This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement Nº 953016

SERENDI PV

D1.8 Roadmap for high PV penetration levels in Europe and most promising scenarios

T1.8 Roadmap for high PV penetration levels in Europe and most promising scenarios

Grant Agreement nº:	**953016**
Call:	H2020-LC-SC3-2020-RES-IA-CSA / LC-SC3-RES-33-2020
Project title:	**Smooth, REliable aNd Dispatchable Integration of PV in EU Grids**
Project acronym:	SERENDI-PV
Type of Action:	Innovation Action
Granted by:	European Climate, Infrastructure and Environment Executive Agency (CINEA)
Project coordinator:	Fundación TECNALIA Research & Innovation
Project website address:	*www.serendi-pv.eu; www.serendipv.eu*
Start date of the project:	October 2020
Duration:	48 months

Document Ref.:	SERENDI-PV-D1.8: Roadmap for high PV penetration levels in Europe and most promising scenarios_v1.docx
Lead Beneficiary:	Lappeenranta-Lahti University of Technology (LUT)
Doc. Dissemination Level:	**PU** – Public
Due Date for Deliverable:	30/09/2024 (M48)
Actual Submission date:	31/10/2024 (M49)
Version	V1

Summary

The present deliverable explores the possible scenarios for solar photovoltaics (PV) development in Europe at the horizon 2050 and how these scenarios translate into national and regional increases in PV penetration. These scenarios examine various technologies and segments, including residential, commercial, industrial and utility-scale PV applications. They investigate innovative and developing system types such as offshore floating PV and agricultural PV, and they differentiate between building-attached PV (BAPV) and building-integrated PV (BIPV) systems, as well as south-facing systems versus east-west facing systems, vertical installations, and bifacial systems, among others. These scenarios assess the role of solar PV in the energy transition, its impact on the energy system structure and cost of energy. Additionally, different demand scenarios will be assessed to study the impact of emerging e-fuels and e-chemicals segments on the role of solar PV in Europe.

This deliverable is an output of task T1.8 of WP1 of the SERENDI-PV project.

Document Information

Title	D1.8: Roadmap for high PV penetration levels in Europe and most promising scenarios
Lead Beneficiary	Lappeenranta-Lahti University of Technology (LUT)
Contributors	
Distribution	PU - Public
Report Name	SERENDI-PV-D1.8: Roadmap for high PV penetration levels in Europe and most promising scenarios

Document History

Date	Version	Prepared by	Organisation	Approved by	Notes
31/10/2024	v1	Aleksandr Borzunov, Dmitrii Bogdanov, Dominik Keiner, Rasul Satymov, Ayobami Solomon Oyewo, Christian Breyer	LUT	Javier del Pozo (TEC)	Submitted to the EC

Acknowledgements

The work described in this publication has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement Nº 953016.

Disclaimer

This document reflects only the authors' view and not those of the European Commission. This work may rely on data from sources external to the members of the SERENDI-PV project Consortium. Members of the Consortium do not accept liability for loss or damage suffered by any third party as a result of errors or inaccuracies in such data. The information in this document is provided "as is" and no guarantee or warranty is given that the information is fit for any particular purpose. The user thereof uses the information at its sole risk and neither the European Commission nor any member of the SERENDI-PV Consortium is liable for any use that may be made of the information.

Contents

Summary ii
Document Information ii
Document History ii
Acknowledgements iii
Disclaimer iii

1 EXECUTIVE SUMMARY 1
1.1 Description of the deliverable content and purpose 1
1.2 Reference material 1
1.3 Relation with other activities in the project 1
1.4 Abbreviation 2

2 ENERGY SYSTEM TRANSITION INSIGHT FOR EUROPE 3
2.1 Introduction 3
2.2 Methods 7
2.2.1 Model description 7
2.2.2 Scenarios 10
2.2.3 Data and energy resources 11
2.3 Results 13
2.3.1 Primary energy demand 13
2.3.2 Final energy demand 14
2.3.3 Electricity supply 15
2.3.4 Heat supply 18
2.3.5 Transport and industry 21
2.3.6 Sector coupling and flexibility in the energy system 23
2.3.7 Regional outlook 25
2.3.8 Energy system cost 34
2.3.9 Emissions 38
2.4 Discussion 39
2.4.1 Role of solar PV in the European energy transition 39
2.4.2 Impact of bifacial PV introduction 40
2.4.3 Prosumers' BAPV and BIPV in the energy system 41
2.4.4 PV as source of energy for e-chemicals and e-fuels 41

3 SUPPORTING RESEARCH FOR ENERGY SYSTEMS 42
3.1 Bifacial PV modelling in energy systems 42
3.2 Improved backtracking strategies for single-axis tracking solar PV 43
3.3 Rooftop PV yield modelling for energy systems 44
3.4 Wind power yield modelling for improved wind power vs PV ratios 45
3.5 Offshore floating PV as export option – Case Maldives 46
3.6 Offshore floating PV as export option – Case Caribbean 48

4 CONCLUSIONS 49

5 REFERENCES 50

Tables

Table 1.1: Relation between current deliverable and other activities in the project 1
Table 2.1: Difference in energy import in EU from Russia [19], [20], [21]. 5
Table 2.2: Scenarios description. 10
Table 2.3: Renewable resource capacity lower limits for key technologies. 11
Table 2.4: Renewable resource capacity upper limits for key technologies. 12

Figures

Figure 2.1: Total energy supply in main fuels in EU in 2022 [18]. 4
Figure 2.2: Schematic representation of LUT-ESTM (left) and the model flowchart (right). 7
Figure 2.3: Schematic representation of LUT-ESTM. 8
Figure 2.4: Primary energy and feedstock demand in Europe from 2020 to 2050 between all scenarios during the transition. 14
Figure 2.5: Final energy demand by sector across all scenarios during the transition on Europe. 15
Figure 2.6: Installed electricity generation capacities for all scenarios during the transition. 16
Figure 2.7: Electricity generation for all scenarios during the transition. 16
Figure 2.8: Electricity storage capacity for all scenarios during the transition. 17
Figure 2.9: Electricity storage output for all scenarios during the transition. 18
Figure 2.10: Installed heat generation capacities in all scenarios during the transition. 19
Figure 2.11: Heat generation mix in all scenarios during the transition. 19
Figure 2.12: Heat storage capacity in all scenarios during the transition. 20
Figure 2.13: Heat storage output in all scenarios during the transition. 21
Figure 2.14: Final energy demand for transport across all scenarios from 2020 to 2050. 22
Figure 2.15: Energy and feedstock for the key industries across the scenarios from 2020 to 2050. 23
Figure 2.16: Energy flows of the European energy system in 2020. 23
Figure 2.17: Energy flows of the European energy system in 2050 for the BPS. 24
Figure 2.18: Regional electricity generation capacities in 2050 across Europe in the BPS-2040. 25
Figure 2.19: Regional electricity generation capacities in 2050 across Europe in the BPS. 26
Figure 2.20: Regional electricity generation in 2050 across Europe in the BPS-2040. 27
Figure 2.21: Regional electricity generation in 2050 across Europe in the BPS. 27
Figure 2.22: Regional heat generation capacities in 2050 across Europe in the BPS-2040. 28
Figure 2.23: Regional heat generation capacities in 2050 across Europe in the BPS. 28
Figure 2.24: Regional heat supply in 2050 across Europe in the BPS-2040. 29
Figure 2.25: Regional heat supply in 2050 across Europe in the BPS-2040. 29
Figure 2.26: Regional electricity storage output in 2050 across Europe in the BPS-2040. 30
Figure 2.27: Regional electricity storage output in 2050 across Europe in the BPS. 30
Figure 2.28: Regional heat storage output in 2050 across Europe in the BPS-2040. 31
Figure 2.29: Regional heat storage output in 2050 across Europe in the BPS. 31
Figure 2.30: Regional fuels and chemicals supply in 2050 across Europe in the BPS-2040. 32
Figure 2.31: Regional fuels and chemicals supply in 2050 across Europe in the BPS. 32
Figure 2.32: Regional electricity trade with net importers and net-exporters in 2050 across Europe in the BSP-2040. 33
Figure 2.33: Regional electricity trade with net importers and net-exporters in 2050 across Europe in the BPS. 33

Figure 2.34: Annualised system costs per sector (left) and cost component (right) during the transition for the BPS. 34
Figure 2.35: Annualised energy system costs across the scenarios from 2020 to 2050. 35
Figure 2.36: Levelized cost of electricity during the transition. 36
Figure 2.37: Levelized cost of heat during the transition. 36
Figure 2.38: Levelized cost of final energy and non-energy use during the transition. 37
Figure 2.39: Levelized cost of final energy and non-energy use (left) and capital expenditures in 5-year intervals (right) during the transition. 38
Figure 2.40: Sectoral annual CO_2 emissions in all scenarios during the transition. 38
Figure 2.41: Cumulative CO_2 emissions. 39

1 EXECUTIVE SUMMARY

1.1 Description of the deliverable content and purpose

This document contains a comprehensive roadmap for the development of the solar PV technology in Europe, focusing on the transition towards high PV penetration levels by 2050. The primary objective is to explore various scenarios that can drive PV expansions across the Europe and at regional levels. Describing the difference in scenarios can help to identify the most promising technologies, system applications, and market opportunities.

The purpose of the deliverable is to provide a strategic pathway to a fully renewable energy system in Europe for accelerating the deployment of PV technologies. The roadmap aims to support the EU's energy transition by offering a clear vision of how different PV technologies will impact the energy transition in Europe and individual regions. By focusing on a high PV penetration in Europe, the transition addresses a substantial portion of emissions from the energy, transport, and industry sector. This aligns with the Green Deal's emphasis on increasing the shares of renewables in the total energy supply of the EU. Additionally, accelerated transition towards renewable energy focused on PV technologies, can meet Europe's climate goals, reduce emissions and lead the global transition to renewable energy systems.

1.2 Reference material

This document does not refer to other SERENDI-PV deliverables but affects another report published simultaneously in the scope of this project: D1.7 Key Sustainable Indicators (KSI) based on LCA for high PV penetration scenarios.

1.3 Relation with other activities in the project

Table 1.1 depicts the main links of this deliverable to other activities (work packages, tasks, deliverables, etc.) within SERENDI-PV project. The table should be considered along with the current document for further understanding of the deliverable contents and purpose.

Table 1.1: Relation between current deliverable and other activities in the project

Project activity	Relation with current deliverable
All	The current deliverable feeds from all project activities and work packages.

1.4 Abbreviation

BAPV	Building-attached PV systems
BIPV	Building-integrated PV systems
BPS	Best policy scenario
CAPEX	Capital expenditure
CF	Capacity factor
CSP	Concentrating solar thermal power
DH	District heating
DLR	German Aerospace Center
EC	European Commission
EU	European Union
FED	Final energy demand
FT liquids	Fisher-Tropsch liquids
GHG	Greenhouse gas
HDV	Heavy duty vehicles
HT	High temperature
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
LCOE	Levelised cost of electricity
LCOFE	Levelised cost of final energy and non-energy use
LCOH	Levelised cost of heat
LDV	Light duty vehicles
LUT-ESTM	LUT Energy System Transition Model
MDV	Medium duty vehicles
NASA	National Aeronautics and Space Administration
NOAA	National Oceanic and Atmospheric Administration
PED	Primary energy demand
PHES	Pumped hydro energy storage
PV	Photovoltaics
RE	Renewable energy
RES	Renewable energy sources
SDGs	Sustainable Development Goals
TES	Thermal energy storage
TPED	Total primary energy demand
UN	United Nations
VRE	Variable renewable energy

2 ENERGY SYSTEM TRANSITION INSIGHT FOR EUROPE

2.1 Introduction

A significant increase in extreme weather events, such as droughts and wildfires in some regions of our planet and incessant rains and floods in others, is leading to a critical climate situation, that has become increasingly discussed in recent years [1], [2]. The average temperature across the Earth's land and ocean surfaces in 2023 was 0.60°C warmer than the 1991-2020 average and 1.48°C warmer than the 1850-1900 pre-industrial level, marking the highest global temperature observed in National Oceanic and Atmospheric Administration (NOAA) [3]. This is another undeniable sign from nature that without mitigation efforts on climate change, the further trend of negative extreme weather impacts will only increase, endangering ecosystems and human well-being.

Governments plays a key role in developing and implementing climate change mitigation measures. However, the consequent reduction of greenhouse gas (GHG) emissions is not instantaneous, but a gradual process of moving away from traditional approaches in energy, transport, industry, and agriculture sectors to the introduction of innovative climate technologies in all spheres [4]. With the adoption of the Paris Agreement [5] and the United Nations (UN) Sustainable Development Goals (SDGs) [6], a clear vision of a future requiring urgent climate action and addressing sustainable development issues, including social and environmental aspects, has arisen. The UN report [7], calls for GHG emissions to be reduced by 7.6% each year between 2020 and 2030, to get on track to keep the 1.5°C temperature limit of the Paris Agreement. The last UN report [8] also indicates that predicted 2030 GHG emissions must fall by 28% for the 2°C pathway and 42% for the 1.5°C pathway.

The European Commission (EC) has envisaged a strategic long-term vision with the European Green Deal [9], which outlines feasible pathways for Europe to lead the transition towards a climate-neutral economy by 2050 in line with the objectives of the Paris Agreement. The European Union (EU) is currently on track to become carbon neutral by 2050, including a target to reduce GHG emissions by at least 55% by 2030 [10]. The REPowerEU [11] strategy of May 2022 emphasises the urgent need to transition away from Russian import of fossil fuels and to accelerate the shift to clean energy. The plan's primary goals included reducing the EU's reliance on imported energy, promoting energy efficiency, diversifying energy sources, and significantly increasing the adoption of renewable energy technologies. In recent years, European countries have been at the forefront of deploying renewable technologies, driven by their vast renewable energy (RE) resource potential and the extensive utilisation of RE sources (RES). In order to achieve these goals, the improvement of the sustainability of energy systems in Europe continues apace [12].

The transition from fossil fuels to low-carbon and RES, along with improved energy efficiency in products, industry, and buildings, and the adoption of a more sustainable energy system based on clean technologies, are key indicators of a sustainable energy future. This transition is already underway in many countries, and studies [13] show, that it not only has favourable climate impacts and serves as a primary method for mitigating climate change but also brings economic benefits. The defossilisation of the energy system, whether for a single country or the entire European continent, is a gradual process rather than an immediate one. However, the ability to respond swiftly to changing climate conditions and address the challenges of enhancing energy security, stabilising prices, and promoting sustainable development presents the EU with an opportunity to take a global leadership role, aiming to become the first continent to achieve zero greenhouse gas emissions and inspire the rest of the world to reach climate neutrality by 2050.

Solar photovoltaic (PV) is the fastest-growing energy technology in the world [14] and is positioned to play an important role in the energy transition. Solar PV plays a crucial role in achieving the EU's goal of a climate-neutral economy by 2050. It is the most cost-effective electricity source, with the capability to meet all final energy demands through sector coupling and power-to-X technologies [15]. Installed solar PV capacity in Europe continues to grow. According to SolarPower Europe [16], solar PV has grown by 27% year-on-year from 2022 to 263 GW in 2023. This year will be another record year for solar PV in the EU, with 55.9 GW planned to be installed in the 27 member states, representing a 40% increase compared to 2022 and a doubling of the market size over the past two years. This is the third year in a row that the EU market has set a record and the third year in a row with an annual growth rate of at least 40%. This steady growth can be seen as a continuation of the trend that emerged in 2022, when EU member states recognised solar PV as a clean, cost-effective, and unrivalled solution to reduce dependence on fossil fuels, including imports from Russia.

According to SolarPower Europe [16] in 2023, Germany regained its position as the leader in solar PV, adding 14.1 GW. It is followed by Spain with 8.2 GW, and Italy is in the top three for the first time in several years with 4.8 GW. Poland (4.6 GW) and the Netherlands (4.1 GW) round out the top five, while Italy displaces France from the leading group. A total of 20 EU member states have reached the maximum level of solar PV installations in 2023, with 25 countries surpassing the previous year's figures. Market diversity is also growing, with 14 countries exceeding 1 GW of annual installations, up from 10 countries in 2022. In terms of total capacity, Germany remains the largest market with 82 GW, followed by Spain with 36 GW and Italy with 29.5 GW. While Germany leads in both annual market size and total solar PV installation capacity in the EU, the Netherlands maintains the highest installed PV capacity per capita in the world, which reached 1280 W per capita in 2023, increasing by more than 250 W per capita over the year. Germany is also approaching the 1000 W per capita mark at 985 W per capita.

The growing adoption of RE in Europe and worldwide has opened new opportunities for citizens and companies in shaping energy choices thanks to the decentralised nature of RE, especially PV and wind power. The share of energy consumed in the EU during 2022 generated from RES was 23% and this increase, from a level of 21.9% in 2021, was largely driven by a strong growth in solar PV [17]. The remaining 77% of the EU's total energy supply in 2022 comes from fossil fuels and nuclear power with both being mostly imported. Total energy supply for the EU in 2022 is presented in Figure 2.1.

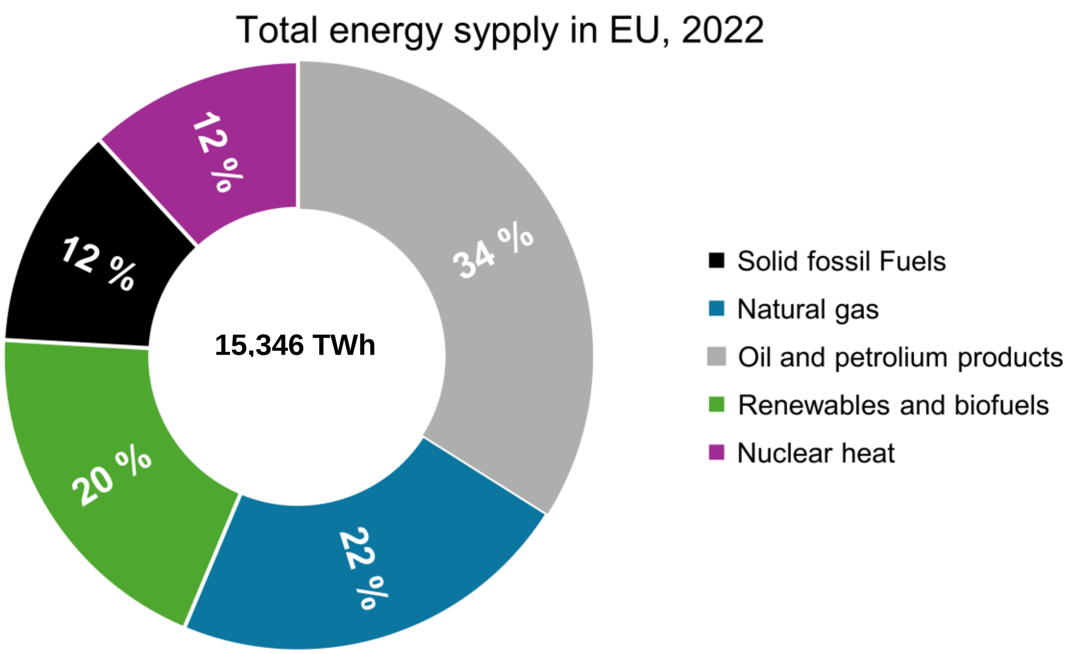

Figure 2.1: Total energy supply in main fuels in EU in 2022 [18].

Before the invasion of Ukraine, Russia was the main supplier of oil products and natural gas to the EU. In the fourth quarter of 2021, its share in energy supplies to the EU was 24.8% [18]. After February 2022, the EU responded with several sanctions packages that directly and indirectly affected oil and natural gas trade. According to Eurostat [18], after September 2022 coal imports from Russia became zero, imports of crude oil dropped to 17% (40% in 2020) and gas imports decreased by 73% compared to 2021. Table 2.1 provides an overview of how the EU-Russia energy trade changed from 2021 to 2023.

Table 2.1: Difference in energy import in EU from Russia [19], [20], [21]**.**

Energy source	Unit	Volumes 2021	Volumes 2023	Percentage change
Coal	Mt	52	0	-100%
Crude Oil	mb/d	2.26	0.22	-90%
Oil Products	mb/d	1.05	0.09	-91%
Natural Gas	bcm	155	27	-83%
Liquefied natural gas (LNG)	bcm	13	18	38%
Electricity	TWh	13	0	-100%
Sum (excl. uranium products)	TWh	4131	595	-86%

Reduction of energy imports from Russia increased demand in local energy supply, especially of RE. The power sector is the leader in RE deployment in 2022, with 41.2% of all electricity generated from renewables. This is followed by the heating and cooling sector (24.9%) and transport sector (9.6%) [17]. In the heat sector, the adoption of RE utilisation in various heating processes is increasing. Thermal demand can be doubled in the form of electricity either directly or through heat pumps [22]. Heat pumps in district heating networks provide about 11% of the world's space heating and domestic hot water and are particularly suitable for use in densely populated regions where the annual heating demand is four months or more.

The transport sector is one of the major energy consumers in the EU, accounting for a significant share of total energy consumption in the region. Conventional fossil fuels, especially oil (over 90%), are the dominant source of energy for transport, and therefore the transport sector is the largest single sector in terms of total GHG emissions in the EU and the only sector with growing emissions. Recently, however, there has been an increasing focus on shifting to cleaner and more sustainable energy sources to reduce GHG emissions. There is a trend towards electrification of road transport across the EU. In 2021, electric vehicles accounted for 17% of total sales in Europe, but there is considerable variation across markets, with the highest share in Norway at 72%, Sweden at 45% and the Netherlands at 30% [23]. Maritime transport has options with the increasing availability of alternative fuels such as biofuels in existing engines, which may be a near-term prospect, and the use of synthetic electricity-based fuels such as e-ammonia, e-methanol and Fischer-Tropsch e-fuels [24]. The production and use of environmentally friendly aviation fuels, in particular bio-based kerosene jet fuels or e-kerosene-based jet fuels, together with direct electrification for short-range flights, could contribute to a greener aviation sector [25].

The growth of RE, electrification, and efficiency measures is increasing across the EU, as indicated by recent trends in various sectors. However, the pace of these developments is not sufficient to achieve the level of carbon neutrality that will ensure climate change mitigation and energy sovereignty. Extensive electrification of the heat, transport, and industry sectors and subsequent integration with the energy sector is required, but will result in further growth of electricity consumption. To accelerate the energy transition, rapid growth in electricity generation from low-cost renewable sources, mainly solar PV and wind power will be needed.

Achieving carbon neutrality with the key target of reducing net GHG emissions by at least 55% by 2030 compared to 1990 levels is the main objective of the European Green Deal program [9]. Targets for defossilisation of shipping and aviation, the adoption of the Energy Performance of Buildings Directive through which the EU will encourage refurbishment, phase out fossil fuel boilers, and aim for full decarbonisation of buildings by 2050 are EU steps towards achieving the main objectives of the agreement.

The updated Renewable Energy Directive [26] raises the binding target for RE in the EU's energy mix from 32% to 42.5%, with the potential to reach 45%. Meeting the 42.5% target by 2030 will necessitate more than doubling the current rate of RE expansion compared to the past decade. This will require significant changes and advancements across the European energy system.

The EU Solar Strategy [27], presented by the EC in May 2022 as part of the REPowerEU plan [11], identifies remaining barriers and challenges in the solar energy sector and defines initiatives to overcome them and accelerate the deployment of solar technologies. For example, the strategy sets an ambitious target to achieve over 320 GW of solar PV installations by 2025 (more than doubling from 2020) and almost 600 GW of solar PV capacity by 2030, reflecting the growing emphasis on solar in the EU energy landscape. To achieve the target, several specific initiatives are promoting rooftop solar (European Solar Rooftop Initiative), domestic production (EU PV Manufacturing Alliance) as well as actions to address other existing challenges such as access to finance, permitting, deployment of PV in the utility sector, efficient distribution of solar energy and a sustainable supply chain [28].

Solar PV has the potential to become one of the largest RES contributors to the defossilisation of Europe's energy system, outpacing the growth potential of other RES such as wind power. One of the most significant drivers of the growth and diffusion of solar PV systems is the dramatic reduction in their cost over the last decade. Cost reductions have been occurring over the past few years and will continue over the next decade [14]. According to the International Energy Agency [29], the cost of solar PV installations has fallen by more than 80% since 2010, making it one of the cheapest sources of electricity generation in many regions of the world, including Europe. In regions with good resources and favourable regulatory and institutional frameworks, costs in the range of 20-30 €/MWh already prevail [30]. In addition, the modular nature of PV systems, from small rooftop installations to large-scale solar PV farms, provides flexibility in deployment and affordability, catering for a wide variety of needs and scales. The possibility of decentralised electricity generation with PV systems not only increases energy security but also reduces transmission losses to the power grid. This wide availability and low cost of solar PV electricity determines the high and significant role of solar PV installations as a major resource in the context of the energy transition and accelerates its implementation in the strategy of national energy and climate plans among EU countries.

The traditional building-attached PV systems (BAPV) and ground-mounted monofacial PV systems are increasingly complemented by new PV system technologies. These are bifacial PV systems, building-integrated PV systems (BIPV), and agricultural PV systems, in particular vertical PV systems, are increasing the efficiency, flexibility, and scope of PV systems, making the application area even wider and more significant. These technologies expand the application possibilities of solar PV systems by maximising the use of available space and thus increasing the efficiency of the application. Bifacial PV technology is promising for application in utility-scale PV projects where land utilisation is crucial. In Europe, bifacial PV modules make it possible to generate more power from the same limited area than conventional monofacial PV technology by absorbing sunlight from both sides [31]. In densely populated areas, where BAPV is the default application and BIPV are slowly emerging, both PV systems have become important components of modern energy supply. With the EU's focus on energy efficiency in the building sector, BAPV and BIPV technologies make it possible to meet targets for net zero emission buildings [32] and at the same time increase the sustainability of the urban environment. The dual utilisation of land in agriculture and the use of agrivoltaics increases the overall productivity of agricultural land. In Europe, vertical agrivoltaics installations represent a viable solution to balance the needs between energy and agriculture [33].

