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Is a 100% renewable European power system feasible by 2050?

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HIGHLIGHTS

- Seven scenarios for a 100% renewable European power system are modelled for 2050.
- A 100% renewable system could operate with the same level of adequacy as today.
- Mass mobilisation of Europe's solid biomass and biogas resources would be required.
- 90% more generation and 240% more transmission capacity would be needed than today.
- Costs would be ~530 €billion per year, 30% more than a system with nuclear or CCS.

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ABSTRACT

In this study, we model seven scenarios for the European power system in 2050 based on 100% renewable energy sources, assuming different levels of future demand and technology availability, and compare them with a scenario which includes low-carbon non-renewable technologies. We find that a 100% renewable European power system could operate with the same level of system adequacy as today when relying on European resources alone, even in the most challenging weather year observed in the period from 1979 to 2015. However, based on our scenario results, realising such a system by 2050 would require: (i) a 90% increase in generation capacity to at least 1.9 TW (compared with 1 TW installed today), (ii) reliable cross-border transmission capacity at least 140 GW higher than current levels (60 GW), (iii) the well-managed integration of heat pumps and electric vehicles into the power system to reduce demand peaks and biogas requirements, (iv) the implementation of energy efficiency measures to avoid even larger increases in required biomass demand, generation and transmission capacity, (v) wind deployment levels of 7.5 GW y^{-1} (currently 10.6 GW y^{-1}) to be maintained, while solar photovoltaic deployment to increase to at least 15 GW y^{-1} (currently 10.5 GW y^{-1}), (vi) large-scale mobilisation of Europe's biomass resources, with power sector biomass consumption reaching at least 8.5 EJ in the most challenging year (compared with 1.9 EJ today), and (vii) increasing solid biomass and biogas capacity deployment to at least 4 GW y^{-1} and 6 GW y^{-1} respectively. We find that even when wind and solar photovoltaic capacity is installed in optimum locations, the total cost of a 100% renewable power system (~530 €bn y^{-1}) would be approximately 30% higher than a power system which includes other low-carbon technologies such as nuclear, or carbon capture and storage (~410 €bn y^{-1}). Furthermore, a 100% renewable system may not deliver the level of emission reductions necessary to achieve Europe's climate goals by 2050, as negative emissions from biomass with carbon capture and storage may still be required to offset an increase in indirect emissions, or to realise more ambitious decarbonisation pathways.

1. Introduction

In 2011, the European Union (EU) reaffirmed its objective to reduce greenhouse gas (GHG) emissions by 80–95% by 2050 compared to 1990 levels, this being seen as a necessary step to keep global warming below 2 °C in line with the projections of the Intergovernmental Panel on Climate Change (IPCC) [1]. This was followed in 2016 by the Paris Agreement to keep warming "*well below 2 °C above pre-industrial levels and pursue efforts to limit the temperature increase to 1.5 °C above pre-industrial levels*" [2,3]. In order to achieve either of these goals, emissions from the power sector must fall essentially to zero, or even turn negative by 2050 [4,5]. This will require large-scale implementation of low-carbon technologies such as renewable energy sources (RES), nuclear power, and carbon capture and storage (CCS).

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Nomenclature

bn	billion (10^9)
AD	anaerobic digestion
BECCS	bioenergy with carbon capture and storage
CAES	compressed air energy storage
CAPEX	capital expenditure
CCS	carbon capture and storage
CDDA	Common Database on Designated Areas
CIGRE	Council on Large Electric Systems
CLC	Corine Land Cover
COP	coefficient of performance
CSP	concentrating solar power
DNI	direct normal irradiance
DSM	demand-side management
ECF	European Climate Foundation
ECMWF	European Centre for Medium-Range Weather Forecasts
EEA	European Environment Agency
EEZ	Exclusive Economic Zone
ENTSO-E	European Network of Transmission System Operators for Electricity
ERA-Interim	European Reanalysis Interim Dataset
ETRI	Energy Technology Reference Indicators
EU	European Union
EV	electric vehicle
FOM	fixed operating and maintenance costs
GDP	gross domestic product
GHG	greenhouse gas
HP	heat pump
HVAC	high-voltage alternating current
HVDC	high-voltage direct current
IDC	interest during construction
IPCC	Intergovernmental Panel on Climate Change
JRC	European Union Joint Research Centre
LoLE	Loss of Load Expectation
LT	long term
MENA	Middle-East and North Africa
MILP	mixed-integer linear programming
NAO	North-Atlantic oscillation
NPV	net present value
OCC	overnight capital cost
OCGT	open-cycle gas turbine
OECD	Organisation for Economic Co-operation and Development
OPF	optimal power flow
PHS	pumped hydro storage
PSM	power system modelling
PV	photovoltaic
RES	renewable energy source
RoR	run-of-river hydro
ST	short term
STO	storage hydro
TCR	total capital requirement
TYNDP	Ten-Tear Network Development Plan
UCED	unit commitment and economic dispatch
VOM	variable operating and maintenance costs
vRES	variable renewable energy source
WACC	weighted average cost of capital

