panel) and 90% Scenarios (right panel)

While there are 99 GW of hydro pumped and electrical energy storage systems, intraday electricity flexibility could be provided by some EVs. In NZ there are 268 million vehicles, of which 204 million, are private EV passenger cars. With the assumed 40 kWh battery capacity per passenger EV this means that theoretically there are 8172 GWh of electrical energy storage on the system; however, most of EV cars will be used during the day. Therefore, in practice, we only see 120 GWh of peak hour V2G output from passenger EVs in our NZ scenario, or 1.47% of total EV battery capacity. Nevertheless, it is potentially a significant source of intraday electricity flexibility.

It is also quite interesting to note that intraday flexibility is also provided by H_2-based storage technologies (e.g., pressurised H_2 tanks and liquid H_2 storage technologies) to manage intra-day variations in VRE output and green H_2 production; H_2-based storage power capacity is the largest – 671 GW – amongst the three storage systems.

4.2.3. The role of ñnewò energy sources and technologies

This section discusses results for hydrogen, synthetic fuels and end-use technologies in helping to integrate low-carbon energy system. Smart energy system integration is focused on at least three inter-related areas:

1. Upstream integration between electricity and gas sectors using H_2-based technologies like water electrolysis;
2. Downstream integration at household level with enabling technologies like hybrid heat pumps (HHP) linking both electricity and gas supply;
3. Circular energy system with smart utilization (re-utilization) of energy and materials resources; for example, utilization of CO_2 emissions from sustainable and short cycle CO_2 sources (bioenergy) to produce carbon neutral H_2-based fuels.

At the upstream level, there has been anticipation that hydrogen production from electrolysis could potentially allow a much greater quantity of variable renewable energy (VRE), such as wind and solar, to be efficiently integrated while meeting climate goals at least cost (and curtailments) (see e.g., Neumann and Brown, 2021). Our modelling results confirm this hypothesis. Figure 9 (left panel) shows a sample of hourly production of electricity from renewables and H_2 production facilities. It is immediately clear that solar generation and H_2 production from water electrolysis are highly correlated (positively, with a correlation coefficient of ca. 90%); green H_2, therefore, helps to integrate at least 780 GW of solar energy capacity in the system, although this would require a six-fold increase relative to today's total EU solar PV capacity.
This is not to say that H_2 production from electrolysers does not facilitate further integration of wind energy production – if we look at the hours when solar PV is not producing (i.e., at evening and night hours) we see an improved hourly correlation (positive) between wind energy production and H_2 production (see Figure 9: right panel). There are even some night hours in a winter day when there is a clear pattern of higher wind speed increase H_2 electrolysers production (see Figure 9, right panel: hours 131-146, for example). In the 90% Scenario, the pattern of wind, solar and hydrogen production is similar to the one we found in the NZ scenario, although the correlation between solar and electrolyser production is slightly lower (0.76), while correlation between wind and electrolysers are marginally negative (-0.14 and -0.12 for offshore and onshore wind respectively).
It is worth mentioning that the diurnal flexibility in the electricity system has been fulfilled by traditional technologies like hydro pumped storage whereby excess overnight electricity production is used to pump water up a hill, and then when electricity during the day, water is released down the hill to generate electricity back to the grid. Round trip efficiency of hydro PS is 75%. The efficiency of H_2 production from electricity (see Appendix 2) is currently 72% but is expected to reach 82-95% by 2050; hence, H_2 production from electricity, as a flexibility option, is no different to traditional technologies like hydro PS, but are potentially more efficient and importantly more valuable to the overall

system because H_2, as a versatile zero-carbon energy carrier, can be used in hard-to-abate sectors like industrial high heat temperature or in long-haul trucks and potentially aviation, where direct electrification is less likely.

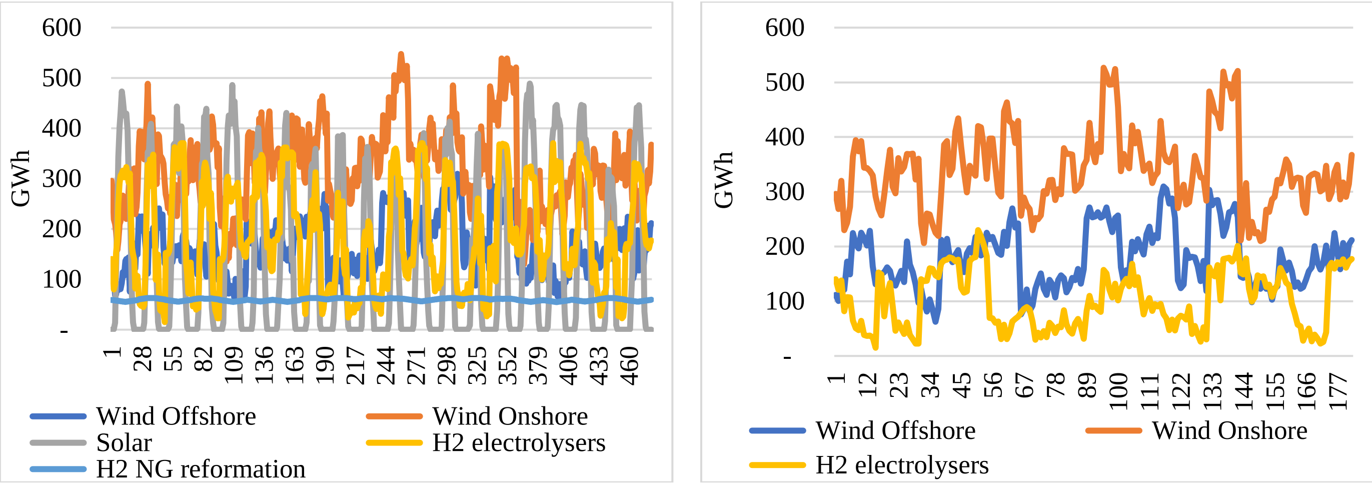

Figure 9: Samples of hourly electricity generation from renewables and H_2 production plants (left panel – day and night time; right panel – only evening and nigh hours) in our NZ scenario
Note: hourly correlation between offshore, onshore wind, solar and H_2 electrolysers are respectively -0.01, 0.00 and 0.82 (left panel) and hourly correlation between offshore, onshore wind and H2 electrolysers are respectively -0.17, 0.18 (right panel)

H_2 production from natural gas reformation plays a rather marginal role in our scenarios (its production share ranges 17-23%, see Figure 6) – in fact, H_2 from gas reformation does not have a similar (system integration) role like green H_2. Therefore, the place of blue H_2 in our future energy system will be limited to:

- the economic competitiveness of both feedstock fossil gas prices and cost reduction potential of advanced steam reformers; we have assumed a gas price of €30/MWh in 2050 but with the recently gas price range (due to the ongoing crisis in Europe) of €30/MWh to €272/MWh hydrogen from imported gas will likely be nil both on grounds of energy security but also driven by potentially high import prices.
- potential increase in CO_2 capture rate as there will still be residual CO_2 emissions from these reformers, unless techno-economic potential of advance reformers suggests a possibility of 100% capture rate;
- lastly, CO_2 pipelines and storage liabilities and public acceptance.

At the downstream level, we find that technologies such as hybrid heat pumps allow for greater system flexibility by enabling within-day ramping sufficient to meet heat loads. This option allows for system flexibility at end-use level and allows for potentially aggressive electrification of buildings demand while minimizing overall system costs. This can be seen in Figure 10 where we provide an example of hourly operations of different heating solutions in buildings on a typical winter day (aggregate of all regions in the model) – electricity-based heat technologies run smoothly as a baseload solution to provide heat while gas-based technologies provide ramping needs during morning and evening peak load. Figure 10 shows heat generation in aggregate, thus, in some instances, the electrical element of HHP might run continuously throughout the day with minimal ramping needs from the gas part of HHP.

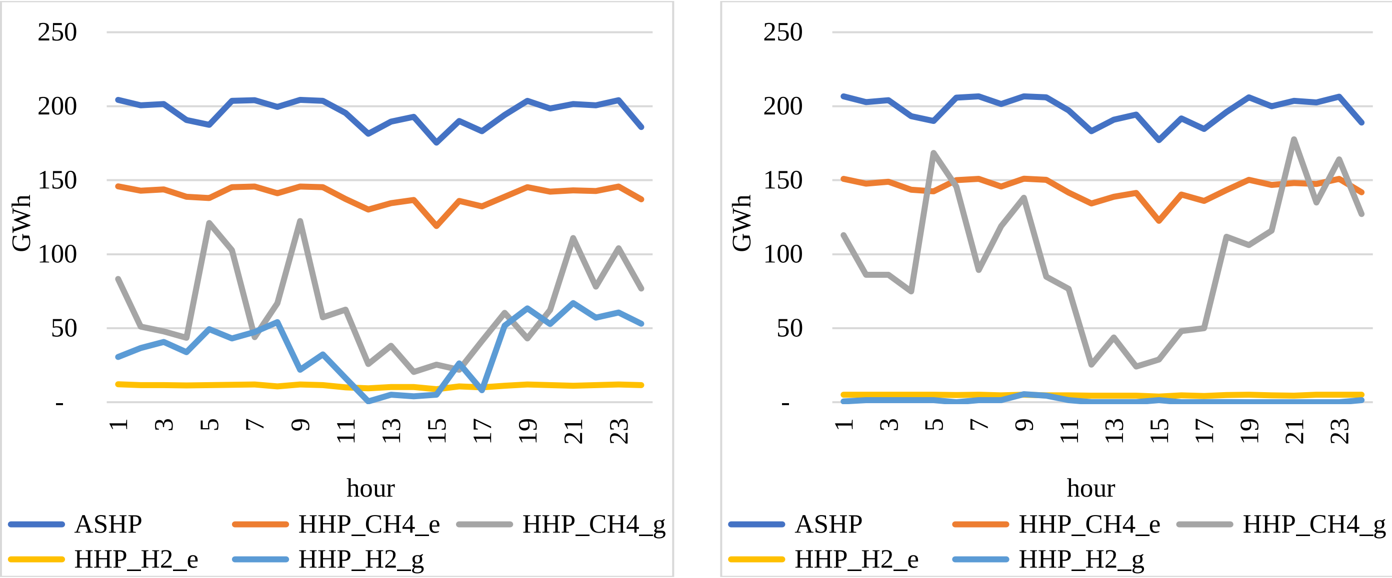

Figure 10: Aggregate hourly heat production in buildings on a winter day across all regions in the model (left panel – NZ scenario; right panel – 90% scenario)
Notes: ASHP – air sourced heat pumps, HHP – hybrid heat pumps (e – electricity-based unit, g – gas-based unit).

5. Conclusions

Ensuring that the energy system is flexible is important to meet deep decarbonisation of the entire economy at least cost. In this research we have tried to systematically assess and quantify sources of flexibility using a Pan-European energy system model, which accounted for spatial, intraday and seasonal variability of energy production and demand across the main European regions. The model explicitly considers both existing (e.g., fossil fuels, bioenergy, renewables, electricity) as well as new energy sources (e.g., H_2, electrofuels) of a tightly integrated energy system. Using this model, we systematically analysed two scenarios – a core scenario which strives to reach net zero (NZ) GHG emissions by 2050 for the Europe and 90% GHG emissions reduction scenario.

The modelling results from the NZ scenario suggest the central role of electricity supply sector and electricity-based end-use technologies (e.g., EVs and heat pumps) in delivering deep decarbonisation. This conclusion is consistent with other academic modelling studies and it is consistent with the EC LTS conclusion in that it is a no regret policy option to further support aggressive roll-out of renewable generation to reach net zero by 2050.

While electricity plays the linchpin role in delivering net zero, it is worth mentioning the role of other low-carbon energy sources, in particular, biomethane, hydrogen, synthetic e-fuels and bioenergy with CCUS. We found that sector coupling occurs not just at the supply level (e.g., via P2X technologies) but also potentially at end use level (e.g., via hybrid heat pumps in buildings). Despite adopting a rather optimistic assumption around bioenergy availability, the role of methane will still need to be substantially reduced as we decarbonise the economy. In terms of energy throughput requirements, the flow of CH4 will be reduced by 35% relative to the 2018 level. At the same time, we see a larger decrease of at least 50% in CH4 flow at primary supply level. In particular, the role of fossil gas will be reduced dramatically in the structure of final consumption (just 7% of the 2018 supply level), while imports are expected to reduce to 907 TWh, or ca. 23% of the EU27's gas import in 2021.

The pace of scaling up renewable energy, in particular electricity supply from wind and solar, to replace fossil fuels cannot be underestimated - electricity flow to final consumption needs to be scaled up by at least 48% between 2018 and 2050, while scaling up of electricity supply is even higher – 88% increase in supply relative to 2018 level. This is almost *five times* the historic growth rate in generation that we have seen in the past 30 years. According to our modelling results, net zero energy system in Europe will rely on zero-carbon electricity generation, consisting of at least 78% VRE and 12% nuclear, with hydro standing at 3% and the rest is dispatchable CCGT and biomass with CCS.

Thus, to reach this ambitious roll-out target, policy makers should pay attention to streamlining local planning procedures to minimise delays in bringing large-scale infrastructure projects associated with renewable energy as well as supporting RD&D of other low-carbon technologies, like CCUS and hydrogen. In fact, the EU authorities have recently reached an agreement on accelerated permitting rules for renewables, as part of an effort to eliminate the bloc's dependence on Russian gas by 2027 by way of faster roll-out of renewables.

As we set out at the beginning, our research question is: *what are the sources of flexibility to support fully decarbonised European energy system by 2050?* We defined energy system flexibility as including (i) energy networks to provide spatial flexibility, (ii) intraday, and (iii) seasonal flexibility provided by various storage technologies. Our modelling results clearly shows the importance and need for both temporal and spatial flexibility.

In particular, spatial flexibility (investments in national electricity networks and cross-border interconnections) is required to support aggressive roll-out of VRE. The growth in electricity cross-border trade that we found is in line with observed historic trends. As we electrify our economies cross-border trade increases even faster: the share of total trade in final consumption at least doubles in our decarbonisation scenarios relative to 2018. Gas trade heads in the opposite direction – due to the reduced requirement for importing fossil gas from non-EU countries, total trade in CH_4 reduces by a factor of at least 4 in NZ and 5 in 90% Scenario. The slightly higher cross border gas trade in the NZ scenario compared to the 90% scenario is because of greater hydrogen requirements to meet the net zero target. That said, given potentially higher gas import prices as well as sensitivities around dependence on import of fossil gas, this higher hydrogen demand may be filled by hydrogen from water electrolysis.

Thus, to reach our deep decarbonisation scenarios, interconnection capacity for electricity cross-border trade should gain more importance than trade in CH4. We found in our scenarios that total cross-border trade in electricity exceed that of CH4 by a factor of 2. However, we also found that CH4 cross-border trade depends on hydrogen demand – for example, due to higher requirements for hydrogen in the NZ scenario than in the 90% scenario, cross-border trade in CH4 increases in NZ. We found limited cross-border hydrogen trade because the commodity is locally produced (predominantly from electricity) in every EU country and the fact that local energy systems can self-balance using a combination of end-use and grid-scale flexibility solutions.

While the current European gas (CH_4) system's capability is at least three and a half times larger than its electricity counterpart, in our scenarios we found the reversal of this trend - electricity transmission capacity will be larger than the CH_4 transmission capacity; in fact, electricity transmission capacity expands by a factor of 2.8-3 relative to 2018 and is just 13-19% smaller than the CH_4 system in 2018. Thus, the conclusion is that in deep decarbonisation scenarios, both cross-border trade in electricity but also national network capacity will provide flexibility to integrate VRE further. Due to a rather limited H_2 in our scenarios, its network size appears to be small – a combination of storage (both in electricity and hydrogen) as well as flexible operation of electrolysers means that there is less need for H2 network to provide spatial flexibility. To decarbonise the last 10% (moving from 90% decarbonisation to net zero), we found that both electricity and H2 network capacity increases (but not CH_4), especially H_2 distribution network, which should increase by almost 5 times (compared to the 90% scenario). Therefore, the role of hydrogen will only gain importance in the NZ scenario.

In our scenarios, we found that traditional inter-seasonal flexibility is delivered by a combination of (i) a much-reduced capacity of seasonal CH_4 (reduced by a factor of 4 compared to the current capacity) and hydrogen storage, and (ii) new forms of seasonal storage – green H_2 production and storage. Green hydrogen production and storage serve mainly to support the differences between winter and summer VRE production (in particular solar) to minimise potential curtailments, while CH4 (and to lesser extent hydrogen) storage supports seasonal variations in heat load and hence requirements to shift biomethane and e-gas supply to buildings. Similar to the role of H2 network, we found that as we move from the 90% scenario to the NZ scenario, H2 storage (especially medium-duration) gain importance at the expense of CH4 and electricity-based storage. We found that intraday flexibility in our scenarios is mostly provided by:

1. electrical energy storage: both traditional storage solutions like hydro-based electrical storage and generation as well as new forms of intraday flexibility – V2G from EVs and electrical energy battery storage;
2. H_2-based intraday storage solutions, like pressurised H_2 tanks and liquid H_2 storage technologies;
3. hybrid heat pumps which allow for greater system flexibility associated with within day ramping requirements to meet heat loads.

We have also conducted extensive sensitivity analysis with regard to costs of traditional and sector coupling flexibility technologies (details in Appendix 3). A conclusion from this sensitivity analysis is that under a binding net zero GHG target, all energy vectors, traditional and new, complement each other either directly or indirectly. For example, by varying network cost assumptions, we found that CH_4 and electricity networks are complementary in the integrated energy system while CH_4 and hydrogen could have different roles in the final consumption sectors depending on costs and availability assumptions. Further, we found that electricity and synfuels are complements and that the role of green H_2, P2X and hybrid heat pumps is to further integrate the energy system under net zero.

As noted by Pollitt and Chyong (2021), the NZ target remains an extremely challenging policy goal, involving the roll out of multiple new technologies at scale within a time frame of less than 30 years. Thus, delivering three times carbon reduction as compared to the last 30 years while facing increasing marginal costs of emissions reduction will be challenging. Lack of scaling up of key technologies such as renewable energy, biomethane, hydrogen, or carbon capture and storage will make it difficult to reach net zero emissions by 2050, unless there is an unforeseen technological breakthrough. Even RES-E, which has seen the most successful scale up to date is still far from being on a trajectory to full decarbonisation, which will become increasingly difficult since it will need either significant negative emissions and/or effective incentives for delivering far more short-term and longer-term energy storage, which returns to our central focus on flexibility.

To conclude, the electricity supply sector and electricity-based end-use technologies are crucial for deep decarbonization. Other low-carbon sources such as biomethane, hydrogen, synthetic e-fuels, and BECCS will also play a role. We find that temporal and spatial flexibility are required to fully decarbonize the European energy system by 2050. This involves investments in electricity networks and cross-border interconnections for the aggressive rollout of renewables, and increased cross-border trade in electricity with larger transmission capacity than natural gas in 2050. Hydrogen storage and green hydrogen production will provide inter-seasonal flexibility. Lastly, the role of hydrogen networks and storage will increase, while the need for natural gas networks and storage will decrease in high decarbonization scenarios.