The diverse applications of new PV technologies play a crucial role in a sustainable energy transition, making a considerable impact on system reliability and increasing the efficiency of space utilisation. These technologies enable more accurate diagnostics and real-time monitoring of PV system components, minimising downtime and improving overall system stability and reliability. Through the application of new technologies, grid operators gain a better understanding of the characteristics and capabilities of the PV fleet. Improved data collection and forecasting enable smoother integration of solar power into the grid, reducing variability and increasing grid stability. PV is becoming both more predominant, with lower electricity generation costs, and it is also expected to become more diversified in the coming years, with emerging cell technologies enabling higher efficiencies. The described technologies complement conventional PV installations and expand the possibilities of solar PV electricity generation in locations previously considered unsuitable. These technologies not only increase overall PV performance but also reduce the levelized cost of electricity (LCOE) through advancements in system design and operation. The use of predictive maintenance and digital twins for diagnostics further improves reliability and reduces downtime, increasing system availability The integration of these advanced PV technologies in Europe will not only improve the energy yield but also enhance the overall feasibility of achieving high PV penetration in various sectors, supporting the EU's roadmap toward a sustainable, defossilised energy future. In conclusion, new solar PV technologies are a key for realising the goals described above and reducing GHG emissions for all sectors in Europe.

2.2 Methods

The LUT Energy System Transition Model (LUT-ESTM) [13], [15] is applied across an integrated energy system, operating in hourly resolution for a number of power grid interconnected regions, covering the energy demand from the power, heat, transport and industry sectors. The unique features of LUT-ESTM enable cost optimal energy system transition pathways on high levels of geo-spatial and temporal resolutions. Conducting hourly simulations enable the assessment of variable RES and energy demand patterns to explore flexibility solutions, such as dispatchable RE, grids, demand response, storage, and curtailment. This helps determine appropriate system sizing and optimise hourly operations. Furthermore, capabilities of LUT-ESTM to analyse energy systems in an hourly resolution for an entire year enables uncovering crucial insights particularly with respect to storage and flexibility options, most relevant to future energy systems.

2.2.1 Model description

LUT-ESTM uses linear optimisation to determine the optimal energy system with minimum annual costs for each stage of the energy transition. A soft-link sub-model is used to model the transition of prosumer electricity and individual heat supply segments, which takes into account that these segments will have a different target function in the future compared to the centralised energy system. The output of the model is a transition path optimised for a given scenario definition, taking into account factors such as CO_2 emission targets, shares of traditional and renewable sources, technology costs in different transition years, and implementation costs and GHG emissions. Figure 2.2 shows the basics architecture of LUT-ESTM.

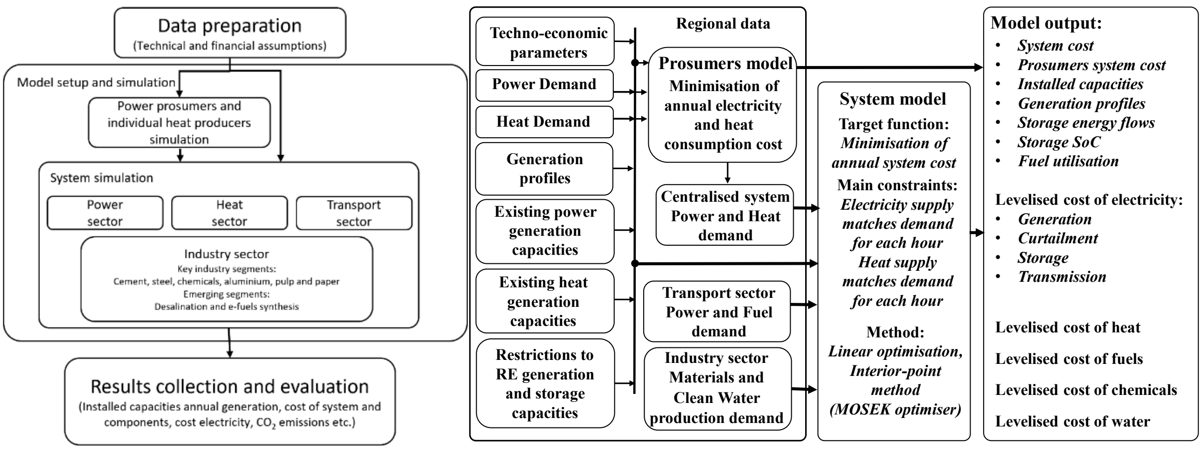

Figure 2.2: Schematic representation of LUT-ESTM (left) and the model flowchart (right).

LUT-ESTM includes a comprehensive list of different generation, storage, energy conversion, and end-use technologies. The model considers capital costs, fixed and variable operating costs, technical life cycles and fuel costs for fossil fuels, biofuels, and imported e-fuels. The primary components of the energy system are illustrated in Figure 2.3.

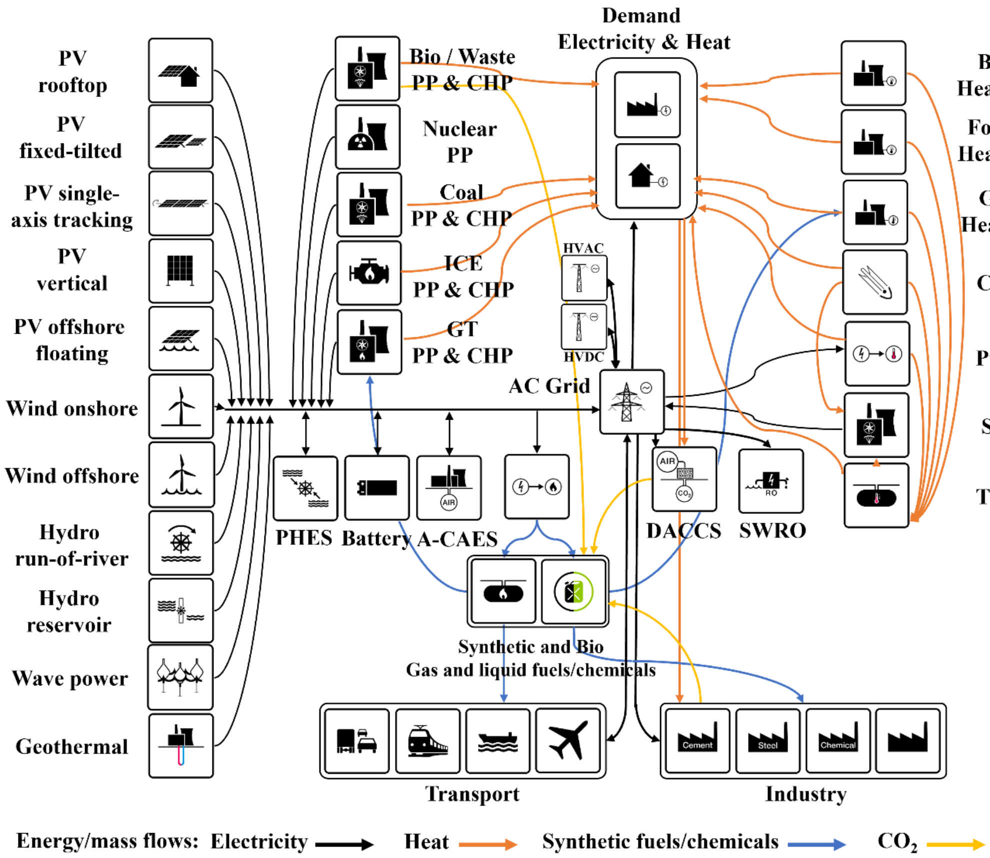

Figure 2.3: Schematic representation of LUT-ESTM.

LUT-ESTM offers a well-established framework for optimising and analysing energy-industry transitions. It enables the testing of various scenarios for shifting from fossil fuel-based systems to RE systems, accounting for technological progress, economic conditions, and environmental considerations. Weather data from 2005 is used as a reference in this study, representing an average resource year for a solar PV and wind power systems in Europe. Due to its extensive list of energy technologies, LUT-ESTM is regarded as one of the most robust tools for analysing long-term energy transition pathways [34]. Simulations within LUT-ESTM follow a two-stage approach. In the first stage, prosumer simulations identify a cost-effective distribution of prosumers across Europe [35], modelling the transition from 2020 to 2050 in five-year intervals.

- <u>**PV technologies CF modelling for the model**</u>

To appropriately quantify the hourly capacity factors (CF) for various PV technologies the hourly CF profiles were modelled based on the weather data form National Aeronautics and Space Administration (NASA) processed by German Aerospace Centre (DLR). Methods of the CF estimation for optimally fixed-tilted and single-axis tracking monofacial PV is described in Afanasyeva et al. [36]. Methods for expansion to optimally fixed-tilted and single-axis tracking, and vertical bifacial PV was developed within this project, by developing a uniform solar PV power plant yield model taking into account the rear side irradiation of bifacial PV based on a detailed yield modelling for shaded and unshaded ground areas and diffuse rear irradiation [37]. This model also includes an approach to optimise the capacity density of solar PV power plants by allowing a 2% higher LCOE for lower row spacing. Additionally, a sophisticated backtracking assessment has been carried out as part of this project for single-axis tracking solar PV power plants, optimising the tilt angle not only based on avoidance of mutual shading, but for a yield and, therefore, cost optimisation [38]. For the yield of BAPV used in prosumers PV modelling, a method has been developed to estimate the yield discrepancy of rooftop solar PV based on fixed-tilted, ground-mounted power plants [39].

- **Prosumer modelling**

Prosumers, who act as both energy suppliers and consumers (for electricity and individual heating), play a crucial role in the integrated energy system [22]. The analysis of the energy system transition includes decentralised self-generation and consumption by residential, commercial, and industrial PV prosumers. This is modelled using a separate sub-model that tracks the development of PV prosumer and battery capacities. PV prosumers have the option to install rooftop solar panels with or without lithium-ion batteries and can also draw power from the grid to meet their energy needs, while having the capability to feed surplus electricity back into the grid [22]. The primary goal for PV prosumers is to minimise their electricity costs, which are calculated as the sum of self-generated electricity, annual system costs, and the cost of grid electricity, minus any income from selling excess electricity. Prosumers also meet their heating needs using a combination of fossil fuel and biofuel boilers, solar thermal collectors, electric heating systems, and heat pumps, depending on what is most suitable for domestic hot water and space heating. Where economically viable, residential thermal energy storage is integrated into the system. Space heating demand varies across Europe based on regional climate and weather conditions, and partial self-supply to power heating systems is considered if it proves cost-effective for prosumers. After determining prosumer adoption levels, the second stage of the process simulates the entire energy system to optimise the energy mix across sectors for cost efficiency at each time step. A separate study has been conducted to assess the role of seasonal hydrogen storage in on- and off-grid residential PV prosumer systems [40].

- **Energy system modelling**

The model incorporates all essential aspects of energy demand across the power, heat, transport, and industry sectors, including non-energetic feedstock for key industries. For each time step, taken in 5-year intervals from 2020 to 2050, it determines the cost-optimal structure and operation of the energy system based on constraints such as power demand, industrial process heat demand, and heating for space and domestic water [41]. The model considers both energy and feedstock requirements for industries like cement, steel, chemicals, pulp and paper, aluminium, and others [15]. A crucial part of the transition is enabling the industry sector to rely entirely on renewable energy and feedstock. Transportation demand is derived across various modes, including road, rail, marine (with inland waterways), and aviation, for both passenger and freight transport. The road segment is further divided into categories such as light duty vehicles (LDVs), two- and three-wheelers (2W/3W), buses for passenger transport, and medium and heavy-duty vehicles (MDVs and HDVs) for freight transport. Demand in other transportation modes is estimated in passenger kilometres (p-km) for passengers and metric ton kilometres (t-km) for freight. Additional details regarding transportation demand, fuel shares, and energy requirements are provided by Khalili et al. [42]. The optimisation aims to minimise the total cost of the energy system.

The energy technologies modelled are:

- electricity generation technologies: RE, fossil, and nuclear technologies;
- heat generation technologies: renewable and fossil;
- energy storage technologies: electricity, heat, gas and CO_2 storage technologies;
- V2G: vehicle-to-grid technology, smart EV charging;
- Power-to-Fuels, Power-to-Chemicals : synthetic e-fuels and e-chemicals production;
- electricity transmission technologies.

A detailed overview of the methodology along with the technical and financial assumptions that are considered in modelling the European power, heat, transport and industry sectors are available in Bogdanov et al. [43]. These are based on the detailed description of the model applied to the global power sector in Bogdanov et al. [44] and all energy sectors in Bogdanov et al. [13], [15].

2.2.2 Scenarios

LUT-ESTM can be applied to generate a wide range of energy scenarios across different regions of the world on a global-local scale. The objective of this study is to explore the possible scenarios for PV development in Europe at the horizon 2050 and how these scenarios translate into national and regional PV penetration increases. These scenarios will look at the possible technologies and segments, including residential, commercial, industrial, and utility-scale PV applications. They will look at innovative and developing system types such as offshore floating PV and agrivoltaics, differentiate between BAPV and BIPV systems, south-facing systems versus east-west facing systems, vertical installations and more. These scenarios will build on the existing available spaces.

Therefore, eight distinct scenarios are envisioned for a sector-coupled energy system combing the power, heat, transport, industry, and desalination demands for the case of Europe and correspondingly the EU, from the current system in 2020 towards cost optimal energy systems with varying features up to 2050. The scenarios include variations in PV technology adoption, the balance between solar PV and other RES, and the role of imported e-fuels in the energy mix. These scenarios are designed to assess the implications of different energy transition strategies, with the goal of identifying the most promising approaches for achieving a carbon-neutral energy system in Europe. Through this analysis, the project aims to provide insights into the optimal pathways for PV integration, ensuring that Europe's energy transition is both sustainable and resilient. The description of each scenario presented in Table 2.2.

Table 2.2: Scenarios description.

Scenario	Description
BPS	**Best Policy Scenario (BPS)**: This scenario assumes a complete phase-out of fossil fuels by 2050, achieving an optimal mix of renewable energy sources. It focuses on local production of e-fuels to meet energy demand, without exceeding the EU's minimum RE targets.
BPS_noBPV	**BPS with Blocked Bifacial PV**: This scenario is similar to the standard BPS, but bifacial PV technology is excluded from the energy mix. The focus is on evaluating the impact of this exclusion on overall PV penetration and the energy supply mix.
BPS_lowPV	**BPS with Reduced PV Share:** This scenario reduces the share of solar PV in the overall energy supply mix compared to the standard BPS. It assesses the implications of relying less on solar PV and compensating with other RES like wind power, hydropower, or bioenergy.
BPS_lowWind	**BPS with Reduced Wind Share**: This scenario decreases the contribution of wind power in the overall supply mix, examining the potential impact on the energy system and the increased reliance on solar PV, along with other renewable and non-renewable sources, to meet energy demand.
BPS_Imports	**BPS with Unlimited e-Fuel Imports**: This scenario allows for unrestricted imports of e-fuels to meet energy demand. It explores the potential for heavy reliance on imported e-fuels and its effects on the domestic RE deployment and energy security.
BPS_Imports50	**BPS with Limited e-Fuel Imports (50%):** This scenario limits e-fuel imports to a maximum of 50% of total demand. The scenario aims to balance local RE supply with a moderate level of imports, analysing how this affects the energy mix and security of supply.

Scenario	Description
BPS_Imports50guided	**BPS with Guided e-Fuel Imports (50%)**: Similar to the BPS_imports50 scenario, but with an additional constraint: imports of specific e-fuels (NH_3, MeOH, LNG, FTL) must meet at least 25% of the demand. This scenario examines the impact of guided import strategies on energy diversity and system stability.
BPS_2040	**Accelerated Transition Scenario (BPS-2040):** This scenario accelerates the transition timeline, completely phasing out fossil fuels by 2040 instead of 2050. It explores the challenges and potential benefits of a faster transition, such as increased renewable deployment, earlier emissions reductions, and technological advancements.

2.2.3 Data and energy resources

The generation profiles for optimally fixed-tilted and single-axis tracking PV, concentrating solar thermal power (CSP), and wind power were determined following the methods outlined in Bogdanov and Breyer [45], with single-axis tracking PV capacity factors derived from the work of Afanasyeva et al. [46]. Hydropower feed-in profiles were calculated using daily water flow data from the year 2005 [47]. The sustainable biomass and waste resource potentials were sourced from Bunzel et al. [48] and categorised into solid wastes (99 TWh), forestry, agriculture, and pulp and paper industry residues (1100 TWh), and biogas (739 TWh). Geothermal energy potential was estimated using the methodology described in Aghahosseini and Breyer [49].

Lower and upper limits were established for RES, including optimally tilted PV, single-axis PV, bifacial PV, CSP, offshore and onshore wind power, wave power, and hydropower, as well as for pumped hydro energy storage (PHES). Lower limits represent the current structure of the energy system and are set for 2020 and 2025. The lower limits for PV technologies, wind power, hydropower, and PHES were determined using data on existing installed capacities across the 20 regions, sourced from the "GlobalData" database, IRENA and IEA-PVPS reports. The lower limits for 2020 and 2025 for key RE technologies are detailed in Table 2.3.

Table 2.3: Renewable resource capacity lower limits for key technologies.

Region	PV [GW_{DC}]		Onshore wind power [GW]		Offshore wind power [GW]		Hydropower [GW]	
	2020	2025	2020	2025	2020	2025	2020	2025
NO	0.16	0.8	2.91	5.1	0.00	0.0	30.73	32.3
DK	1.63	4.2	4.41	4.8	1.70	2.6	0.01	0.0
SE	1.20	4.2	8.48	16.1	0.20	0.2	16.37	16.3
FI	0.31	1.1	2.21	6.9	0.07	0.1	3.16	3.2
BLT	0.38	2.8	0.93	1.8	0.00	0.0	1.57	1.6
PL	3.95	19.0	5.84	9.3	0.00	0.0	0.63	0.6
IBE	16.95	39.1	30.81	36.6	0.00	0.0	20.20	21.1
FR	13.10	24.7	16.41	20.3	0.01	0.5	19.49	19.5
BNL	17.18	39.5	5.97	10.2	2.51	6.2	1.34	1.4
BRI	13.70	20.0	18.10	20.2	9.91	14.8	2.37	2.4

Region	PV [GW$_{DC}$]		Onshore wind power [GW]		Offshore wind power [GW]		Hydropower [GW]	
	2020	2025	2020	2025	2020	2025	2020	2025
DE	53.89	98.1	53.19	61.1	7.55	8.4	4.51	4.9
CRS	2.71	3.8	0.34	0.3	0.00	0.0	4.04	4.1
AUH	4.17	15.2	3.55	4.3	0.00	0.0	9.18	9.3
BKN-W	0.65	3.1	1.29	2.0	0.00	0.0	10.86	11.3
BKN-E	5.77	14.3	7.33	9.0	0.00	0.0	11.74	11.7
IT	21.64	36.0	10.68	12.3	0.00	0.0	15.81	16.2
CH	2.97	7.0	0.08	0.1	0.00	0.0	12.39	12.7
TR	9.65	14.3	7.75	11.9	0.00	0.0	28.50	31.8
UA	7.34	9.8	1.29	1.9	0.00	0.0	5.42	5.4
IS	0.01	0.01	0.00	0.0	0.00	0.0	1.19	2.1

The upper limits for PV and wind power plants are determined by land use constraints and capacity density. PV systems are restricted to a maximum of 6% of the total land area, while wind power plants are limited to 4%. For densely populated areas of Belgium, Netherlands, and Luxemburg the limits are reduced to 4% and 2%, respectively. The capacity densities are set at 75 MW/km² for optimally tilted PV systems for current PV systems, following Breyer et al. [50] and 8.4 MW/km² for onshore wind farms. Offshore wind expansion is controlled following the EC targets. For hydropower it is assumed that nameplate capacity can increase by maximum of 25% due to existing power plants equipment refurbishment and limited introduction of new capacities. A summary of the upper limits for installable capacities across regions in Europe can be found in Table 2.4**.**

Table 2.4: Renewable resource capacity upper limits for key technologies.

Region	PV utility-scale [GW$_{DC}$]	Onshore wind power [GW]	Hydropower [GW]
NO	1457	109	38.4
DK	194	14	0
SE	2026	151	20.5
FI	1522	114	3.9
BLT	788	59	2.0
PL	1407	105	0.8
IBE	2689	201	25.2
FR	2484	185	24.4
BNL	224	13	1.7
BRI	1416	106	3.0
DE	1607	120	5.6
CRS	576	43	5.1

Region	PV utility-scale [GW_{DC}]	Onshore wind power [GW]	Hydropower [GW]
AUH	796	59	11.5
BKN-W	1281	96	13.6
BKN-E	2166	162	14.7
IT	1358	101	19.8
CH	186	14	15.5
TR	3568	266	35.6
UA	2868	214	6.8
IS	464	35	1.4

The installation density for PV is relatively low and considering observed trends in PV modules efficiency improvement the density of the PV utility-scale installations can increase to 120 MW/km² leading to further increase in the upper limit. Higher wind turbines installation is possible but will lead to higher wind shading then considered in wind CF calculations.

2.3 Results

The transition from the current state of the power, heat, transport, and industry sectors in 2020 to an integrated system meeting the EU's energy and raw material needs by 2050 will require significant changes. This study assumes an increase in the rate of sector coupling from 2020 to 2050, leading to a fully integrated energy system by mid-century, with varying improvements in efficiency, import shares, the absence or low share of new PV technologies and wind power technologies, in the scenarios presented. The results section analyses trends in primary and final energy demand, installed capacity, the electricity and heat supply mix, and considers transitions in the power, heat, transport, and industry sectors. It also compares energy costs and CO_2 emissions in the different scenarios and highlights regional differences in Europe.

2.3.1 Primary energy demand

During the transition of Europe energy system from 2020 to 2050 the significant shift toward electrification in primary energy demand (PED) is observed in varying levels and rates. The increasing electrification rate is most evident in the heat, transport, and industry sectors, where electricity demand is rising as more services and applications become reliant on electricity. Affordable solar PV and wind power are key drivers of renewable electricity adoption across these sectors. In 2020, Europe's energy system has a major share of fossil fuels with a modest share of RES. As it is shown in Figure 2.4, the TPED for Europe (including primary energy consumption and non-energy use) in 2020 was 19,212 TWh, composed by fossil fuels 13,463 TWh (69.9%), nuclear energy 2227 TWh (11.5%), and RE contributing more than nuclear energy with 3547 TWh (18.5%). In the BPS, by 2050 the TPED stabilises at around 17,602 TWh, where renewable electricity becoming the primary energy source with 17,166 TWh (97.3%) and nuclear energy 488 TWh (2.1%) covers the rest.

By 2030, a shift towards RE becomes evident, although fossil fuels continue to play a significant role. The scenarios with unlimited, limited and guided imports of e-fuels (BPS_Imports, BPS_Imports50, BPSImports50-guided) show the lowest TPED values of around 16,000 TWh. A maximum TPED of about 18,300 TWh for 2030 and 17,900 for 2040 is observed for the original BPS. By 2040, there is significant defossilisation in most scenarios, with RE supplying a significant part of Europe's energy demand. However, the pace of the transition depends on the scenario. Scenarios with a low share of PV show slower progress in implementation of renewable electricity, with fossil fuels retaining a larger share of the energy mix. On the contrary, the scenario with a low share of wind power shows the highest share of renewable electricity at around 68% in 2040 and 82% in 2050. The scenario in which fossil fuel imports are unlimited (BPS_Imports50) is characterised by a faster rate of defossilisation, with renewable electricity taking up a larger share of the energy supply. e-Fuel imports play an important role in importing scenarios, allowing a more gradual phase-out of fossil fuels and therefore lower TPED.

By 2050, Europe's energy system is almost completely defossilised in all scenarios. The lowest TPED is observed for the scenario with limited e-fuels imports (BPS_imports) and scenario with guided e-fuels import (BPS_Imports_guided) of the order of 14,000 TWh. The highest demand remains the best policy defossilisation scenario till 2050. Despite the possibility of different development pathways, Europe's energy future is characterised by a transition from fossil fuels to a predominantly RE system. The speed of this transition depends on the level of integration of solar PV and wind power technologies, as well as the role of e-fuels imports. However, all scenarios show that a fully renewable and defossilised energy system is achievable by 2050, which is in line with Europe's climate goals.

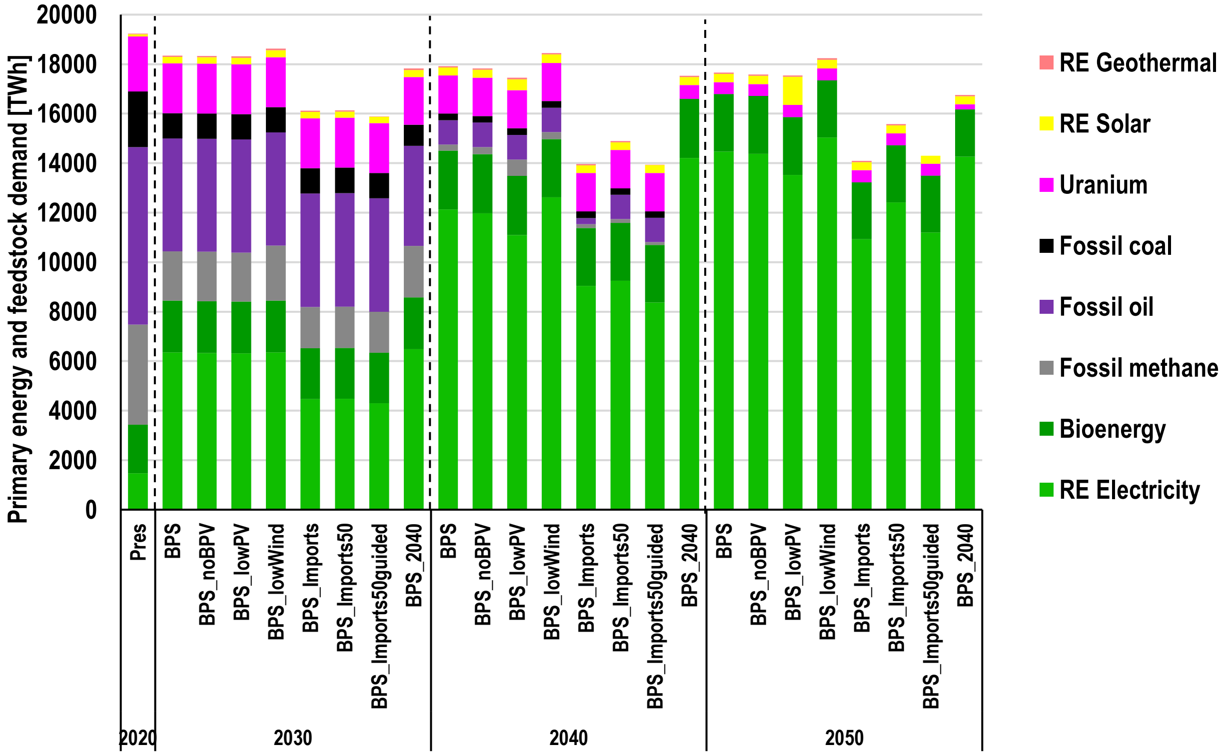

Figure 2.4: Primary energy and feedstock demand in Europe from 2020 to 2050 between all scenarios during the transition.