For one reason or another, a number of studies have excluded nuclear and CCS technologies and investigated whether national power systems could rely on 100% RES, such as those for Denmark [6,7], The Netherlands [8], Germany [9,10], France [11,12], Ireland [13], Portugal [14], Israel [15], Japan [16], Australia [17], New Zealand [18,19], the United States [20], or even the whole world [20,21]. Fully renewable scenarios have also been proposed for the whole of Europe in 2050, of which some of the most notable are summarized in Table 1.[1] These scenarios are usually developed using energy system models to assess whether projected demand could be met by potential RES supply; however, sufficient RES supply alone does not indicate that a 100% RES power system is feasible as, due to their intermittent generation, variable renewable energy sources (vRES) such as wind and photovoltaics (PV) make balancing electricity demand and supply more difficult than in power systems without vRES [22–25]. In a 100% RES power system, any residual demand not supplied by vRES must be provided by one of the dispatchable RES generation technologies (hydro, bioelectricity, concentrating solar thermal power (CSP), and geothermal), or storage. However, in the short term, technical limitations mean that it may not be possible for these plants to ramp quickly enough to keep supply and demand in balance, leading to over-voltages or unserved energy in the network. In the long term, some years can be less sunny or windy then others, meaning that wind and PV installations cannot be relied upon to produce the same amount of electricity each year. Therefore, we consider that any assessment of the feasibility of a 100% RES power system should include some analysis of both its long- and short-term reliability.

Although there is no standard definition, the Council on Large Electric Systems (CIGRE) and the European Network of Transmission System Operators for Electricity (ENTSO-E) define **reliability** as *"the ability of the [power] system to deliver electrical energy to all points of utilization within acceptable standards and in the amounts desired"* [26,27].[2] This definition of reliability incorporates two other terms: system **adequacy,** the ability of the power system to supply the required power and energy requirements subject to outages and operational constraints; and system **security,** the extent to which a power system can withstand sudden disturbances *(ibid.)*. Assessing the reliability of power systems is one of the objectives of power system modelling (PSM).

In their assessment of the feasibility of 100% RES power systems based on a review of 24 studies, Heard et al. [42] found no consistent definition for feasibility, and instead based their assessment on whether studies: (i) performed simulations using PSM to ensure that supply could meet demand reliably, (ii) assumed demand levels consistent with mainstream forecasts, (iii) identified the necessary transmission and distribution requirements, and (iv) considered the provision of ancillary services. Meanwhile, in their critique of Heard et al., Brown et al. [43] refuted several of their feasibility criteria as being surmountable at minimal cost, instead arguing that *"how to reach a high share of renewables in the most cost-effective manner while respecting environmental, social and political constraints*" is the key issue. Thus, while there is no agreement in the literature on the definition of power system feasibility, achieving a reliable and cost-effective system seems a fundamental requirement.

Only two ([32,35]) of the studies presented in Table 1 were

[1] Several other scenario studies have also been published for the European power system in 2050 [49,54,127–130], but these are not discussed as they report insufficient technical detail, or do not approach 100% RES.

[2] ENTSO-E uses this definition in the Continental Europe Operation Handbook (2004) [27], however more recently, ENTSO-E defines another term – *security of supply* – as "*the ability of a power system to provide an adequate and secure supply of electricity in ordinary conditions*" which is similar to reliability [131]. The main distinction between system adequacy and security is that security refers to the short-term operation of the power system (e.g. resilience to generator outages, transmission faults), whereas adequacy refers to long-term operation. System adequacy can also be divided into generation adequacy, and transmission adequacy [26].