In terms of possible major extensions of our modelling work, we suggest five.

First, a future study might focus on the impact on Europe of global developments in hydrogen and CCS and hence how these might affect the path to net zero. A global hydrogen market or massive scale up of negative emissions elsewhere might allow Europe to avoid higher costs at home and/or purchase emissions allowances from abroad.

Second, energy efficiency in buildings, demand side flexibility and the role of energy and carbon prices and taxes could be further investigated as using them to manipulate demand in a helpful way could promote low carbon technology adoption and helpful behavioural change.

Thirdly, more rigorous analysis of other hydrogen production pathways should be carried out; in particular, bioenergy to hydrogen with CCS and pyrolysis of methane to produce hydrogen and solid carbon (thus avoiding CCS chain entirely) should be included in the modelling.

Fourth, we have not modelled the potential impact of different climate change and weather variability scenarios on energy demand and renewable energy supply. Different potential climate outcomes, together with already observed annual variations in VRE generation could significantly impact on our model results, and would be a worthwhile stand-alone exercise.

Finally, we have focussed on techno-economic modelling and the overall technology mix for net zero. The substantial question of how these costs can and should be allocated across vectors, end-use sectors, European countries and between individual consumers remains.

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CRediT author statement

CKC, MP: Conceptualisation, analysis, supervision, reviewing and editing; DMR: analysis, supervision, reviewing and editing; CKC: methodology, model development, data gathering, analysis, writing; CL: methodology (appendix A.1.3), data gathering.

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Appendix 1 ï Energy System Modelling for Net Zero Policy Analyses: Formulation

A.1.1. Model notation

This section gives details about symbols used in our energy system model. For clarity of presentation, all parameters are CAPITALISED whereas decision variables are written as lowercase and *italicised*. Subscripts are used for indexation while superscripts are used to clarify the meaning of variables and parameters, when these are necessary.

Sets and Indices

$t, tt \in T$	Set of time periods (in hours) in a representative day *(s)* $t=\{1..N_t\}$
$s, ss \in S$	Set of representative days or clusters (day types) in the modelling horizon $s=\{1..N_s\}$
$d, dd \in D$	Set of calendar days in the modelling horizon $d=\{1..N_d\}$
$y, yy \in Y$	Set of years in the modelling horizon $y=\{1..N_y\}$
$hr, hrr \in HR$	Set of rolling horizons $hr=\{1..N_{hr}\}$
$n, nn \in N$	Set of nodes in the model; nodes are all objects representing spatial and technological vectors in the model
$m, mm, \in M$	Set of final consumption sectors *{buildings, transport, industry}* in the model, a subset of all nodes
$i, ii \in I$	Set of commodities represented in the model
$j, jj \in J$	Set of all technologies modelled
$k, kk \in J$	Set of all storage technologies, a subset of *J*

Variables

Name	Description/Comment	Unit
	Operational Decision Variables	
$s_{y,s,t,i,n} \geq 0$	Supply of commodity *i {coal, natural gas, gasoline, diesel, biomass, biomethane, uranium}*	*GWh*
$g_{y,s,t,j,i,n} \geq 0$	Conversion to commodity *i* by technology *j;* for energy production the units are in GWh; for road transport modes the units are in million km-vehicle (mnkm-v)	*GWh or mnkm-v*
$g\_EV_{y,s,t,j,i,n} \geq 0$	Electric vehicle (EV) travelling decision	*mnkm-v*
$x_{y,s,t,j,i,n} \geq 0$	Consumption of commodity *i* by technology *j*	*GWh*
$z^{nonneutral}_{y,s,t,j,in} \geq 0$	Capture of non-neutral CO_2 emissions by power station technology *j*	*ktCO2e*
$z^{neutral}_{y,s,t,j,in} \geq 0$	Capture of neutral CO_2 emissions by power station technology *j*.	*ktCO2e*
$z\_DAC^{nonneutral}_{y,s,tj,i,n} \geq 0$	Direct air capture of non-neutral CO_2 emissions.	*ktCO2e*
$z\_DAC^{neutral}_{y,s,tj,i,n} \geq 0$	Direct air capture of neutral CO_2 emissions.	*ktCO2e*
$c\_CO_2{}^{neutral}_{y,s,t,j,i,n} \geq 0$	Permanent underground storage of captured CO_2 emissions. Note the model differentiate between CO_2 sources (CO_2 neutral and non-neutral)	*ktCO2e*
$c_{y,s,t,j,i,n} \geq 0$	Storage *j* charging decision	*GWh*
$d_{y,s,t,j,i,n} \geq 0$	Storage *j* discharging decision	*GWh*
$flow\_x_{n,nn,i,y,s,t} \geq 0$	Flow of commodity *i* from *n* to *nn*	*GWh*
	Operational Auxiliary Variables	
$input\_required_{y,s,t,j,i,n}$	Commodity *i* input requirement by technology *j*. This variable allows the model to choose between a set of similar commodity (e.g., by energy content) for consumption to produce a unit of output. For example, biomethane, e-gas and natural gas has similar energy properties except their CO_2 emissions intensity.	*GWh*
$d\_EV_{y,s,t,j,i,n} \geq 0$	Electricity consumption by EV technology *j*	*GWh*
$flow\_n_{y,s,t,j,i,n} \geq 0$	Flow of commodity *i* within node *n*	*GWh*
$curtailment^{vre}_{y,s,t,j,i,n} \geq 0$	Curtailment of variable renewable energy *i* at node *n*	*GWh*
$stor\_level^{intra}_{y,s,t,j,i,n}\ (free)$	Storage level within day type *s*	*GWh*
$c\_CO_2{}^{nonneutral}_{y,s,t,j,i,n} \geq 0$	Permanent underground storage of non-neutral CO_2 emissions.	$ktCO2_e$
	Auxiliary CO2 emissions definitions variables	
$e\_CO_2{}^{neutral}_{y,s,t,j,i,n} \geq 0$	Neutral CO_2 emissions by technology *j*	$ktCO2_e$
$e\_CO_2{}^{biomethane}_{y,s,t,i,n} \geq 0$	Captured neutral CO_2 emissions from upgrading biogas to biomethane	$ktCO2_e$
$e\_CO_2{}^{nonneutral}_{y,s,t,j,i,n} \geq 0$	Non-neutral CO_2 emissions by technology *j*	$ktCO2_e$
$e\_CO_2{}^{negative}_{y,s,t,j,i,n} \geq 0$	Negative CO_2 emissions by technology *j*	$ktCO2_e$
	Investment Decision Variables	
$kflow\_x_{n,nn,i,y} \geq 0$	Investment in interconnection capacity to transport commodity *i* from *n* to *nn*	*GW*
$kflow\_n_{n,i,y} \geq 0$	Investment in capacity to transport commodity *i* within node *n*	*GW*

$kg_{j,i,n,y} \geq 0$	Investment in capacity of a conversion technology *j* for energy activities; for transport demand activities, the units are million vehicles	*GW or Mn vehicles*
$ks_{j,i,n,y} \geq 0$	Investment in capacity of a storage technology *j*	*GWh*
$ks\_EV_{j,i,n,y} \geq 0$	Investment in EV road transport modes	*Mn vehicles*
	Auxiliary time-sequenced decision variables	
$g\_ts_{y,d,t,j,i,n} \geq 0$	Production of commodity *i* by technology *j* with calendar day index *d;* this variable applies to technology with hourly ramping constraints only	*GWh*
$g\_initial_{y,d,j,i,n} \geq 0$	Production level of technology *j* at the beginning of the calendar day *d*	*GWh*
$stor\_level^{inter}_{y,d,j,i,n} \geq 0$	Storage level at the beginning of the calendar day *d*	*GWh*
$stor\_level^{total\_state}_{y,d,t,j,i,n} \geq 0$	Total storage level (sum of inter-state, $stor\_level^{inter}_{y,d,j,i,n}$, and intra-state, $stor_{level}{}^{intra}_{y,s,t,j,i,n}$, storage levels)	*GWh*
	Auxiliary cost definitions variables	
$v^{opex}_{commodity}$	Total cost of primary commodity supply	*€ mn/yr*
$v^{opex}_{x\_network}$	Total operating cost of cross-border networks and trades	*€ mn/yr*
$v^{opex}_{n\_network}$	Total operating cost of national networks (transmission and distribution)	*€ mn/yr*
$v^{opex}_{conversion}$	Total operating cost of conversion technologies	*€ mn/yr*
$v^{opex}_{storage}$	Total operating cost of storage technologies	*€ mn/yr*
v^{opex}_{EV}	Total operating cost of EV technologies	*€ mn/yr*
v_{carbon}	Total cost of carbon emissions (non-neutral sources) in ETS covered sectors	*€ mn/yr*
$v_{curtailment}$	Total cost of energy curtailment	*€ mn/yr*
$v^{capex}_{networks}$	Total investment (annuitized) cost for all types of networks	*€ mn/yr*
$v^{capex}_{conversion}$	Total investment (annuitized) cost for all conversion technologies	*€ mn/yr*
$v^{capex}_{storage}$	Total investment (annuitized) cost for all storage technologies	*€ mn/yr*

Exogenous Parameters and Functions

Name	Description/Comment	Unit
	General	
$\mathrm{DEMAND}_{y,s,t,i,m}$	Final energy (or transport activities) demand in sector *m*; Energy demand: *GWh;* Transport activities: *mnkm-v*	*Commodity specific*
$\mathrm{AMB\_TEMP}_{s,t,n}$	Outside temperature	*Celsius degrees °C*
$\mathrm{CO}_{2_y}^{\mathrm{LIMIT\_All}}$	Annual CO_2 emissions limit. Note that we implement both at EU27 level CO_2 emissions limit and for individual countries and regions in the model	*ktCO2*$_e$
$\mathrm{CO}_{2_y}^{\mathrm{LIMIT\_Buildings}}$	Annual CO_2 emissions limit set for the buildings sector at EU level.	*ktCO2*$_e$
$\mathrm{CO}_{2_y}^{\mathrm{LIMIT\_Transport}}$	Annual CO_2 emissions limit set for the road transport sector at EU level.	*ktCO2*$_e$
$\mathrm{CO}_{2_{y,n}}^{\mathrm{emissions\_exog}}$	Exogenous CO_2 emissions not directly modelled *{industrial, agricultural, other transport, non-* CO_2 *and LULUCF* CO_2 *emissions}*	*ktCO2*$_e$
$\mathrm{PRIMARY\_SUPPLY}_{n,i}$	Exogenous supply of commodity *i*. Note that we do not explicitly differentiate between domestic production and imports of primary energy supply but this can be easily amended.	*GWh/yr*
α_s	Weight of cluster *s*: number of calendar days cluster *s* represents	*days*
	Networks	
$\overline{\mathrm{TX}_{n,nn,\imath}}$	Existing (exogenous) cross border network capacity to transport commodity *i* from *n* to *nn*	*GW*
$\overline{\mathrm{TN}_{n,\imath}}$	Existing (exogenous) network capacity to transport commodity *i* within node *n*	*GW*
$\mathrm{TL}_{n,nn,i}$	Loss factor applied to flows between *n* and *nn*	%
$\mathrm{TL}_{n,i}$	Loss factor applied to flows within node *n*	%
$\mathrm{DT}_{n,nn,i}$	Depreciation rate of a link *(n,nn),* as % of installed transport capacity $\overline{\mathrm{T}_{n,nn,\imath}}$	%
$\mathrm{DT}_{n,i}$	Depreciation rate of network capacity to transport commodity *i* within node *n*, as % of installed network capacity $\overline{\mathrm{TG}_{n,\imath}}$	%
	Generation & conversion	

$\eta^{I}_{s,t,i,j,ii,n}$	Consumption of commodity *i* by technology *j* to produce one unit of commodity *ii;* for energy activities the units are *GWh-th/GWh-th*; for transport activities the units are *GWh/mnkm-v*	*technology specific*
$\overline{G_{j,i,n}}$	Existing (exogenous) conversion capacity of a technology *j*	*GW*
RUF_j	Maximum ramp-up factor of technology *j*, expressed as % of maximum conversion capacity, $\overline{G_{j,i,n}}$ or $kg_{j,i,n,y}$	*%/hour*
RDF_j	Maximum ramp-up down of a technology *j*, expressed as % of maximum conversion capacity, $\overline{G_{j,i,n}}$ or $kg_{j,i,n,y}$	*%/hour*
$CF_{s,t,j,n}$	Capacity factor of technology *(j,i)*, as % of installed capacity	*%*
CI_i	CO_2 intensity of commodity *i*	*$ktCO_2$/GWh*
$CI_i^{biomethane}$	CO_2 capture from the process of upgrading biogas to biomethane. Note we assume 90% capture rate for this process.	*$ktCO_2$/GWh*
$CR_{j,i}$	CO_2 capture rate of the technology *j*, as % of total emissions from *j*	*%*
CN_i	CO_2 type of the energy commodity *i* (1 – neutral, 0 otherwise).	*Dimensionless*
PL_j	Power station self-consumption, as % of conversion/production rate ($g_{y,s,t,j,i,n}$)	*%*
DG_j	Depreciation rate of conversion technology *j*, as % of installed capacity $\overline{G_{J,\iota}}$ or $kg_{j,i,n,y}$	*%*
HHP_RATIO	Ratio of gas to electricity capacity in a hybrid heat pump system	*Dimensionless*
	Storage	
$STOR\_EFF_j$	Efficiency of charging a storage unit *j*, as % of charge rate $c_{y,s,t,j,i,n}$	*%*
$STOR\_CAP_{j,n}^{INIT}$	Existing (exogenous) capacity of the storage unit *j*	*GWh or ktCO2*
$STOR\_LEVEL_{j,i,n}^{INIT}$	Initial volume stored at the beginning of the modelling horizon	*GWh or ktCO2*
$CHARGE\_DURATION_j$	Number of hours a storage need to be fully charged up to the installed capacity	*hours*
$DISCHARGE\_DURATION_j$	Number of hours a storage unit need to fully discharge down to 0 capacity	*hours*
DS_j	Depreciation rate of storage technology *j*, as % of installed capacity $S_{j,i,n}$ or $ks_{j,i,n,y}$	*%*
	Road transport	
$T\_DISTANCE_{s,t,j,i,n}$	Average travel distance covered by road transport mode *j*	*Km/vehicle*
$EV\_BATT\_CAP_j$	Average size of battery in an EV vehicle *j*	*kWh/vehicle*
$V2G\_DERATING_j$	V2G derating factor, a sensitivity parameter with a range of [0; 1]. In the baseline modelling this is 1	*dimensionless*
	Operational costs	
VOM_j	Variable operating cost of technology *j*	*€/GWh*
FOM_j	Fixed operating cost of technology *j*	*€/GW*
$VOM_{n,nn,i}$	Variable operating cost of cross-border line *(n,nn,i)*	*€/GWh*
$FOM_{n,nn,i}$	Fixed operating cost of cross-border line *(n,nn,i)*	*€/GW*
$VOM_{n,i}$	Variable operating cost of network node *(n,i)*	*€/GWh*
$FOM_{n,i}$	Fixed operating cost of network node *(n,i)*	*€/GW*
$COST_{n,i}^{PrimaryComm}$	Wholesale cost of commodity *i*	*€/GWh*
$COST_y^{Carbon}$	Carbon cost	*€/tCO_2*
$COST_{j,n}^{curtailment}$	Cost of curtailing outputs of technology *j* at node *n;* we assume a very large number to minimise curtailment but we can also calibrate this to technology-specific LCOE	*€/GWh*
	Investment costs	
δ_y	Discount factor	*Dimensionless*
ρ_tech_j	Annuity factor applied to storage and conversion technologies	*Dimensionless*
$\rho\_networks_{n,i,y}$	Annuity factor applied to networks *n*	*Dimensionless*
$\rho\_networks\_x$	Annuity factor applied to cross-border networks	*Dimensionless*
$KF_{n,nn,i,y}^{Intercon\_Capex}$	Per unit incremental capital cost of expanding cross border network capacity to transport commodity *i* from *n* to *nn*	*€/GW*
$KF_{n,i,y}^{Network\_Capex}$	Per unit incremental capital cost of expanding network capacity to transport commodity *i* within node *n*	*€/GW*
$KG_{j,y}^{Convesion\_Capex}$	Per unit incremental capital cost of expanding capacity of the conversion technology *j*	*€/GW*
$KS_{j,y}^{Storage\_Capex}$	Per unit incremental capital cost of expanding capacity of the storage technology *j*	*€/GW*

A.1.2. Equations

A.1.3.1. System constraints

This section outlines system-wide constraints, such as nodal balance and emissions constraints implemented in the model. Thus, the first equation relates to energy and commodity balance for every node *n* and time period that must be satisfied (eq. A1). Equations A2-A4 constraint CO_2 emissions for all countries and sectors (eq. A2) and specifically for transport (eq. 3) and buildings (eq. A4) sectors.

$$\forall n,i,y,s,t \quad \begin{aligned} &\sum_j g_{y,s,t,j,i,n} \times (1-\mathrm{PL_{j,i}}) \times (1-\mathrm{TL_{n,i}}) + \sum_j g\_EV_{y,s,t,j,i,n} \\ &+ \sum_j (z^{nonneutral}_{y,s,t,j,in} + z^{neutral}_{y,s,t,j,in}) + \sum_j (z\_DAC^{nonneutral}_{y,s,tj,in} + z\_DAC^{neutral}_{y,s,tj,in}) \\ &+ \sum_{nn} flow\_x_{nn,n,i,y,s,t} \times (1-\mathrm{TL_{nn,n,i}}) \times (1-\mathrm{TL_{n,i}}) \\ &+ \sum_j d_{y,s,t,j,i,n} \times (1-\mathrm{TL_{n,i}}) + s_{y,s,t,i,n} \times (1-\mathrm{TL_{n,i}}) \\ &+ e\_CO_2{}^{biomethane}_{y,s,t,i,n} \\ &= \mathrm{DEMAND_{y,s,t,i,n}} + \sum_j x_{y,s,t,j,i,n} + \sum_{nn} flow\_x_{n,nn,i,y,s,t} + \sum_j c_{y,s,t,j,i,n} \\ &+ \sum_j c\_CO_2{}^{neutral}_{y,s,t,j,i,n} + \sum_j c\_CO_2{}^{nonneutral}_{y,s,t,j,i,n} \end{aligned} \tag{A1}$$

$$\forall y \quad \sum_{s,t,j,i,n} \alpha_s \times (e\_CO_2{}^{nonneutral}_{y,s,t,j,i,n} - c_{CO}{}_2{}^{nonneutral}_{y,s,t,j,i,n} - e\_CO_2{}^{negative}_{y,s,t,j,i,n}) \le \mathrm{CO}_{2_y}^{\mathrm{LIMIT\_All}} \tag{A2}$$

$$\forall y \quad \sum_{s,t,j,i,n|n=\text{"transport"}} \alpha_s \times e\_CO_2{}^{nonneutral}_{y,s,t,j,i,n} \le \mathrm{CO}_{2_y}^{\mathrm{LIMIT\_Transport}} \tag{A3}$$

$$\forall y \quad \sum_{s,t,j,i,n|n=\text{"buildings"}} \alpha_s \times e\_CO_2{}^{nonneutral}_{y,s,t,j,i,n} \le \mathrm{CO}_{2_y}^{\mathrm{LIMIT\_Buildings}} \tag{A4}$$