2.3.2 Final energy demand

Significant improvements in efficiency of the energy system occur during the transition among all scenarios provided in different sectors. Figure 2.5 shows that in 2020 final energy demand is just over 16,000 TWh, with a significant share from transport at 5633 TWh (34%) and heat at 4408 TWh (27%). Between 2030 and 2050, improvements in the efficiency of energy systems could alter the projected growth in demand for transport services and industrial products, leading to lower final energy demand (FED). Over time, by 2050, in all scenarios, FED gradually decreases from 16,370 TWh in BPS to 12,675 TWh in BPS_2040, with shrinking sectoral patterns.

In the different scenarios, the FED decreases slightly compared to 2020, with transport demand decreasing to 3617 TWh in 2040 and in the heat sector to 3889 TWh. This is on account of the high share of electric vehicles in transportation that leads to increased efficiency along with shift towards higher use of electrified rail and less demand. In 2050, the downward trends in FED continue. Notably, in the scenario with accelerated transition, total demand stabilises at a lower level than in the other scenarios, below 13,000 TWh from 2040 onwards. The main trends show that in all scenarios energy demand gradually declines, with transport and heat leading the sectoral decline. Industrial energy demand remains stable in all scenarios and there is a slight increase from 3774 TWh to 3934 TWh. In 2050 it is the industry sector that dominates, while the other sectors are more evenly balanced.

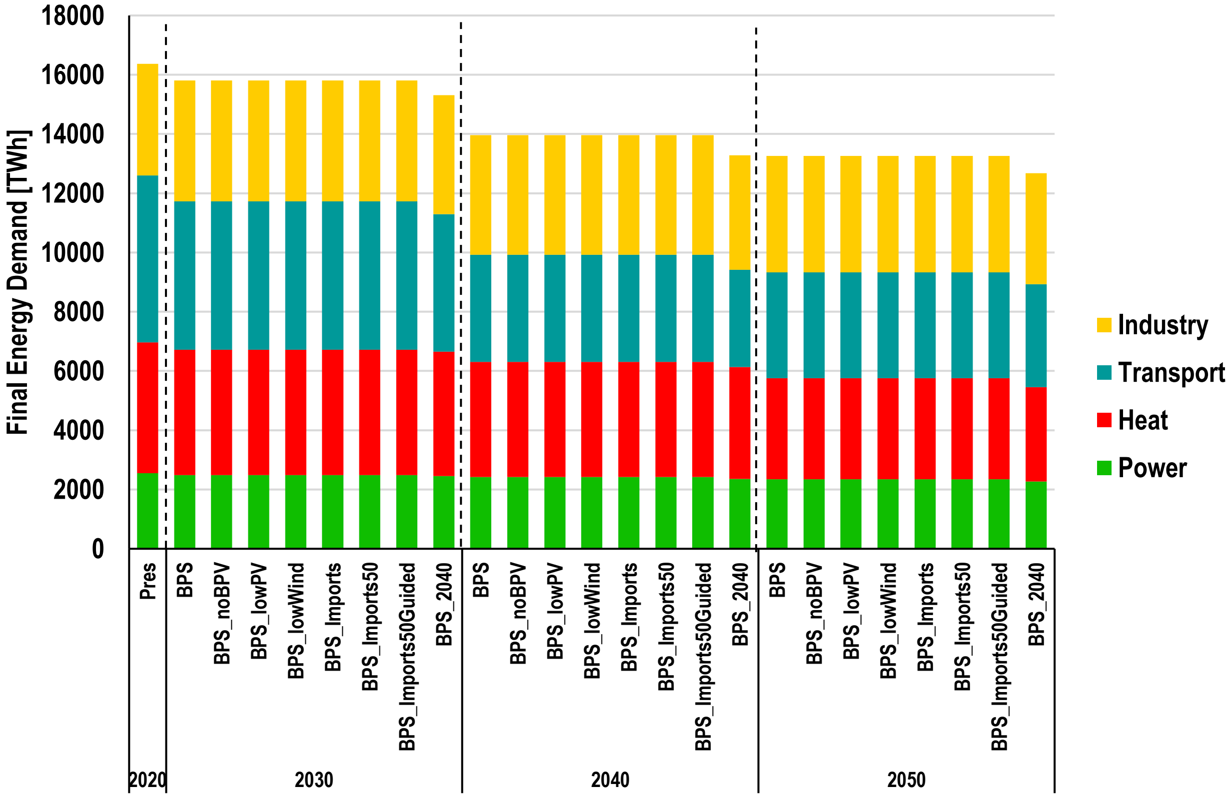

Figure 2.5: Final energy demand by sector across all scenarios during the transition on Europe.

2.3.3 Electricity supply

The energy system in Europe is currently on the right course for the transition. In 2022, RE accounted for 42% of gross electricity consumption. This trend is maintained in all scenarios with different levels of renewable electricity generation, as shown in Figure 2.6.

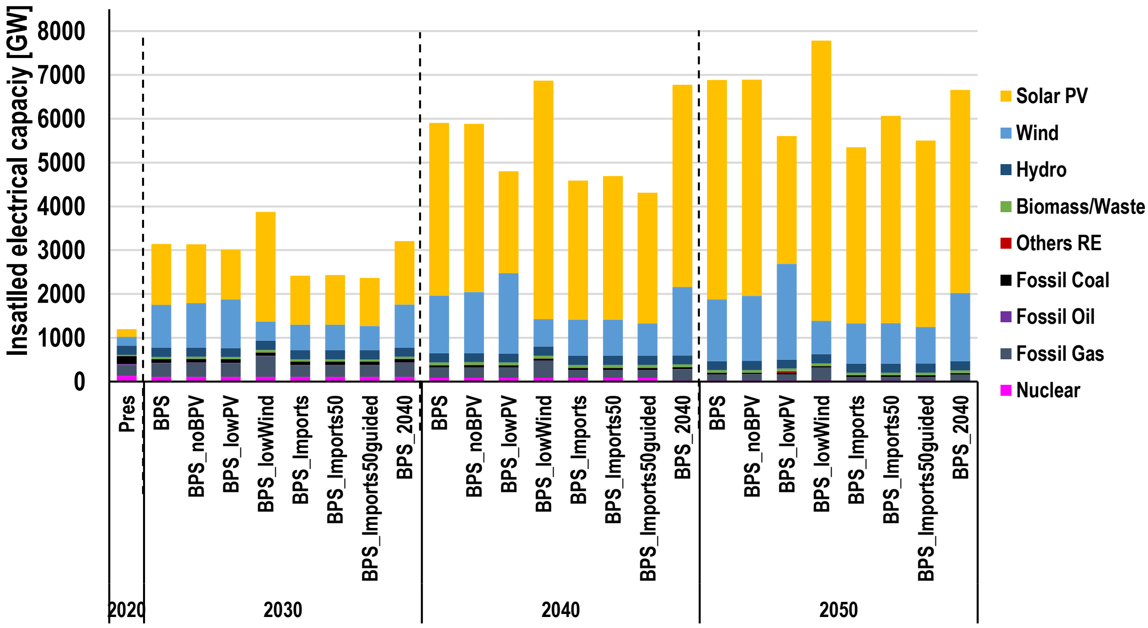

Figure 2.6: Installed electricity generation capacities for all scenarios during the transition.

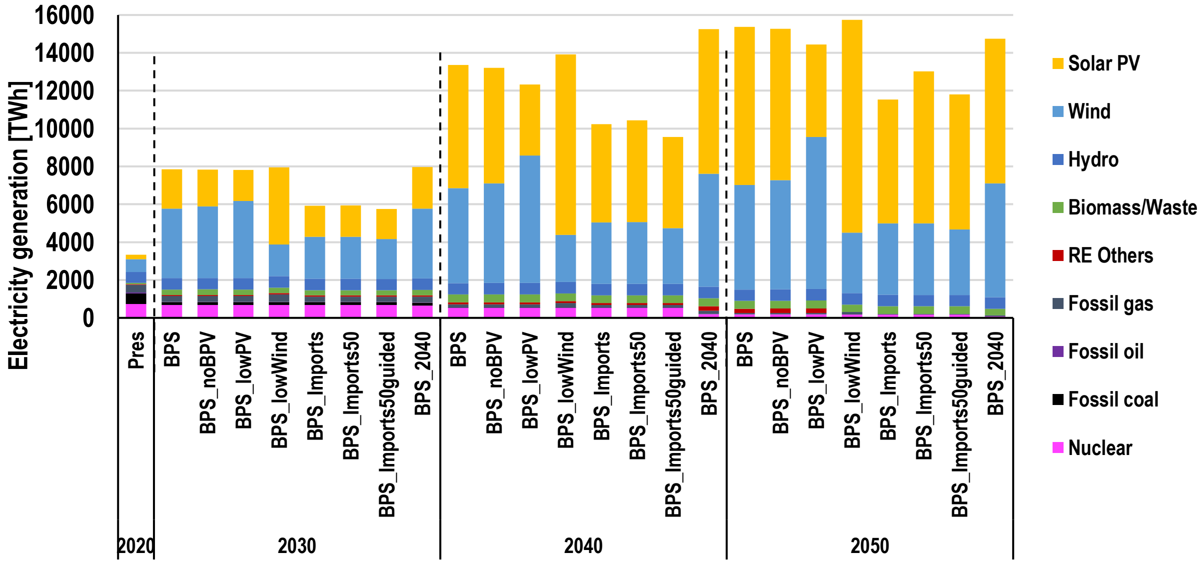

Figure 2.7: Electricity generation for all scenarios during the transition.

The increase in the electrification level leads to an increase in electricity generation by almost 5 times by 2050 compared to 2020 in all scenarios. The leading scenario in terms of electricity generation is the scenario with reduced wind power share, with a generation of 15,999 TWh in 2050 (see Figure 2.7). In the BPS_lowPV and BPS_Imports, RE capacity grows more slowly at around 4500 GW over 30 years and renewable electricity generation reaches over 10,000 TWh by 2050.

In the accelerated scenario, the rapid growth of RE capacity of more than 5,500 GW provides 15,000 TWh of electricity generation by 2050, where solar PV accounts for the largest share at 7635 TWh (51%). The low wind scenario shows the second highest capacity growth (over 6500 GW), providing 100% renewable electricity, totalling almost 16,000 TWh in 2050. Wind power is the main source of electricity generation in the scenario with low share of PV technologies, while solar PV becomes the main source from 2040 in the low wind scenario due to its higher cost competitiveness. In 2050, solar PV provides more than 55% of electricity in all scenarios except the scenario with low PV share. The BPV installation constraint has little effect on the capacity growth rate of solar plants. For example, in 2050, the difference in installed capacity and electricity production between the BPS and BPS_noBPV is minimal, 6885 GW in the BPS and 6890 GW in the BPS_noBPV.

Scenarios that allow for limited or unlimited imports of e-fuels show smaller amounts of installed capacity and hence electricity generation. The use of solar PV also contributes to an efficient energy system in Europe, as electricity is generated close to consumption locations, reducing transmission and distribution losses.

Nuclear power is phased out in all scenarios by 2050, except for the accelerated scenario where it ceases to operate by 2040. Nuclear power plants continue to operate until the end of their technical lifetime, providing a small fraction of electricity in 2050. However, nuclear power is recognised in all scenarios as being uncompetitive compared to low-cost renewable electricity and poses significant environmental and social risks, which are well documented in Europe and worldwide [51].

A high share of RE in all scenarios is observed due to the significant role of electricity storage technologies. Figure 2.8 and Figure 2.9 illustrate the installed capacities and throughputs of electricity storage. In 2020, the installed capacity of electricity storage is about 397 GWh, mainly due to PHES. The changes in the capacities are gradual for all scenarios. To ensure uninterrupted power supply in all scenarios, the role of storage becomes crucial. From 2040 onwards, the share of battery prosumers and vehicle-to-grid (V2G) technologies increases for each scenario to 840 GWh (21%) and almost 2500 GWh (65%) respectively. Electricity storage capacity will grow as an integral part of a sustainable transition to regulate electricity distribution. By 2050, installed capacity increases almost 19 times to about 7470 GWh, with the largest share in V2G batteries reaching 5670 GWh (76%).

As installed capacity increases, electricity storage output also follows. As shown in Figure 2.9, electricity storage output for most scenarios increases gradually and reaches a maximum of 1392 TWh by 2050 in the scenario with limited imports of e-fuels, with a significant contribution from battery prosumers of 1025 TWh. Battery prosumers are the main resource of electricity storage output and account for between 70% and 90% in each scenario. The lowest output in the scenarios with low PV share is 1097 TWh.

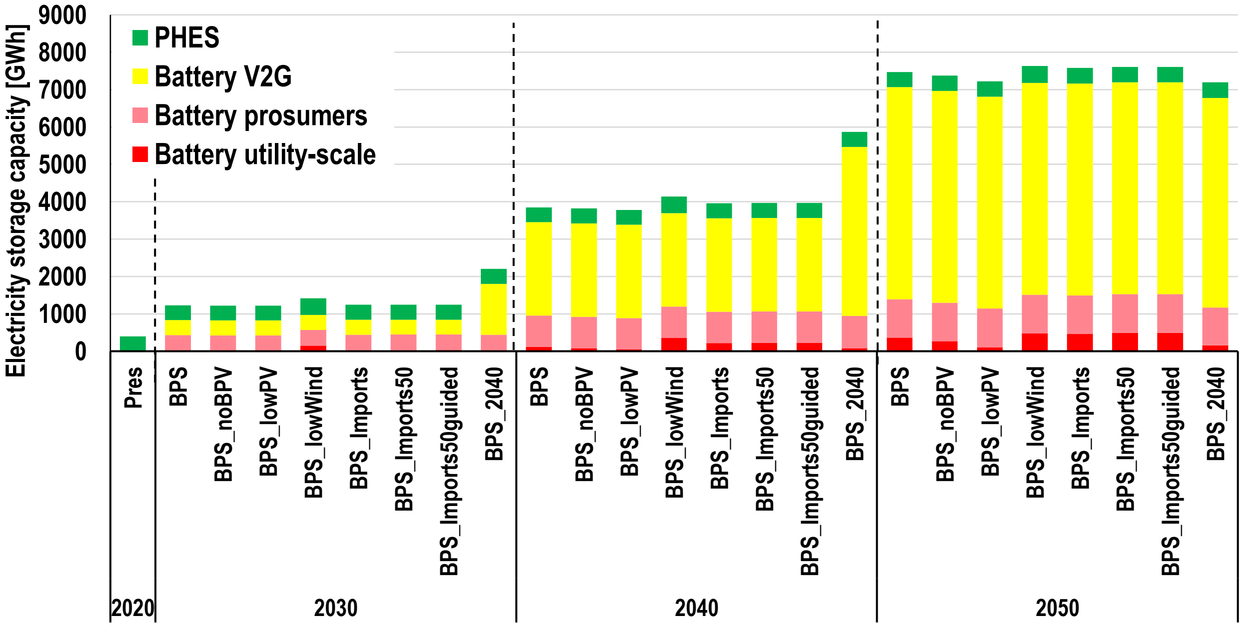

Figure 2.8: Electricity storage capacity for all scenarios during the transition.

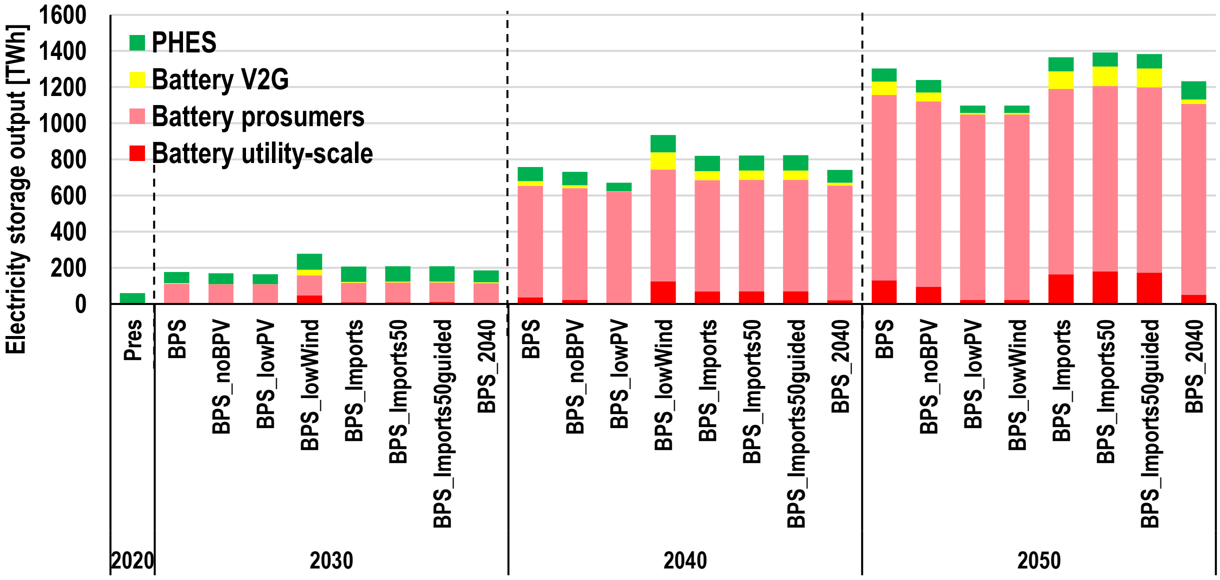

Figure 2.9: Electricity storage output for all scenarios during the transition.

2.3.4 Heat supply

Heat is a crucial energy source for Europe, primarily utilised for space heating and domestic hot water. In 2020, approximately 30% of the heat supply was generated from RES, predominantly bioenergy, while fossil gas remained the dominant contributor, accounting for over 40% (see Figure 2.10). The use of direct electric heating and heat pumps is increasing across many European countries due to their significant efficiency advantages and cost-effective alternatives to imported fossil gas. Starting in 2030, across all scenarios, the share of fossil gas in heat generation capacity is reduced by more than half, while the capacity of heat pumps grows steadily from 27.4 GW in 2020 to 470 GW by 2050. By 2050, fossil-based fuels are completely phased out and heat pumps become the primary source of heat generation, contributing 53% of the total capacity.

In all scenarios, heat pumps combined with electric heating dominate heat generation by 2050. A diminishing share of bioenergy, which fully transitions to waste and residual biomass, continues to contribute to heat production alongside recovered heat. Conversely, fossil fuel-based heat generation declines rapidly across all scenarios and reaches zero by 2040 (see Figure 2.11). The fastest reduction is observed in the scenario with guided import, where the share of fossil fuel-based heat becomes almost negligible by 2030, at around 4%. However, in this scenario, the total heat generation capacity is the lowest among the scenarios.

These findings indicate that the heat sector is transitioning towards a higher reliance on heat pumps and electric heating, supplemented by waste and residual biomass-based heat, alongside efficiency improvements, increased renovation rates, and the integration of recovered heat. The widespread adoption of these technologies across Europe has the potential to significantly reduce the dependency on imported fossil gas, particularly from Russia, and create pathways toward greater energy independence.

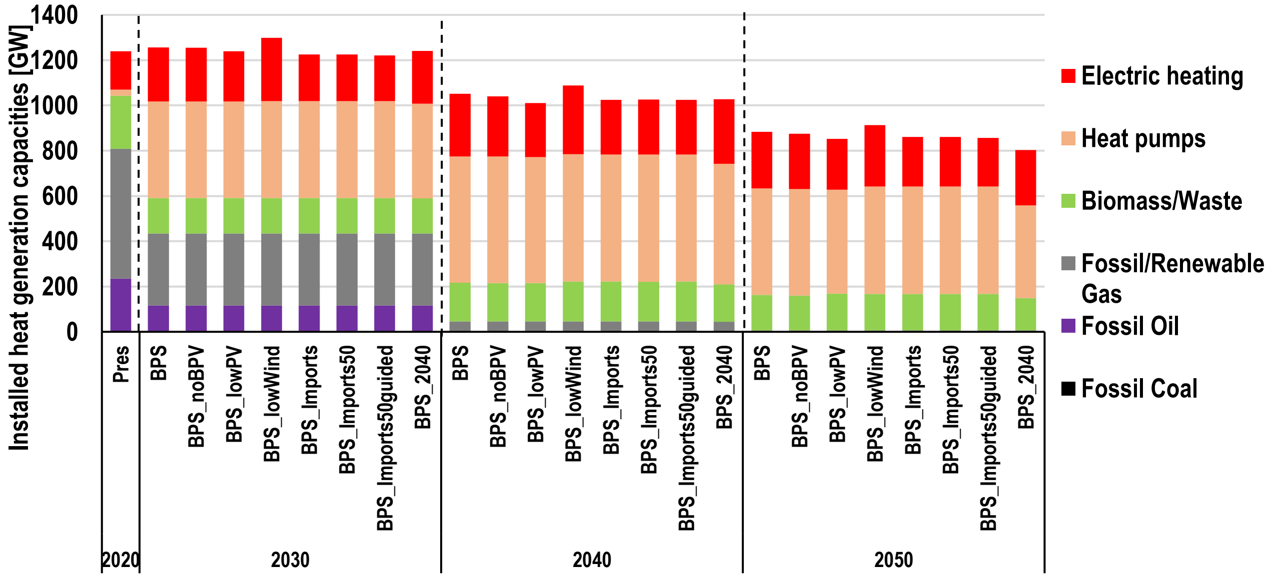

Figure 2.10: Installed heat generation capacities in all scenarios during the transition.

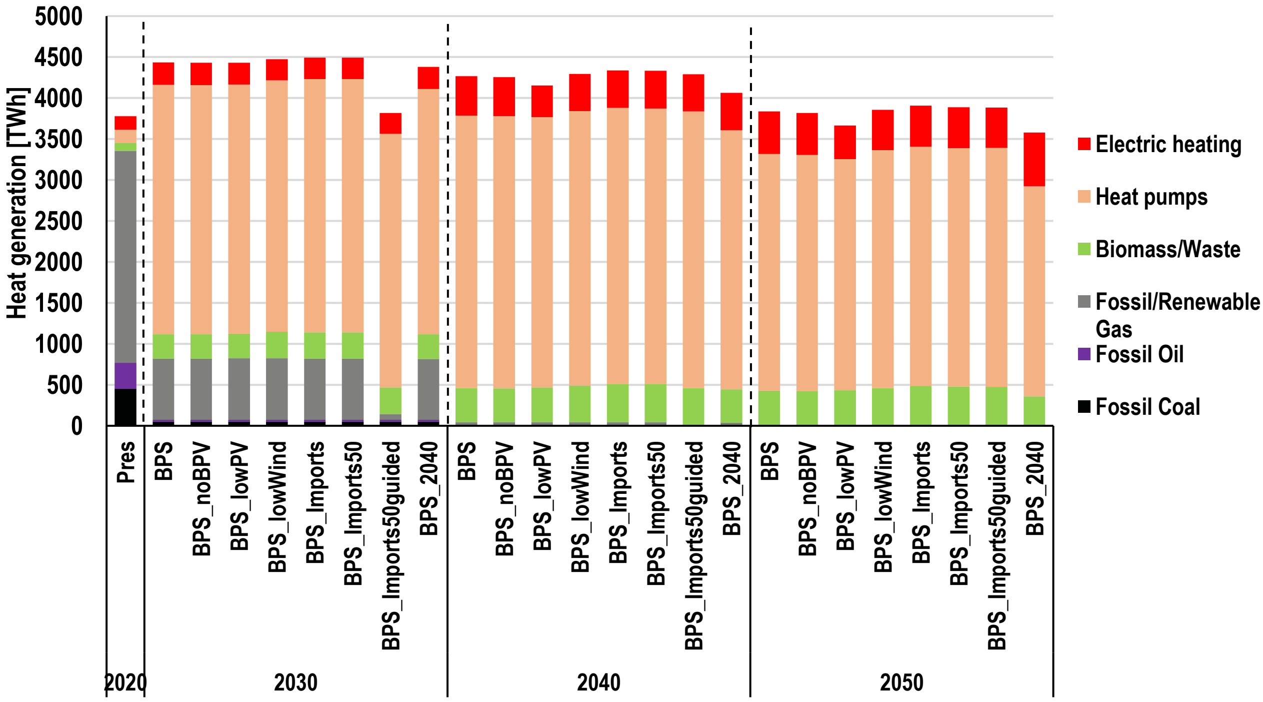

Figure 2.11: Heat generation mix in all scenarios during the transition.

Starting in 2020, the total storage capacity is low, dominated by a small fraction of methane-based storage. During the transition a major share of the heat storage is provided by renewables-based hydrogen storage across the scenarios (see Figure 2.12). The methane and hydrogen storage can be discharged to provide fuel for heating, running power plants, buffering hydrogen for e-fuels production, or provide feedstock for industry. The scenario with low wind power technologies stands out with the largest increase in storage capacity, reaching almost 88,000 GWh in 2050, where the hydrogen storage share is more than 60% and methane storage on a second place with 39%. On the other hand, in scenarios with unlimited fuels exports shows the lowest growth in heat storage capacities among all scenarios, with a maximum capacity around 26,700 GWh.

Heat storage output is also changing during the transition. Starting with a low output in 2020 it reaches about 3000 TWh in 2050 for the scenario with reduced wind share (see Figure 2.13). This substantial rise indicates the growing importance of hydrogen as a key contributor to heat storage systems. Similar to the heat storage capacity trend, the scenario with low wind power technologies shows a performance in heat output in 2040 and 2050 with a heat output from hydrogen around 2035 TWh and 2376 TWh, respectively. Scenarios with absence of bifacial PV and low share of PV technologies present relatively lower outputs, indicating slower heat generation advancements. Hydrogen becomes a crucial part of the energy transition, as seen from its dominant role in storage capacity and output. While thermal energy storage (TES), both high temperature (HT) as well as district heating (DH) provide significant shares in the later stages of the transition, the consistency in TES DH and TES HT systems indicates that they will continue to play a supportive role in heat generation.