Table 1
Total electricity generation and installed capacity in several studies featuring high-RES European power systems. For comparison, data for the current (2015) power system is also shown, as well as the European Commission Joint Research Centre's (JRC) Reference Scenario for 2050.

Study	Reference portfolios				High-RES Scenarios									
	Current situation (2015) [28,29]		JRC EU Reference Scenario [30]		EU Energy Roadmap 2050 [31]		Roadmap 2050 [32]		Energy Revolution (5th Edition) [33]		Re-thinking 2050 [34]		e-Highway 2050 [35]	
Scenario (year)	–		2050		High RES (2050)		100% RES (2050)		Advanced (2050)		2050		100% RES X-7 (2050)	
Geographical scope	EU28 + NO + CH		EU28		EU28		EU27 + NO + CH (+North Africa for CSP)		OECD Europe (+North Africa for CSP)		EU27		EU28 + NO + CH + Balkans + North Africa	
Final demand (TWh y^{-1}) [a]	2912[h]		3574		3377		4385[g]		3889 (6020)[e]		–		4385	
Model(s) used[l]	–		PRIMES		PRIMES		Undisclosed		MESAP/Planet		Undisclosed		Antares	
PSM performed?	–		–		No		Yes		Partly[k]		No		Yes	
Generation portfolio	Generation (TWh/y)	Capacity (GW)	Generation (TWh/y)	Capacity (GW)	Generation (TWh/y)	Capacity (GW)	Generation (TWh/y)	Capacity (GW)	Generation (TWh/y)	Capacity (GW)	Generation (TWh/y)	Capacity (GW)	Generation (TWh/y)	Capacity (GW)
Onshore wind[n]	310	136	980	368	2504	612	758	245	1450	594	1552	462	2238	875
Offshore wind						373	758	190	901	237				
PV	102	95	429	295	843	603	900	815	1080	926	1347	962	743[i]	675
CSP	6[m]	2.3[m]	0	0	0	0	980[b]	203[b]	1050[f]	208[f]	385	96	278[i]	58
Ocean[c]	0.5[m]	0.2[m]	0	0	0	30	0	0	160	53	158	65	0	0
Biomass	119	25	391	57	494	163	587	85	467	108	496	100	454	184
Geothermal	6[m]	0.8[m]	14	4	31	4	343[b]	47[b]	390	52	601	77	0	0
Hydro	536	194	421	142	396	131	591	205	620	223	448	194	890	297
Natural gas	409	217	836	269	386	182	144	215	0	0	0	0	13	73
Coal	888	187	252	52	108	62	0	0	0	0	0	0	0	0
Oil	32	32	5	4	0	19	0	0	0	0	0	0	0	0
Nuclear	836	125	737	93	180	41	0	0	0	0	0	0	0	0
Hydrogen[d]	–	–	0	0	200	0	0	0	267	181	0	0	0	0
Total RES	1008 (31%)	404 (40%)	2235 (55%)	866 (67%)	4267 (83%)	1916 (86%)	4917 (97%)	1790 (89%)	6118 (96%)	2401 (93%)	4987 (100%)	1956 (100%)	4603 (100%)	2088 (97%)
of which vRES[j]	412 (13%)	231 (23%)	1409 (35%)	662 (52%)	3347 (65%)	1618 (73%)	2416 (48%)	1250 (62%)	3591 (56%)	1810 (70%)	3057 (61%)	1489 (76%)	2981 (65%)	1549 (72%)
Total Non-RES	2241 (69%)	608 (60%)	1828 (45%)	418 (33%)	874 (17%)	304 (14%)	144 (3%)	215 (11%)	267 (4%)	181 (7%)	0 (0%)	0 (0%)	13 (0%)	73 (3%)
Total	3249	1012	4064	1283	5141	2220	5061	2005	6385[f]	2582[f]	4987	1956	4616	2162

Abbreviations: CSP – Concentrating solar power, EU – European Union, PSM – Power system modelling, PV – Photovoltaic, RES – Renewable energy source, vRES – variable renewable energy source,

[a] Excluding grid losses and own consumption in electricity generation sector.

[b] ECF's 100% RES scenario was based on an 80% RES scenario, increased to 100% RES by adding 15% CSP generation from North Africa and 5% from Enhanced Geothermal technologies.

[c] Includes wave, tidal and all other forms of marine energy.