A.1.3.2. Conversion and ramping constraints

The first three constraints are related to conversion limit (eq. A5), ramping up (eq. A6) and ramping down (eq. A7) capability of a conversion unit *j*. Note that constraint A5 applies to both energy demand and transport demand activities; for transport demand activities, the division on the left hand side of the inequality converts travel distance decision (km-vehicle) into quantities of vehicles. Thus, for transport activities $kg_{j,i,n,y}$ is measured in million vehicles. Constraint (A8) ensures divestment of new conversion capacity does not exceed the depreciation rate, if it is cost optimal to divest. This formulation of investment in capacity allows us to potentially analyse optimal closure and divestment. A similar formulation has been applied in the natural gas market modelling literature (see e.g., Zwart and Mulder, 2006[6]). Equation A9 ensures input balance while equation A10 specify capacity ratio of gas- to electric-driven parts of hybrid heat pumps.

$$\forall y,s,t,j,i,n \quad \frac{g_{y,s,t,j,i,n}}{\mathrm{T\_DISTANCE_{s,t,j,i,n}}} \le \mathrm{CF_{s,t,j,i,n}} \times \left[\overline{\mathrm{G_{j,i,n}}} \times (1-\mathrm{DG_{j,i}})^y + kg_{j,i,n,y}\right] \tag{A5}$$

$$\forall y,s,t,j,i,n \quad g_{y,s,t,j,i,n} - g_{y,s,t-1,j,i,n} \le \mathrm{RUF_j} \times [\overline{\mathrm{G_{j,i,n}}} \times (1-\mathrm{DG_{j,i}})^y + kg_{j,i,n,y}] \tag{A6}$$

$$\forall y,s,t,j,i,n \quad g_{y,s,t-1,j,i,n} - g_{y,s,t,j,i,n} \le \mathrm{RDF_j} \times [\overline{\mathrm{G_{j,i,n}}} \times (1-\mathrm{DG_{j,i}})^y + kg_{j,i,n,y}] \tag{A7}$$

$$\forall j,i,n,y \quad kg_{j,i,n,y} - (1-\mathrm{DG_{j,i}}) \times kg_{j,i,n,y-1} \ge 0 \tag{A8}$$

$$\forall y,s,t,j,i,n \quad \sum_{ii} x_{y,s,t,j,ii,n} = input\_required_{y,s,t,j,i,n} \tag{A9}$$

$$\forall y,i,n \quad \sum_{j=\text{"HHP\_g"}} kg_{j,i,n,y} = \mathrm{HHP\_RATIO} \times \sum_{j=\text{"HHP\_e"}} kg_{j,i,n,y} \tag{A10}$$

Constraint (A11) defines technology *j*'s energy *i* consumption while constraint (A12) defines curtailment of VRE energy.

$$\forall y,s,t,j,i,n \quad \begin{aligned} &input\_required_{y,s,t,j,i,n} \\ &= \sum_{ii} \left(g_{y,s,t,j,ii,n} + z\_DAC^{nonneutral}_{y,s,tj,i,n} + z\_DAC^{neutral}_{y,s,tj,i,n}\right) \times \eta^{\mathrm{I}}_{\mathrm{s,t,i,j,ii,n}} \end{aligned} \tag{A11}$$

$$\forall y,s,t,j,i,n \quad curtailment^{vre}_{y,s,t,j,i,n} = \mathrm{CF_{s,t,j,i,n}} \times \left[\overline{\mathrm{G_{j,i,n}}} \times (1-\mathrm{DG_{j,i}})^y + kg_{j,i,n,y}\right] - g_{y,s,t,j,i,n} \tag{A12}$$

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[6] Zwart, G. and Mulder, M. (2006). "NATGAS: A model of the European natural gas market," CPB Memorandum 144. http://www.cpb.nl/sites/default/files/publicaties/download/memo144.pdf, accessed 9 January 2009.

A.1.3.3. Energy Storage Constraints

Operations of energy storage facilities are modelled using equations A13-A21. Charging (eq. A13) and discharging (eq. A14) cannot exceed capacity limitations. Eq. A15 assign the state of storage level at the end of each intra period *s* to the initial storage volume. Eq. A16 and A17 defines storage level at the end of time period *t* and *d*. Eq. A18 and A19 specify that total energy volume stored cannot exceed storage volume capacity while equation A20 make sures that intra-period storage level for some storage technologies cannot be negative. Finally, eq. A21 ensures divestment of new storage capacity does not exceed storage depreciation rate.

$$\forall y,s,t,j,i,n \quad c_{y,s,t,j,i,n} + c\_CO_{2\,y,s,t,j,i,n}^{nonneutral} + c\_CO_{2\,y,s,t,j,i,n}^{neutral} \leq \frac{\mathrm{STOR\_CAP}_{\mathrm{j,n}}^{\mathrm{INIT}} \times (1 - \mathrm{DS}_{\mathrm{j,i}})^{y} + ks_{j,i,n,y}}{\mathrm{CHARGE\_DURATION}_{\mathrm{j}}} \tag{13}$$

$$\forall y,s,t,j,i,n \quad d_{y,s,t,j,i,n} \leq \frac{\mathrm{STOR\_CAP}_{\mathrm{j,n}}^{\mathrm{INIT}} \times (1 - \mathrm{DS}_{\mathrm{j,i}})^{y} + ks_{j,i,n,y}}{\mathrm{DISCHARGE\_DURATION}_{\mathrm{j}}} \tag{14}$$

$$\forall y,s,j,i,n \quad \sum_{t|ord(t)=card(t)} stor\_level_{y,s,t,j,i,n}^{intra} = \mathrm{STOR\_LEVEL}_{\mathrm{j,i,n}}^{\mathrm{INIT}} \tag{15}$$

$$\forall y,s,t,j,i,n \quad stor\_level_{y,s,t,j,i,n}^{intra} = stor\_level_{y,s,t-1,j,i,n}^{intra} + \mathrm{STOR\_EFF}_{\mathrm{j}} \times \left(c_{y,s,t,j,i,n} + c_{CO_2}{}_{y,s,t,j,i,n}^{nonneutral} + c_{CO_2}{}_{y,s,t,j,i,n}^{neutral}\right) - d_{y,s,t,j,i,n} - d\_EV_{y,s,t,j,i,n} \tag{16}$$

$$\forall y,d,j,i,n \quad stor\_level_{y,d,j,i,n}^{inter} = stor\_level_{y,d-1,j,i,n}^{inter} + \sum_{t|ord(t)=card(t)} stor\_level_{y,d(s),t,j,i,n}^{intra} \tag{17}$$

$$\forall y,s,t,j,i,n \quad stor\_level_{y,s,t,j,i,n}^{intra} \leq \mathrm{STOR\_CAP}_{\mathrm{j,n}}^{\mathrm{INIT}} \times (1 - \mathrm{DS}_{\mathrm{j,i}})^{y} + ks_{j,i,n,y} \tag{18}$$

$$\forall y,d,t,j,i,n \quad stor\_level_{y,d,t,j,i,n}^{total\_state} \leq \mathrm{STOR\_CAP}_{\mathrm{j,n}}^{\mathrm{INIT}} \times (1 - \mathrm{DS}_{\mathrm{j,i}})^{y} + ks_{j,i,n,y} \tag{19}$$

$$\forall y,s,t,j,i,n \quad stor\_level_{y,s,t,j,i,n}^{intra} \geq 0 \tag{20}$$

$$\forall j,i,n,y \quad ks_{j,i,n,y} - (1 - \mathrm{DS}_{\mathrm{j,i}}) \times ks_{j,i,n,y-1} \geq 0 \tag{21}$$

A.1.3.4. Electric vehicles constraints

We model electric vehicles (EV) as storage units that would allow representation of its main features and how they interact with the whole energy system: (a) to optimise EV charging optimally (or impose further constraints on charge profile), (b) to provide storage services back to the electricity system (so-called V2G storage services). With the below formulation we can constraints these features allowing flexibility for sensitivity analyses.

$$\forall y,s,t,j,i,n \quad d\_EV_{y,s,t,j,i,n} = \sum_{ii} \eta_{\mathrm{s,t,i,j,ii,n}}^{\mathrm{I}} \times g\_EV_{y,s,t,j,ii,n} \tag{A22}$$

$$\forall y,s,t,j,i,n \quad \frac{g\_EV_{y,s,t,j,i,n}}{\mathrm{T\_DISTANCE}_{\mathrm{s,t,j,i,n}}} \leq \mathrm{STOR\_CAP}_{\mathrm{j,n}}^{\mathrm{INIT}} \times (1 - \mathrm{DG}_{\mathrm{j,i}})^{y} + ks\_EV_{j,i,n,y} \tag{A23}$$

$$\forall y,s,t,j,i,n \quad c_{y,s,t,j,i,n} \leq \frac{\mathrm{STOR\_CAP}_{\mathrm{j,n}}^{\mathrm{INIT}} \times (1 - \mathrm{DS}_{\mathrm{j,i}})^{y} + ks\_EV_{j,i,n,y} \times \mathrm{EV\_BATT\_CAP}_{\mathrm{j}}}{\mathrm{CHARGE\_DURATION}_{\mathrm{j}}} \tag{A24}$$

$$\forall y,s,t,j,i,n \quad d_{y,s,t,j,i,n} + d\_EV_{y,s,t,j,i,n} \leq \frac{\mathrm{STOR\_CAP}_{\mathrm{j,n}}^{\mathrm{INIT}} \times (1 - \mathrm{DS}_{\mathrm{j,i}})^{y} + ks\_EV_{j,i,n,y} \times \mathrm{EV\_BATT\_CAP}_{\mathrm{j}}}{\mathrm{DISCHARGE\_DURATION}_{\mathrm{j}}} \tag{A25}$$

$$\forall y,d,t,j,i,n \quad stor\_level_{y,d,t,j,i,n}^{total\_state} \leq \mathrm{STOR\_CAP}_{\mathrm{j,n}}^{\mathrm{INIT}} \times (1 - \mathrm{DS}_{\mathrm{j,i}})^{y} + ks\_EV_{j,i,n,y} \times \mathrm{EV\_BATT\_CAP}_{\mathrm{j}} \times \mathrm{V2G\_DERATING}_{\mathrm{j}} \tag{A26}$$

$$\forall j,i,n,y \quad ks\_EV_{j,i,n,y} - (1 - \mathrm{DS}_{\mathrm{j,i}}) \times ks\_EV_{j,i,n,y-1} \geq 0 \tag{A27}$$

A.1.3.5. Network constraints

Cross border flows of commodity *i* from zone *n* to the next zone *nn* are restricted by respective capacity (eq. A28 and A29). Lastly, total commodity *i* injected into node *n* (eq. A30) cannot exceed network capacity in each node *n* (eq. A31 and A32).

$$\forall n,nn,i,y,s,t \quad flow\_x_{n,nn,i,y,s,t} \leq \overline{\mathrm{TX}}_{\mathrm{n,nn,i}} \times (1 - \mathrm{DT}_{\mathrm{n,nn,i}})^{y} + kflow\_x_{n,nn,i,y} \tag{A28}$$

$$\forall n,nn,i,y \quad kflow\_x_{n,nn,i,y} - (1 - \mathrm{DT}_{\mathrm{n,nn,i}}) \times kflow\_x_{n,nn,i,y-1} \geq 0 \tag{A29}$$

$$\forall y,s,t,i,n \quad flow\_n_{y,s,t,i,n} = \sum_j g_{y,s,t,j,i,n} \times \left(1 - \mathrm{PL_{j,i}}\right) + \sum_j (z^{nonneutral}_{y,s,t,j,in} + z^{neutral}_{y,s,t,j,in}) + \sum_j (z\_DAC^{nonneutral}_{y,s,tj,in} + z\_DAC^{neutral}_{y,s,tj,in}) + \sum_{nn} flow\_x_{nn,n,i,y,s,t} \times (1 - \mathrm{TL_{nn,n,i}}) + \sum_j d_{y,s,t,j,i,n} + s_{y,s,t,i,n} - \sum_{j|j="Residential\_SolarPV"} g_{y,s,t,j,i,n} \times \left(1 - \mathrm{PL_{j,i}}\right) \tag{A30}$$

$$\forall y,s,t,i,n \quad flow\_n_{y,s,t,i,n} \leq \overline{\mathrm{TN_{n,i}}} \times (1 - \mathrm{DT_{n,i}})^y + kflow\_n_{n,i,y} \tag{A31}$$

$$\forall n,i,y \quad kflow\_n_{n,i,y} - (1 - \mathrm{DT_{n,i}}) \times kflow\_n_{n,i,y-1} \geq 0 \tag{A32}$$

A.1.3.6. CO_2 Emissions definitions

As noted, in the modelling we make an explicit distinction between carbon neutral (eq. A33) and carbon non-neutral (eq. A35) sources of CO_2 emissions. This is differentiation is required to constraint the model to produce synthetic fuels only using carbon neutral CO_2 sources; all non-carbon neutral sources of CO_2 emissions are either released to the atmosphere or captured and permanently stored in underground CO_2 storages (see next section for formulation of CCS constraints). Further, CO_2 capture in the process of upgrading biogas to biomethane is also taken into account (eq. A34) in our modelling. Finally, negative CO_2 emissions are defined as permanently stored CO_2 emissions from carbon neutral sources (eq. A36).

$$\forall y,s,t,j,i,n \quad e\_CO_2{}^{neutral}_{y,s,t,j,i,n} = \sum_{ii} \mathrm{CI_{ii}} \times x_{y,s,t,j,ii,n} \times \mathrm{CN_{ii}} \tag{A33}$$

$$\forall y,s,t,i,n \quad e\_CO_2{}^{biomethane}_{y,s,t,i,n} = \sum_{j,ii} \mathrm{CI_i^{biomethane}} \times x_{y,s,t,j,ii,n} \times \mathrm{CN_{ii}} \tag{A34}$$

$$\forall y,s,t,j,i,n \quad e\_CO_2{}^{nonneutral}_{y,s,t,j,i,n} = \sum_{ii} \mathrm{CI_{ii}} \times x_{y,s,t,j,ii,n} \times (1 - \mathrm{CN_{ii}}) \tag{A35}$$

$$\forall y,s,t,j,i,n \quad e\_CO_2{}^{negative}_{y,s,t,j,i,n} = c\_CO_2{}^{neutral}_{y,s,t,j,i,n} \tag{A36}$$

A.1.3.7. Carbon capture and storage constraints

This section outlines constraints for power stations with carbon capture (eq. A37-A39) and also standalone direct air capture rates (eq. A40-A42) as well as carbon storage rates (eq. A43-A44).

$$\forall y,s,t,j,i,n \quad z^{neutral}_{y,s,t,j,in} \leq e\_CO_2{}^{neutral}_{y,s,t,j,i,n} \times \mathrm{CR_{j,i}} \tag{A37}$$

$$\forall y,s,t,j,i,n \quad z^{nonneutral}_{y,s,t,j,in} \leq e\_CO_2{}^{nonneutral}_{y,s,t,j,i,n} \times \mathrm{CR_{j,i}} \tag{A38}$$

$$\forall y,s,t,j,i,n \quad z^{neutral}_{y,s,t,j,in} + z^{nonneutral}_{y,s,t,j,in} \leq (e\_CO_2{}^{neutral}_{y,s,t,j,i,n} + e\_CO_2{}^{nonneutral}_{y,s,t,j,i,n}) \times \mathrm{CR_{j,i}} \tag{A39}$$

$$\forall y,s,t,j,i,n \quad z\_DAC^{neutral}_{y,s,tj,in} \leq \sum_{jj} (e\_CO_2{}^{neutral}_{y,s,t,jj,i,n} - z^{neutral}_{y,s,t,jj,in}) \times \mathrm{CR_{j,i}} \tag{A40}$$

$$\forall y,s,t,j,i,n \quad z\_DAC^{nonneutral}_{y,s,tj,in} \leq \sum_{jj} (e\_CO_2{}^{nonneutral}_{y,s,t,jj,i,n} - z^{nonneutral}_{y,s,t,jj,in}) \times \mathrm{CR_{j,i}} \tag{A41}$$

$$\forall y,s,t,j,i,n \quad z\_DAC^{neutral}_{y,s,tj,in} + z\_DAC^{nonneutral}_{y,s,tj,in} \leq \sum_{jj} (e\_CO_2{}^{neutral}_{y,s,t,jj,i,n} + e\_CO_2{}^{nonneutral}_{y,s,t,jj,i,n} - z^{neutral}_{y,s,t,jj,in} - z^{nonneutral}_{y,s,t,jj,in}) \times \mathrm{CR_{j,i}} \tag{A42}$$

$$\forall y,s,t,j,i,n \quad c\_CO_2{}^{neutral}_{y,s,t,j,i,n} \leq \sum_{jj} (z^{neutral}_{y,s,t,jj,in} + z\_DAC^{neutral}_{y,s,tj,in}) + e\_CO_2{}^{biomethane}_{y,s,t,i,n} \tag{A43}$$

$$\forall y,s,t,j,i,n \quad c\_CO_2{}^{nonneutral}_{y,s,t,j,i,n} = \sum_{jj} (z^{nonneutral}_{y,s,t,jj,in} + z\_DAC^{nonneutral}_{y,s,tj,in}) \tag{A44}$$

A.1.3.8. Cost functions

Total operating costs of a modelled energy system, $\boldsymbol{v_{OPEX}}$, consists of commodity (eq. A45), network (eq. A46-A47), conversions (eq. A48), storage (eq. A49), EV (eq. A50), carbon (eq. A51), and energy curtailment (eq. A52) costs.