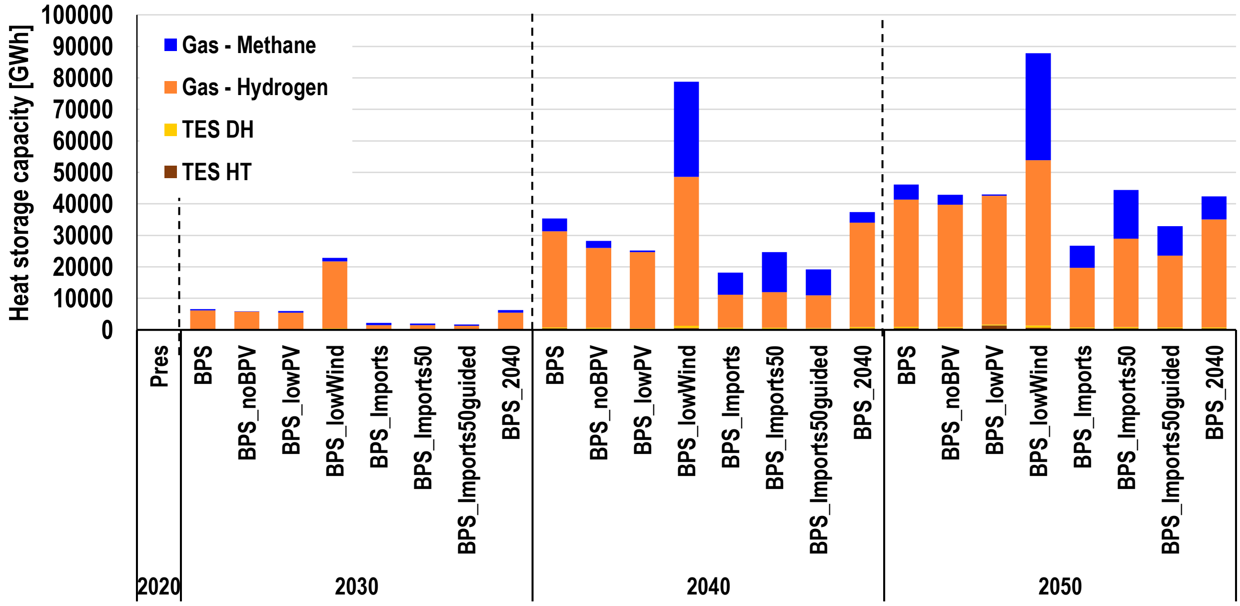

Figure 2.12: Heat storage capacity in all scenarios during the transition.

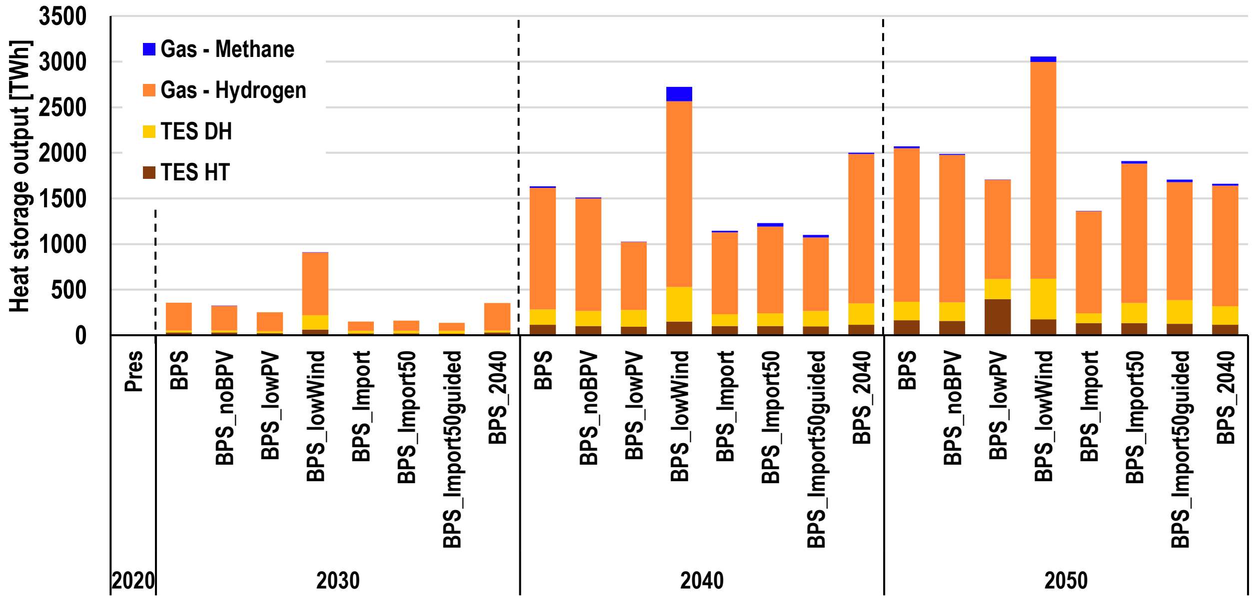

Figure 2.13: Heat storage output in all scenarios during the transition.

2.3.5 Transport and industry

The transport sector across Europe is undergoing some significant changes: electrification, digitalisation, automation, modal shifts, and the sharing economy are fast transforming transport services. Figure 2.14 illustrates the FED for transport across various transport segments, including road transport passenger and freight, aviation freight, aviation passenger, marine freight, marine passenger, rail freight, and rail passenger. In 2020, the energy demand is dominated by road, both freight (1656 TWh) and passenger (2653 TWh) followed by marine freight (612 TWh) and aviation passenger (612 TWh). Road transportation has a high level of direct and rapid electrification in the accelerated scenario till 2040. The FED for road passenger and freight transport declines significantly through the transition across the scenarios. Aviation freight and passenger transport continue to consume the largest share of energy across all scenarios, indicating that air transport remains energy intensive.

The contrasting trends in the development of the FED are because of the level of direct electrification possible in the different transport modes as well as the modal shifts mainly towards electrified rail. Aviation transport, mainly passenger, has a growing FED across the scenarios from 612 TWh in 2020 to 1286 TWh and 1190 TWh (BPS_2040) by 2050, as additional electricity is required to produce renewable e-fuels. Aviation remains the most energy-intensive mode of transport across all scenarios, with relatively slow declines in energy demand, reflecting the challenges of defossilising this sector. Marine transport and freight have small shares in energy demand for transport, indicating stable but limited contribution to overall transport energy needs.

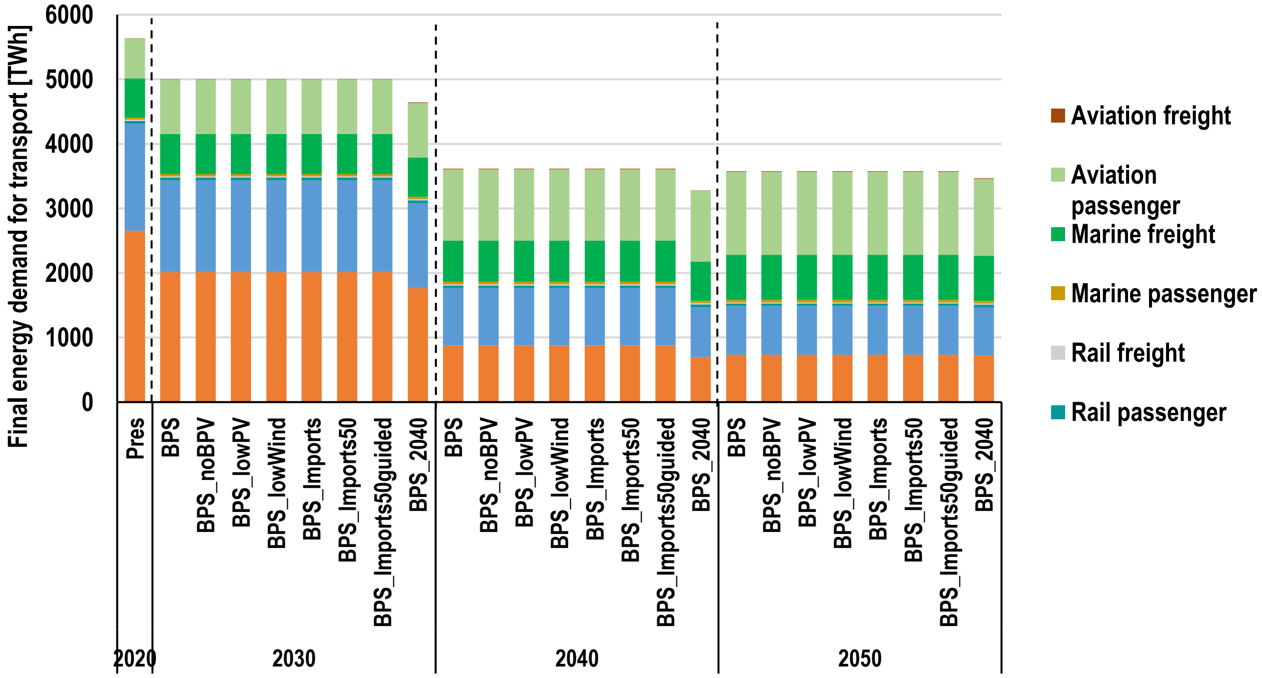

Figure 2.14: Final energy demand for transport across all scenarios from 2020 to 2050.

The European industry sector plays a crucial role in the economies of its member states. However, many of these industries are energy-intensive and significant contributors to CO_2 emissions, primarily because fossil fuels are their main source of energy and raw materials. As energy sources and technological processes evolve, these industries are advancing towards a new stage of development. Over time, in all scenarios, they are expected to reduce their reliance on fossil fuels.

This transition is accompanied by an increase in energy demand in the chemical industry, as illustrated in Figure 2.15. By 2030, energy and feedstock demand in the chemical industry is projected to reach 1839 TWh in scenarios without e-fuel imports and 1665 TWh in the scenario with e-fuel imports. The chemical industry's share of total energy demand in 2030 ranges from 40% in scenarios with e-fuel imports to 43% in those without. This shift presents an opportunity for the chemical industry to pursue more sustainable development by transitioning from fossil fuels to RES for chemicals production. By 2050, two key chemicals, ammonia and methanol, are expected to serve as primary feedstocks for the chemical industry [52]. The chemical industry will require substantial energy inputs, particularly to produce e-hydrogen, enabling a shift towards sustainable chemical production.

By 2050, total energy demand across all industries is expected to rise slightly compared to the 2020 baseline. The most significant reductions in energy demand are anticipated in the steel industry, where processes will become increasingly electrified. In all scenarios, the steel industry's energy demand is projected to decrease by nearly 2.5 times, from 938 TWh to 385 TWh. Meanwhile, energy demand in the pulp and paper, aluminium, and other industries is expected to remain stable throughout the transition period across the scenarios.

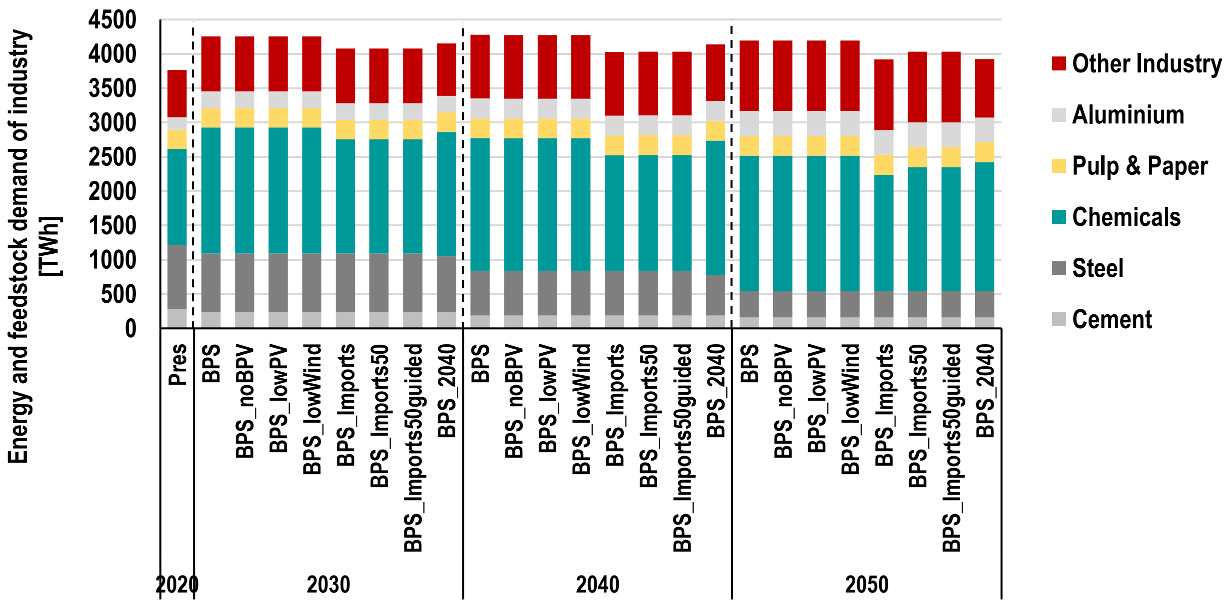

Figure 2.15: Energy and feedstock for the key industries across the scenarios from 2020 to 2050.

2.3.6 Sector coupling and flexibility in the energy system

Sectoral integration can be a cost-effective key enabler of GHG reductions in the European energy system by assessing the potential for synergies and integration between different uses, applications, and sectors. The impact of sectoral coupling is illustrated in Figure 2.17, which shows the energy flows in the European energy system in 2050 for the accelerated scenario. It is compared to the current European energy system in 2020, which is rather sector decoupled as shown in Figure 2.16.

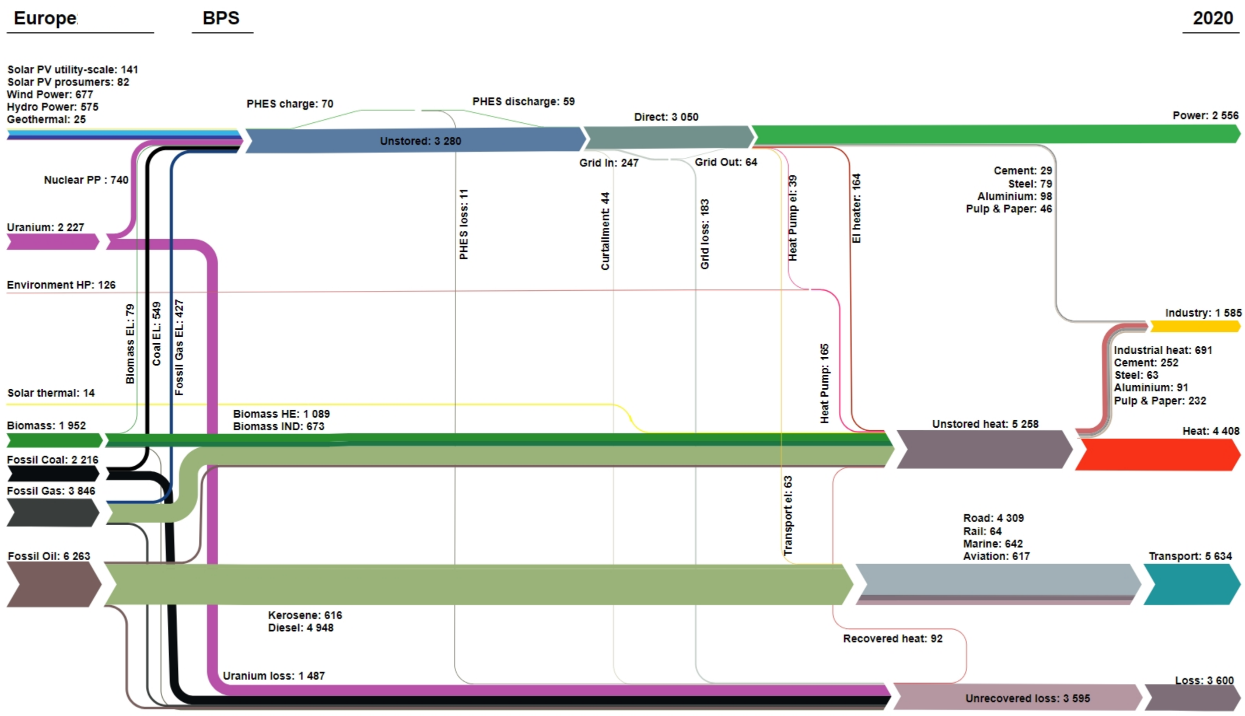

Figure 2.16: Energy flows of the European energy system in 2020.

The current energy system is based on centralised supply and is predominantly decoupled, contributing to the dominance of fossil fuels and nuclear power as the main sources. Energy flows in the European energy system in 2020, according to Figure 2.16, are characterised by high resource intensity and inefficiency, with large energy losses at the end-use stage, and even more significant when converting final energy into energy services, especially in the transport sector. The power sector has the greatest diversity of energy sources, while transport, especially road, aviation and maritime transportation, is the least diversified sector and almost entirely dependent on fossil fuels. The heat sector is partially diversified but still relies heavily on fossil gas. This emphasises that the current European energy system is fundamentally less diversified, divided, inflexible, and highly dependent on energy imports. However, recent changes in the power sector and the development of affordable renewable electricity as a key resource have outlined a shift towards a more decentralised, flexible, and demand-driven system linked to different sectors.

The BPS leads to a fully coupled and integrated energy system in 2050 (see Figure 2.17). This integrated energy system characterises high diversification of power, heat, transport, and industry sectors. The energy system is dominated by solar PV utility-scale and wind power, contributing 7378 TWh and 5527 TWh, respectively. Solar PV prosumers add 954 TWh once again emphasising its significant role in the structure of the energy mix. The energy system receives substantial flexibility from large electrolyser capacities producing 7979 TWh of hydrogen, which is stored and used for various industrial and power applications. This includes 89 TWh of H_2 storage and 195 TWh of hydrogen-to-power conversions. Hydrogen is also crucial in industry, with 55 TWh used for steel production and 792 TWh of ammonia and 1638 TWh of methanol supplied to industrial processes. Additionally, 294 TWh of ammonia and 33 TWh of methanol are directed towards transportation use. The high flexibility of electrolysers enables the efficient uptake of variable electricity generation from solar PV and wind power, which along with V2G effectively reduces the demand for electricity storage.

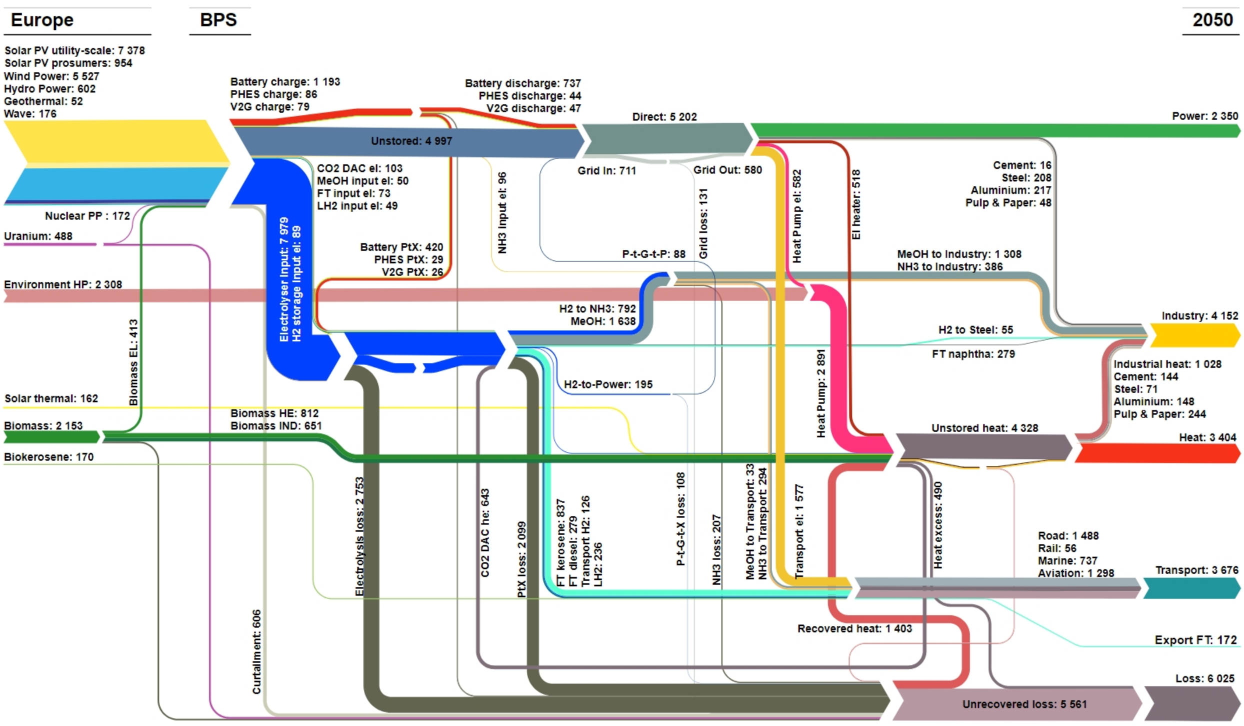

Figure 2.17: Energy flows of the European energy system in 2050 for the BPS.

2.3.7 Regional outlook

Europe, with its characteristic developed energy structure uniting different countries, is one of the most interconnected regions in the world. In terms of RES, Europe shows a good balance: the northern and western regions (including the United Kingdom and Ireland) [53] have significant wind energy potential, which is harmoniously complemented by a high solar energy potential in the southern EU countries and Turkey [54]. Other RES are also evenly distributed across the continent, influencing the energy balance of different countries and regions. The accelerated transition scenario up to 2040, combining ambitious goals with a realistic approach to achieving the European climate targets, is thoroughly analysed with consideration of regional specifics.

Electricity generation capacities are installed across Europe satisfying the energy demand from power, heat, transport, and industry up to 2050. PV utility-scale is the largest electricity generation source across most European regions, especially in Southern Europe, and Turkey, due to favourable solar conditions. While onshore and offshore wind power also represent significant shares, particularly in Northern Europe and coastal regions (see Figure 2.18 and Figure 2.19).

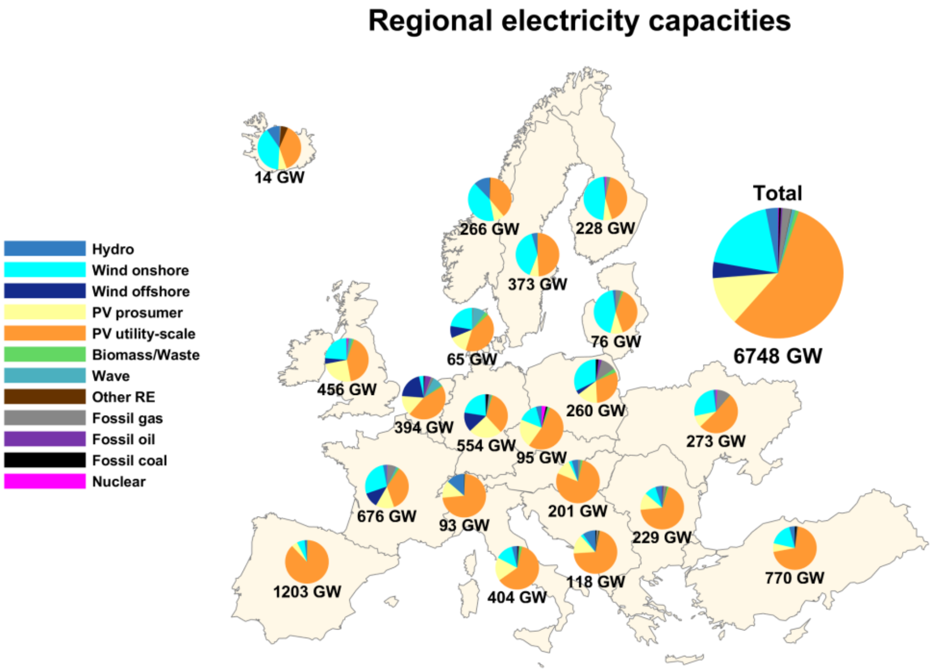

Figure 2.18: Regional electricity generation capacities in 2050 across Europe in the BPS-2040.

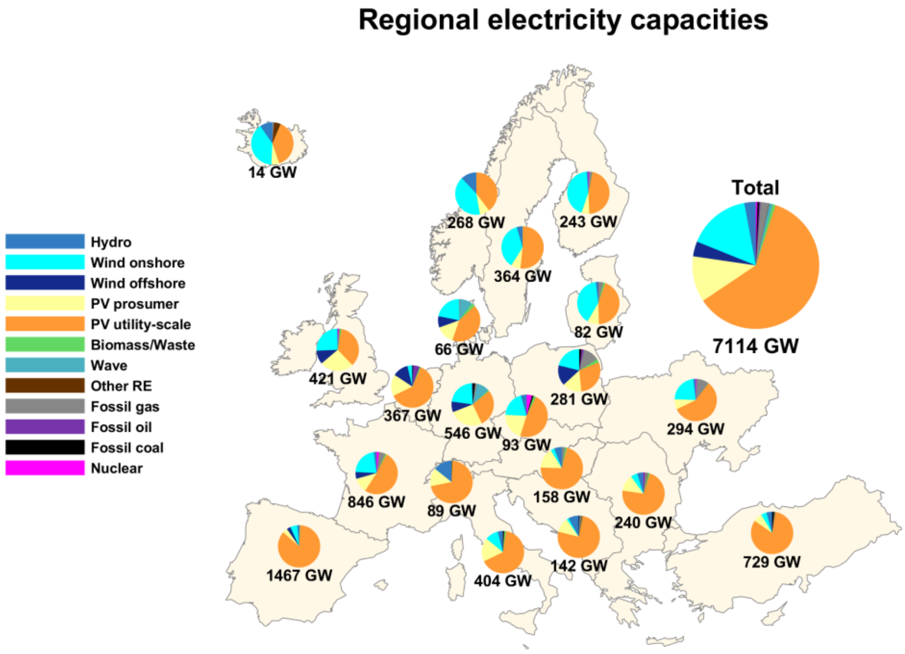

Figure 2.19: Regional electricity generation capacities in 2050 across Europe in the BPS.

In the BPS-2040, the majority of the installed capacity in Europe by 2050—totalling 6748 GW—will come from PV and wind power, alongside some contributions from hydropower and wave power. As the BPS-2040 is on a more progressive pathway, achieving 100% RE by 2040 leads to additional capacities, powering the production of e-fuels and e-chemicals until 2050. For the standard BPS total installed capacities also will come from PV and wind power, in total 7114 GW.