[d] Hydrogen is reported as non-renewable in this table for clarity as even though some studies assume hydrogen is 100% renewable (e.g. [33]), it is not always clear.

[e] Final consumption (3889 TWh) reported does not include 1924 TWh of demand for hydrogen production, or 207 TWh for synfuel production. Once included, total final consumption is 6020 TWh.

[f] Total installed capacity (2460 GW) and generation (5764 TWh) reported in the original study for OECD Europe do not include an assumed import of 620 TWh y^{-1} from north African CSP, so CSP capacity increased to compensate for this by assuming the same capacity factor for North Africa CSP as for European CSP in the study (55%).

[g] Calculated from total reported demand of 4900 TWh y^{-1}, including 10.5% grid losses as assumed in original study.

[h] Based on Eurostat data for EU28 and NO, Swiss final consumption (58.2 TWh) from the Swiss Federal Office of Energy [36].

[i] Only aggregated generation from PV and CSP of 1021 TWh was reported in this study, disaggregated here by assuming a 55% capacity factor for CSP.

[j] Considering wind, PV and ocean power as variable renewable energy sources (vRES). Run-of-river (RoR) hydro capacity could also be considered vRES, however not all studies indicate the share of RoR capacity.

[k] Modelling studies were performed by Energynautics on an earlier (2009) edition of the Energy Revolution report [37,38]. This included transmission but, judging from published information, did not model detailed generator flexibility constraints. No evidence of detailed modelling of the most recent edition (5th) of the Energy Revolution report could be found.

[l] *PRIMES* is an energy system model developed by the E3MLab at the National Technical University of Athens [39], it is not a detailed power system model. MESAP and PlaNet are energy system and network planning models originally developed by the University of Stuttgart but now maintained by Seven2one [40]. *Antares* is a sequential Monte-Carlo power system simulator developed by RTE [41].

[m] Current contribution is so small that it is not reported specifically by ENTSO-E, thus the value is taken from Eurostat instead but not included in the total [29].

[n] When the breakdown between onshore and offshore wind is unavailable, the total (onshore + offshore) is reported under onshore wind.

supported by detailed PSM simulations, which revealed additional portfolio requirements.[3] Several other studies have also investigated a high-RES European power system using either PSM or another modelling approach [32,33,35,38,44–54]. However, even including these studies, we identify several common limitations – in addition to those raised by Heard et al. [42] and Brown et al. [43] – which leave doubts about the feasibility of a 100% RES European power system:

- Dispatchable thermal generator flexibility limitations are not included, meaning backup and balancing requirements may be underestimated (e.g. [32,35,46–51]).
- Bioelectricity is treated crudely using one fuel or generation technology, or without considering regional differences in supply potentials and costs (e.g. [32,38,49,50]).
- Simulations are run for only a single arbitrary (e.g. [44,50]) or several weather years (e.g. [38,47,53]) which does not guarantee system adequacy in the worst year.
- Studies rely on significant capacities from technologies such as CSP, geothermal, seasonal storage or biomass, which currently show few signs of growth (e.g. [32,34,35,55]).
- Studies allocate vRES capacity exogenously to locations or countries with the highest capacity factors (e.g. [32,38,52]). Within countries, capacity is allocated based on currently exploited sites (e.g. [46,47]), or averaged across all sites (e.g. [48,50,53]). However, these approaches ignore the possibility that insufficient suitable land or sea area may be available to support the assumed level of vRES deployment, leading to optimistic aggregated generation profiles. Furthermore, simply allocating capacity ignores the potential to reduce costs by optimising the spatial distribution of vRES along with transmission.
- A fixed capacity credit is assumed for vRES technologies, whereas in reality this varies with both location and time.
- Significant electricity is imported from the Middle East and North African (MENA) countries (e.g. [32,33,35,38,49,54]). While still renewable, it could be considered misleading to label a European power system 100% renewable if it relies on significant imports of electricity from outside Europe.
- The power system is modelled at some point in the future (e.g. 2050), without considering whether the transition from the current system and expansion of renewable capacity is practically achievable (e.g. [50]).