$$v^{opex}_{commodity} = \sum_{y,s,t,i,n} \delta_y \times \alpha_\mathrm{s} \times s_{y,s,t,i,n} \times \mathrm{COST^{PrimaryComm}_{n,i}} \tag{A45}$$

$$v_{x\_network}^{opex} = \sum_{i,n,nn,y,s,t} (\delta_y \times \alpha_s \times flow\_x_{n,nn,i,y,s,t} \times \mathrm{VOM_{n,nn,i}}) + \sum_{n,nn,i,y} \delta_y \times [\overline{\mathrm{TX_{n,nn,i}}} \times (1-\mathrm{DT_{n,nn,i}})^y + kflow\_x_{n,nn,i,y}] \times \mathrm{FOM_{n,nn,i}} \tag{A46}$$

$$v_{n\_network}^{opex} = \sum_{i,n,y,s,t} (\delta_y \times \alpha_s \times flow\_n_{n,i,y,s,t} \times \mathrm{VOM_{n,i}}) + \sum_{n,i,y} \delta_y \times [\overline{\mathrm{TN_{n,ı}}} \times (1-\mathrm{DT_{n,i}})^y + kflow\_n_{n,i,y}] \times \mathrm{FOM_{n,i}} \tag{A47}$$

$$v_{conversion}^{opex} = \sum_{j,i,y,s,t,n} (\delta_y \times \alpha_s \times (g_{y,s,t,j,i,n} + z\_DAC_{y,s,tj,in}^{nonneutral} + z\_DAC_{y,s,tj,in}^{neutral}) \times \mathrm{VOM_{j,i}}) + \sum_{j,i,n,y} \delta_y \times \left[\overline{\mathrm{G_{j,ı,n}}} \times (1-\mathrm{DG_{j,i}})^y + kg_{j,i,n,y}\right] \times \mathrm{FOM_{j,i}} \tag{A48}$$

$$v_{storage}^{opex} = \sum_{j,i,y,s,t,n} \delta_y \times \alpha_s \times (d_{y,s,t,j,i,n} + c_{y,s,t,j,i,n}) \times \mathrm{VOM_{j,i}}) + \sum_{j,i,n,y} \left[\mathrm{STOR\_CAP_{j,n}^{INIT}} \times (1-\mathrm{DS_{j,i}})^y + ks_{j,i,n,y}\right] \times \mathrm{FOM_{j,i}} \tag{A49}$$

$$v_{EV}^{opex} = \sum_{j,i,y,s,t,n} \delta_y \times \alpha_s \times (g\_EV_{y,s,t,j,i,n} + d_{y,s,t,j,i,n} + c_{y,s,t,j,i,n}) \times \mathrm{VOM_{j,i}}) + \sum_{j,i,n,y} \left[\mathrm{STOR\_CAP_{j,n}^{INIT}} \times (1-\mathrm{DS_{j,i}})^y + ks\_EV_{j,i,n,y}\right] \times \mathrm{FOM_{j,i}} \tag{A50}$$

$$v_{carbon} = \sum_{j,i,y,s,t,n} \delta_y \times \alpha_s \times [e_{CO_2}{}_{y,s,t,j,i,n}^{nonneutral} + \mathrm{CO_{2}}_{y,n}^{\mathrm{emissions\_exog}} - e\_CO_2{}_{y,s,t,j,i,n}^{nonneutral}] \times \mathrm{COST_y^{Carbon}} \tag{A51}$$

$$v_{curtailment} = \sum_{y,s,t,j,i,n} \delta_y \times \alpha_s \times curtailment_{y,s,t,j,i,n}^{vre} \times \mathrm{COST_{j,n}^{curtailment}} \tag{A52}$$

Further, total capital cost, $\boldsymbol{v_{CAPEX}}$, related to investments in networks (eq. A53), conversion technologies (eq. A54), and storage capacity (eq. A55) are defined as follows:

$$v_{networks}^{capex} = \sum_{n,nn,i,y} \rho\_networks\_x \times \delta_y \times \left[\left(kflow_{x_{n,nn,i,y}} - (1-\mathrm{DT_{n,nn,i}}\right) \times kflow_{x_{n,nn,i,y-1}} + \overline{\mathrm{TX_{n,nn,i}}}) \times \mathrm{KF_{n,nn,i,y}^{Intercon\_Capex}}\right] + \rho\_networks_{n,i,y} \times \delta_y \times \sum_{n,i,y} \left[(kflow\_n_{n,i,y} - (1-\mathrm{DT_{n,i}}) \times kflow\_n_{n,i,y-1}) \times \mathrm{KF_{n,i,y}^{Network\_Capex}}\right] \tag{A53}$$

$$v_{conversion}^{capex} = \sum_{j,i,y,n} \rho\_tech_j \times \delta_y \times \left[\left(kg_{j,i,n,y} - (1-\mathrm{DG_{j,i}}\right) \times kg_{j,i,n,y-1} + \overline{\mathrm{G_{j,ı,n}}}) \times \mathrm{KG_{j,y}^{Convesion\_Capex}}\right] \tag{A54}$$

$$v_{storage}^{capex} = \sum_{j,i,y,n} \rho\_tech_j \times \delta_y \times \left[\left(ks_{j,i,n,y} - (1-\mathrm{DS_{j,i}}\right) \times ks_{j,i,n,y-1} + ks\_EV_{j,i,n,y} - (1-\mathrm{DS_{j,i}}) \times ks\_EV_{j,i,n,y-1} + \mathrm{STOR\_CAP_{j,n}^{INIT}}) \times \mathrm{KS_{j,y}^{Storage\_Capex}}\right] \tag{A55}$$

A.1.3.8. Objective function

Thus, the objective of this optimization problem is to minimize total operational and investment costs (eq. A56) for the entire planning horizon *Y*. The optimization assumes a *central planner* who has perfect information about the cost structure of all technologies, the levels of demand and all other technical conditions and as such assumes perfect foresight over the planning horizon *Y* when searching for an optimal solution while meeting a set of constraints (eq. A1-A55).

$$\min_{\{\boldsymbol{decision\ varibales}\}} \boldsymbol{v_{OPEX}} + \boldsymbol{v_{CAPEX}}$$

Decision variables:

$$\{s_{y,s,t,i,n} \geq 0;\ g_{y,s,t,j,i,n} \geq 0;\ g_{EV}{}_{y,s,t,j,i,n} \geq 0;\ x_{y,s,t,j,i,n} \geq 0;\ z_{y,s,t,j,in}^{nonneutral} \geq 0;\ z_{y,s,t,j,in}^{neutral} \geq 0;\ z\text{-}\_DAC_{y,s,tj,in}^{nonneutral} \geq 0;\ z\_DAC_{y,s,tj,in}^{neutral} \geq 0;\ c\_CO_2{}_{y,s,t,j,i,n}^{neutral} \geq 0;\ c_{y,s,t,j,i,n} \geq 0;\ d_{y,s,t,j,i,n} \geq 0;\ flow\_x_{n,nn,i,y,s,t} \geq 0;\ kflow\_x_{n,nn,i,y} \geq 0;\ kflow\_n_{n,i,y} \geq 0;\ kg_{j,i,n,y} \geq 0;\ ks_{j,i,n,y} \geq 0;\ ks\_EV_{j,i,n,y} \geq 0\} \tag{56}$$

Subject to:

Constraints (1-55)

The modelling framework is flexible and can be setup to simulate a market outcome without investment decisions, treating conversion, transmission, and storage capacity expansion as fixed (e.g., exogenously defined) and setting the investment-related decision variables to zero.

A.1.3. Modelling procedures

Due to hourly time granularity of the optimal dispatch coupled with at least a 20-year optimal investment horizon, the resulting optimization problem, although linear, could be intractable and difficult to solve. This section describes our time series aggregation method that we applied in the modelling. We also describe the superposition method we use to make sure storage state transition is properly modelled in the framework of reduced time series.

A.1.4.1. Representative operation days

One way of reducing temporal dimension is by solving the optimisation problem over a small set of representative periods (see e.g, Pfenninger (2017) for a review and the references therein). Samples are selected both heuristically and statistically. In order to cover the extrema in the time series such as peak demand or high demand coinciding with no wind or solar, they are often *hand-picked* to be included in the reduced dataset. The remaining 'normal' operation periods are then partitioned into equivalent classes according to their similarities using statistical methods such as k-means (as in e.g., Räsänen et al., 2010, Baringo & Conejo, 2013, Green et al., 2014, Rhodes et al., 2014, McLoughlin et al., 2015, and Hsu, 2015), k-medoids (as in McLoughlin et al., 2015), dynamic time warping barycenter averaging (Teichgraeber & Brandt, 2019), k-shape (Yang et al., 2017 and Teichgraeber & Brandt, 2019), hierarchical (as in Räsänen et al., 2010, Mena et al., 2014, and Nahmmacher et al., 2016), and density based (Hsu, 2015) clustering, or even as a MILP optimisation problem (Poncelet et al., 2017). There is, however, not a single 'best' approach as the accuracy depends very much on the time series itself.

Regardless of the details in these clustering algorithms, they share one thing in common: the representative of a cluster is always taken to be the mean (centroid), or an actual data point with the smallest distance from all others (medoid). Nevertheless, since the hour-to-hour variations are inevitably averaged out by a (multidimensional) centre point, neither the mean nor the medoid is sufficiently representative as both fail to fully capture the intra-day dynamics. In order to *construct* a representative profile that is capable of capturing both the mean behaviour and the *variations* exhibited by the data, we shall adopt a randomised sampling approach by drawing hourly samples according to the distribution of the data points within the cluster In particular, we follow the Markov Chain Monte Carlo (MCMC) sampling method to keep the sampling *sequential*; details of our representative profiles construction procedure are given in algorithm 1 below. The MCMC technique has previously been applied in wind generation simulations (e.g. Papaefthymiou and Klockl (2008) and Zheng et al. (2015)).

We begin by partitioning the 2018 hourly time series data into 20 clusters using k-means. Since the spatial nodes in the model – namely the countries and regions – vary hugely in their populations and therefore their demand and VRE generation in absolute terms, they are *not* treated on equal grounds in the clustering algorithm. Thus not all 27 (plus Morocco representing North Africa) countries are considered in the clustering algorithm: on top of the 6 core countries with the biggest economies, namely UK, DE, FR, IT, NL and ES, we group the remaining countries into regions such that each region has comparable populations and the member countries are adjacent, and one of the members is chosen to be the representative depending on the time series category. For example, while LT is chosen to solely represent the southern Baltic cluster region which consists of PL, LT, LV and EE (i.e., *not* the Baltics region as in the optimisation model) for the VRE series in the clustering due to its central location, PL is chosen to represent the demands in the Baltic region due to its much larger population. In summary, the countries considered for the different categories in the clustering are as follows:

- offshore: UK , DE, FR , IT , NL, ES, NO, DK, LT, GR
- onshore: UK , DE, FR , IT , NL, ES, SE, LT, AT, GR
- solar: UK , DE, FR , IT , NL, ES, SE, LT, AT, GR, MT
- demand: UK , DE, FR , IT , NL, ES, SE, PL, AT, GR

Each day is therefore a 61×24-dimensional vector (flattened) in the clustering.

In order to be able to compare the different quantities with different units in the times series in the k-means clustering – for instance demands measured in MWh/h vs VRE generations in dimensionless capacity factors – we first need to normalise them. We do so by allocating each feature or non-temporal dimension in the time series into decile bins. Since the capacity of the power system is pretty much dependent on the peak demand, the 10th bin of each demand series is divided further into 90%, 99% and 99.5% quantiles, and the bin values for the last two bins (11^{th} and 12^{th}) are increased from 10 and 11 to 12 and 15 to increase the Euclidean distance from the rest so that it encourages the clustering algorithm to group the peak days into the same cluster. On the other hand, because solar generates nothing at all during night time, a zero-th bin is added to capture this particular property of solar. The binned time series is then passed onto the k-means clustering algorithm, which assigns to each day a cluster label ranging from 0 to 19. The clustering result is illustrated in Figure A. 1.

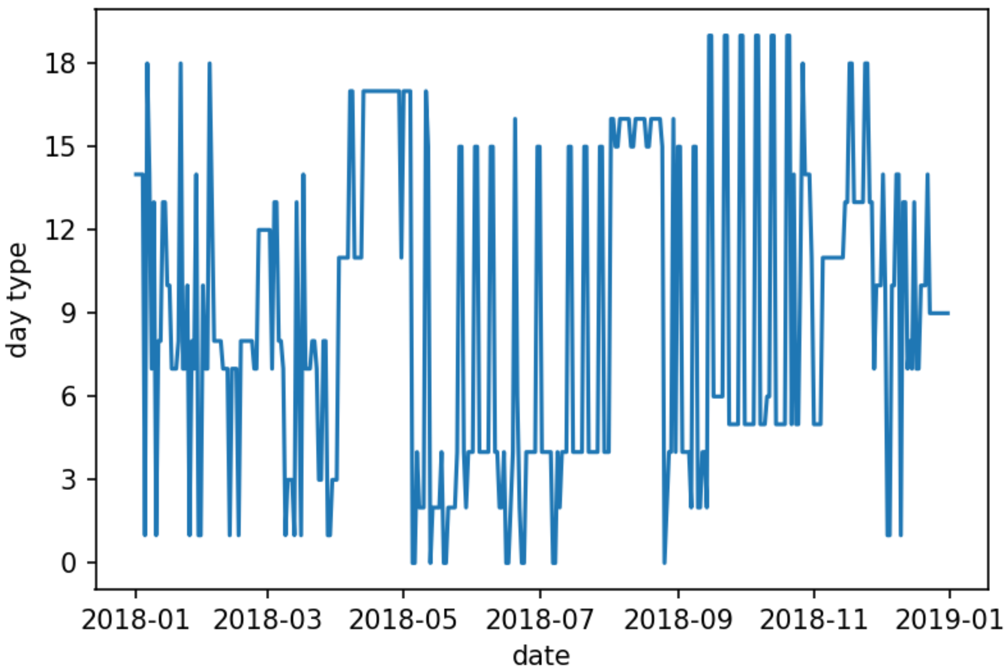

Figure A. 1: The day type clustering result from k-means with 20 clusters

Now instead of simply using the cluster centroid as the representative for each cluster, we draw random samples according to the distribution of the hourly data in the cluster by following algorithm 1. It constructs the 24-hour representative profile for each feature (e.g. UK residential demand) and for each cluster as follows:

1. fit a normal distribution to the data at the 0th hour (which is the first hour of the day) and draw a random sample from the normal distribution
2. compute the ratio *a* between the probability density of drawing the particular candidate and the probability density of drawing the mean
3. sample another number *u* from the uniform distribution in the unit interval
4. if $a > u$, meaning that x_0= the drawn candidate is sufficiently probable, and if the candidate is between 0.8× the minimum and 1.2× the maximum in the data, which filters out the too out-of-bound candidates, we accept the candidate and move onto the next time step; otherwise we reject it and sample another candidate

After having an accepted candidate for x_0 at the first hour, x_t for the subsequent hours are selected as such:

1. fit a bivariate normal distribution from the data X_t and X_{t-1} in the cluster
2. draw a random sample for X_t by conditioning on the previously drawn value for X_{t-1} to preserve the autocorrelation
3. compute the ratio *a* between the probability density of drawing the candidate for X_t and the probability density of drawing the previous, accepted candidate for X_{t-1}
4. sample another number *u* from the uniform distribution in the unit interval
5. if $a > u$, which again acts as a filter to reject very unlikely candidates, and if the candidate is between 0.8× the minimum and 1.2× the maximum in the data, which filters out the too out-of-bound candidates, we accept the candidate and move onto the next time step; otherwise we reject it and sample another candidate

Algorithm 1 MCMC representative profile construction

For quantity X, initialise $X_0 \sim \mathcal{N}\left(\mu_0, \sigma_0^2\right)$
t=0
while $t = 0$ **do**
  Draw a candidate x_0^{cand} from the univariate normal distribution
  Compute acceptance probability $a\left(x_0^{cand}|\mu_0\right) = \frac{p\left(x_0^{cand}\right)}{p(\mu_0)}$
  Sample u from $\mathcal{U}(0,1)$
  if $u < a$ **and** $0.8 \cdot X_0^{min} \leq x_0^{cand} \leq 1.2 \cdot X_0^{max}$ **then**
    Accept the candidate $x_0 \leftarrow x_0^{cand}$
    $t = 1$
  else
    Reject the candidate
    $t = 0$
  end if
end while

for $t = 1, ..., 23$ **do**
  Initialise $\begin{bmatrix} X_t \\ X_{t-1} \end{bmatrix} \sim \mathcal{N}\left(\begin{bmatrix} \mu_t \\ \mu_{t-1} \end{bmatrix}, \begin{bmatrix} \Sigma_{t,t} & \Sigma_{t,t-1} \\ \Sigma_{t-1,t} & \Sigma_{t-1,t-1} \end{bmatrix}\right)$
  Draw x_t^{cand} conditioning on the previously drawn x_{t-1}, with $X_t|X_{t-1} \sim \mathcal{N}\left(\mu_{t|t-1}, \Sigma_{t|t-1}\right)$ where $\mu_{t|t-1} = \mu_t + \Sigma_{t,t-1}(x_{t-1} - \mu_t)/\Sigma_{t-1,t-1}$ and $\Sigma_{t|t-1} = \Sigma_{t,t} - \Sigma_{t,t-1}^2/\Sigma_{t-1,t-1}$ from the conditioning property of multivariate Gaussian
  Compute the acceptance probability $a\left(x_t^{cand}|x_{t-1}\right) = \min\left\{1, \frac{p\left(x_t^{cand}\right)}{p(x_{t-1})}\right\}$ where $X_t \sim \mathcal{N}(\mu_t, \sigma_t^2)$ from the marginalisation property of multivariate Gaussian
  Sample u from $\mathcal{U}(0,1)$
  if $u < a$ **and** $0.8 \cdot X_t^{min} \leq x_t^{cand} \leq 1.2 \cdot X_t^{max}$ **then**
    Accept the candidate $x_t \leftarrow x_t^{cand}$
    $t = t + 1$
  else
    Reject the candidate
    $t = t$
  end if
end for

As concrete examples, Figure A. 2 below illustrate the representative profiles obtained from MCMC sampling in comparison with the original data in the cluster and the cluster centroid for UK onshore wind for day type 10, and DE residential demand for day type 15. The profiles constructed from MCMC sampling clearly capture the range better than the centroids, which are inherently flat due to averaging.

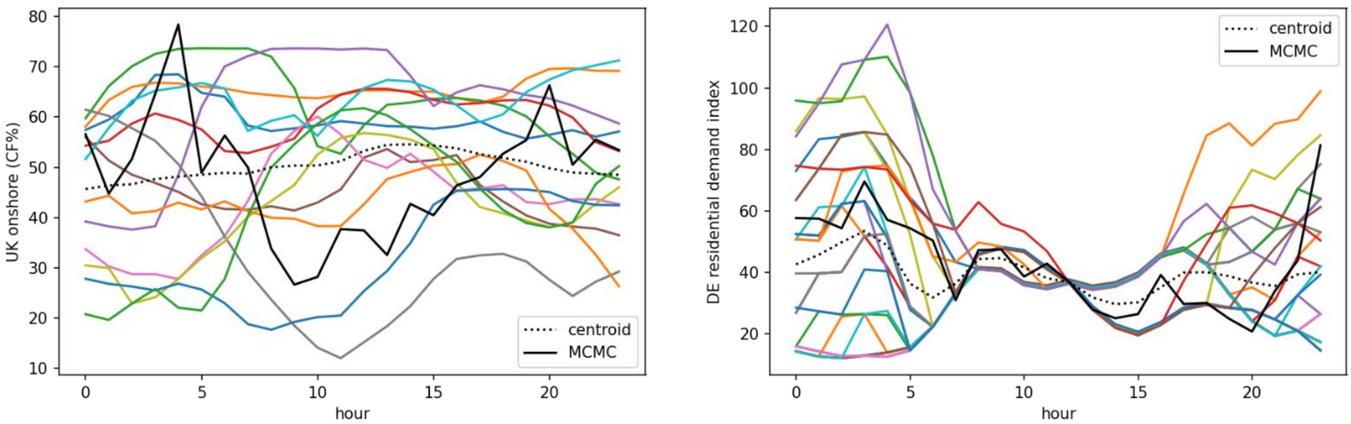

Figure A. 2: Comparison of cluster centroid and MCMC sampled profile (left panel: against the original UK onshore wind profiles in cluster 10; right panel: against the original DE residential demand profiles in cluster 15)

We may also compare the mean and spread of the reduced time series as obtained from the MCMC and centroid methods against the original data using boxplots. Comparisons are made for onshore wind, offshore wind, residential and commercial demand for the 6 core countries in Figure A. 3. Again, the boxplots show that reduced times series reconstructed from cluster centroids, although always reproduce the mean exactly by construction, consistently underrepresent the spread.