Similar to electricity generation capacities, a higher share of generation from wind power is found in the northern and western European countries (see Figure 2.20 and Figure 2.21), while a higher share of solar PV generation is concentrated in the southern countries. Solar PV prosumers do contribute significant shares across Europe and complement utility-scale solar PV generation. This can enhance the complementarity of solar PV and wind power in the interconnected European energy system. In the accelerated scenario for 2050, electricity generation in the European power, heat, transport, and industry sectors is predominantly from solar PV and wind power. The share of solar PV provides more than 50% of electricity across Europe, while the share of wind power accounts for an average of 40% in the accelerated scenario. In the standard BPS the share of solar PV gets higher and provides up to 55% of the electricity generated. The total electricity generation in 2050 for this accelerated scenario is projected to be 14,889 TWh and for the standard BPS 15,295 TWh.

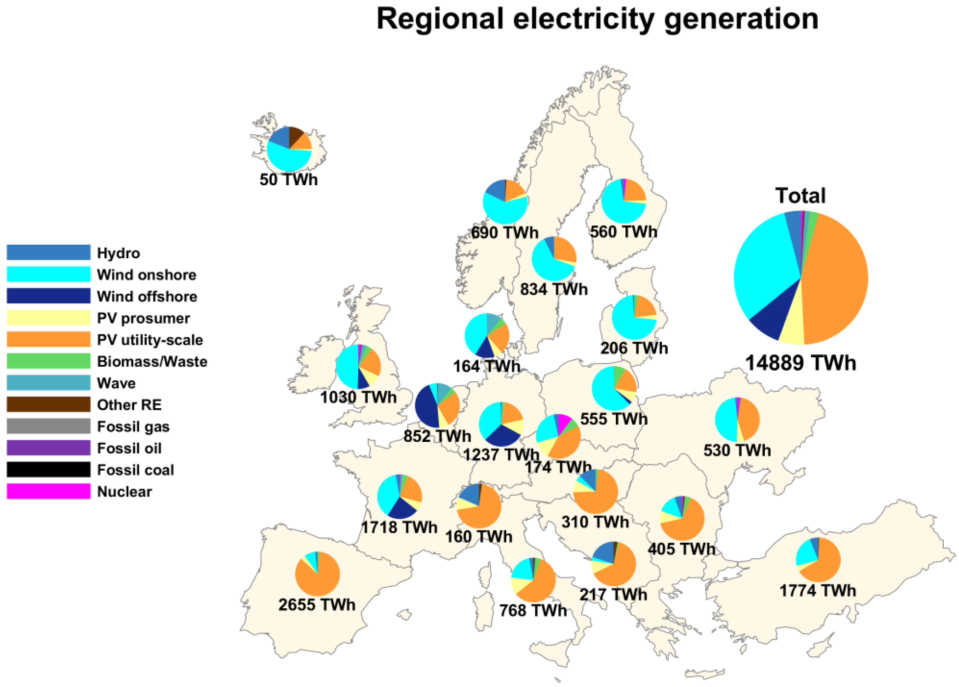

Figure 2.20: Regional electricity generation in 2050 across Europe in the BPS-2040.

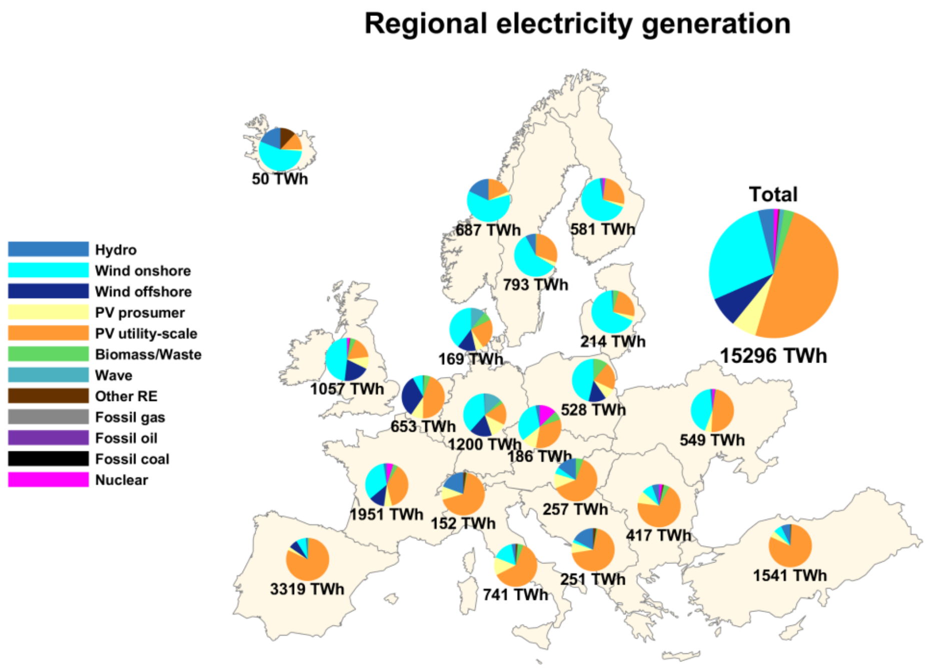

Figure 2.21: Regional electricity generation in 2050 across Europe in the BPS.

During the transition, the heating demand in Europe shifts towards a dominance of heat pumps, combined with electric heating and waste and biomass heating (see Figure 2.22), while the consumption of fossil sources, mainly gas, gradually decreases and becomes almost non-existent by 2050. The total heating capacity in Europe for the accelerated transition scenario by 2040 is projected to be 921 GW in 2050 and for the standard BPS it reaches 991GW. Electric heating capacity is evenly distributed across Europe. Heat pumps will be the main heating technology in Europe by 2050, especially in Ireland, where the share of heat from heat pumps exceeds 90%. However, in regions such as the Nordics and the Balkan, the majority of the heating capacity will come from electric heating.

Heat production in Europe largely meets the demand for domestic hot water, space heating, and industrial process heat through heat generation from heat pumps. In the accelerated transition scenario for 2050, the total heat generation is projected to reach 3979 TWh and 4219 TWh for the standard BPS. Heat pumps, in combination with electric heating, dominate heat generation in western, central, and southern European countries, while heating from waste and biomass residues plays a significant role in eastern and northern European countries (see Figure 2.23 and Figure 2.24). In southern European countries, the contribution of solar heat is minimal. The leading countries in terms of heat production from heat pumps are Norway, the United Kingdom, and Ireland, where over 90% of heat is produced by heat pumps.

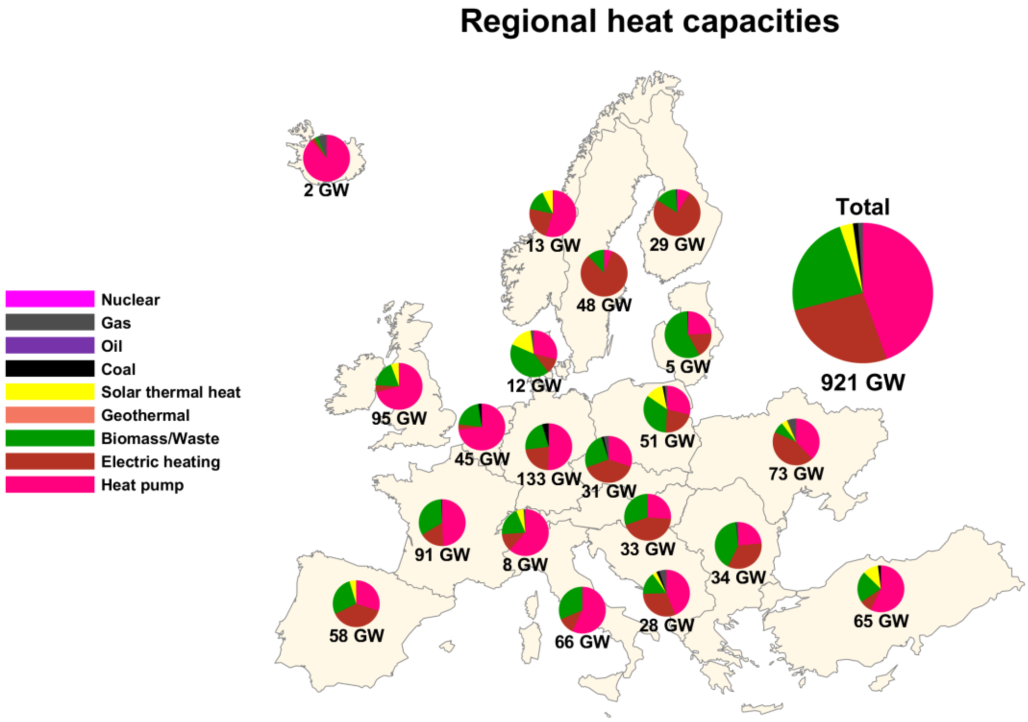

Figure 2.22: Regional heat generation capacities in 2050 across Europe in the BPS-2040.

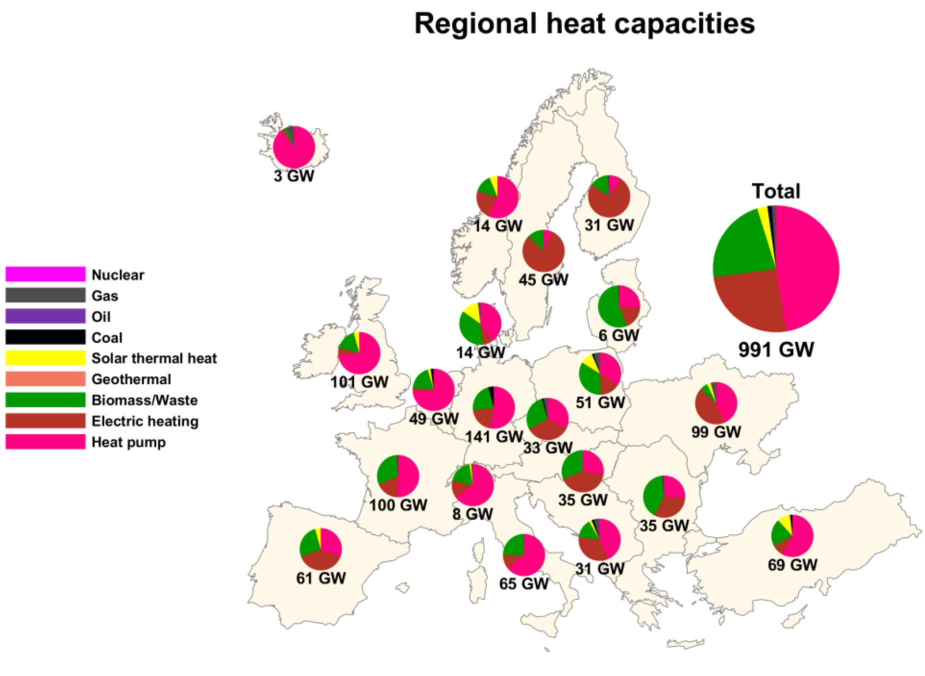

Figure 2.23: Regional heat generation capacities in 2050 across Europe in the BPS.

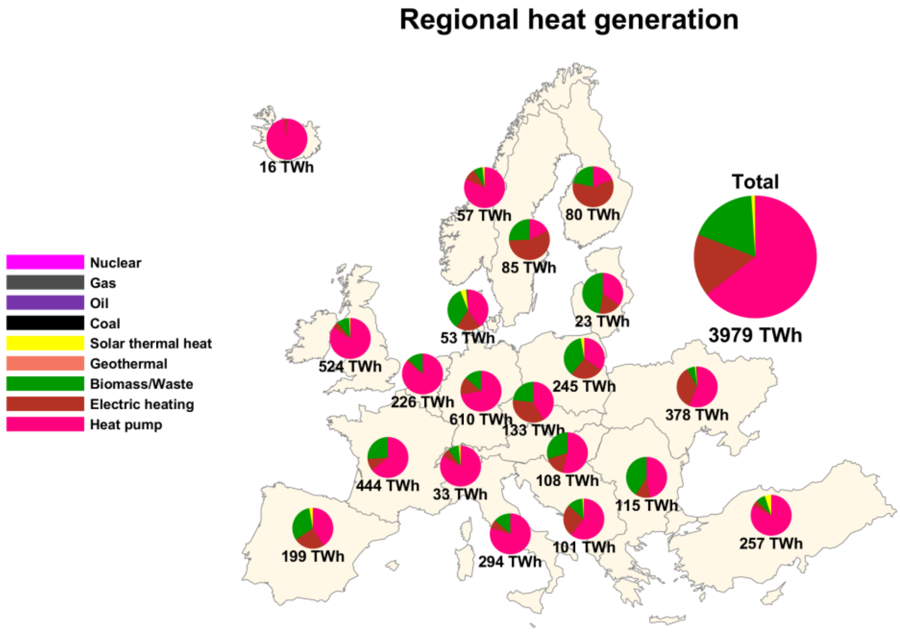

Figure 2.24: Regional heat supply in 2050 across Europe in the BPS-2040.

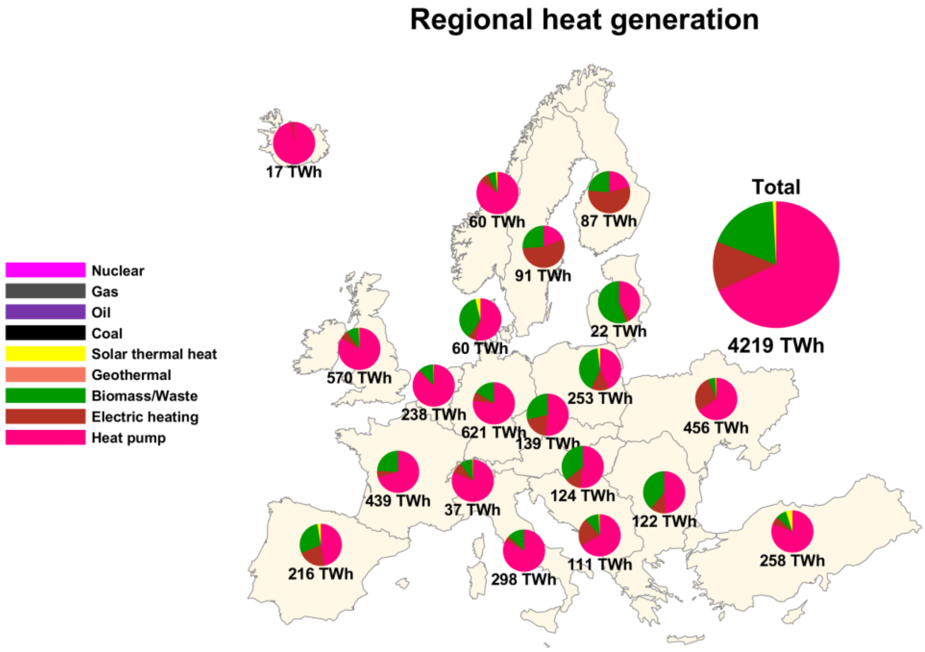

Figure 2.25: Regional heat supply in 2050 across Europe in the BPS-2040.

In 2050, batteries, including utility-scale, residential, commercial, and industrial prosumers, will be employed for energy storage across the integrated power, heat, transport, and industry sectors in Europe. PHES ranks second in terms of electricity supply. Prosumer batteries, which constitute the majority of Europe's storage capacity, have a higher share in southern countries. In the BPS-2040, the total electricity storage annual output in Europe is projected to be 1232 TWh by 2050, and for the BPS it is projected to be 1276 TWh, with most of the capacity concentrated in central and southern countries (see Figure 2.26 and Figure 2.27).

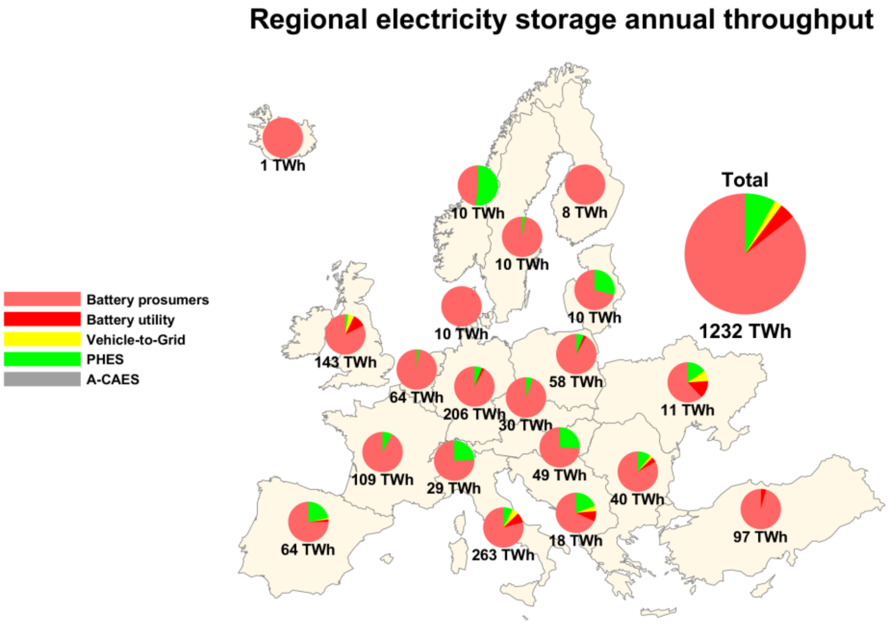

Figure 2.26: Regional electricity storage output in 2050 across Europe in the BPS-2040.

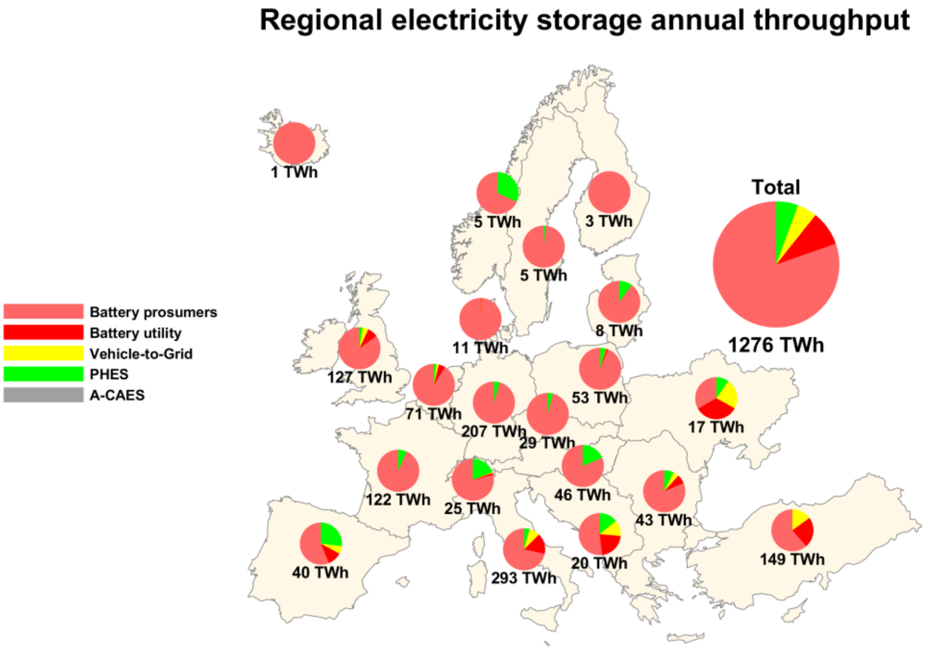

Figure 2.27: Regional electricity storage output in 2050 across Europe in the BPS.

During winter, when heating demand surges in European countries, especially in the northern part, heat storage plays a crucial role in maintaining a stable energy supply. In the accelerated scenario, hydrogen, along with TES (at both district and individual levels), ensures heat supply across Europe (see Figure 2.28 and Figure 2.29). In the accelerated scenario, total heat storage output in Europe is projected to reach 1661 TWh by 2050 and for the same time 2121 TWh for the standard BPS. TES has a greater output share in countries like Sweden and Finland, while hydrogen and biomethane storage contribute more significantly to countries such as France and Germany.

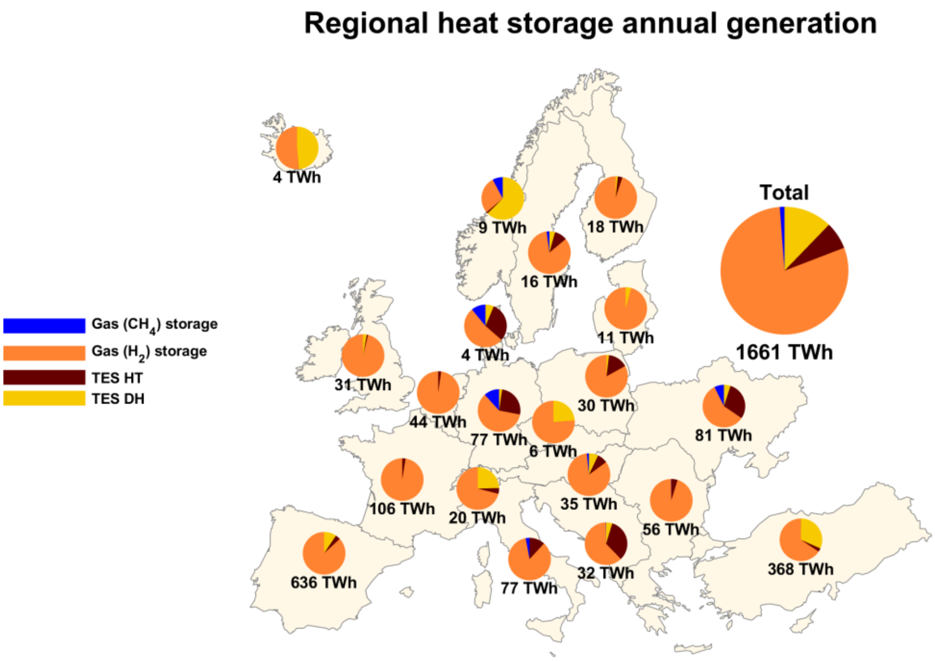

Figure 2.28: Regional heat storage output in 2050 across Europe in the BPS-2040.

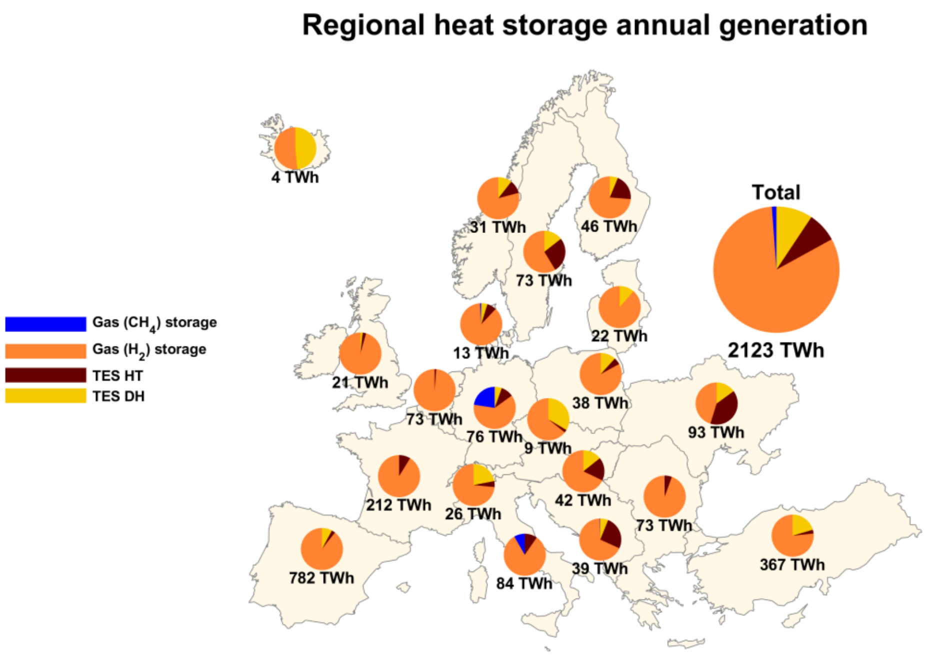

Figure 2.29: Regional heat storage output in 2050 across Europe in the BPS.

In 2050, the total European supply of fuels and chemicals, including e-methanol, e-ammonia, and Fischer-Tropsch (FT) fuels, is projected to reach 5896 TWh in the accelerated transition scenario and 6745 in the standard BPS. Central and southern European countries will become major production hubs for FT fuels and e-chemicals, which play a critical role in the transition, particularly in the transport and industry sectors. Meanwhile, the north-western European countries with large harbours are evolving into key import centres for e-fuels and e-chemicals (see Figure 2.30 and Figure 2.31). Fuels derived from waste and biomass residues are more prevalent in central European countries, while e-methanol production is concentrated in the eastern and northern regions. Even in this accelerated scenario, by 2050, Europe could shift from being a fossil fuel importer to a producer of e-fuels and e-chemicals. As illustrated in Figure 2.30, e-fuels dominate the supply and provision of energy across Europe.

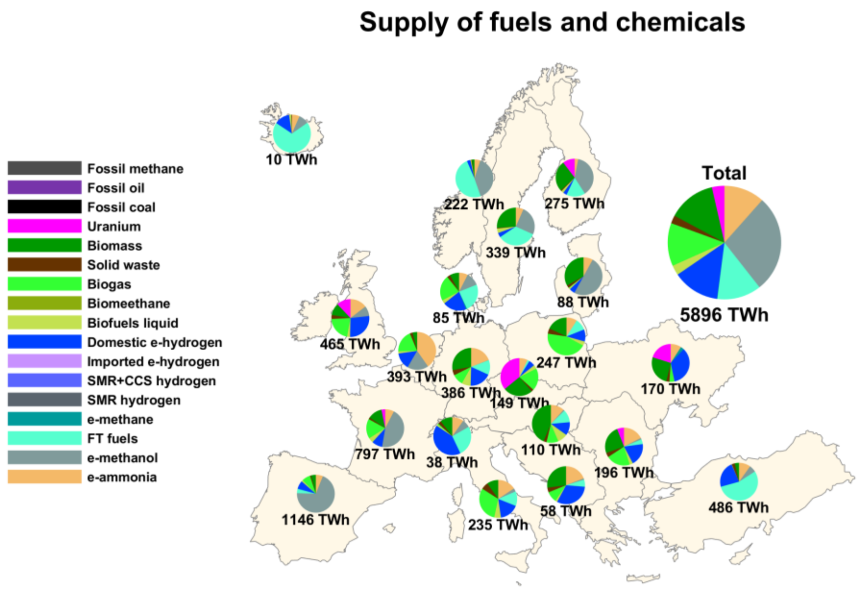

Figure 2.30: Regional fuels and chemicals supply in 2050 across Europe in the BPS-2040.