In this study, we aim to get insights into the feasibility of a 100% RES European power system in 2050 without these shortcomings by building a model of the power system in which dispatchable generators and their flexibility limitations are modelled in detail. By including the spatial deployment of vRES directly in the optimisation, land availability is accounted for explicitly, and vRES generation profiles are consistent with their spatial deployment. We model seven scenarios for a 100% RES European power system to explore the impact of uncertainties in future demand, technology development, and compare the costs with one scenario of a non-RES power system. Lastly, we use long-term weather data and detailed hourly simulations to assess system adequacy. Given the lack of consensus on the definition of power system feasibility, we instead attempt to answer the following more concrete questions, leaving the final verdict of feasibility to the reader:

- Could a future 100% RES European power system be supplied using European resources alone, and have the same level of system adequacy as today's power system?
- What is the most cost-effective portfolio of RES generation and transmission network capacity?
- How do the costs of a 100% RES European power system compare with a power system which includes non-RES technologies?
- Could the transition to a 100% RES power system be made by 2050?

Our study is structured as follows. First, we outline our overall approach in Section 2, which is underpinned by significant input data (Section 2.2). Based on the results presented in Section 3, we discuss the implications of our study in Section 4. Finally, we offer some concluding remarks in Section 5 (see Table 2).

2. Method

Our model of a 100% RES power system is built using the PLEXOS modelling package (Section 2.1).[4] After supplying the necessary input data and assumptions (Section 2.2) and defining several scenarios (Section 2.3), we run a long-term (LT) capacity expansion optimisation to determine the least-cost portfolio of generation technologies and transmission infrastructure investments which can meet demand reliably (Section 2.4.1). The optimised portfolio for each scenario is then simulated at hourly resolution using detailed unit commitment and economic dispatch (UCED) calculations, to ensure that demand can be met in the short term (ST) (Section 2.4.2). An overview of our method is given in Fig. 1. Extensive appendices supporting our work can be found in the supplementary material available online.

2.1. Build model

PLEXOS is a mixed-integer linear programming (MILP) model which has been used in several studies on RES integration and system adequacy (e.g. [50,56–58]). By coupling its LT Plan and ST Schedule modules, PLEXOS can be used to perform both capacity expansion (i.e. building new generation and transmission infrastructure) and UCED calculations, considering power plant flexibility limitations and flexible loads. The objective function of the LT Plan is to minimise the total net present value (NPV) of build costs, fixed operation and maintenance (FOM) costs, and variable operating and maintenance (VOM) costs [59], while the objective function of the ST Schedule is to minimise generation costs. A more detailed explanation of the PLEXOS software can be found in other published works (e.g. [57]). We take the geographical scope of Europe in our study as the EU28 countries as well as Switzerland and Norway, as shown in Fig. 2.[5]

Unlike traditional thermal generators, spatial considerations play a vital role in modelling vRES generators as their location determines not only the available resource, but also how much capacity can be deployed in a given area. To account for this, we introduce the spatial distribution of vRES capacity directly into the optimisation by coupling

[3] For example, in [32] it was found that in addition to the base RES capacity (1790 GW), 215 GW of natural gas turbines would be required for back-up and balancing. However, accounting for this gas use reduced the share of RES to 97%, and meant the target of 95% decarbonisation was not met. While noting that this natural gas could be replaced by biogas or renewable hydrogen, the consequences and costs of these options were not fully explored. Thus, neglecting analysis with PSM leaves uncertainty as to whether the system would actually work, whether emission reductions can really be achieved, and at what cost.

[4] PLEXOS (version 7.2) is developed by Energy Exemplar and is available from http://www.energyexemplar.com/.

[5] Despite the UK's decision in 2016 to leave the EU, we include the UK in this study as for grid stability and economic reasons, it would be in both the EU's and the UK's interests for the UK to remain well-integrated with continental Europe. However, this would require finding solutions to various legal issues and coming to an agreement with the EU [132]. Furthermore, the UK remains committed to decarbonisation and scenarios published by National Grid in 2017 show significant increases in offshore wind and interconnection capacity by 2050 [133]. While part of the Continental European network, we exclude the Balkan states due to a lack of data.

Table 2
Demand profile parameters.