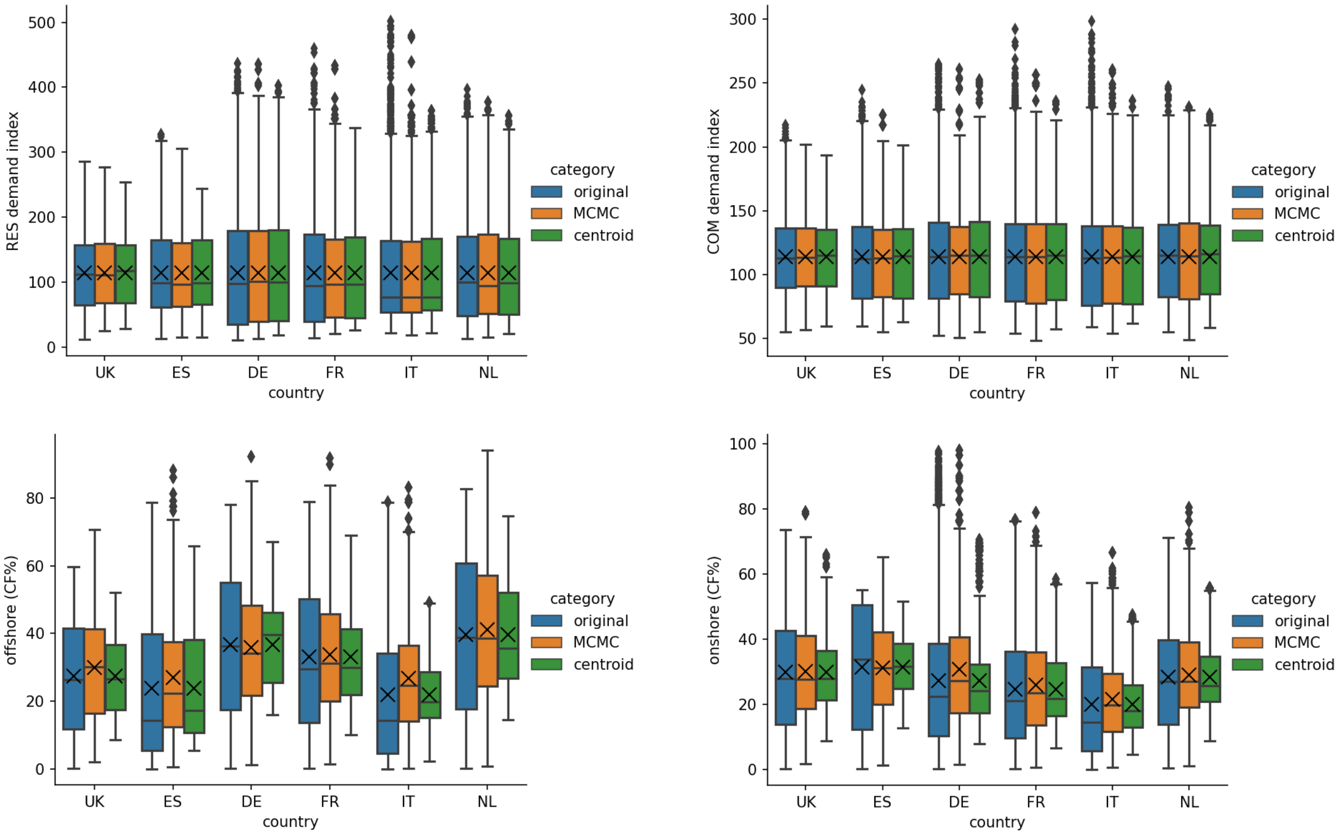

Figure A. 3: Boxplots comparing the mean and spread of various reduced time series against the original for the 6 core countries

A.1.4.2. Superposition of intra- and inter-period states for storage modelling

Kotzur et al. (2018) proposed a framework to restore the sequence of the reduced time series of representative periods for any linear state model by decomposing the state of the system into inter-period and inter-period states. They showed that this superposition allows the splitting of the state equation into a intra-period state equation which does not depend on the inter-period state, and a inter-period state equation which is independent of the control decision variables. Since each inter-period boundary has a state equation which manifests as a constraint, there is a clear trade-off between the number of inter-period constraints and the length as well as the accuracy of each representative period.

Using a storage system as an example, the state of the system is simply the state of charge SR_t of the storage unit at time t and the state equation is

$$SR_{t+1} = SR_t + c_t \cdot SE^c - \frac{d_t}{SE^d} \tag{A57}$$

where SE^c and SE^d are the charge and discharge efficiencies; it is assumed that there is no self-discharging over time. If we set the degradation rate of the storage unit to zero (DS=0), the decision variables c_t, d_t are then bounded by just

$$0 \le c_t, d_t \le K \qquad \forall\, t \tag{A58}$$

And the state of charge SR_t is bounded above by its maximum capacity k, which itself is an investment variable

$$0 \le SR_t \le k \qquad \forall\, t \tag{A59}$$

Now let us rewrite the time index t which runs from 0 to N_t, with the period index π where $0 \le \pi \le N_\pi$, and the time step index τ where $0 \le \tau \le N_\tau$ so that $N_t = N_\pi \times N_\tau$. The state of charge SR_t can then be written as the superposition

$$SR_t \to SR_{\pi,\tau} = SR_\pi^{inter} + SR_{\pi,\tau}^{intra} \tag{A60}$$

such that at the beginning of each period, the state is equal to just the inter-period state $SR_{\pi,1} = SR_\pi^{inter}$ and therefore $SR_{\pi,1}^{intra} = 0\ \forall\, \pi$. Since representative sampling c (e.g. clustering) maps each period into one of the representative periods $c{:}\, \pi \to c(\pi)$, the state of charge can therefore also be written as

$$SR_{\pi,\tau} = SR_\pi^{inter} + SR_{c(\pi),\tau}^{intra} \tag{A61}$$

in the reduced time series. This means that while the state of charge may follow the same *pattern* on two similar days. We can rewrite the state equation in terms of the inter- and intra- period states as follows. Consider a transition taking place within the period π i.e. consider current time step π, τ where $\tau \neq N_\tau$. By expansion we simply have

$$SR^{intra}_{\pi,\tau+1} = SR^{intra}_{\pi,\tau} + c_{\pi,\tau} \cdot SE^c - \frac{d_{\pi,\tau}}{SE^d} \quad \forall\ \pi,\ \tau \tag{A62}$$

with SR^{inter}_{π} on both sides cancelling each other. This is the intra-period state equation which does not depend on the inter-period state. For transition occurring on the boundary i.e. at current time step π, τ with $\tau = N_\tau$, we have

$$SR^{inter}_{\pi+1} + SR^{intra}_{\pi+1,1} = SR^{inter}_{\pi} + SR^{intra}_{\pi,N_\tau} + c_{\pi,N_\tau} \cdot SE^c - \frac{d_{\pi,N_\tau}}{SE^d} \quad \forall\ \pi \tag{A63}$$

but since $SR^{intra}_{\pi+1,\,1} = 0$ and

$$SR^{intra}_{\pi,N_\tau} + c_{\pi,N_\tau} \cdot SE^c - \frac{d_{\pi,N_\tau}}{SE^d} = SR^{intra}_{\pi,N_\tau+1} \tag{A64}$$

by definition, it gives

$$SR^{inter}_{\pi+1} = SR^{inter}_{\pi} + SR^{intra}_{\pi,N_\tau+1} \quad \forall\ \pi \tag{A65}$$

which is the inter-period state equation, and it is independent of the decision variables. Note that with representative sampling, the number of intra-period state equations reduces to $N_c \times N_\tau$, but the number of inter-period state equations remains as N_π, independent of the number of equivalence classes.

The remaining rate of change and state of charge bounds can be rewritten straightforwardly as

$$0 \leq c_{\pi,\tau}, d_{\pi,\tau} \leq K\ , \tag{A66}$$

$$0 \leq SR^{inter}_{\pi} + SR^{intra}_{\pi,\tau} \leq k \quad \forall\ \pi,\ \tau \tag{A67}$$

We may also impose the cyclic boundary condition over the entire solution horizon such that

$$SR^{inter}_{N_\pi+1} = SR^{inter}_{1} \tag{A68}$$

.

Appendix 2 ï Data inputs and assumptions

This appendix outlines technologies and energy vectors considered in this research, spatial resolution of the model, data calculations, processing and assumptions that were used in the modelling. It covers the following:

1. How we derive input data from EC LTS and calibrate our model to model our own scenarios.
2. Sources for techno-economic parameters for modelling (e.g., ramp rate, efficiency of power stations etc.).
3. Other supply and demand projections.

We start by describing the model structure and its spatial resolution. We then give details regarding data and assumptions for the demand side, then we cover the supply side and finally we discuss networks and storage solutions.

A.2.1. Model structure and spatial resolution

For this research project, the model represents 12 European market areas allowing for endogenous trade in main commodities (Figure A. 4 shows the interconnections we model and Table A. 1 shows spatial aggregation). The model covers hourly dispatch and operations of main technologies and investment in capacities of:

- Power generation technologies;
- heat technologies in buildings;
- road transport modes such as EVs, FCEVs, gas mobility and conventional road transport;
- H_2 production technologies: green H_2 via water electrolysis and blue H_2 via natural gas reformation with CCS
- Synthetic fuels production: e-gas and e-liquids (methanation of H_2);
- Storage technologies for CH_4, CO_2, H_2, electricity, heat;
- Transmission and distribution networks;
- and interconnection capacity to allow endogenous cross-border trade in CH_4, H_2, electricity, CO_2, bioenergy and e-liquids.

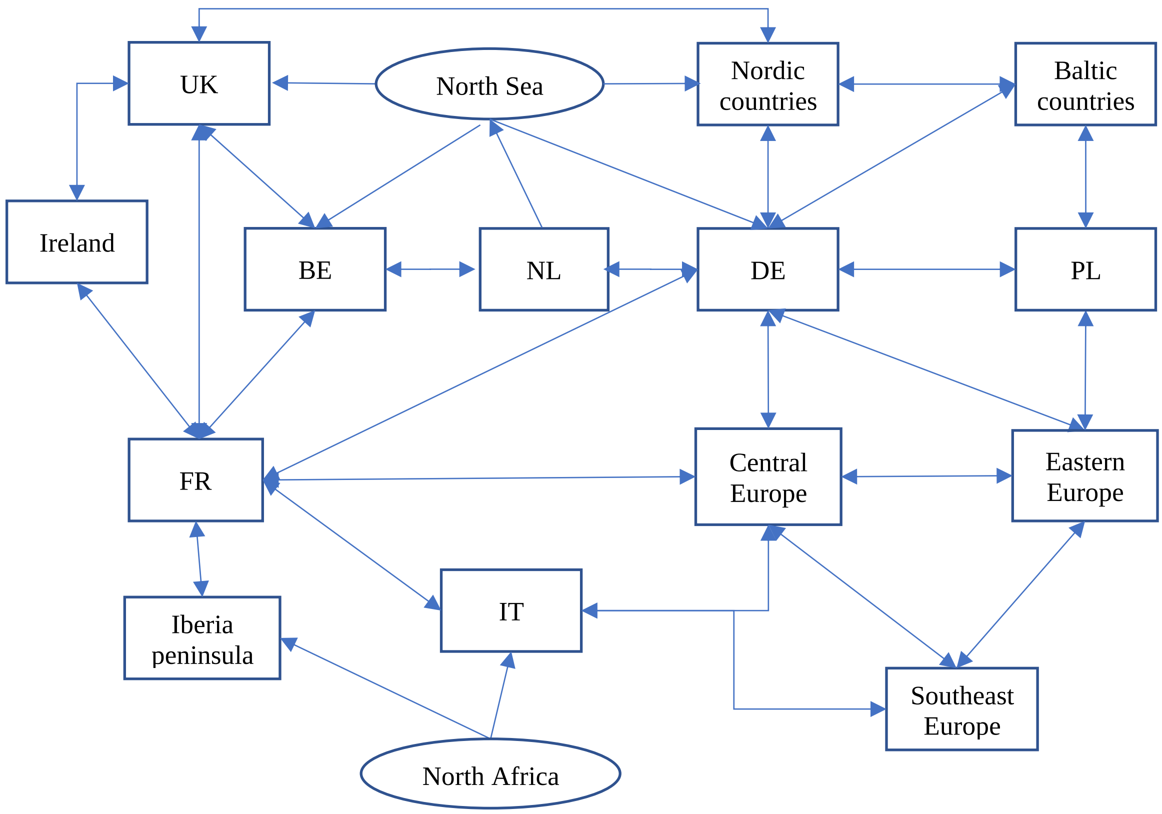

Figure A. 4: Geographical coverage of the energy system model and interconnections

Table A. 1: Spatial resolution and aggregation in this model

Regions in the model	Countries & Comments
UK	United Kingdom
Ireland	Rep. of Ireland

Nordic	Norway (NO), Sweden (SE), Finland (FI), Denmark (DK)
BE	Belgium (BE), Luxembourg (LU)
DE	Germany (DE)
NL	Netherlands (NL)
FR	France (FR)
IT	Italy (IT)
Baltics	Lithuania (LT), Latvia (LV), Estonia (EE)
PL	Poland (PL)
Eastern Europe	Czech Rep (CZ), Slovakia (SK), Hungary (HU)
Central Europe	Austria (AT), Switzerland (CH), Slovenia (SL)
SEE	Bulgaria (BG), Greece (GR), Croatia (HR), Romania (RO), Malta (MT), Cyprus (CY)
Iberia	Spain (ES), Portugal (PT)
North Africa	Utility scale solar generation
North Sea	Offshore wind generation

The model covers the main final consumption sectors – residential, commercial, transport and industry. For this research project we have aggregated final consumption as follows:

- **Buildings** sector represents final consumption of residential, commercial and energy use in the agriculture sectors.
- **Road transport** represents demand for road activities of passenger cars, public road transport and heavy goods vehicle (HGV).
- **Industry** represents final energy consumption in the industrial sector
- **Other transport** represents final energy consumption by aviation, inland navigation and rail transport activities.

In terms of supply and transformation technologies the model takes into account:

- main power generation and storage technologies for the electricity sector;
- and main end-use technologies in buildings and transport sectors;
- cross-border trade in main commodities including via electricity transmission and gas pipelines;
- primary supply sources include coal lignite and bituminous, uranium, biomass, natural gas, biomethane, e-gas, H_2, electricity, e-liquids.

The model also includes important emerging technologies, such as hydrogen production as well as CCS, direct air capture, and renewable gases - Figure A. 5 highlights the structure of an energy system we implement in our model.

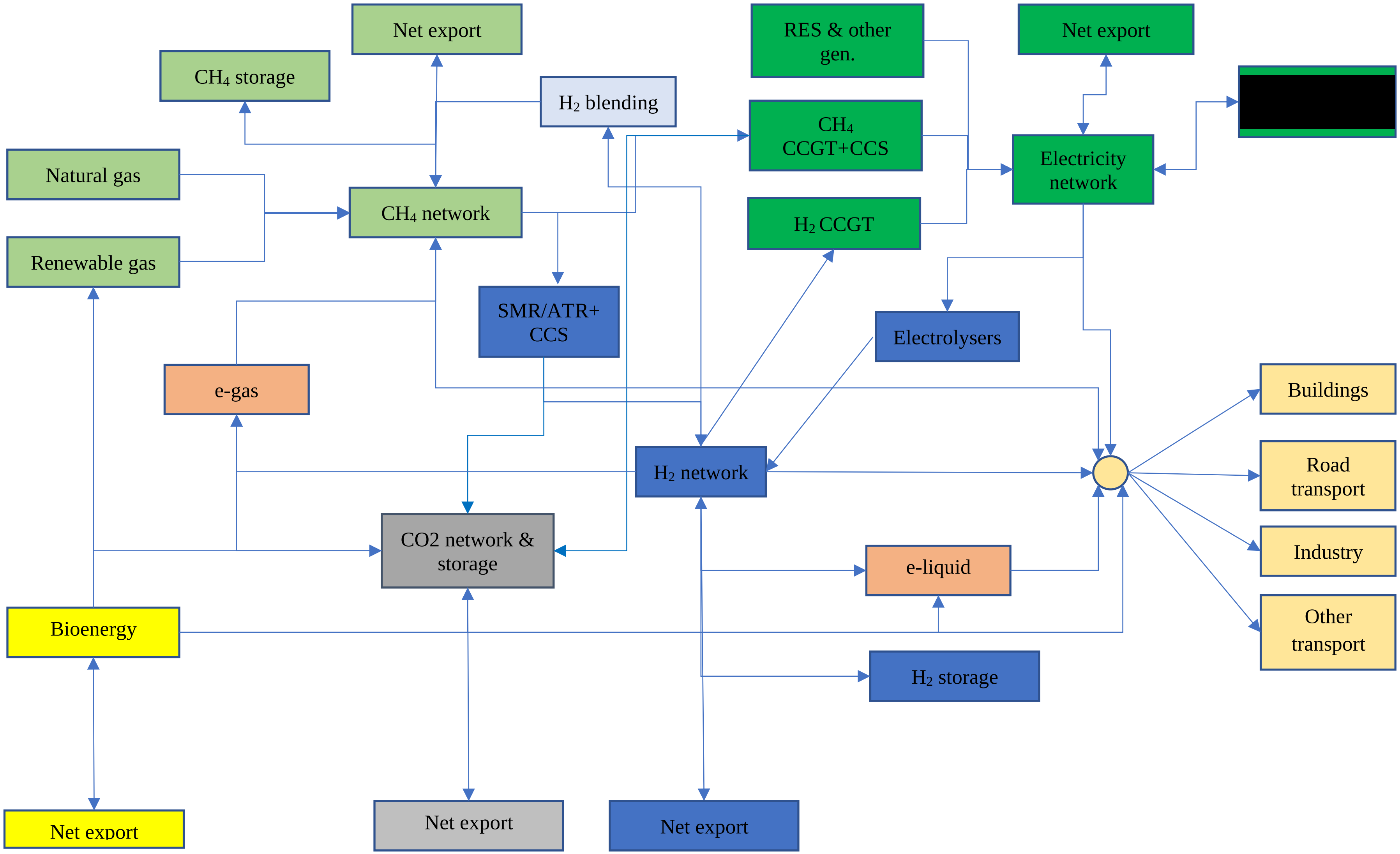

Figure A. 5: Main energy supply technologies, networks and demand in the model

A.2.2. Demand side

A.2.1. Buildings

We derive thermal energy services demand in buildings based on EC JRC TIMES input database for every country in our model. The following thermal energy services demand categories were considered for residential and commercial buildings:

1. Cooking thermal energy services demand.
2. Cooling thermal energy services demand.
3. Space heating thermal energy services demand.
4. Water heating thermal energy services demand.
5. Lighting and appliances and specific electricity uses demand.