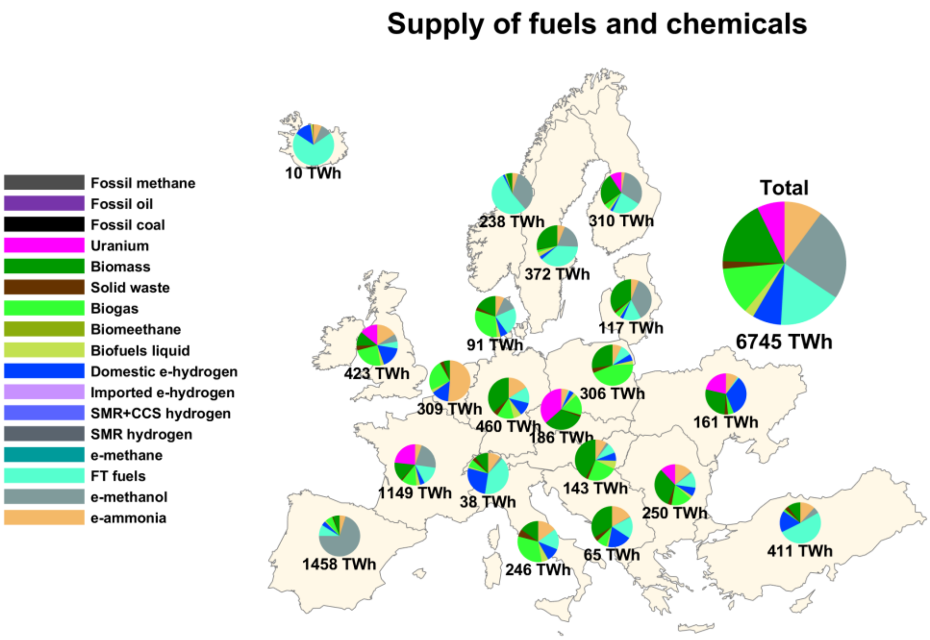

Figure 2.31: Regional fuels and chemicals supply in 2050 across Europe in the BPS.

Transmission interconnections between the 20 regions play an important role to optimise the use of local resources and reduce energy costs across Europe. A power system with a high level of electrification, sector coupling, and the use of energy storage technologies favours optimal electricity trade between the 20 regions, reaching about 553 TWh by 2050 for the accelerated scenario and 428 TWh for the standard PBS (see Figure 2.32 and Figure 2.33). The efficient utilisation of local resources to cover annual electricity consumption reflects a harmonious balance among the regions. About 17% of the electricity generated, is transmitted through interconnected regions, indicating that about 83% is generated domestically within the respective region. Turkey, Spain, and Germany are the main electricity exporters, contributing to a highly decentralised and cost-optimised energy system for Europe. In an optimal BPS solution with a full switch to RES, curtailed electricity is less than 3%, which is achieved through close cross-sectoral integration of the entire power system. Regions with high wind power and solar PV potential become net exporters, while the northern, eastern and central regions act as net importers.

Regional data on electricity, heat, storage, supplies of fuels and chemicals, and electricity grids confirm that a fully renewable and sector-coupled energy system for power, heat, transport, and industry across Europe is technically feasible and economically viable. This allows European countries to develop cost-optimal energy systems that use local resources and integrate into the wider European grid, reducing dependence on fossil fuel imports and ensuring Europe's energy security through a decentralised, integrated and independent energy system.

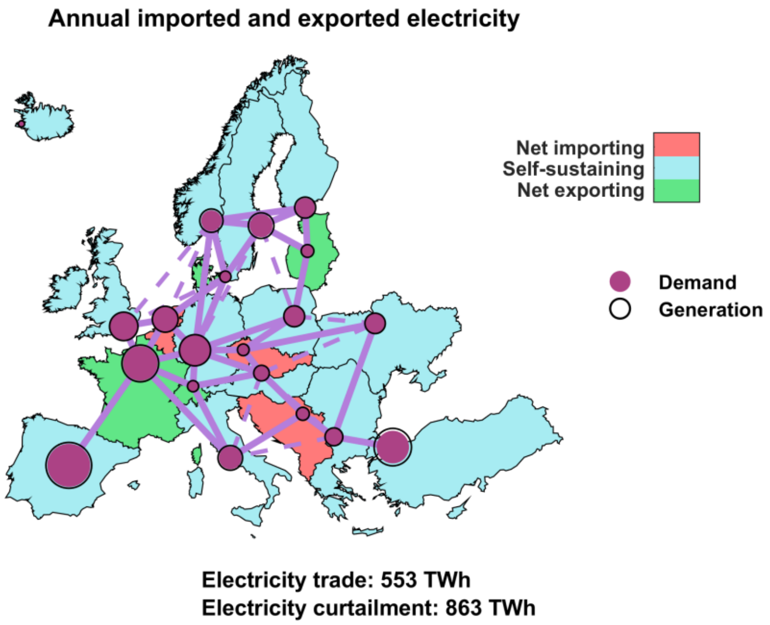

Figure 2.32: Regional electricity trade with net importers and net-exporters in 2050 across Europe in the BSP-2040.

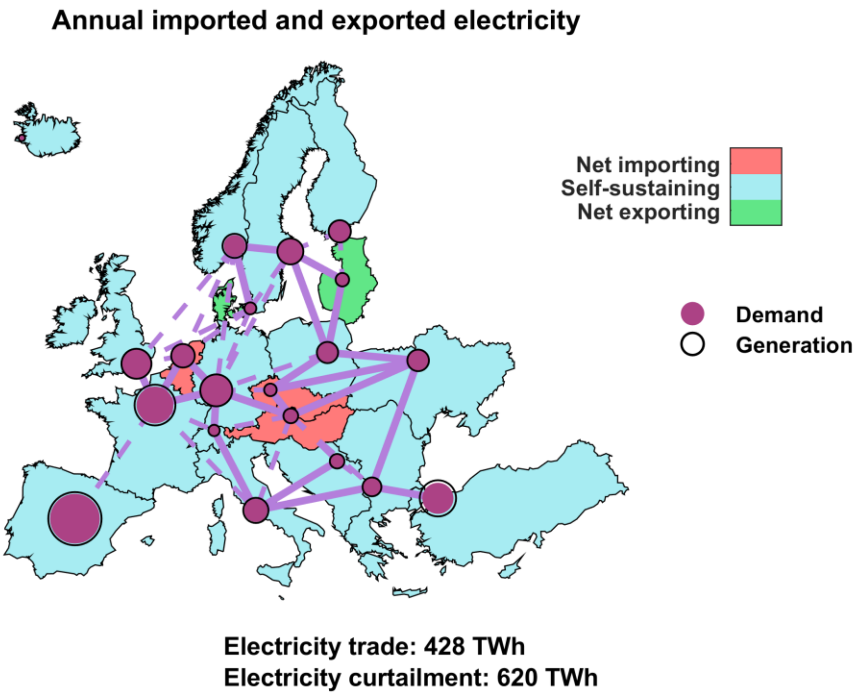

Figure 2.33: Regional electricity trade with net importers and net-exporters in 2050 across Europe in the BPS.

2.3.8 Energy system cost

The cost of energy is a critical factor in determining the feasibility of energy scenarios, roadmaps, and pathways. In the first half of the 21st century, renewable energy supply, along with electricity and heat storage technologies, and e-fuels produced from renewable electricity, become essential components of Europe's energy system. Figure 2.34 illustrates the annual system costs by sector and cost components, while Figure 2.35 shows the overall annual system costs across all scenarios.

Initially, the annual costs of the energy system rise until 2030, followed by a decline up to 2050 in the baseline scenario (BPS). Scenarios that anticipate e-fuel imports by 2030 show lower costs compared to those without imports. In scenarios without e-fuel imports, costs increase to 743 b€, whereas with imports (BPS_imports), the costs are reduced to 638 b€. The accelerated transition scenario, which targets 2040, presents higher annual system costs, rising to 952 b€ by 2035, before decreasing to 743 b€ by 2050.

The annualised energy system costs demonstrate the economic advantages of operating energy systems based predominantly on RE. Costs begin to decrease steadily from 2035 onwards, as the system transitions to 100% RE by 2050. By 2050, the total annualised energy system costs in scenarios without e-fuel imports are comparable to current costs in 2020, and even lower in scenarios with imports. This suggests that a transition to 100% RE across Europe offers significant long-term cost benefits.

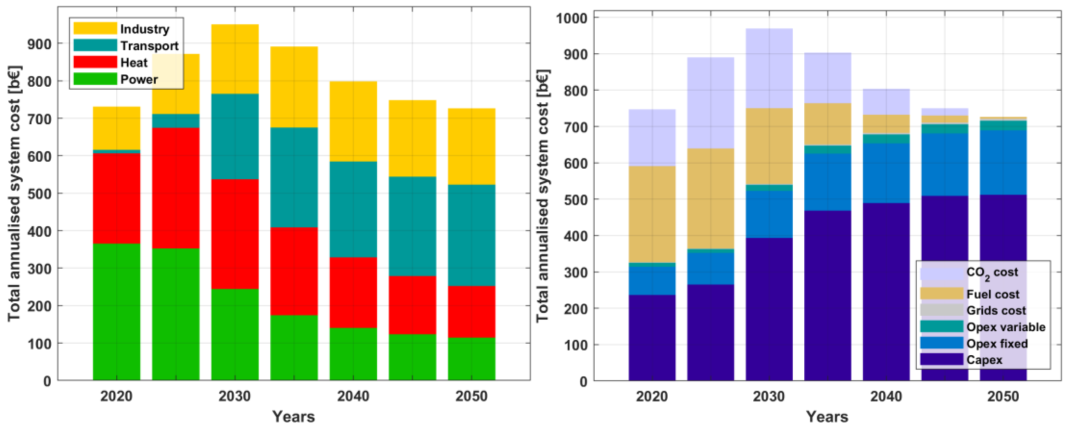

Figure 2.34: Annualised system costs per sector (left) and cost component (right) during the transition for the BPS.

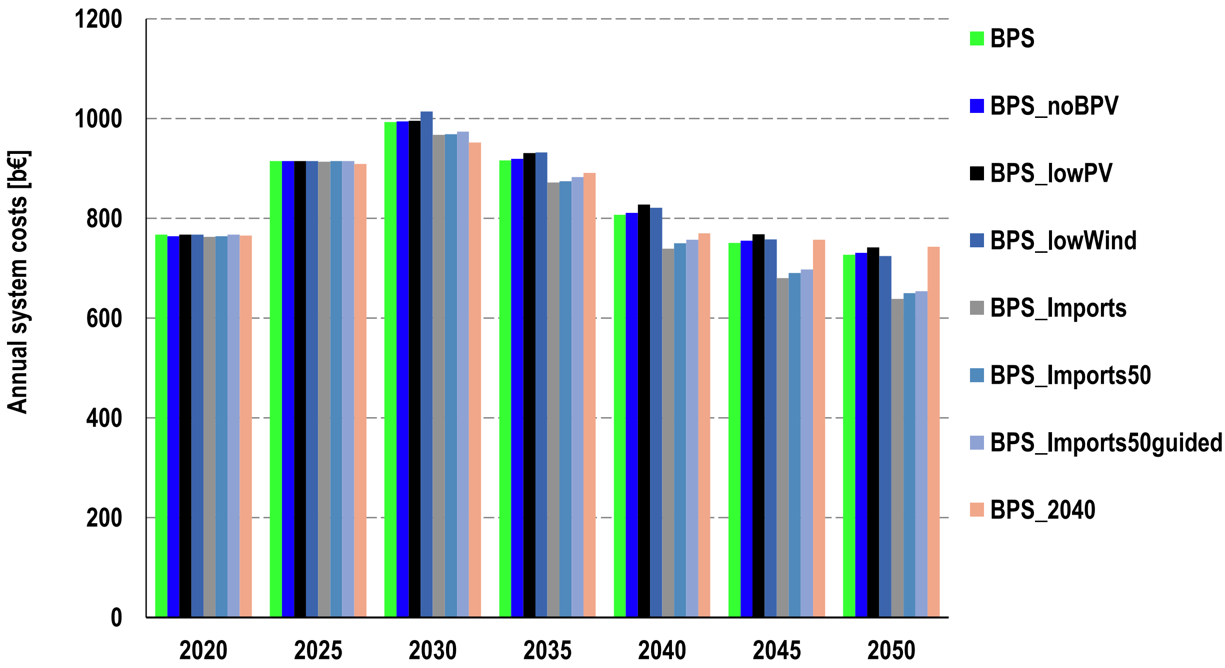

Figure 2.35: Annualised energy system costs across the scenarios from 2020 to 2050.

The levelized cost of electricity (LCOE) shows a substantial decline throughout the transition period from 2020 to 2050, as illustrated in Figure 2.36. This reduction is primarily driven by the growing share of renewable electricity, increased efficiency from sector coupling, and a decreasing reliance on fossil fuels and their associated CO_2 emission costs. Advances in technology, economies of scale, and the falling costs of wind power and solar PV, along with their operational expenses, contribute to a significant reduction in overall system costs.

In all scenarios, except for the accelerated scenario targeting 2040, the LCOE decreases by approximately 50% by 2050 compared to 2020 levels. In the accelerated scenario, the reduction is slightly smaller, dropping from 90.6 €/MWh to 40.3 €/MWh. This highlights that renewable electricity is expected to become the most cost-effective energy source across Europe. As the transition progresses, fuel costs steadily decline, and from 2040 onwards, capital expenditures become the primary driver of energy system costs, with fuel costs becoming nearly negligible. After 2050, the LCOE is projected to fall by an additional 15%, largely due to major reinvestments occurring beyond 2050, which benefit from lower capital expenditures. This suggests that long-term investments in RE will continue to drive down electricity costs well into the future.

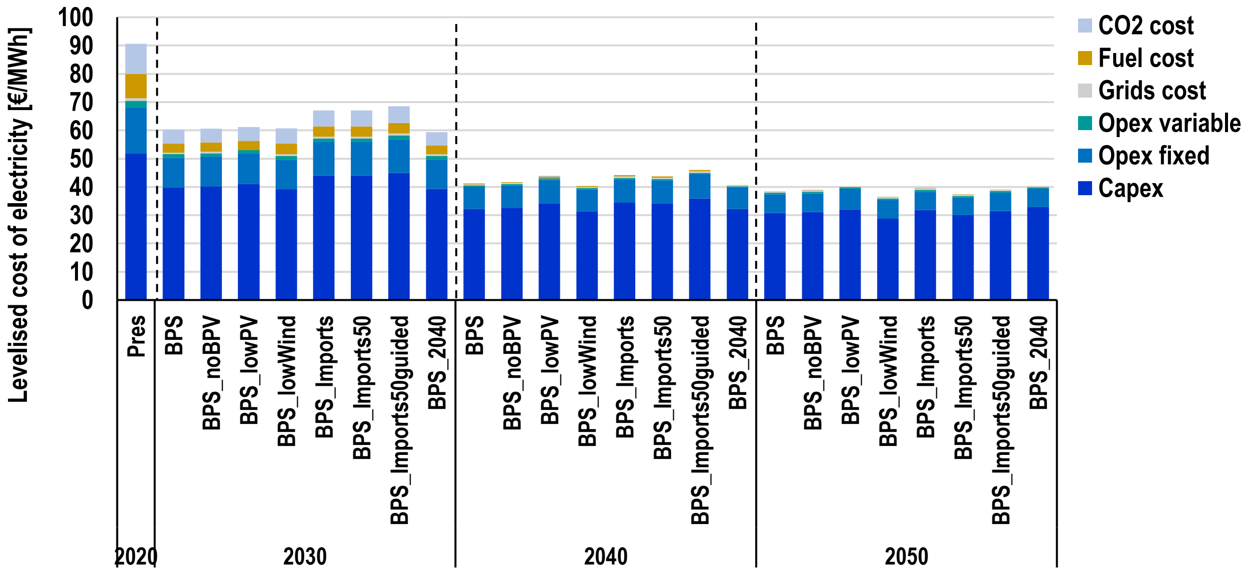

Figure 2.36: Levelized cost of electricity during the transition.

The levelized cost of heat (LCOH), after an initial rise, decreases throughout the transition period across all scenarios until 2050 (see Figure 2.37). In the heat sector, the LCOH drops from approximately 34 €/MWh in 2020 to around 24 €/MWh in the scenarios without imports of e-fuels, and to around 23 €/MWh in scenario with reduced share of PV, by 2050. The LCOH is mainly driven by capital expenditures, as fuel costs diminish during the transition. Despite a significant rise in heat demand across Europe, primarily due to increased industrial process heat and greater space heating needs driven by more space per person, the LCOH sees a notable reduction by 2050. This decrease is largely attributed to higher levels of electrification within the heat sector, which offsets the growing demand.

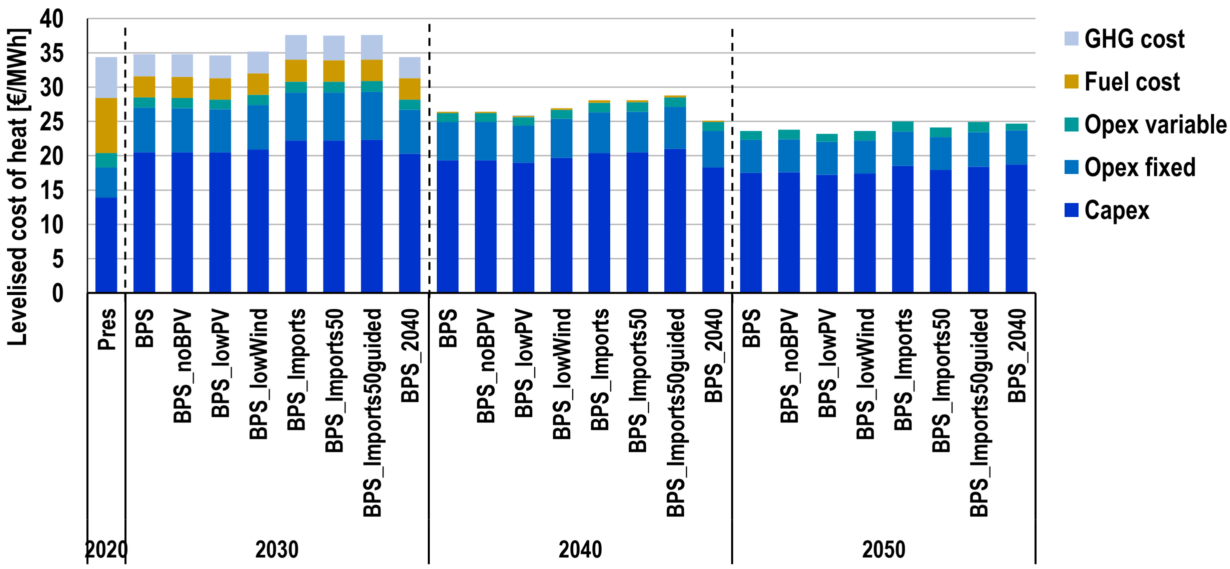

Figure 2.37: Levelized cost of heat during the transition.

The levelized cost of final energy and non-energy use (LCOFE) follows a similar pattern to the total annualised system cost across the different scenarios (as shown in Figure 2.38). In 2020, the LCOFE stood at 50 €/MWh, primarily driven by CO_2 emissions costs and fuel expenses.

By 2050, the scenario with limited e-fuel imports achieves the lowest system-wide LCOFE, around 49 €/MWh, while the scenario with guided e-fuel imports shows a slightly higher LCOFE of approximately 49.5 €/MWh.

In contrast, the accelerated transition scenario leading up to 2040 has a higher LCOFE, reaching 58 €/MWh by 2040. Other scenarios, which incorporate varying shares of PV or wind power technologies, maintain a similar LCOFE in the range of 48-55 €/MWh. This indicates that an accelerated shift towards 100% RE is appealing from an energy security standpoint, while the LCOFE remains comparable to 2020 levels. Over the long term, the LCOFE becomes increasingly dominated by capital expenditures as fuel costs diminish in significance during the transition, suggesting enhanced energy security across Europe by 2050. Additionally, the LCOFE accounts for all aspects of the energy system, with electricity and heat being the primary energy sources. Thus, the LCOE and LCOH are key indicators of overall costs during the energy transition.

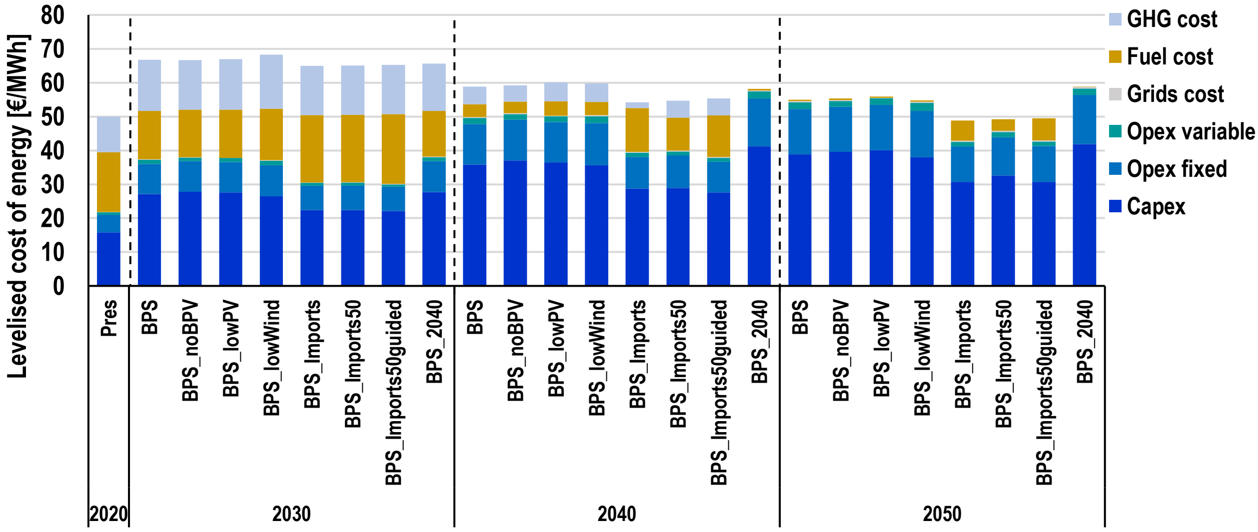

Figure 2.38: Levelized cost of final energy and non-energy use during the transition.

Figure 2.39 (left) illustrates the differences in investments from 2020 to 2050 across the scenarios. In the accelerated scenario through 2040, investments in RE technologies and infrastructure reach their highest levels, peaking at around 1916 b€ by 2030 and 2008 b€ by 2035. However, capital expenditures (capex) in this scenario significantly decrease in 2045 and 2050, falling to 203 b€ and 175 b€, respectively. In scenarios featuring varying shares of PV and wind power technologies, investments also peak during a similar period but at a lower level of approximately 1900 b€. In scenarios considering different conditions for importing e-fuels, capital expenditures follow the general trend, but, starting from 2040, align with those seen in scenarios focused on varying shares of RE technologies. By 2050, capex in all scenarios is projected to decline substantially, indicating a stabilisation of investments as RE technologies mature and infrastructure requirements decrease.

The scenario involving unlimited imports of e-fuels is expected to result in cumulative costs of approximately 25,314 b€ by 2050 (see Figure 2.39, right), making it the least expensive scenario. Although initial investments in the energy system are substantial, especially from the late 2020s to the early 2040s, this scenario later benefits from low-cost RE technologies, imported e-fuels, and high-efficiency standards. The scenario with reduced share of wind power shows the highest cumulative costs of 26,766 b€, about 5% higher than the least-cost scenario. Scenarios incorporating different shares of PV fall in between, with total costs nearing 26,500 b€ by 2050, 4.6% higher than the unlimited imports scenario and 1% lower than the scenario with reduced share of wind power.

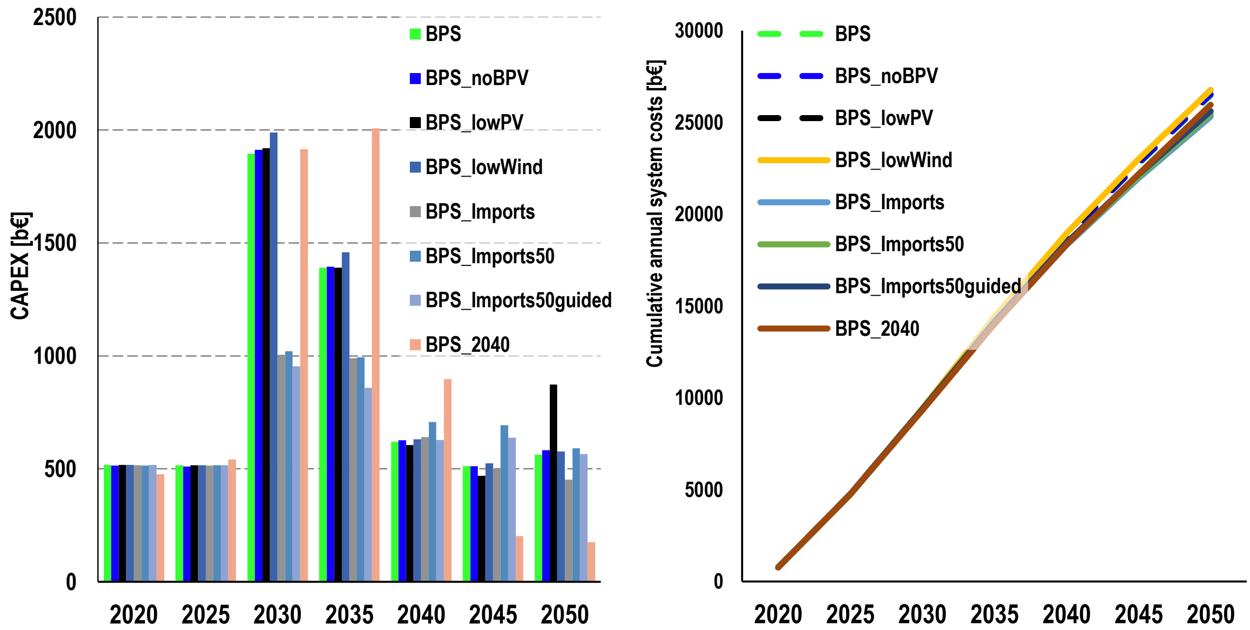

Figure 2.39: Levelized cost of final energy and non-energy use (left) and capital expenditures in 5-year intervals (right) during the transition.