Demand Profile		Source profile	Modifications	Demand		
				Minimum (GW)	Maximum (GW)	Annual (TWh)
Underlying source demand profiles	Actual 2015 demand from ENTSO-E [66]	–	–	230	504	3109
	TYNDP 2016 Vision 4 [67]	–	–	266	563	3616
Modelled demand profiles	Base[a]	Actual 2015 demand from ENTSO-E	HPs: +500 TWh y^{-1} EVs: +800 TWh y^{-1}	241	889	4409
	High Demand	Base	Scaled up to 6020 TWh y^{-1}	329	1214	6020
	Alternative Demand	TYNDP 2016 Vision 4[b]	Scaled up to 4409 TWh y^{-1}	324	686	4409

[a] Demand increases from HPs and EVs are taken from [32]. This study assumed that 90% of building heat demand could be met by HPs by 2050 (including HPs in district heating systems), assuming an average coefficient of performance (COP) of 4. For EVs, the study assumed almost complete electrification of passenger vehicles by 2050. Assuming an average EV efficiency of ~140 Wh km^{-1} (Tesla Model 3) and mileage of 15,000 km y^{-1} per vehicle, 800 TWh y^{-1} would be sufficient to cover approximately 370 million passenger EVs in 2050. While this is significantly more than the current fleet of 260 million passenger vehicles [68], 800 TWh y^{-1} would allow for continued growth in the European fleet (which could reach 370 million by 2050 if the current average growth rate of 1.1% y^{-1} is maintained), or partial electrification of light and medium commercial vehicles.

[b] Based on published information, the Vision 4 profile assumes increasing total demand, full implementation of smart-grid technology, large-scale adoption of HPs and EVs with flexible charging and generation (~10% vehicle fleet), and large-scale adoption of HPs (~9% heat demand) [69].

the PLEXOS model with a high-resolution spatial grid.[6] This grid is based on a regular 0.75° × 0.75° grid, modified to respect national boundaries [60], exclude protected conservation areas [61], and restricted to offshore water depths of up to 50 m within the Exclusive Economic Zone (EEZ) of each country [62]. We combine the spatial grid with the Corine Land Cover (CLC2012) dataset [63,64] and European Reanalysis Interim (ERA-Interim) weather dataset [65], in order to determine both the amount of suitable land area for vRES deployment, and the weather conditions at each location.[7] These are used to define the maximum installed capacity and generation profiles for wind and PV per grid cell.

2.2. Input data and assumptions

2.2.1. Electricity demand

As a starting point, we take the hourly historical electricity demand for each country for the year 2015 from ENTSO-E [66]. To account for potential electrification of the heating and transport sectors by 2050, for our *Base* demand profile we add additional demand of 500 TWh y^{-1} for heat pumps (HPs) and a further 800 TWh y^{-1} for electric vehicles (EVs), based on the levels from ECF's *Roadmap 2050* study which assumes almost complete electrification of passenger vehicles, and significant uptake of HPs [32].

We consider two additional demand profiles to account for uncertainty in future demand. For the *High Demand* profile, we scale up the *Base* profile to match the 2050 demand of 6020 TWh y^{-1} from Greenpeace's *Energy [R]evolution* scenario [33]. For the *Alternative Demand* profile, we take the *Vision 4* demand profile from ENTSO-E's Ten-Year Network Development Plan (TYNDP) for 2030 and scale it up to 4409 TWh y^{-1} so that total demand matches the *Base* profile total, but the hourly profile itself is smoother.[8] Further details are provided in the supplementary material.

2.2.2. Generation technologies

We consider a broad portfolio of RES generation technologies including wind (onshore and offshore), PV (utility and rooftop), bioelectricity, CSP, geothermal, and hydro power.[9] The main techno-economic assumptions for all generator types are given in Table 3. In order to compare the costs of a 100% RES power system with a non-RES power system, Table 3 also includes techno-economic parameters for selected natural gas and coal generation technologies (with and without CCS), nuclear, and bioenergy with CCS (BECCS).[10] Due to model limitations, seasonal storage (e.g. power to gas) is not considered. For consistency, most costs are taken from the European Commission Joint Research Centre's (JRC) Energy Technology Reference Indicator (ETRI) projections for 2010–2050 [70]. As investments for a 100% RES power system by 2050 would need to be made before 2050, we take the costs for 2040. A uniform weighted average cost of capital (WACC) of 8% is used to annualise investment costs in new generation and transmission capacity.[11] A brief explanation of how each technology is modelled is provided below.