Further, agriculture energy demand has been included into the 'buildings' demand category, following EC PRIMES modelling convention (see (EC, 2016)). In our modelling, we do not consider explicitly end-use technology options for agriculture final energy demand (e.g., different farming machine drives) so we use historic fuel mix from the EC JRC TIMES model (2010) with some adjustments as follows:

1. Diesel consumption is assumed to be carbon-neutral e-liquids.
2. Natural gas consumption is assumed to be carbon-neutral biomethane.

A.2.1. Transport

Road transport activities demand projection for every country that we model is based on European Commission's 2016 Reference scenario (EC, 2016) results adjusting for growth rates projected by EC LTS modelling work (Table A. 2).

Table A. 2: Passenger transport activity

	Baseline			**relative to Baseline****	
	'95-'15	'15-'30	'30-'50	COMBO	1.5TECH
Road	1.00%	0.70%	0.60%	-1%	-3%
Rail	1.20%	2.10%	1.20%	5%	2%
Aviation	2.80%	2.30%	1.60%	-3%	-3%
Inland navigation	-0.50%	1.20%	0.50%	5%	3%

Notes: * average growth rates per year; ** % changes to the Baseline in 2050

Table A. 3: Inland freight transport activity

	LTS Baseline*			**relative to baseline****	
	'95-'15	'15-'30	'30-'50	COMBO	1.5TECH
Road	1.80%	1.50%	0.80%	-3.20%	-4.80%
Rail	0.50%	2.50%	1.30%	8.30%	4.40%
Inland navigation	1.30%	1.70%	0.70%	5.50%	2.40%

Source: EC LTS
Notes: * average growth rates per year; ** % changes to the Baseline in 2050

Projections for passenger transport demand activities are based on passenger-km, while freight transport demand activities are based on tonnes-km. Therefore, to model potential energy demand further assumption is needed in terms of average occupancy of various modes of transport. We use EC TIMES data (2019) which used real data on occupancy of main transport modes at EU MS level. We took an average of MS level data and within main transport modes (public road transport, passenger cars, HGVs) and use the following to inform our modelling:

1. Public transport – 20.8 passengers/vehicle
2. Passenger cars – 1.58 passengers/vehicle
3. Heavy goods vehicles (HGV) – 5.40 tonnes/vehicle

Further, calculations of travel mileage for the above transport was also based on EC TIMES (2019) dataset:

1. Public transport – 45,743 km/vehicle/year

2. Passenger cars – 17,440 km/vehicle/year
3. HGV – 42,808 km/vehicle/year

Note that travel mileage could be further disaggregated down to MS level data as well as by transport mode but for this research project we have decided to use averages. Further research on the impact of transport modes on energy system could use detailed MS and transport mode level data.

Other transport modes include aviation, rail and inland navigation which we do not model explicitly in the research paper (i.e., our modelling does not take into account end-use transport modes for aviation, rail and inland navigation) and hence we calibrate final energy consumption from these other transport modes to EC LTS. Table A. 4 outlines projections for aviation final energy consumption, according to EC LTS.

Table A. 4: Aviation fuels mix (2050), mtoe

	jet fuels	e-liquids	liquid biofuel	electricity
LTS Baseline	63.2	0	1.8	0
COMBO	44.6	3.3	11.9	0.4
1.5TECH	23.9	19.8	13.7	1.2

Source: EC LTS

Projection of final energy consumption for rail and inland transport is based on the following methodology. First, we use annual growth rates of energy consumption for rail and inland navigation from the EC LTS (Table A. 5**Error! Reference source not found.**) and use the historic energy consumption for the year 2005 to calculate total energy consumption in 2050 for the respective scenarios. The EU28 total final energy consumption for rail transport sector was 8,553.1 ktoe and for inland navigation transport sector was 6,838.9 ktoe in 2005, according to Eurostat (Eurostat, 2020).

Table A. 5: Change in final energy consumption per transport mode in 2050 compared to 2005

	Total	Road	Rail	Air	Inland navigation
LTS Baseline	-24%	-35%	22%	30%	-7%
COMBO	-38%	-50%	25%	21%	-3%
1.5TECH	-45%	-58%	20%	17%	-6%

Source: EC LTS

Finally, the fuel mix for 2050 was then calculated using the projections from EC LTS as follows –the net zero GHG scenario sees 95% electricity and only 5% diesel in the fuel mix for the rail transport sector, while for the inland navigation electricity constitute 3%, hydrogen – 2%, liquid biofuels – 40%, e-liquids – 40%, e-gas – 5%, biomethane – 1%, diesel – 9%. We use this fuel mix projections for the 90% scenario as well. Further sensitivity analysis will be carried out regarding this assumption. Disaggregation of fuel mix down to the EU MS level follows the results of the EU Reference scenario 2016 (EC, 2016).

A.2.3. Industry

Final energy demand in the industrial sector was calibrated to the results of EC LTS (see Table A. 6**Error! Reference source not found.**) because the current modelling version does consider end-use technologies in the industry sector and as such out of scope of this research. That said, the projection of final fuels consumption impacts the choices further "upstream" (e.g., electricity or gas network expansion to meet expected industrial loads).

Table A. 6: Final energy consumption in industry (2050), mtoe

	Electricity	Natural gas	Biogas & biomethane	Hydrogen	E-gas	Biomass	others
LTS Baseline	102	64	5	0	0	38	83
COMBO	116	10	15	15	17.2	26	37
1.5TECH	119	4	10	29	10.7	25	32

Source: EC LTS

Since EC LTS did not publish results at EU MS level, a careful disaggregation by country is based on the following methodology.

In the Industrial sector the focus of the Long-Term Strategy is again on reducing the overall emissions. The three main factor affecting industrial emissions are process emissions, which are emitted as a result of the chemical and production processes carried out in industries (21%), emissions due to energy used in heating processes (70%), and space heating (9%). Indirectly, the emissions are caused by the volume of output from energy-intensive industries causes the emissions. Apart from modifying production processes and improving energy efficiency, if the output of these industries can be reduced, indirectly the emissions would also be reduced. However, maintaining production, or even increasing it is important to sustain economic growth.

The total industrial energy consumption is derived for the scenarios using the percentage change of industrial energy consumption over the Baseline scenario in each scenario.

EU Reference scenario 2016 (EC, 2016) provides a disaggregation of industrial energy consumption between energy-intensive industries (EIIs) and other industrial sectors. For the LTS Baseline scenario the share of the two kind of industries within the total industrial final energy demand is assumed to be the same as given in the Reference scenario 2016. However, since the LTS does not provide such a disaggregation it is important to understand the characteristics of the two industrial sub-sectors and how their final energy demand is affected within each of the considered scenarios to be able to discern the disaggregation for each scenario and subsequently each MS.

There are ten industries classified as EIIs[8]:

1. Iron and steel,
2. Cement,
3. Chemicals and fertilizers,
4. Refineries,
5. Non-ferrous metals,
6. Ferro-alloys and silicon,
7. Pulp and paper,
8. Ceramics,
9. Lime, and
10. Glass

Apart from using non-emitting chemical processes and material substitution, the main source of decarbonisation in industries is energy efficiency and fuel-switching of heat and steam production either to clean fuels like biomass, hydrogen and e-fuels, or electrification, assuming that the electricity provided can be decarbonised. Other options include increasing resource efficiency, reducing and reusing the raw materials used in the production cycle, and carbon capture and utilisation (CCU) to store capture carbon from production processes and storing it in materials.

Only the circular economy scenarios (CIRC and 1.5LIFE) in the LTS assume reduced output from certain industrial sub-sectors and a greater production of secondary materials replacing production of primary materials, which are less energy intensive. ELEC focuses on electrification of industrial heat and processes. Electric heating is less efficient than thermal heating methods for high-temperature heating requirements, while also reducing the potential for heat recovery. Although electricity is more efficient than thermal heating for low temperatures, the percentage of demand for low-temperature heating applications is much smaller than high-temperature heating. Hence, in 2050 in the ELEC scenario, industrial energy demand is the same as in the Baseline, while emissions are reduced mainly via substitution of natural gas and other fossil fuels by electricity and biomass. Hence, we assume that the sub-sector share in the final energy demand also remains the same as in Baseline (57% EIIs and 43% other industries), since the overall energy efficiency of the sector increases by 10% of the eventual 11% in 2050 over 2015, because of heat recovery applications between 2020 and 2030. However, there is no evidence provided of a redistribution of production activity or final energy consumption between EIIs and other industries.

A similar reasoning can be applied to the P2X scenario, where natural gas and fossil fuels are replaced by e-gases, hydrogen and biomass, without reductions in output and a restructuring of production activity among the two sub-sectors.

On the other hand, the COMBO and 1.5TECH scenarios achieve energy demand reductions of 24.4 Mtoe and 32.7 Mtoe respectively, through circular economy measures, or shifting of production activity from energy-intensive primary materials to less intensive secondary production. This amounts to 80% of the entire final energy demand reduction achieved in COMBO compared to Baseline, and 84% in 1.5TECH. This is combined with energy efficiency for the remaining final energy demand reduction, and fuel substitution and CCS for further decarbonisation. The eventual reduction in final energy demand in these scenarios is comparable, at 19% and 22% in COMBO and 1.5TECH respectively. Thus, given that the production activity decreases in EIIs and increases in other industries, to achieve the

[8] Industrial Value Chain: A Bridge Towards a Carbon Neutral Europe: https://www.ies.be/files/Industrial_Value_Chain_25sept_0.pdf

aforementioned 'total reduction' in output through shifting of production activity, EII output must reduce by *at least* an equivalent amount, while production in other industries will increase by some amount. Therefore, to re-calculate the share of EII and other industries we assume that the entire reduction in output is attributed to EIIs, and adjust the final energy demand of 'other industries' to match the total energy demand, thus, redistributing the *percentage share* of the two in the final energy demand.

Doing this calculation, we find that the share of EIIs in the total energy demand of the industrial sector falls from 57% in Baseline to 54% in COMBO and 52% in 1.5TECH, while the balance is attributed to the 'other industries' sub-sector.

The above reasoning is true if we hold another assumption that secondary production takes place only in 'other industries', while primary production takes place only in EIIs. This is a reasonable assumption to make as the distinguishing factor between primary and secondary production is its energy intensity. If the energy intensity of production falls considerably, regardless of the nature of the output, it may no longer be classified as an EII.

A.2.3. Supply side

A.2.2.1 Traditional energy sources

This section describes main assumptions for the supply of traditional energy sources. First, we outline assumptions for bioenergy, then for other commodities and finally we discuss CO2 emissions associated with these energy carriers.

The supply availability of bioenergy is taken from the EC LTS for the two respective baselines that we model: in 2050 under the 1.5TECH the projection of bioenergy availability is 2919 TWh and under the COMBO scenario it is 2640 TWh. To disaggregate this total EU level bioenergy supply we use the shares of bioenergy calculated from the Fischer et al (2020) study for the European Commission. For the 1.5 TECH, in line with the Trinomics study, we assume that the availability of biomethane is 1150 TWh while the rest is biomass (1769 TWh). For the COMBO scenario we keep this proportion and scale it with the total bioenergy supply projected by the EC LTS for the COMBO scenario (2640 TWh). Cost of biomethane is based on the Trinomics study while the cost of biomass is based on Navigant (2019) study but to calculate MS level cost we scale this cost using the Trinomics study numbers. Table A. 7 shows the results of these calculations and calibration process.

Table A. 7: Supply and cost of bioenergy (2050)

	Biomethane			Biomass		
	Cost, €/GWh	Supply, TWh/yr		Cost, €/GWh	Supply, TWh/yr	
		1.5TECH	COMBO		1.5TECH	COMBO
Central Europe	64,394.1	24.0	21.7	26,654.1	36.9	33.39
BE	68,104.6	13.2	12.0	28,190.0	20.4	18.41
SEE	75,009.3	133.9	121.1	31,048.0	206.0	186.30
East Europe	74,581.0	69.1	62.5	30,870.7	106.3	96.13
Nordic	59,624.3	137.5	124.4	24,679.8	211.6	191.35
Baltics	68,355.9	36.7	33.2	28,294.0	56.4	51.01
FR	72,500.0	184.4	166.7	30,009.4	283.6	256.50
DE	71,400.0	133.9	121.1	29,554.0	206.0	186.30
Ireland	65,200.0	10.2	9.2	26,987.7	15.7	14.20
IT	67,800.0	88.3	79.8	28,063.9	135.8	122.83
NL	67,700.0	19.2	17.4	28,022.5	29.5	26.71
PL	73,600.0	91.3	82.5	30,464.7	140.4	126.98
Iberia	69,791.6	138.7	125.4	28,888.3	213.4	192.97
UK	71,000.0	69.7	63.0	29,388.5	107.2	96.91

Source: own calculations based EC LTS; Trinomics (2019); Navigant (2019)

Apart from bioenergy, the model takes into account the main energy commodities. Supply and costs assumptions are reported in Table A. 8. We assume unlimited supply availability but in practice the model will constrain the usage of these commodities due to GHG emissions constraints and high carbon cost associated with usage of these technologies. Cost of coal and natural gas for 2050 is based on Navigant (2019) while cost of diesel and gasoline is based on EU Reference scenario 2016 (EC, 2016). Cost of uranium is based on Word Nuclear (2020).

Table A. 8: Cost and CO_2 intensity of energy commodities in the model

Energy carrier	Cost (2050	CO_2 intensity, ktCO2e/GWh
Coal bituminous	9,000	0.32611
Coal lignite	8,100	0.37638
Natural gas	30,000	0.20444
Diesel	58,333	0.27000
Gasoline	52,500	0.25000
Uranium	3,588	0
Biomass	See Table A. 7	0.35777
Biomethane	See Table A. 7	0.20444

Source: for cost: own calculations based Navigant (2019); (EC, 2016); World Nuclear Association (2020); for CO_2 intensity: based on BEIS, EIA, Fachbuch Regenerative Energiesysteme and UBA

Note that although combustion of bioenergy for end-use services results in CO_2 emissions but because in the process of growing feedstock the same quantity of CO_2 is captured from the atmosphere in the photosynthesis process the feedstock has short carbon cycle. IPCC guidelines suggest, therefore, that CO_2 emissions from combusting bioenergy should count as zero emissions as the carbon stock embodied in the fuel is already counted in Agriculture, Forestry and Other Land-Use (AFOLU), and Waste (IPCC, 2019[9]).

Moreover, if CO_2 emissions from combustion of bioenergy is captured and permanently stored in underground storage formations then this result in "negative" emissions and can be used to offset emissions of CO2 from hard-to-decarbonise activities. It is also worth noting that in the process of producing biomethane from biogas short carbon cycle CO_2 is captured and the economic value of biomethane is not just carbon neutrality but also that CO_2 as a by-product has an economic value – either as negative emissions, if captured and permanently stored, or utilised, for example, to produce carbon neutral e-fuels.

Various methods could be used to produce biomethane that can be used in the existing gas grid (Navigant, 2019):

1. Anaerobic digestion (AD),
2. Thermal gasification (TG), and
3. Biological methanation[10]

In this research we do not explicitly model technological processes of biomethane production and hence have we assumed country-specific costs and supply availability (see Table A. 7) without looking into the economics of various biomethane production methods. Therefore, to estimate the potential for negative emissions from the upgrading of biogas produced from AD we follow Navigant's (2019) assumption that ca. 64% of all biomethane supply by 2050 (Table A. 7) is produced from AD while the rest is from TG process. The calculation assumes:

1. Efficiency of 54% for converting biogas to biomethane; that is, to produce 1 TWh of biomethane, 1.852 TWh of biogas with 55% CH_4 content while the rest is short carbon cycle CO_2 is needed.
2. Therefore, to produce biomethane at the required specification (96% CH_4 and 3% CO_2) to inject into the existing grid, 42% of CO_2 contents should be removed from the biogas mixture. This results in 138.72 ktCO2/TWh being captured when biomethane is produced from biogas AD.
3. Since only 64% of biomethane is produced from AD process while assuming that only 90% of CO_2 can be captured, the useful CO_2 captured is 80.257 ktCO_2/TWh.

In our modelling, we take this potential CO_2 capturing from AD process upgrading to biomethane explicitly. We allow the model to use this CO_2 captured either to store permanently in underground storages resulting in negative emissions or to be utilised with H_2 to produce carbon neutral e-fuels.

A.2.2.2 Hydrogen and Power-to-X

This section outlines our techno-economic assumptions for hydrogen and power-to-X production technologies.

We model two main routes for hydrogen production – water electrolysis and natural gas steam reformation with CCUS. We further model production of synthetic methane (e-gas) and synthetic diesel (e-liquid) using hydrogen and carbon dioxide from sustainable sources (e.g., biomass with CCS or biogas upgrading to biomethane) so that those e-fuels are

[9] https://www.ipcc-nggip.iges.or.jp/public/2019rf/index.html
[10] Ecofys & Imperial College, 2017. Assessing the Potential of CO2 Utilization in the UK. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/799293/SISUK17099AssessingCO2_utilisationUK_ReportFinal_260517v2__1_.pdf

carbon neutral. Table A. 9 outlines our cost assumptions for these emerging technologies, based on the Asset (2018) project.

Table A. 9: Cost of producing new energy carriers

	Investment cost per unit of capacity (ú / t-output)			Fixed O&M cost (ú / t-output)			Variable, fuel and emissions cost per unit (ú / t-output or per tCO2)		
	2015	2030	Ultimate	2015	2030	Ultimate	2015	2030	Ultimate
Hydrogen from natural gas SMR - Large Scale with CCU	900	850	800	36	34	32	0.00015	0.0002	0.000153
Hydrogen from natural gas ATR - Large Scale with CCU	1241	1069	984	36	34	32	0.00015	0.0002	0.000153
Hydrogen from low temperature water electrolysis PEM centralised	1400	340	200	49	15	10	0	0	0
Hydrogen from low temperature water electrolysis Alkaline centralised	1100	300	180	28	14	9	0	0	0
Hydrogen from high temperature water electrolysis SOEC centralised	1595	804	600	55.8	36.2	39	0	0	0
Methanation: e-gas	1200	633	263	42	22	9	1	1	1
Methanation: e-liquids	1000	620	364	50	31	18	7	10	94
Capture CO2 from air (per 1 tCO2)	1015	771	506.5	35.5	27	17.7	0.15	0.15	0.2

Source: De Vita et al. (2018)[11] *; others*

Table A. 10: Water electrolysis technical parameters

	2020	2030	2050
PEM electrical efficiency (HHV)	72%	79%	82%
AE electrical efficiency (HHV)	77%	80%	82%
SOE electrical efficiency (HHV)	85%	91%	95%
Water consumption (tap water) of electrolysers, litres/kWh H_2 HHV		0.45-0.55	
footprint AE, m2/kW H_2 HHV		0.136	
footprint PEM, m2/kW H_2 HHV		0.074	
footprint SOE, m2/kW H_2 HHV		0.136	
minimum load factor		none	
ramp rate PEM, full capacity		seconds	
ramp rate AE, full capacity		minutes	
ramp rate SOE, full capacity		hours to one day	
Stack lifetime AE, operating hours (thousands)	60-90	90-100	100-150
Stack lifetime PEM, operating hours (thousands)	30-90	60-90	100-150
Stack lifetime SOE, operating hours (thousands)	10-30	40-60	75-100

Source: various

Table A. 11: Hydrogen from natural gas technical input parameters

	SMR	ATR

[11] De Vita, A., Kielichowska, I., Mandatowa, P., Capros, P., Dimopoulou, E., Evangelopoulou, S., Fotiou, T., Kannavou, M., Siskos, P. and Zazias, G., 2018. Technology pathways in decarbonisation scenarios. *Tractebel, Ecofys, E3-Modelling: Brussels, Belgium*.