2.3.9 Emissions

The results of the energy transition demonstrate a sharp decline in CO_2 emissions across the power, heat, transport, and industry sectors in all three scenarios by 2050, as shown in Figure 2.40. In 2020, CO_2 emissions from the power sector were over 580 $MtCO_2$, but they experience a rapid decrease to zero by 2040 in all scenarios. The lowest emissions occur in 2035 in scenarios involving the import of e-fuels. The transport sector, which accounts for the highest emissions in 2020 of around 1490 $MtCO_2$, achieves zero emissions by 2040 in the e-fuels import scenario. In other scenarios, emissions from the transport and industry sectors persist but remain minimal. Overall, emissions across all sectors experience an accelerated reduction to zero by 2040 in the relevant scenario, and a steady decline to zero by 2050 other scenarios.

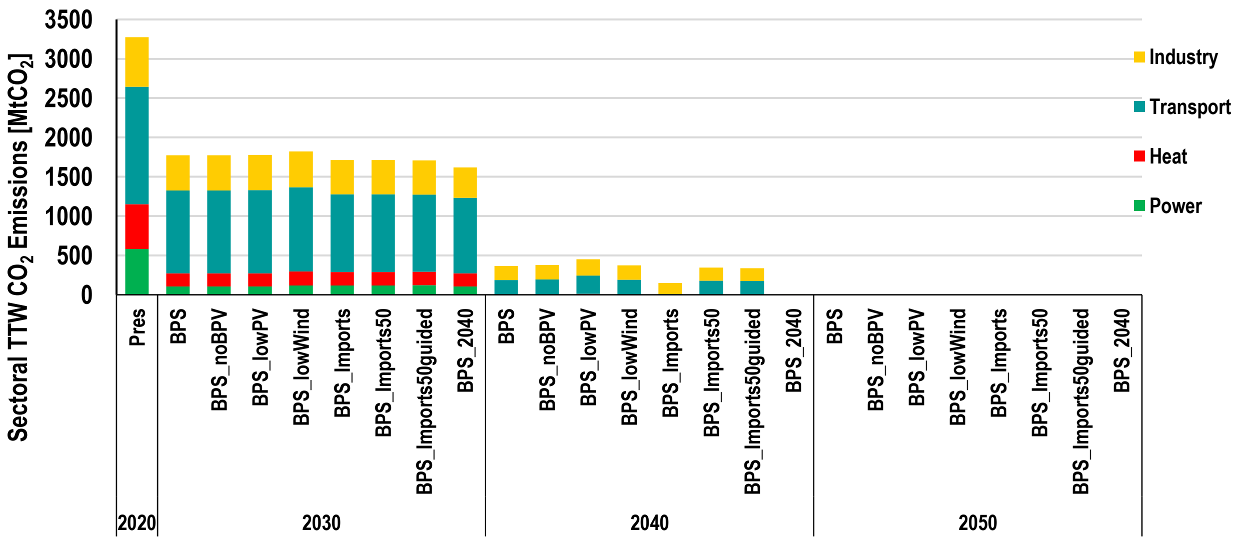

Figure 2.40: Sectoral annual CO_2 emissions in all scenarios during the transition.

Emissions begin at around 3273 $MtCO_2$ in 2020 and gradually decline. In the accelerated scenario, all sectors reach zero emissions by 2040. The lowest CO_2 emissions projected for 2040 are observed in the e-fuels import scenario, with emissions of approximately 152 $MtCO_2$.

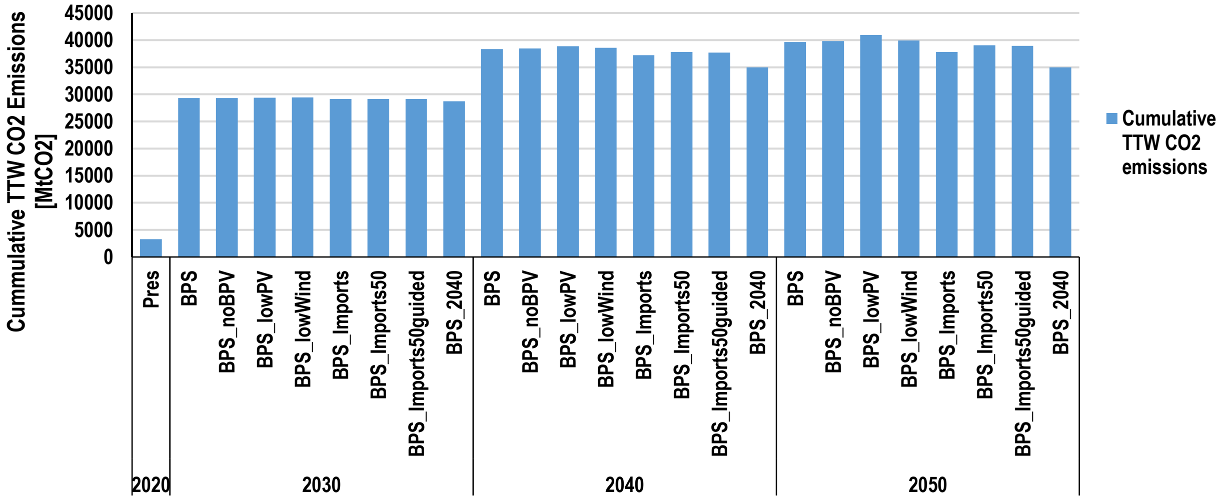

Figure 2.41: Cumulative CO_2 emissions.

The accelerated scenario till 2040 achieves zero CO_2 emissions by 2040 and a 65% reduction by 2030 compared to 1990 levels, aligning more closely with the target to limit global temperature rise to 1.5°C above pre-industrial levels. Other scenarios reach zero emissions by 2050, with around a 60% reduction by 2030, which may hinder efforts to fully meet the goals of the Paris Agreement, especially considering Europe's economic growth and capabilities.

Climate mitigation is one of the most urgent challenges of our time, underscored by the IPCC's findings that even slight additional warming beyond the safe and just planetary boundary of 1.0°C already experienced will amplify risks and impacts globally. Recent research [55] also points to the coupling of major climate change tipping points, which highlights the critical importance of not surpassing the 1.5°C threshold. Achieving this goal requires transformative systemic changes integrated with sustainable development globally. In this context, the EU must take a leadership role by rapidly reducing CO_2 emissions within Europe while also acting as a catalyst for global adoption of sustainable energy technologies. As this research demonstrates, achieving these reductions is both technologically feasible and economically viable for all EU member states and the wider European region.

2.4 Discussion

2.4.1 Role of solar PV in the European energy transition

Solar PV plays a key role in the energy transition of Europe. Ongoing cost decline, abundant resources in most of the regions and lower limitations compared to wind power generation will lead to increasing impact of solar PV on the energy transition. In the coming decade solar PV generation growth rate will be comparable to that of onshore wind power, but after 2035 the installation rates of PV will far exceed the growth rate of wind power. Then the combined cost decline of PV and energy storage technologies, in particular batteries, will allow PV to become the core of the energy supply, while batteries and other energy storage technologies will reallocate excess PV generation from daytime to cover energy demand during the evening peak and nighttime. Wind electricity generation built in the first decades of the transition will play an important role in supporting the energy system's operation, especially in the winter months when solar PV output is minimal while energy demand in central and northern Europe increases. However, installation of new wind power capacities stagnates after 2040, due to higher cost and utilisation of the best wind locations in the initial stages of the transition.

In the reference BPS, the installed capacity of PV reaches 1390 GW by 2030 and peaks at 5000 GW in 2050. The more the ambitious BPS-2040 will require about 1450 GW by 2030 and peaks at 4615 GW. Such a pace of PV installations will be challenging as it demands more than quadrupling installed capacity from 2023 to 2030, however, the defossilisation of the power sector and overall energy system electrification will require a rapid growth in electricity supply and a scalable PV industry is the best option to satisfy the electricity consumption growth. The fast growth of PV and wind power capacity will require adjustments to legislation, further development of agile installation techniques and proactive grids development to speed up the realisation of new RE projects. Renewable electricity generation must grow rapidly in the coming decades to provide enough electricity to substitute current fossil fuel-based generation and provide additional electricity for the electrification and defossilisation of the heat, transport, and industry sectors.

The BPS and BPS-2040 show the case of an optimised energy mix, however in some regions further development of onshore wind power is limited due to area constrains or a low social acceptance. Naturally, scenarios with limited wind power installations rates show a bigger role of solar PV and even more challenging installation upscaling rates supporting arguments for the relevance for RES diversification. Energy sources diversification and optimisation of solar PV and wind power shares in the regional energy mixes also help to minimise energy costs. The results show that both low PV shares and low wind shares scenarios result in higher energy costs compared to an optimal mix in the BPS. A suboptimal mix leads to an LCOE increase of 0.8-1.6% in 2030. The energy system is feasible and can satisfy energy demand even in the case of a PV share reduction from 54% of electricity supply in the BPS to 34% in the BPS_lowPV, or an increase to 70% in the BPS_lowWind. However, scenarios with a lower share of PV result in slightly higher energy costs even in 2050.

In the VRE-based energy system, pan-European transmission grids and energy storage become extremely important to balance supply and demand across the continent. The results show a nexus between solar PV and storage, and wind power and grids, as a system relying on wind power generation will demand pan-European transmission grid expansion, while the solar PV-based system can be more localised with greater reliance on local energy storage and demand flexibility. This can be seen as another advantage of solar PV generation, considering long realisation periods of interregional grid projects for development and permitting, and often low social acceptance of grid projects in many regions of Europe.

The optimal mix of electricity generation, storage, and grids differs from region to region, naturally the wind-rich regions such as the Nordics tend to rely on local wind resources, as high shares of wind power can be seen in Ireland and the UK, France, the regions benefiting from Atlantic winds. Some regions benefit from local hydropower or a sustainable biomass potential, but a substantial share of PV can be seen in every region of Europe. The key reasons are the more evenly distributed PV potential, making solar PV economically feasible in every region of Europe, and diversity of PV technologies. Utility-scale PV, agrivoltaics, prosumers PV, all have their niche and are economically viable on the energy market. New developments, such as single-axis tracking and bifacial modules further improve the system efficiency and economic viability of PV.

2.4.2 Impact of bifacial PV introduction

The Introduction of bifacial PV can result in a 3-5% improvement in yield with virtually zero additional costs. The results show that it is always beneficial to use bifacial PV modules. The scenario without bifacial PV leads to a 1.3% higher LCOE in 2050 and higher energy cost. For the European energy system, the introduction of bifacial PV will allow for savings of about 3 b€ in 2050 alone, over the transition period, cost savings from bifacial system utilisation will exceed 50 b€. In all scenarios with bifacial PV, most of newly installed utility-scale PV capacities are bifacial and use single-axis tracking technology.

2.4.3 Prosumers' BAPV and BIPV in the energy system

In the optimal mix, the share of solar PV in total electricity supply reaches 26% in 2030 and 54% in 2050. This share combines utility-scale PV and prosumers PV. Prosumer PV is an important source of energy, particularly in the early 2020s, as relatively high retail prices motivate consumers to install their own PV systems. Limited rooftop area leads to a decline of the prosumer PV share in total PV capacity, however even in 2050, prosumers PV capacity represents almost 20% of the total PV capacity.

Further development of BAPV and BIPV systems will be necessary to enable the installation of more than 800 GW of residential, commercial, and industrial prosumer PV. That will require the development and dissemination of advanced installation techniques to accelerate and reduce the cost of PV installations on roofs and the facades, increasing the efficiency of building surface use. Another important aspect is the development of advanced communication tools and adaptation of legislation to prepare the infrastructure for development of large-scale distributed electricity generation, as prosumers have already become in some regions of Europe.

2.4.4 PV as source of energy for e-chemicals and e-fuels

As solar PV becomes the core of the future energy system, solar energy rich regions become the powerhouses of Europe. By 2040s, Spain and Portugal host substantial PV capacities far exceeding their own energy demands. With abundant, low-cost solar energy, the Iberian Peninsula emerges as a major energy exporter in Europe, providing e-fuels and e-chemicals across the continent. However, only higher cost e-fuels and e-chemicals are traded in bulk, whereas most of the low cost and often hard-to-transport e-fuels and e-chemicals, such as hydrogen and ammonia, are mostly produced in the same regions where they are consumed. At the same time, e-fuels and e-chemicals industry provides valuable flexibility to VRE-based electricity supply. The flexible operation of electrolysers allows for maximising electricity demand during peak supply periods and minimising it during electricity deficit periods. Local production of e-fuels and e-chemicals, at least hydrogen production for local chemical and steel industries, becomes an important asset for the energy system.

Sustainable energy imports from outside of Europe change the situation, but only for more sophisticated e-fuels and e-chemicals, such as Fischer-Tropsch fuels and methanol. Simple molecules, like hydrogen and ammonia, still tend to be produced locally due to relatively high cost of transportation. Nevertheless, unlimited imports of e-fuels results in increased battery storage capacity to compensate the lack of flexibility from local e-fuels production and a 20% decline of PV capacity needed by the system in 2050.

3 SUPPORTING RESEARCH FOR ENERGY SYSTEMS

The following sections (subchapters) represent a brief overview on research that supported the core research on the role of solar PV for the energy transition Europe. Each section represents the respective scientific paper published as part of this project. As these aspects support and complement the core research, the abstracts and conclusions of the respective papers are presented with a link to the open access paper which provides more details. At the time of the finalisation of this deliverable four in six scientific papers had been published with the remaining two expected in the foreseeable future.

3.1 Bifacial PV modelling in energy systems

Bifacial PV modules gain very fast considerable market shares due to higher yield, longer lifetimes, and no differences in manufacturing costs. To further improve the yield modelling of PV systems in general and to improve their representation in energy system modelling in particular, comprehensive bifacial PV yield modelling has been implemented in this project.

The results are under review at the time of finalisation of this deliverable and will be available in open access [37] in foreseeable future.

Abstract

Bifacial solar PV technology is currently taking over the solar PV module market with an expected 70% market share until 2030. This significantly important technology has to be included in future energy system modelling. This study provides a method for calculating the yield of monofacial and bifacial power plants in fixed-tilted, single-axis tracking, and East-West facing vertical setup. Furthermore, a novel method is introduced to optimise the capacity density of the solar PV power plants without the need for detailed land area cost for a most efficient use of the occupied area. The results indicate a 15-20% yield gain from single-axis tracking compared to fixed-tilted PV power plants, and a limited bifacial gain of up to 10% for most areas of the world. Higher bifacial gains are sporadically possible in specific conditions. Fixed-tilted systems show higher bifacial gains. Optimising tilt angles and row pitch lead to up to 147 MW/km^2 capacity density, though on average 70-110 MW/km^2 can be achieved today. The impact on the power system, studied in a free cost optimisation scenario and forcing vertical PV scenario, is not significant with a ±10% change in total solar PV capacity, change in installed wind power of on average -10%, increase of installed battery capacity of on average 5%, and an on average changed LCOE of -2% globally. Bifacial solar PV technology has been found to be no game changer for future power systems; system improvements are widely possible underlining the important role of this technology.

Conclusions

This study presented a modelling approach (LUT-PV) for fixed-tilted and horizontal single-axis tracking solar PV power plants for a setup with monofacial and bifacial module technologies, and an East-West facing vertical bifacial setup. Single-axis tracking includes a sophisticated method for backtracking and intra-day yield optimisation. The method presented standard front side irradiation calculations, as well as a novel rear side irradiation calculation approach based on ground segmenting for an accurate representation for all possible tilt angles, making it generally applicable for fixed-tilted and single-axis tracking setups. Furthermore, an approach to optimise the capacity density based on LCOE of solar PV power plants was presented, advancing the state-of-art of methods relying on land cost data. The yield modelling was verified for 10 test sites globally with various climatic conditions with the PVsyst software.

The results show a good match of LUT-PV compared to PVsyst modelling within a ±4% mismatch band for all system setups except the vertical option, which cannot be modelled with PVsyst. Yield calculations were done for all land area globally in 0.45° x 0.45° resolution. The yield gain from single-axis tracking versus fixed-tilted largely outweighs the bifacial gain, while both parameters are highly location-dependent. Yield gains of more than 15-20% by using single-axis tracking against fixed-tilted systems are the norm, while bifacial gains of more than 10% are only possible in specifically favourable conditions. Fixed-tilted systems show higher bifacial gains than single-axis tracking systems, due to the effect of "tracking the shadow". The optimisation of the tilt angles for fixed-tilted systems showed a mostly even change over latitude, while bifacial tilt angles skip the area of ca. 25°-40° at a latitude of ca. 15° to optimise the rear side irradiation. The row pitch, and subsequently capacity density, could be optimised to achieve up to 147 MW/km^2 for monofacial systems near the equator already today, while bifacial modules require higher row pitch for optimised conditions and, therefore, achieve lower capacity densities of ca. 110 MW/km^2. Globally, most of the sites lie between 70 - 100 MW/km^2.

For the impact of bifacial technology on the future power system, four central parameters have been assessed, modelling the power systems for 145 regions globally in a 2040 overnight transition: Total installed solar PV capacity, installed wind power capacity, installed battery storage capacity, and LCOE. The focus lies on the changes of these parameters for two scenarios, one free cost optimisation of all technologies, and one forcing vertical solar PV into the system simulating a stronger uptake of agrivoltaics, compared to a reference scenario without bifacial solar PV. Total solar PV capacities are insignificantly affected by bifacial technologies, and most regions lie within a ±10% change band. Wind power is mainly reduced with a lower role in the energy mix at a global average change of almost -10%. Battery capacities are rather added than removed if bifacial modules are used, though the change is kept below 5% in the majority of regions. The most homogeneous effect has been found for LCOE, as the parameter can be improved in almost all modelled regions. However, the effect is not significant and stays below 2% improvement for most of the regions.

This study showed that bifacial solar PV technology is able to improve the techno-economic performance of future power systems. However, bifacial technology may not be a game changer, as very high yield improvements are only possible in specific conditions, that might not be available in most of the world's regions. As bifacial technology does not impose significant up to no cost changes in manufacturing, bifacial solar PV modules are able to further advance the system efficiency, and from power system perspective there seems to be no limitation to bifacial modules becoming the future standard.

3.2 Improved backtracking strategies for single-axis tracking solar PV

Single-axis tracking solar PV systems gain considerable market shares due to higher yield and lower LCOE. To further improve the benefits of single-axis tracking PV systems improve backtracking strategies have been implemented in the yield modelling of this project.

The results have been published in open access [38].

Abstract

Optimisation of horizontal single-axis tracking solar PV power plants is important for its optimal application. Commonly, standard backtracking has been applied to avoid mutual shading and improve the full load hours and LCOE; however, this approach is not always the best solution for state-of-the-art modules with half cell technology. Backtracking has not yet been studied for different test sites with different solar and climatic conditions. This study aims to improve the knowledge on the techno-economic performance of horizontal single-axis tracking systems with half cell modules applying different backtracking strategies in full hourly resolution for nine test sites globally and varying row spacing. In addition to the standard backtracking algorithm, an advanced backtracking algorithm that varies the tracking angle only if the irradiance can be improved, and an advanced sophisticated backtracking algorithm simulating the irradiance for all possible tracking angles, are studied. The results confirm that standard backtracking is only superior for specific conditions. Compared to no backtracking, standard backtracking shows up to ca. 9% higher LCOE due to lower full load hours. Advanced backtracking can lower the LCOE by up to 9% and advanced sophisticated backtracking by up to 12%, due to improved full load hours. In general, results are similar and comparable for all test sites studied. This study highlights the importance of backtracking for optimised future horizontal single-axis tracking system planning.

Conclusions

This study assessed the impact of different backtracking strategies on the techno-economic performance of horizontal single-axis tracking solar PV power plants using state-of-the-art half cell modules. As a general reference, the performance of the artificial power plant has been simulated without applying a backtracking strategy. This reference case has been used to validate the LUT–PV model with the PVsyst software. Furthermore, three different backtracking strategies have been studied: Standard backtracking always avoiding mutual shading of the tracker rows, advanced backtracking only applying backtracking if the total irradiation on the modules for a reduced tracking angle is favourable, and advanced sophisticated backtracking calculating the total irradiance on the modules for each of the possible tracking angles between the true tracking angle and a horizontal orientation and choosing the angle with the highest total irradiation. All strategies were studied for nine different test sites distributed all over the globe to cover different climatic conditions. In addition, the row spacing was varied to cover the impact of the backtracking strategies on area-optimised power plants.

The results indicate that the standard backtracking strategy is almost always outperformed by other backtracking strategies. Not applying backtracking and keeping the tracker at maximum tracking angles at times with low sun elevation was shown to be the superior strategy most of the time as well. Standard backtracking only showed an improved performance in high latitudes and wide row spacing. Compared to no backtracking, the full load hours of the power plant for the assessed test sites were generally lower for standard backtracking (–8.7% to 0.4%), about the same with tendency to higher full load hours for advanced backtracking (0.0% to 1.2%), and higher for advanced sophisticated backtracking (0.4% to 5.0%). Due to the linear relationship of yield, or full load hours, and LCOE, the LCOE of the standard backtracking strategy are up to 8.7% higher, the advanced strategy up to 1.2% lower for the advanced backtracking strategy, and up to 5.0% lower for the advanced sophisticated backtracking strategy. Compared to standard backtracking, the advanced backtracking strategy was able to outperform the standard backtracking with up to 8.9% higher yield and 8.9% lower LCOE. The advanced sophisticated backtracking strategy achieved up to 12.0% higher full load hours and consequently, 12.0% lower LCOE.

Solar PV becomes the leading RES in the decades to come. An optimal application of this technology, more specifically, horizontal single-axis tracking solar PV power plants, will only be possible if all aspects are considered. This study showed that backtracking is an important topic for single-axis tracking power plant planning. The results and limitations of the assessment were discussed and an outlook on future research opportunities provided.

3.3 Rooftop PV yield modelling for energy systems

The research on rooftop PV yield modelling for energy systems has been published in open access [39] .

Abstract

Solar PV, especially rooftop systems also called distributed solar PV, are crucial in the ongoing energy transition. Modeling these systems is vital to understanding their role in a decentralised energy system. While ground-mounted PV power plants are easier to model, generalising yield profiles for rooftop systems is challenging. This study aims to estimate yield loss effects for rooftop solar PV systems compared to optimised ground-mounted systems. Anticipated yield losses are 18% for residential, 7% for commercial, and 4% for industrial rooftop systems. The impact on residential prosumers' viability is assessed by comparing prosumer system optimisation results with and without yield losses. Results show a non-uniform change in installed solar PV and battery capacities, with a tendency to compensate for reduced yields by increasing PV capacity by up to 20%, given favourable cost prospects by 2050. The annualised total cost of energy for prosumer households could therefore increase by up to 20% by 2050. Despite yield reductions, installing a solar PV prosumer system remains more favourable than relying entirely on-grid electricity. This study highlights the

importance of considering yield losses in rooftop solar PV and the significant role of prosumers despite identified yield losses.

Conclusions

Understanding the yield prospects of rooftop solar PV power plants is necessary to allow for the rightful accounting of yield losses in energy system transition modelling with a differentiated consideration of solar PV prosumers. Usually, dedicated rooftop solar PV profiles are not available. This article presented the literature and method to estimate the yield losses of residential, commercial, and industrial rooftop solar PV systems in comparison to optimal yield represented by utility-scale ground-mounted solar PV power plants on three different levels: environmental level, cell and module level, and system level. The assessment indicated about 18% annual loss for average real-world residential systems compared to optimally simulated systems. This impact was estimated to be 7% for commercial-sized systems and to 4% for big-scale industrial rooftop PV systems.

The viability of residential solar PV prosumer systems with the reduced, that is, anticipated, yield has been assessed by comparing the total annualised cost of energy, including electricity demand, heat demand, and one-battery electric vehicle, in an on-grid case scenario for 145 regions globally. The results indicate a nonuniform change in installed solar PV capacity and stationary battery capacity, due to individual parameter combinations and grid electricity cost for each region. For most regions, the missing yield of the solar PV system is counter-balanced with higher solar PV capacity by 2050 of up to 20%. The change in installed stationary battery capacity is similar; however, the change is not as significant as for the solar PV capacity. The annualised total cost of energy of the prosumer systems increases in all regions by 2050, as the cost-optimised average households are all equipped with a solar PV system by mid-century. On global average, an 18% yield reduction leads to about 16% higher system cost by 2050.

This study provided a novel view of the loss effect of rooftop solar PV systems compared to ground-mounted solar PV systems. The results indicate the significance of the necessity to include differentiated rooftop solar PV options in energy transition models, or solar PV prosumer sub-models in the best case, with a respective consideration of the yield losses. The results aim to improve the quality and detail of research of future energy system transition studies with a better consideration of one of the main pillars of the energy transition, which are distributed renewable energy sources such as rooftop solar PV.

3.4 Wind power yield modelling for improved wind power vs PV ratios

The research on wind power yield modelling was required to avoid a misbalance of optimised PV yield modelling and thus reaching relatively too high solar PV supply shares, thus, respective efforts for improved wind power modelling could minimise that risk [56].

Abstract

This study aims to contribute to the field of energy systems modelling with high-resolution cost-optimised onshore wind turbine configurations and an openly available hourly data of wind electricity yield on a global-local scale. It introduces a more rigorous and novel methodology to estimate the wind electricity yield for lowest cost electricity generation by considering different wind classes and hub height related capital expenditures along with limitations induced by extreme wind gusts. Based on up-to-date financial and technical assumptions, including the latest power curves for ENERCON wind turbines, the results of this study show that there exists a certain hub height that enables wind turbines to deliver the lowest cost electricity and growing beyond that height does not pay-off the rise in capital expenditures needed for stronger foundations and taller and sturdier towers. Class III turbines provide higher full load hours and more stable hourly generation profiles, but in some areas higher cost does not pay-off or wind gusts become a limiting factor. The application of this novel multi-turbine multi-hub height high resolution optimisation results to energy system modelling would significantly increase the quality of modelling by improved estimation of the wind generation cost at different locations.

Conclusions

The aim of this research was to determine the global-local cost-optimised onshore wind turbine configurations and it was achieved by simulating wind conditions at fifteen different heights and comparing the performance of six turbines for three different wind classes, considering air density, wind gust and the rise in hub height related CAPEX. The resultant hourly profiles for wind electricity yield can be appropriated within energy system models to reduce a potential distortion of the role of wind power among other RE technologies.

The conventional approach applying one turbine with a fixed hub height tends to underestimate the annual wind electricity yield for a given location, whereas the optimised turbine and hub heights method of this study is more closely aligned with real world approach of harnessing wind. The results demonstrate concrete calculations of the optimal configurations for the given data and assumptions and provides a framework for further optimisation. Additionally, given the financial and technical assumptions, the findings show the wind class III turbines dominate in parts of the world with moderate wind speeds above 5 m/s and below 8 m/s, as it provides the lowest cost electricity production, and its power curve fits well for the average wind speeds observed globally at different heights. Additionally, wind class III turbines provide more stable hourly generation profiles, which can be a further benefit for energy systems and potentially reduce the storage capacity demand for energy systems with high RE penetration. Meanwhile, wind class II turbines are preferred in the regions of the world with high extreme wind gusts, e.g., coastlines up to 100 km, where wind class III turbines are not allowed to be installed. Wind class I turbines, that are designed for high wind speeds, are preferred in regions of the world with excellent wind resources, such as Patagonia, North Sea, North Atlantic from Canada via Greenland to Iceland, where average wind speeds are above 9 m/s, and regions of the world prone to very high extreme wind gusts above 60 m/s, such as the Northwest Pacific Basin. The inclusion of six wind turbines of three different wind classes and hub height adjusted CAPEX for wind power modelling improves the quality of findings and reduces uncertainties, though the validation shows that results are highly sensitive to inputs, and further research is required into wind class adapted CAPEX and rise in hub height related CAPEX calculations. The results show increase in global wind power full load hours compared to the conventional approach of one turbine at a fixed hub height, with gains of over 20% in many regions. The supplementary material may help researchers to validate the results of this study and assess the sensitivity of the assumptions. Although, this conclusion stands to further prove the consensus of the wind industry regarding the optimal configuration of wind turbines of different classes, the results of this study can help future energy system modelling studies to incorporate more robust wind power potential for regions around the world.

3.5 Offshore floating PV as export option – Case Maldives

Within this project it was possible to transfer the knowledge on onshore floating solar PV to offshore floating solar PV as a potential attractive export market of European PV systems know-how.

The case study on the Maldives is published in open access [57].

Abstract

Low-lying coastal areas and archipelago countries are particularly threatened by the impacts of climate change. Concurrently, many island states still rely on extensive use of imported fossil fuels, above all diesel for electricity generation, in addition to hydrocarbon-based fuels to supply aviation and marine transportation. Land area is usually scarce and conventional renewable energy solutions cannot be deployed in a sufficient way. This research highlights the possibility of floating offshore technologies being able to fulfil the task of replacing fossil fuels with RE solutions in challenging topographical areas. On the case of the Maldives, floating offshore solar PV, wave power and offshore wind power are modelled on a full hourly resolution in two different scenarios to deal with the need of transportation fuels: By importing the necessary, carbon neutral synthetic e-fuels from the world market, or by setting up local production

capacities for e-fuels. Presented results show that a fully RE system is technically feasible in 2030 with a relative cost per final energy of 120.3 €/MWh and 132.1 €/MWh, respectively, for the two scenarios in comparison to 105.7 €/MWh of the reference scenario in 2017. By 2050, cost per final energy can be reduced to 77.6 €/MWh and 92.6 €/MWh, respectively. It is concluded that offshore floating solar PV and wave energy converters will play an important role in defossilisation of islands and countries with restricted land area.

Conclusions

The aim of this research was to provide an insight whether offshore floating technologies have the potential to supply a RE system for an archipelago country, either in combination with the import of CO_2 neutral synthetic e-fuels, or for supplying own synthesis units within the country on the example of the transportation intensive context of the Maldives. This study showed that novel technological approaches such as offshore floating PV and wave power are able to secure the energy supply as needed. Additionally, a global e-fuel trade will be an important option for a cost-effective and reliable of transport fuel supply. The example of the Maldives shows that a transport- and fuel-intensive energy system does not necessarily have to be a bottleneck in transitioning to a fully renewable energy system when using available RES technologies. This study reveals that a transition of the Maldivian energy system towards 100% renewable based until 2030 is technically possible with a minor increase in cost per final energy unit.

Novel technology approaches, namely, offshore floating PV and wave power have been verified as potentially main technologies for countries with very limited land area and access to sea areas. Phasing out diesel-based electricity generation will have a positive effect on the countries' cost for final energy in the long-term. In the Maldives, for example, from a starting point of 105.7 €/MWh in 2017, a transitioned system would cost 120.3 €/MWh in 2030 and 77.6 €/MWh in 2050, if the CO_2-neutral e-fuels for the transport sector are imported from the global market. In case of setting up own transport e-fuel production facilities in the country, the cost would account to 132.1 €/MWh in 2030 and 92.6 €/MWh in 2050. Especially wave power with its relatively stable electricity generation over the whole year and especially during the monsoon season will be the backbone of the archipelago's energy system, in particular when energy intensive facilities for transport e-fuel production are set up within the country. Besides the cost advantages, CO_2 emissions drop substantially, or are avoided completely if a sustainable solution for handling waste residues can be found.

However, with an increase of RES, the demand for storage technologies grows, especially short-term battery storage. Not having interconnections available and geographically widespread storage options, the Maldives require a specialised balancing and seasonal storage option. Hydrogen is most qualified to take over this task, not least because of a well distributable nature of the system components, which can be placed on the islands all over the country. Without the domestic transport e-fuel production, more than a third of the electricity in the considered scenario is cycled via storage technologies. If the scenario includes local production facilities for e-fuels, the share of wave power, wind power and directly used solar power increases and less electricity has to be provided via storage options. In 2030, about 25% of the electricity is supplied by storage technologies, whereas in 2050 it is 13.5%.

Many islands and countries are in a similar situation to the Maldives, in that they are dependent on diesel-based electricity generation and have limited land area but have access to sea areas. Floating offshore PV and wave power have the potential to provide suitable solutions for these regions to ensure a sustainable energy transition reaching a 100% renewable energy supply share between 2030 and 2050. Further research is required by implementing these technologies in optimisation models and studying the advantages of the technologies based on a comprehensive techno-economic optimisation. Further research in the necessary efforts and implications for grid connections of the technologies will be necessary. Nevertheless, the present study provides useful insights for the future of offshore floating PV and wave power and their role in the energy transition.

3.6 Offshore floating PV as export option – Case Caribbean

Within this project it was possible to broaden the insight on offshore floating solar PV from the case of the Maldives to the much larger region of the Caribbean as a potential attractive export market of European PV systems know-how.

The case study on the Caribbean is published in open access [58].

Abstract

The Caribbean and Puerto Rico are lagging in ramping RE capacities. Energy system transition pathways reaching 100% RE by 2050 for Puerto Rico and the Caribbean are analysed for all energy supplies. Islands are often limited in available land; therefore, scenario variations are considered, including offshore floating solar PV. The results for Puerto Rico clearly indicate the enormous benefits of reaching 100% RE, as the LCOE can be reduced from more than 100 €/MWh in 2020 to 47.4 €/MWh in 2050, and the LCOFE, including all energy sectors, declines from 79 to 53 €/MWh, respectively. PV reaches 81% of all electricity supply, leading to 33.4 GW installed capacity, thereof 17.5 GW offshore floating solar PV due to area limitation. Without area limitation, the total system cost would be about 2.7% lower. The key metrics for the Caribbean development from 2020 to 2050 are as follows: electricity generation from 110 to 677 TWh, PV supply share from 2% to 92%, PV capacity from 1 to 332 GW, thereof 19% prosumer, 81% utility-scale with up to 38% offshore floating solar PV, and LCOE from above 100 to 31.9 €/MWh. The prosperity of Puerto Rico and the Caribbean is closely related to solar PV, the dominating source of energy in their Solar-to-X Economy.

Conclusions

This research highlights the enormous opportunities for Puerto Rico and the entire Caribbean in transitioning toward 100% RE supply, as the LCOE drastically declines and the LCOFE comprising the entire energy system also declines. Maintaining and increasing standards of living in Puerto Rico and the Caribbean strongly correlate with an ambitious energy transition. The dominating source of energy for electricity supply and the entire energy system is found to be solar PV with 80% and 91% of supply share in Puerto Rico and the Caribbean, respectively. When limited onshore land availability is applied, a substantial share of all PV generation can be provided by offshore floating solar PV for minimal extra costs. Only marine and aviation fuels need to be imported, and all other energy demand, electricity or hydrogen, can be provided locally. The arising energy system of Puerto Rico and the Caribbean can be described best as a Solar-to-X Economy.

4 CONCLUSIONS

Solar PV will play core role in the energy transition of Europe. Depending on the scenario the cumulative capacity of solar PV in 2050 will reach from 2900 GW to 6400 GW with the share of PV in the electricity mix varying from 34% to 70%. Solar PV will be the major supplier in all the regions, even in the Nordics utility-scale and prosumers PV will be economically viable. The system can operate and balance supply and demand in a wide range of configurations, but the cost-optimised transition brings the system to approximately 54% of solar PV in electricity supply, however, the impact on the system cost is not that significant and the total annualised system cost changes are in a 2% range.

Introduction of bifacial PV has a positive impact on the system cost as the yield increases without increase of the system costs. The system choses to use bifacial PV modules whenever available and in all regions, however, the cost benefit is limited to a 1.3% decline of LCOE or 0.5% of annualised system cost in 2050.

PV prosumers already represent major electricity supply in Europe and BIPV and BAPV capacity have increased fast in the recent years. The potential of BIPV and BAPV is limited by available rooftop and façade area, but the scenarios results show that it can reach 800 GW by 2050. Unlike the centralised power plants, prosumers are currently not controlled by power utilities which may pose threats to grid stability with further growth of prosumers capacity, whereas the introduction of batteries may counter-balance maybe risks.

The future energy demand is an important question for Europe and the European energy market. The energy transition and local RE supply provide Europe an opportunity to reach energy sufficiency. Domestic RE can be used to produce sustainable e-fuels and e-chemicals for transport and industry and substitute fossil fuel, which are currently imported. Domestic energy supply will require a significant increase of renewable electricity generation capacities but will also provide the opportunity for RE-rich regions of Europe to become major energy suppliers. Results show that a fully localised e-fuels and e-chemicals production will demand a 25% (1000 GW) higher PV capacity compared to a case of cost optimised imports. Due to favourable solar conditions of the Iberian Peninsula, Portugal and Spain may become major energy exporters across the continent, providing Fischer-Tropsch liquids and methanol for the European transport and industry sector, especially in densely populated regions, such as Belgium, Netherlands, and Luxemburg.

Growth of RE and solar PV during the energy transition, must be supported by continuous development and innovations to make possible an accelerated growth of PV capacity, fast and risk-free development of new PV projects, and its reliable operation in the energy system. The innovations must also target the storage and grids systems which will be viable for further growth of the RE share in electricity generation, and innovations in communications of individual elements of the future energy system comprising dozens of generation, storage, and grid technologies operating together with solar PV systems.

5 REFERENCES

[1] [IPCC] - Intergovernmental Panel on Climate Change, “Climate Change 2023. Synthesis Report. Summary for Policymakers,” Geneva, 2023.

[2] [WMO] - World Meteorological Organization, “State of the Global Climate 2023 (WMO-No. 1347),” Geneva, 2023. Accessed: Sep. 02, 2024. [Online]. Available: https://library.wmo.int/viewer/68835/?offset=#page=1&viewer=picture&o=download&n=0&q=

[3] Copernicus Climate Change Servicve, “Surface Air Temperature.” [Online]. Available: https://climate.copernicus.eu/surface-air-temperature-july-2021

[4] N. Abid, F. Ahmad, J. Aftab, and A. Razzaq, “A blessing or a burden? Assessing the impact of Climate Change Mitigation efforts in Europe using Quantile Regression Models,” *Energy Policy*, vol. 178, p. 113589, Jul. 2023, doi: 10.1016/j.enpol.2023.113589.

[5] [UNFCCC] - United Nations Framework Convention on Climate Change, “Adoption of Paris Agreement. Proposal by the President.,” Bonn, 2015. Accessed: Jul. 15, 2024. [Online]. Available: https://unfccc.int/documents/184656

[6] [UN] - United Nations, “Addressing Energy’s interlinkages with other SDGs,” New York, 2022. Accessed: Oct. 11, 2022. [Online]. Available: https://sdgs.un.org/sdg7tag

[7] [UNEP] - United Nations Environment programme, “Emissions Gap Report 2019,” Nairobi, 2019. [Online]. Available: https://www.unenvironment.org/resources/emissions-gap-report-2019

[8] [UNEP] - United Nations Environment programme, “Emissions Gap Report 2023,” Nairobi, Nov. 2023. Accessed: Sep. 19, 2024. [Online]. Available: https://www.unep.org/emissions-gap-report-2023

[9] [EC] - European Commission, “The European Green Deal,” Brussels, 2019. [Online]. Available: https://ec.europa.eu/info/sites/info/files/european-green-deal-communication_en.pdf

[10] [EC] - European Commission, “Technology pathways in decarbonisation scenarios,” Brussels, 2018.

[11] [EC] - European Commission, “REPowerEU Plan,” Brussels, 2022. Accessed: Sep. 19, 2024. [Online]. Available: https://eur-lex.europa.eu/resource.html?uri=cellar:fc930f14-d7ae-11ec-a95f-01aa75ed71a1.0001.02/DOC_1&format=PDF

[12] [IRENA] - International Renewable Energy Agency, “Overview of European renewable energy sources.” Accessed: Sep. 19, 2024. [Online]. Available: https://www.irena.org/How-we-work/Europe

[13] D. Bogdanov *et al.*, “Low-cost renewable electricity as the key driver of the global energy transition towards sustainability,” *Energy*, vol. 227, p. 120467, Jul. 2021, doi: 10.1016/j.energy.2021.120467.

[14] C. Breyer *et al.*, “On the role of solar photovoltaics in global energy transition scenarios,” *Progress in Photovoltaics: Research and Applications*, vol. 25, no. 8, pp. 727–745, 2017, doi: 10.1002/pip.2885.

[15] D. Bogdanov, A. Gulagi, M. Fasihi, and C. Breyer, “Full energy sector transition towards 100% renewable energy supply: Integrating power, heat, transport and industry sectors including desalination,” *Appl Energy*, vol. 283, p. 116273, Feb. 2021, doi: 10.1016/j.apenergy.2020.116273.

[16] SolarPower Europe, “EU Market Outlook for Solar Power 2023-2027.,” Brussels, Dec. 2023. Accessed: Sep. 19, 2024. [Online]. Available: https://www.solarpowereurope.org/insights/outlooks/eu-market-outlook-for-solar-power-2023-2027/detail#introduction

[17] [EEA] - European Environmental Agency, “Share of energy consumption from renewable sources in Europe.” Accessed: Sep. 19, 2024. [Online]. Available: https://www.eea.europa.eu/en/analysis/indicators/share-of-energy-consumption-from?activeAccordion=

[18] Eurostat, “Energy Data,” Luxembourg, 2021. doi: 10.2785/68334.

[19] "IEA, Coal Information," Paris, Apr. 2024. Accessed: May 24, 2024. [Online]. Available: https://www.iea.org/reports/coal-information-overview/exports

[20] G. Sgaravatti, S. Tagliapietra, and G. Zachmann, "Adjusting to the energy shock: The right policies for European industry," Bruegel, Brussels, 2023. [Online]. Available: https://hdl.handle.net/10419/274225

[21] B. Hilgenstock, E. Ribakova, N. Shapoval, T. Babina, O. Itskhoki, and M. Mironov, "Russian Oil Exports Under International Sanctions," *SSRN Electronic Journal*, 2023, doi: 10.2139/ssrn.4430053.

[22] D. Keiner, M. Ram, L. D. S. N. S. Barbosa, D. Bogdanov, and C. Breyer, "Cost optimal self-consumption of PV prosumers with stationary batteries, heat pumps, thermal energy storage and electric vehicles across the world up to 2050," *Solar Energy*, vol. 185, pp. 406–423, Jun. 2019, doi: 10.1016/j.solener.2019.04.081.

[23] [IEA] - International Energy Agency, "Electric cars fend off supply challenges to more than double global sales," Paris, 2022. Accessed: Sep. 19, 2024. [Online]. Available: https://www.iea.org/commentaries/electric-cars-fend-off-supply-challenges-to-more-than-double-global-sales

[24] Wärtsilä, "A clean environment - Towards zero-emission shipping. Business White Paper.," 2018. Accessed: Sep. 19, 2024. [Online]. Available: ttps://cdn.wartsila.com/docs/default-source/services-documents/white-papers/wartsila-bwp-a-clean-environment---towards-zero-emission-shipping.pdf?sfvrsn=95c73644_13

[25] [ETC] - Energy Transition Comission, "Mission Possible: Reaching Net-Zero Carbon Emissions," London, 2018. Accessed: Aug. 10, 2023. [Online]. Available: https://www.energy-transitions.org/publications/mission-possible/

[26] [EC] - European Comission, "Renewable Energy Directive ," Brussels, Oct. 2023. Accessed: Sep. 19, 2024. [Online]. Available: https://eur-lex.europa.eu/eli/dir/2023/2413/oj

[27] [EC] - European Comission, "EU Solar Energy Strategy," Brussels, May 2022. Accessed: Sep. 19, 2024. [Online]. Available: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2022%3A221%3AFIN#footnote2

[28] C. Breyer *et al.*, "Reflecting the energy transition from a European perspective and in the global context—Relevance of solar photovoltaics benchmarking two ambitious scenarios," *Progress in Photovoltaics: Research and Applications*, vol. 31, no. 12, pp. 1369–1395, Dec. 2023, doi: 10.1002/pip.3659.

[29] [IEA] - International Energy Agency, "Tracking Clean Energy Progress 2023," Paris, Jul. 2023. Accessed: Sep. 19, 2024. [Online]. Available: https://www.iea.org/reports/tracking-clean-energy-progress-2023

[30] IRENA, "Renewable Power Generation Costs in 2020," Abu Dhabi, 2021. Accessed: Aug. 25, 2021. [Online]. Available: https://www.irena.org/publications/2021/Jun/Renewable-Power-Costs-in-2020

[31] W. Gu, T. Ma, S. Ahmed, Y. Zhang, and J. Peng, "A comprehensive review and outlook of bifacial photovoltaic (bPV) technology," *Energy Convers Manag*, vol. 223, p. 113283, Nov. 2020, doi: 10.1016/j.enconman.2020.113283.

[32] A. K. Shukla, K. Sudhakar, and P. Baredar, "Recent advancement in BIPV product technologies: A review," *Energy Build*, vol. 140, pp. 188–195, Apr. 2017, doi: 10.1016/j.enbuild.2017.02.015.

[33] K. Ali Khan Niazi and M. Victoria, "Comparative analysis of photovoltaic configurations for agrivoltaic systems in Europe," *Progress in Photovoltaics: Research and Applications*, vol. 31, no. 11, pp. 1101–1113, Nov. 2023, doi: 10.1002/pip.3727.

[34] M. G. Prina, G. Manzolini, D. Moser, B. Nastasi, and W. Sparber, "Classification and challenges of bottom-up energy system models - A review," 2020. doi: 10.1016/j.rser.2020.109917.

[35] M. Child, C. Kemfert, D. Bogdanov, and C. Breyer, “Flexible electricity generation, grid exchange and storage for the transition to a 100% renewable energy system in Europe,” *Renew Energy*, vol. 139, pp. 80–101, Aug. 2019, doi: 10.1016/j.renene.2019.02.077.

[36] S. Afanasyeva, D. Bogdanov, and C. Breyer, “Relevance of PV with single-axis tracking for energy scenarios,” *Solar Energy*, vol. 173, pp. 173–191, Oct. 2018, doi: 10.1016/j.solener.2018.07.029.

[37] Keiner D, Walter L, Bogdanov D, and Breyer C, “Assessing the impact of bifacial solar photovoltaics on future power systems based on capacity-density-optimised power plant yield modelling.,” *Submitted*, 2024.

[38] D. Keiner, L. Walter, M. ElSayed, and C. Breyer, “Impact of backtracking strategies on techno-economics of horizontal single-axis tracking solar photovoltaic power plants,” *Solar Energy*, vol. 267, p. 112228, Jan. 2024, doi: 10.1016/j.solener.2023.112228.

[39] D. Keiner, D. Bogdanov, S. Krauter, and C. Breyer, “Assessing Yield Disparities: Anticipated versus Optimal Rooftop Photovoltaic Systems and Implications for Prosumer Viability,” *Solar RRL*, Oct. 2024, doi: 10.1002/solr.202400435.

[40] D. Keiner, C. Thoma, D. Bogdanov, and C. Breyer, “Seasonal hydrogen storage for residential on- and off-grid solar photovoltaics prosumer applications: Revolutionary solution or niche market for the energy transition until 2050?,” *Appl Energy*, vol. 340, p. 121009, Jun. 2023, doi: 10.1016/j.apenergy.2023.121009.

[41] D. Keiner *et al.*, “Global-Local Heat Demand Development for the Energy Transition Time Frame Up to 2050,” *Energies (Basel)*, vol. 14, no. 13, p. 3814, Jun. 2021, doi: 10.3390/en14133814.

[42] S. Khalili, E. Rantanen, D. Bogdanov, and C. Breyer, “Global Transportation Demand Development with Impacts on the Energy Demand and Greenhouse Gas Emissions in a Climate-Constrained World,” *Energies (Basel)*, vol. 12, no. 20, p. 3870, Oct. 2019, doi: 10.3390/en12203870.

[43] D. Bogdanov *et al.*, “Costs and benefits of highly ambitious energy transition pathways for Europe,” *Submitted*, 2024.

[44] D. Bogdanov *et al.*, “Radical transformation pathway towards sustainable electricity via evolutionary steps,” *Nat Commun*, vol. 10, no. 1, p. 1077, Dec. 2019, doi: 10.1038/s41467-019-08855-1.

[45] D. Bogdanov and C. Breyer, “North-East Asian Super Grid for 100% renewable energy supply: Optimal mix of energy technologies for electricity, gas and heat supply options,” *Energy Convers Manag*, vol. 112, pp. 176–190, Mar. 2016, doi: 10.1016/j.enconman.2016.01.019.

[46] S. Afanasyeva, D. Bogdanov, and C. Breyer, “Relevance of PV with single-axis tracking for energy scenarios,” *Solar Energy*, vol. 173, pp. 173–191, Oct. 2018, doi: 10.1016/j.solener.2018.07.029.

[47] K. Verzano, “Climate Change Impacts on Flood Related Hydrological Processes: Further Development and Application of a Global Scale Hydrological Model,” University of Kassel, 2009. doi: 10.17617/2.993926.

[48] K. Bunzel, V. Zeller, M. Buchhorn, F. Griem, and D. Thrän, “Regionale und globale räumliche Verteilung von Biomassepotenzialen,” Leipzig, 2009.

[49] A. Aghahosseini and C. Breyer, “From hot rock to useful energy: A global estimate of enhanced geothermal systems potential,” *Appl Energy*, vol. 279, p. 115769, Dec. 2020, doi: 10.1016/j.apenergy.2020.115769.

[50] C. Breyer, D. Bogdanov, K. Komoto, T. Ehara, J. Song, and N. Enebish, “North-East Asian Super Grid: Renewable energy mix and economics,” *Jpn J Appl Phys*, vol. 54, no. 8S1, p. 08KJ01, Aug. 2015, doi: 10.7567/JJAP.54.08KJ01.

[51] M. Ram, M. Child, A. Aghahosseini, D. Bogdanov, A. Lohrmann, and C. Breyer, “A comparative analysis of electricity generation costs from renewable, fossil fuel and nuclear sources in G20 countries for the period 2015–2030,” *J Clean Prod*, vol. 199, pp. 687–704, 2018, doi: 10.1016/j.jclepro.2018.07.159.

[52] Á. Galán-Martín, V. Tulus, I. Díaz, C. Pozo, J. Pérez-Ramírez, and G. Guillén-Gosálbez, “Sustainability footprints of a renewable carbon transition for the petrochemical sector within planetary boundaries,” *One Earth*, vol. 4, no. 4, pp. 565–583, Apr. 2021, doi: 10.1016/j.oneear.2021.04.001.

[53] P. Diesing, D. Bogdanov, R. Satymov, M. Child, I. Hauer, and C. Breyer, “Offshore versus onshore: The underestimated impact of onshore wind and solar photovoltaics for the energy transition of the British Isles,” *IET Renewable Power Generation*, vol. 17, no. 13, pp. 3240–3266, Oct. 2023, doi: 10.1049/rpg2.12840.

[54] A. Kies, B. U. Schyska, and L. von Bremen, “The optimal share of wave power in a highly renewable power system on the Iberian Peninsula,” *Energy Reports*, vol. 2, pp. 221–228, Nov. 2016, doi: 10.1016/j.egyr.2016.09.002.

[55] C. Breyer *et al.*, “Proposing a 1.0°C climate target for a safer future,” *PLOS Climate*, vol. 2, no. 6, p. e0000234, Jun. 2023, doi: 10.1371/JOURNAL.PCLM.0000234.

[56] R. Satymov, D. Bogdanov, and C. Breyer, “Global-local analysis of cost-optimal onshore wind turbine configurations considering wind classes and hub heights,” *Energy*, vol. 256, 2022, doi: 10.1016/j.energy.2022.124629.

[57] D. Keiner *et al.*, “Powering an island energy system by offshore floating technologies towards 100% renewables: A case for the Maldives,” *Appl Energy*, vol. 308, p. 118360, Feb. 2022, doi: 10.1016/j.apenergy.2021.118360.

[58] C. Breyer, A. S. Oyewo, A. Kunkar, and R. Satymov, “Role of Solar Photovoltaics for a Sustainable Energy System in Puerto Rico in the Context of the Entire Caribbean Featuring the Value of Offshore Floating Systems,” *IEEE J Photovolt*, vol. 13, no. 6, pp. 842–848, Nov. 2023, doi: 10.1109/JPHOTOV.2023.3319022.