Efficiency with CCS (kWh-th H_2 HHV/kWh-th NG HHV)	73.80%	73.10%
CO_2 capture rate	90%	95%
NG emission factor, kg CO2e/kWh-th HHV	0.184	0.184
H_2 emission factor, kg CO2e/kWh-th HHV	0.249	0.252
CO2 captured, kg CO2e/kWh-th HHV	0.2244	0.2391
CO2 emitted, kg CO2e/kWh-th HHV	0.0249	0.0126
Footprint m2/kW H_2 HHV	0.107	0.055
Raw water requirement, litres/kWh H_2 HHV	0.12	0.18
Sea water requirement, litres/kWh H_2 HHV	30	0
Waste water litres/kWh H_2 HHV	0.06	0
Return sea water litres/kWh H_2 HHV	30	0
minimum load factor	70%	70%
ramp rate, %/hour	0.417%	0.417%

Source: various

Table A. 12: Hydrogen to e-fuels technical input parameters

H_2 to e-gas efficiency	80.000%
CO_2 required, tCO_2/kWh(methane)	0.000198
H_2 to e-liquid efficiency	79.900%
CO_2 required, tCO_2/kWh(PtL)	0.000251

Source: Agora (2018)[12]

A.2.2.3. Power sector

This section reports our main assumptions for power generation technologies we used in our modelling. Note that we also consider CCGT running on H_2 and have assumed the same techno-economic parameters for H_2-based CCGT as “Gas combined cycle advanced no CCS” in the tables below.

[12] Agora_2018_The Future Cost of Electricity based fuels

Table A. 13: Power generation techno-economic input parameters

Power generation technologies	Overnight investment cost, EUR/kW				Fixed O&M, EUR/kW/yr				Variable O&M, EUR/MWh			
	2020	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Pulverised Lignite Supercritical CCS post combustion	3600	3420	3250	3200	68.6	65.0	61.6	60.6	6.24	6.02	4.28	4.04
Integrated Gasification Coal CCS pre combustion	3550	3350	3250	3150	69.8	65.9	63.9	61.9	7.74	7.44	7.17	6.91
Integrated Gasification Lignite CCS pre combustion	3950	3750	3650	3550	77.6	73.6	71.6	69.6	6.38	6.15	5.95	5.75
Pulverised Coal Supercritical CCS oxyfuel	3400	3150	2890	2850	75.5	64.7	55.5	53.9	6.06	5.86	5.64	5.59
Pulverised Lignite Supercritical CCS oxyfuel	3800	3550	3350	3300	72.6	67.6	63.6	62.6	6.94	6.70	4.76	4.50
Gas combined cycle advanced no CCS	820	770	750	750	15.00	15.00	15.00	15.00	1.99	1.90	1.81	1.73
Gas combined cycle CCS post combustion	1750	1625	1500	1500	41.0	38.2	35.0	34.3	3.10	2.99	2.88	2.78
Gas combined cycle CCS oxyfuel	2013	1820	1650	1628	46.3	42.1	38.0	36.8	3.45	3.34	3.20	3.07
Steam Turbine Biomass Solid Conventional	2000	1800	1700	1700	47.5	40.1	39.2	38.4	3.56	3.56	3.56	3.56
Steam Turbine Biomass Solid Conventional w. CCS	3800	3450	3090	3000	81.5	69.1	63.0	61.4	5.99	5.91	5.82	5.80
Nuclear III gen. (no economies of scale)	6000	6000	6000	6000	120.0	115.0	108.0	105.0	6.40	7.40	7.60	7.80
Wind onshore*	1483	1343	1260	1213	14.0	14.0	13.0	12.0	0.18	0.18	0.18	0.18
Wind offshore (with transmission)*	2612	2061	1632	1203	42.0	31.0	29.0	28.0	0.39	0.39	0.39	0.39
Utility scale Solar PV*	718	494	364	308	12.6	10.8	10.0	9.2	0.00	0.00	0.00	0.00
Residential Solar PV*	1306	989	765	606	24.0	17.0	15.0	13.0	0.00	0.00	0.00	0.00
Tidal and waves	6100	3100	2025	1975	39.6	33.3	28.0	23.5	0.10	0.10	0.10	0.10
Run of River	2450	2400	2350	2300	8.9	8.2	8.2	8.1	0.00	0.00	0.00	0.00
Geothermal Medium Enthalpy	4970	4586	3749	3306	95	95	92	92	0.32	0.32	0.32	0.32

*Source: Asset (2018); *BNEF*

Table A. 14: Power generation techno-economic input parameters (continued)

Power generation technologies	Electrical efficiency (net)				Self-consumption of electricity, %				Technical lifetime, years	Capacity Factor (equivalent full load operation), %			
	2020	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**		**2020**	**2030**	**2040**	**2050**
Pulverised Lignite Supercritical CCS post combustion	0.32	0.33	0.34	0.35	33%	30%	28%	28%	40	80%	80%	80%	80%
Integrated Gasification Coal CCS pre combustion	0.37	0.39	0.4	0.41	32%	27%	25%	25%	30	80%	80%	80%	80%
Integrated Gasification Lignite CCS pre combustion	0.34	0.37	0.38	0.39	35%	29%	26%	26%	30	80%	80%	80%	80%
Pulverised Coal Supercritical CCS oxyfuel	0.36	0.37	0.38	0.38	32%	27%	24%	24%	40	80%	80%	80%	80%
Pulverised Lignite Supercritical CCS oxyfuel	0.32	0.33	0.34	0.35	34%	28%	25%	25%	40	80%	80%	80%	80%
Gas combined cycle advanced no CCS	0.60	0.61	0.62	0.63	2.0%	2.0%	2.0%	2.0%	30	35%	35%	35%	35%
Gas combined cycle CCS post combustion	0.43	0.46	0.48	0.49	34%	18%	16%	16%	30	80%	80%	80%	80%
Gas combined cycle CCS oxyfuel	0.4	0.46	0.49	0.5	27%	19%	15%	14%	30	80%	80%	80%	80%
Steam Turbine Biomass Solid Conventional	0.35	0.39	0.4	0.4	10%	10%	10%	10%	40	80%	80%	80%	80%
Steam Turbine Biomass Solid Conventional w. CCS	0.27	0.31	0.32	0.32	34%	29%	27%	26%	40	80%	80%	80%	80%
Nuclear III gen. (no economies of scale)	0.38	0.38	0.38	0.38	5%	5%	5%	5%	60	85%	85%	85%	85%
Wind onshore*	1.00	1.00	1.00	1.00	0%	0%	0%	0%	30	based on 30 years of hourly data from JRC EC study			
Wind offshore (with transmission)*	1.00	1.00	1.00	1.00	0%	0%	0%	0%	30				
Utility scale Solar PV*	1.00	1.00	1.00	1.00	0%	0%	0%	0%	30				
Residential Solar PV*	1.00	1.00	1.00	1.00	0%	0%	0%	0%	30				
Tidal and waves	1.00	1.00	1.00	1.00	0%	0%	0%	0%	80	24%	33%	36%	36%
Run of River	1.00	1.00	1.00	1.00	0%	0%	0%	0%	50	22%	22%	22%	22%
Geothermal Medium Enthalpy	0.1	0.1	0.1	0.1	0	0	0	0	30	45%	45%	45%	45%

*Source: Asset (2018); * BNEF*

A.2.4. Networks

In our model, we have a simplified representation of networks in that we do not consider engineering details which would make this economic model intractable due to the level details we model in other areas. Instead, we treat transmission and distribution networks for each of markets/countries we model as “copper plate”. This simplification is necessary given the scope of sectors and technologies. This section outlines our cost assumptions for the networks we model.

Costs for for CH_4, H_2, CO_2 networks (distribution and transmission) are based on ASSET 2018 project for EC (see Table A. 15). Clearly, these values represent academic estimates and have not been benchmarked with actual cost data, mainly because the real cost of building and running a hydrogen or CO_2 network is subject to great uncertainty. That is why, we have conducted extensive sensitivity analysis to capture uncertainties in these cost assumptions. Note that the ASSET project did not have costs information for electricity networks.

Table A. 15: Gases network costs

	Investment cost per unit of capacity-output (t)ú /			Fixed O&M cost per unit of capacity-output)			Variable co		
	2015	**2030**	**2050**	**2015**	**2030**	**2050**	**2015**	**2030**	**2050**
CH_4 Transmission Network	126	126	126	5	5	5	0.7	0.7	0.7
CH_4 Distribution Network	552	552	552	22	22	22	3.2	3.2	3.2
H_2 Transmission 60bar	178	173	166	7	7	7	1	1	1
H_2 Distribution 10 bar	723	723	723	29	29	29	4.1	4.1	4.1
CO_2 Transmission network (per tCO_2)	23	23	23	1.3	1.3	1.3	1	1	1

Source: Asset (2018)

An alternative approach was developed for electricity networks whereby we estimate recognised cost for existing electricity transmission and distribution networks and apply historic (2015) “de-rated”[13] peak flow to calculate “per peak unit” (GW) cost. Where data on recognised cost is not available we use Eurostat electricity network cost component to scale with the recognised costs that we have gathered from NRAs. Note that we remove the cost of capital from the recognised cost base and then apply 4% interest rate to get to the uniform cost of capital for all network types and countries in our model. Table A. 16 shows results of our calculations with 4% interest rate applied.

Note also that the two sets of costs (Table A. 15 and Table A. 16) are not directly comparable as such because electricity network include all costs components (such as capex and opex) while the gases network costs have an explicit break down in terms of costs components. Further, while the electricity costs in **Error! Reference source not found.**Table A. 16is annuitized costs, gases network costs are total costs over the life time of a gas network. For example, we assume 50 years of life time for all networks and therefore with 4% interest rate, annuity factor applied to the gases network cost is ca. 0.04655; therefore, taking CH_4 transmission (ultimate cost) capex and fixed O&M costs as an example, we have 0.04655 x (126 + 5) = 6.098 €/kW/year for CH_4 transmission network costs which is still not comparable to the electricity costs as we still have to account for variable O&M costs for gases network, which is “flow-based” cost component.

[13] Assuming a 10% margin above the historic peak flow to account for electricity system security margin in electricity network planning

Table A. 16: Electricity network costs (€/kW/year)

	Transmission	Distribution
UK	53.79	101.62
Ireland	28.44	171.41
Nordic	20.91	148.33
BE	22.49	194.78
DE	34.59	151.90
NL	29.62	135.04
FR	31.14	120.04
IT	22.68	113.70
Baltics	54.38	114.31
PL	36.95	135.46
Eastern Europe	64.66	149.01
Central Europe	25.48	149.63
South East Europe	27.36	92.13
Iberia	27.45	132.15

Source: own calculations based on Eurostat, ARERA, EC JRC TIMES datasets

Further, the cross-border electricity interconnection costs have also been taken into account because the model expand capacity also for cross-border trade in CH_4, H_2, electricity, and CO2. For CH_4, H_2 and CO_2 this is based on costs in Table A. 15. For cross-border electricity interconnection we rely on EC JRC TIMES costs which different between three types of interconnection depending on distance as follows:

1. Short distance interconnection: 57,500,000 EUR/GW
2. Medium distance interconnection: 414,000,000 EUR/GW
3. Long distance interconnection: 828,000,000 EUR/GW

A.2.5. Storage

This section outlines our techno-economic assumptions for storage technologies.

Table A. 17: Energy storage costs

	Investment cost per unit of energy stored per year (ú / MWh)			F i x e d O&M c o			Variable, fuel and emissions cost per unit of s t o r e d e n e r g		
	2015	**2030**	**2050**	**2015**	**2030**	**2050**	**2015**	**2030**	**2050**
Compressed Air Energy Storage	125,000	112,500	110,931	39	35	34	-	-	-
Flywheel	1,750,000	1,575,000	1,553,029	52.5	47.3	46.6	0	0	0
Large-scale batteries*	563,522	156,741	126,886	40.5	15	13.1	0	0	0
Small-scale batteries*	767,846	248,174	194,061	16.9	6.3	5.5	0	0	0
Pumping	100,000	90,000	88,745	22.5	20.3	20	0	0	0
Underground Hydrogen Storage	5,340	3,936	3,821	0	0	0	0.6	0.7	0.8
Pressurised tanks - Hydrogen storage	6,000	4,800	4,659	0	0	0	0.6	0.7	0.8
Liquid Hydrogen Storage - Cryogenic Storage	8,455	6,800	4,000	0	0	0	0.7	0.9	1
Metal Hydrides - Hydrogen Storage	12,700	11,430	11,271	0	0	0	0.5	0.7	0.8

Thermal Storage Technology	100,000	90,000	88,745	100	97.2	95.8	0	0	0
LNG Storage Gas	135	135	135	0	0	0	0.6	0.7	0.8
Underground NG Storage	33	33	33	0	0	0	0.6	0.7	0.8

*Source: Asset (2018) ; * BNEF*

Table A. 18: CO_2 storage costs

	Investment cost per ton CO2 stored per year (ú / t) C O 2			**Investment cost per ton C O 2 (ú)/ t C O**			**ú / t 2 C O Liquefaction cost**		
	2015	**2030**	**2050**	**2015**	**2030**	**2050**	**2015**	**2030**	**2050**
Liquid CO_2 storage tank	1000	1000	1000	15	15	15	3.18	3.18	3.18
Underground CO_2 storage*	33	33	33	-	-	-	1	1	1

*Source: Asset (2018); * our own assumption*

A.2.6. Buildings end-use heat technologies

Table A. 19: Purchase cost of building heat technologies

	Purchasing cost, EUR/kW						
	Current	**2030**			**2050**		
		From [1]	**[2]**	**To [3]**	**From [4]**	**[5]**	**To [6]**
Boilers condensing gas	195	191	224	273	171	210	237
Heat pump air source	784	603	835	1080	267	673	1030
Hybrid heat pump*	600	510	855	1200	226	689	1144
Boilers condensing H_2**		191	224	273	171	210	237

*Source: Asset (2018); * GRDF; **our own assumption*

For our modelling of 2050, we use average 2050 purchase cost in column [5].

Table A. 20: Efficiencies of building heat technologies

	Efficiency						
	Current	**2030**			**2050**		
		from		**to**	**From**		**to**
Boilers condensing gas	0.87	0.89	0.93	0.96	0.90	0.98	1.03
Boilers condensing H_2*		0.89	0.93	0.96	0.90	0.98	1.03

*Source: Asset (2018); *our own assumption*

We use 0.98 as an efficiency of condensing boilers (both for gas and H_2-based boilers) for modelling a 2050 energy system. Performance of heat pumps depends on outside temperature with the following relationship[14]: **Heat pump**

[14] Zhang, X., Strbac, G., Teng, F., & Djapic, P. (2018). Economic assessment of alternative heat decarbonisation strategies through coordinated operation with electricity system–UK case study. *Appl. Energy*, 222, 79-91.

efficiency = 0.07T + 2.07, where T is outside temperature; thus, for example, when outside temperature is 0 C˚ heat pump's efficiency is 2.07.

A.2.7. Road transport technologies

For the road transport modes, we use the following values for costs and efficiencies (Table A. *21* and Table A. *22*).

Table A. 21: Technical and economic assumptions for transportation means

	Fuel	Purchasing cost **EUR/vehicle**			Fixed O&M costs **EUR/vehicle/year**		
		2015	**2030**	**2050**	**2015**	**2030**	**2050**
Public road transport	Diesel	277,090	282,107	293,908	8,857	8,857	8,857
Public road transport	Gas	301,283	304,418	309,122	9,557	9,557	9,557
Public road transport	Electricity	351,517	310,375	312,790	14,054	10,831	10,831
Public road transport	Hydrogen	377,386	344,376	322,856	16,397	11,934	11,934
Private cars	Diesel	22,795	22,869	24,942	1,450	1,450	1,450
Private cars	Gasoline	19,403	20,077	22,623	1,300	1,300	1,300
Private cars	Gas	21,484	22,891	24,704	1,380	1,380	1,380
Private cars	Electricity	48,010	25,956	24,685	1,650	1,272	1,272
Private cars	Hydrogen	82,130	38,729	28,616	1,718	1,250	1,250
Heavy duty vehicles	Diesel	105,926	111,777	134,001	6,527	6,527	6,527
Heavy duty vehicles	Gas	118,980	124,830	147,054	7,034	7,034	7,034
Heavy-duty vehicles	Electricity	230,600	151,929	157,320	10,180	7,846	7,846
Heavy duty vehicles	Hydrogen	240,372	193,252	172,662	10,780	7,846	7,846

Source: Asset (2018)

Table A. 22: Technical and economic assumptions for transportation means (cont-d)

	Fuel	Variable Non-fuel Cost **EUR/vehicle-km**			Specific energy consumption **kWh/vehicle - km**		
		2015	**2030**	**2050**	**2015**	**2030**	**2050**
Public road transport	Diesel	0.89	0.89	0.89	3.49	3.22	2.85
Public road transport	Gas	0.89	0.89	0.89	3.89	3.72	3.47
Public road transport	Electricity	0.89	0.89	0.89	1	0.97	0.96
Public road transport	Hydrogen	0.89	0.89	0.89	2.3	2.04	1.93
Private cars	Diesel	0.09	0.09	0.09	0.47	0.32	0.27
Private cars	Gasoline	0.09	0.09	0.09	0.56	0.38	0.31
Private cars	Gas	0.09	0.09	0.09	0.52	0.48	0.45
Private cars	Electricity	0.09	0.09	0.09	0.19	0.13	0.12
Private cars	Hydrogen	0.09	0.09	0.09	0.38	0.3	0.28
Heavy duty vehicles	Diesel	0.59	0.59	0.59	2.74	2.28	1.89
Heavy duty vehicles	Gas	0.59	0.59	0.59	3.39	2.83	2.34
Heavy-duty vehicles	Electricity	0.59	0.59	0.59	1.32	1.29	1.28
Heavy duty vehicles	Hydrogen	0.59	0.59	0.59	1.88	1.64	1.55

Source: Asset (2018)

A.2.8. GHG emissions

This section outlines GHG emissions assumptions in this model.

Table A. 23: GHG emissions for the baseline scenarios from EC LTS

	LTS Baseline	COMBO	1.5TECH	Endogenous
Non-CO_2 other	205.5	60.5	60.5	No
Non-CO_2 agriculture	404.2	277	276.9	No
Residential	129.6	19.3	11.8	Yes
Tertiary	77.7	23	19.3	Yes
Transport	666.9	256.8	85.6	Yes
Industry	483.6	175.6	109.8	No
Power	246.3	61.9	37.5	Yes
LULUCF	-236.3	-248	-316.9	No
Carbon Removal Technologies	0	-6	-258.4	Yes

Source: PRIMES model & EC LTS

Table A. 24: Share of CO_2 emissions in EU28 total (2017)

	Agriculture non energy	Industry non energy	LULUCF
Baltics	2%	1%	3%
BE	2%	5%	1%
Central Europe	2%	5%	2%
DE	15%	17%	10%
Eastern Europe	4%	9%	5%
FR	17%	12%	11%
UK	9%	8%	4%
Iberia	11%	10%	11%
Ireland	4%	1%	-1%
IT	7%	9%	8%
NL	4%	3%	-2%
Nordic	6%	4%	21%
PL	7%	7%	13%
South East Europe	8%	10%	14%

Source: European Environment Agency (2019) “Annual European Union greenhouse gas inventory 1990–2017 and inventory report 2019” (https://www.eea.europa.eu/publications/european-union-greenhouse-gas-inventory-2019/annex-v-summary-tables.zip/view)

A.2.9. EU level and regional/country specific constraints

This section outlines lower and upper bounds that we have implemented for various energy resources and technologies in all our scenarios (NZ and 90% scenarios), primarily to:

1. Reflect resource constraints (such as how much sustainable bioenergy is available or how much offshore wind capacity can be installed in various locations etc.);
2. Reflect capacity build rate and implicitly reflecting also supply chains for various traditional as well as emerging energy technologies

We start with EU level constraints and then proceed with country-specific bounds imposed in our modelling.

Thus, upper bounds for power generation capacity at EU aggregate level was implemented for the following technologies, based on EC 1.5 TECH results:

1. Tidal and wave (11.9 GW); geothermal (5.04 GW); hydro (227.9 GW);
2. Battery storage (69 GW); Hydro pumped storage (52.4 GW).

Similarly, the upper bound for uptake of EVs in 2050 (in line with EC 1.5 TECH) was implemented for the total EU vehicle stock as follows:

1. 80% of total passenger car stock;
2. 83.5% of total public transport vehicle stock;
3. 8% of total HGV stock.

At the EU MS level we have implemented both lower and upper bounds (for 2050) for electricity generation technologies. The lower bound on electricity generation reflects the installed capacity to date (2020). The reason for imposing this lower bound is that we assume a 2050 electricity system will not start from scratch but will at least have capacity mix in line with today's system. This does not however reflect any potential policy changes in respect of nuclear generation closure. Other than nuclear, all other technologies that we consider to have lower bounds are all renewables and hence power system will have to be largely decarbonised, thus the lower bounds shown in Table A. *25* will not be binding in practice. It is however important to reflect sunk capacity of such large installations as hydro in the Nordic countries, Central and Southern Europe as lower bounds.

Table A. 25: Lower bounds for electricity generation capacity in 2050 for the NZ and 90% scenarios (GW)

	Nuclear	Wind Onshore	Wind Offshore	Utility Solar PV	Residential Solar PV	Tidal &Wave	Hydro	Geothermal	Hydro PS
UK	8.21	12.84	10.37	5.84	10.84		1.88		4.05
Nordic	11.38	17.12	1.70	0.39	0.89		48.79		
BE	5.93	2.25	1.67	0.05	4.83		0.18		1.31
NL	0.49	3.97	1.71	1.23	5.94		0.04		
FR	63.13	15.66		5.03	6.54	0.24	19.23		5.02
Eastern Europe	7.88	0.65		1.79	2.81		2.77	0.00	2.09
Central Europe	3.67	3.14		0.10	1.92		15.32		9.97
South East Europe	3.30	7.57		3.55	2.56		13.05	0.01	1.84
Iberia	7.12	29.63		8.91	2.24		24.67		8.47
Ireland		1.92					0.22	0.02	0.29
DE		53.40	7.71	15.27	43.10		5.26	0.04	9.42
IT		10.22		1.22	4.91		14.90	0.87	7.28
Baltics		0.92		0.10	0.18		1.68		0.90
PL		5.95		0.35	1.30		0.60		1.78

Table A. 26 outlines upper bounds for electricity generation applied to our countries and regions in the two baseline scenarios. For Italy, Germany, France, and Belgium the bounds were based on discussion with leading energy firms and independent energy regulators in those countries. For all other countries and regions the bounds were derived from either EC JRC ENSPRESSO study or as the highest historical build rate of more than 20 years of capacity expansions.

Table A. 26: Upper bounds for electricity generation capacity in 2050 for the NZ and 90% scenarios

	Biomass	Biomass CCS	Wind Onshore	Wind Offshore	Tidal & Wave	Hydro
UK			24.56	103.61		
Ireland			45.59	0.99		

Nordic			223.67	79.61		
BE		0.50	9.00	13.00		
DE			210.00	64.00		
NL			48.87	47.75		
FR			80.00	80.00	13.24	
IT	9.00	10.00	31.00	17.00	3.00	22.00
Baltics			235.05	19.19		
PL			105.31	12.31		
Eastern Europe			270.73			
Central Europe			21.77			
South East Europe			76.89	11.31		
Iberia			131.74	0.66		

Appendix 3 ï sensitivity analysis of costs of traditional and sector-coupling flexibility technologies

As we discussed in the research methodology section (§3) we performed several sensitivity analyses to understand the impacts of key assumptions on our results. For each of the key technologies we increase its projected cost by a fraction and measure the impacts of these cost sensitivities on the structure of final consumption. Thus, for each of the technology we listed in Figure 3, we change their projected costs by a fraction from the baseline costs assumptions (see Table *3*). Here, we describe the impact of electricity, hydrogen and CH_4 network capex on the structure of final consumption and fuel mixes. In the second part of this section we report our sensitivity analysis for system integration technologies (detailed results are reported in). Examining the sensitivity results reveals some very interesting insights regarding potential complementarities between our key energy carriers – electricity, hydrogen, synfuels (e-gas and e-liquid), biomethane and natural gas.

Electricity network

Varying electricity network capex between +/-50% from the baseline does not change its share in the final consumption very much relative to other networks, suggesting a robust and central role of the electricity network in delivering deep decarbonisation targets. It also suggests that our assumptions regarding electricity network costs do not impact the conclusions when net zero target is a binding constraint and that the modelling results are robust because of the correct "directional impact" – higher (lower) electricity network costs does decrease (increase) its share in the final consumption but marginally. Further, these rather insensitive results towards electricity network costs can be explained by the fact that electricity network costs constitute 27-29% of total electricity system costs. In terms of complementarities and coupling with other energy carriers, one can see that for example, lower electricity network costs have a positive impacts on the position of e-gas and marginally negative impacts on the role of biomethane and hydrogen in the final consumption. This is because electricity-based end-use solutions seem to compete with biomethane and hydrogen but not with e-gas. This could suggest that there is secondary and indirect effect whereby cheaper electricity displaces both biomethane and hydrogen from end-use but then hydrogen is used more to produce synfuels.

Hydrogen network

Our sensitivity analysis with respect to H_2 network seem to suggest that the position of H_2 in the final consumption sectors is relatively sensitive to the costs assumptions (if we compare this with the electricity network costs sensitivity results) – its consumption can vary between +/-11% relative to the baseline in responses to changes in the H_2 network costs. While we see that there are complementarities between electricity and synfuels in the final consumption sectors (and hence indirectly with H_2, actually), there are less complementarities between H_2 and other energy carriers. It seems that in the final consumption sectors, H_2 competes the most with e-gas and less so with electricity and biomethane.

CH_4 network

The results from changing the costs of CH_4 network show that the role of biomethane and e-gas in the final consumption sectors do depend on the costs of the gas network, as expected, but it is somewhat less sensitive relative to the sensitivity of H_2 network costs. What is interesting to note is the complementarities between gas and electricity networks – for example, a higher (or lower) cost of CH_4 network relative to our baseline assumption decreases the biomethane and e-gas consumption in the final sectors but the high gas network costs also decreases electricity consumption in the final sectors (albeit marginally, -0.2% relative to the baseline consumption). Thus, gas and electricity are complementary in the integrated energy system while gas and hydrogen competes for direct final uses. Worth mentioning that CH_4 network costs have a rather large impact on the position of transport fuels – diesel, e-liquids, gasoline – if gas network costs were to be 50% higher than the baseline assumption then this would negatively impact the role of gasoline but positively impacts the role of carbon neutral diesel (e-liquid). A possible explanation is higher costs of the CH_4 network reduces competitiveness of biomethane and e-gas in the final consumption and hence reducing the carbon offsetting of gasoline emissions.
Lastly, the cost of gas network has asymmetric impacts – for example a 50% higher gas network cost sensitivity reduces the consumption of e-gas by 28% while a 50% lower gas network cost sensitivity increases the consumption of e-gas only by 7% suggesting a limit of gases in the final consumption sectors which are independent of costs of gases.

Electrolysers
The role of green H_2 in integrating different energy vectors is examined in this sensitivity analysis by changing the costs of green H_2 technologies – alkaline, PEM, SOEC. First, while an increase of 200% (relative to the baseline assumption) of total costs of electrolysers does reduce the share of H_2 by 3.3% in the final consumption, a decrease of 50% of electrolysers' cost increases the share of H_2 by the same amount: +3.3% (see Table A. 27); hence, a marginal reduction in green H_2 cost has far greater impact on its competitive position then a marginal increase in its cost.
It is rather obvious that green H_2 competes with biomethane in the final consumption sectors; what is less so obvious is the relationship between green H_2 and synfuels – when costs of electrolysers are increased this mainly reduces the consumption of e-gas but a decrease in the cost of green H_2 seems to benefit e-liquid but not e-gas. This does suggest that cheaper green H_2 will have an important role in transport sector – it allows synthetic diesel (carbon neutral) to displace gasoline, e-gas and biomethane.
Overall, the evolution of the cost of electrolysers to 2050 does seem to have an impact on various energy carriers but it seems that the cost of H_2 infrastructure (pipelines) have far greater impact on the position of green H_2 than the cost of H_2 production.

P2X technologies
The cost of P2X technologies seem to be even more important than the costs of electrolysers – lower (than in the baseline) costs of P2X allows both carbon neutral and fossil diesel to increase their shares in the transport sector at the expense of e-gas and gasoline. A reason for this is that diesel-based transport can use both synthetic and fossil diesel and in general these are more efficient than either gas or gasoline-based transport modes. An increase in costs of P2X (relative to the baseline cost) reduces the role of e-gas in the final consumption. Thus, cost evolution of P2X technologies have a rather asymmetric and different effects on the position of input fuel (H_2) as well as output products (e-gas and e-liquids) – when P2X cost are very high we see more direct usage of H_2 in the final consumption sectors displacing mostly e-gas and marginally biomethane and electricity.
All in all, P2X creates an additional channel through which energy system can become more integrated – from offshore wind to car pumping stations.

Hybrid heat pumps
While green H_2 and P2X technologies allows integration of low-carbon energy vectors at the upstream level, hybrid heat pump (HHP) systems allows integration of two important energy vectors – electricity and gas – at household level. The impacts of varying costs for HHP does not seem to have a dramatic shift in final consumption mix; thus, the cost of HHP themselves might play a marginal role in the overall system cost; for example, increasing the cost of HHP by 50% (relative to the baseline cost) only reduces consumption of biomethane by 2.7% but increasing the cost of CH_4 network by the same 50% reduces biomethane consumption by 8.2%; thus, cost of HHP have smaller impacts but the value it provides to manage system peak is rather important.

Table A. 27: Impact of energy technologies costs on final consumption structure: NZ scenario (2050)

	Biomethane	**Diesel**	**E-gas**	**Electricity**	**E-liquids**	**Gasoline**	**H_2**	**CH_4**	**Total**
NZ Baseline, TWh	**1,059**	**290**	**611**	**4,175**	**429**	**45**	**921**	**199**	**8,246**
S1 H_2 Network	1.4%	0.0%	5.5%	0.6%	0.0%	0.0%	-8.7%	0.0%	-0.1%
S2 H_2 Network	1.9%	0.0%	9.5%	1.0%	0.0%	0.0%	-14.7%	0.0%	-0.2%
S3 H_2 Network	3.6%	0.0%	20.0%	1.2%	0.0%	0.0%	-22.5%	0.0%	0.0%
S4 H_2 Network	-0.1%	0.0%	-1.2%	-0.2%	0.0%	0.0%	2.5%	0.0%	0.1%
S5 H_2 Network	-0.4%	0.0%	-2.3%	-0.4%	0.0%	0.0%	5.5%	0.0%	0.2%
S6 H_2 Network	-1.7%	0.0%	-3.1%	-1.0%	0.0%	0.0%	11.2%	0.0%	0.3%
S1 Electricity Network	0.6%	0.0%	-0.9%	-0.2%	0.0%	0.0%	1.7%	0.0%	0.1%

S2 Electricity Network	0.4%	0.0%	-2.3%	-0.8%	0.0%	0.0%	5.8%	0.0%	0.1%
S3 Electricity Network	-1.0%	0.0%	-4.4%	-1.5%	0.0%	0.0%	11.0%	0.0%	0.0%
S4 Electricity Network	-0.3%	0.0%	1.3%	0.2%	0.0%	0.0%	-1.7%	0.0%	0.0%
S5 Electricity Network	-0.8%	0.0%	3.9%	0.5%	0.0%	0.0%	-5.4%	0.0%	-0.2%
S6 Electricity Network	-1.3%	0.0%	9.5%	1.3%	0.0%	0.0%	-12.3%	-5.7%	-0.3%
S1 CH_4 Network	-1.4%	0.1%	-1.1%	0.1%	0.2%	-0.9%	1.1%	0.0%	-0.1%
S2 CH_4 Network	-3.9%	5.3%	-11.3%	-0.1%	9.8%	-36.7%	3.6%	0.0%	-0.5%
S3 CH_4 Network	-8.2%	13.6%	-27.9%	-0.2%	24.9%	-94.3%	8.0%	-1.1%	-1.1%
S4 CH_4 Network	1.5%	0.0%	1.5%	0.0%	0.0%	0.0%	-1.9%	0.0%	0.1%
S5 CH_4 Network	3.5%	0.0%	3.9%	0.0%	0.0%	0.0%	-5.2%	0.0%	0.2%
S6 CH_4 Network	5.4%	0.0%	7.0%	0.1%	0.0%	0.0%	-9.6%	0.0%	0.2%
S1 Green H_2	1.0%	0.0%	-1.0%	0.1%	0.0%	0.0%	-1.5%	0.0%	-0.1%
S2 Green H_2	1.5%	0.0%	-1.6%	0.1%	0.0%	0.0%	-2.5%	0.0%	-0.2%
S3 Green H_2	2.6%	0.0%	-3.0%	0.1%	0.0%	0.0%	-3.3%	0.0%	-0.2%
S4 Green H_2	-0.4%	0.0%	0.6%	0.1%	0.0%	0.0%	-0.2%	0.0%	0.0%
S5 Green H_2	-1.1%	0.3%	1.0%	0.1%	0.5%	-1.8%	-0.2%	0.0%	0.0%
S6 Green H_2	-1.7%	1.9%	-3.7%	-0.4%	4.5%	-13.0%	3.3%	0.0%	-0.1%
S1 P2X	-0.3%	0.0%	-2.1%	-0.1%	0.0%	0.0%	1.8%	0.0%	0.0%
S2 P2X	-0.3%	0.0%	-3.1%	-0.1%	0.0%	0.0%	2.4%	0.0%	-0.1%
S3 P2X	-0.2%	0.0%	-3.9%	-0.2%	0.0%	0.0%	2.9%	0.0%	-0.1%
S4 P2X	0.1%	0.0%	0.5%	0.0%	0.0%	0.0%	-0.4%	0.0%	0.0%
S5 P2X	0.0%	2.5%	-3.7%	-0.1%	5.9%	-17.2%	-0.8%	0.0%	-0.1%
S6 P2X	-0.5%	9.7%	-14.8%	-0.2%	20.6%	-67.0%	-2.1%	-2.8%	-0.5%
S1 HHP CH_4	-0.5%	0.0%	-0.2%	0.0%	0.0%	0.0%	0.4%	0.0%	0.0%
S2 HHP CH_4	-1.3%	0.0%	-0.5%	0.1%	0.0%	0.0%	1.0%	0.0%	-0.1%
S3 HHP CH_4	-2.7%	0.0%	-0.7%	0.2%	0.0%	0.0%	1.4%	0.0%	-0.2%
S4 HHP CH_4	0.8%	0.0%	0.4%	0.0%	0.0%	0.0%	-0.5%	0.0%	0.1%
S5 HHP CH_4	1.2%	0.0%	0.8%	0.0%	0.0%	0.0%	-1.5%	0.0%	0.0%
S6 HHP CH_4	0.3%	0.0%	2.2%	0.4%	0.0%	0.0%	-5.2%	0.0%	-0.2%
S1 H_2 Storage	-0.7%	0.0%	-0.7%	0.0%	0.0%	0.0%	1.2%	0.0%	0.0%
S2 H_2 Storage	-0.7%	0.0%	-0.7%	0.0%	0.0%	0.0%	1.1%	0.0%	0.0%
S3 H_2 Storage	-0.5%	0.0%	-0.7%	0.0%	0.0%	0.0%	1.0%	0.0%	0.0%
S4 H_2 Storage	0.8%	0.0%	0.5%	0.0%	0.0%	0.0%	-1.4%	0.0%	0.0%
S5 H_2 Storage	2.6%	0.0%	2.7%	0.0%	0.0%	0.0%	-3.4%	0.0%	0.1%

S6 H_2 Storage	2.5%	0.0%	4.9%	0.2%	0.0%	0.0%	-6.6%	0.0%	0.0%
S1 Electricity Storage	-0.2%	0.0%	-0.1%	-0.1%	0.0%	0.0%	0.1%	0.0%	-0.1%
S2 Electricity Storage	-0.4%	0.0%	-0.1%	-0.2%	0.0%	0.0%	0.2%	0.0%	-0.1%
S3 Electricity Storage	-0.5%	0.0%	0.0%	-0.3%	0.0%	0.0%	0.1%	0.0%	-0.2%
S4 Electricity Storage	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%	-0.4%	0.0%	0.1%
S5 Electricity Storage	0.3%	0.0%	0.2%	0.3%	0.0%	0.0%	-0.5%	0.0%	0.1%
S6 Electricity Storage	0.3%	0.0%	0.2%	0.3%	0.0%	0.0%	-0.5%	0.0%	0.1%
S1 CH_4 Storage	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.1%	0.0%	0.0%
S2 CH_4 Storage	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.2%	0.0%	0.0%
S3 CH_4 Storage	0.2%	0.0%	0.2%	0.0%	0.0%	0.0%	-0.4%	0.0%	0.0%
S4 CH_4 Storage	-0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%
S5 CH_4 Storage	-0.1%	0.0%	-0.1%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%
S6 CH_4 Storage	-0.1%	0.0%	-0.2%	0.0%	0.0%	0.0%	0.3%	0.0%	0.0%

Note: there was no impact on the final consumption of biomass so it was not reported here for clarity purpose.