Hourly generation from wind farms is estimated by combining wind speed profiles from ERA-Interim with commercial wind turbine power curves. ERA-Interim is also used as the source of solar radiation data to model both PV and CSP. Solar PV is modelled with efficiencies of 21% and 17% for rooftop and utility-scale systems respectively [71,72]. CSP generators are modelled as solar tower plants equipped with two-axis-tracking heliostats, and eight hours of molten salt thermal storage at nominal load. By calculating the maximum suitable area for wind and PV deployment per grid cell, and limiting how much is available for each technology, we allow PLEXOS to optimise the spatial deployment of wind and PV capacity.[12]

We consider two bioelectricity technologies: biomass fluidised bed

[6] Built using the software ArcGIS Pro from ESRI. http://www.esri.com/.

[7] ERA-Interim is a global atmospheric reanalysis produced by the European Centre for Medium-Range Weather Forecasts (ECMWF) covering 1979 to the present (2017), and includes 3-hourly data on wind speed, solar radiation, and temperature [65,134]. The spatial grid in this study is built to match that of ERA-Interim, which has a resolution of 0.75° × 0.75° (approximately 50 km).

[8] The Vision 4 profile was developed for the year 2030 assuming lower penetration of HP and EVs than our Base profile, and includes the effects of smart EV charging and other demand-side technologies which the Base profile does not.

[9] We exclude ocean (tidal and wave) energy [135,136] and osmotic power (derived from salinity gradients) [137] as their slow growth makes it unlikely for them to produce significant amounts of electricity by 2050.

[10] Even though BECCS uses renewable biomass, we consider any technology employing CCS as non-renewable as while the European potential for CO_2 storage is significant (~117 Gt CO_2), it is finite [138].

[11] The cost of capital can vary significantly between countries and between technologies [139]. We choose 8% as a common value used in similar studies, assuming that perceived risks for renewable investments are likely to fall in the future [140]. This is higher than the reference financial and social discount rates of 3–5% recommended by [140,141].

[12] Assumed availability is taken from the literature, ranging from 1% for utility PV on arable land to 20% for offshore wind on open water. Further details are given in the supplementary material.

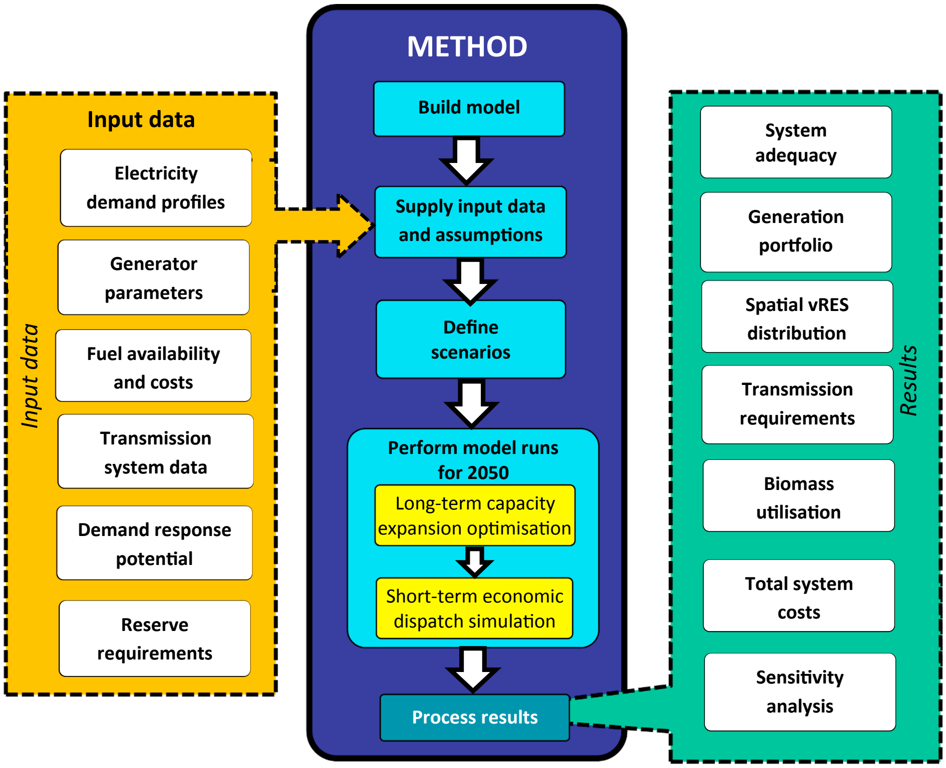

Fig. 1. Overview of the method used in this study.

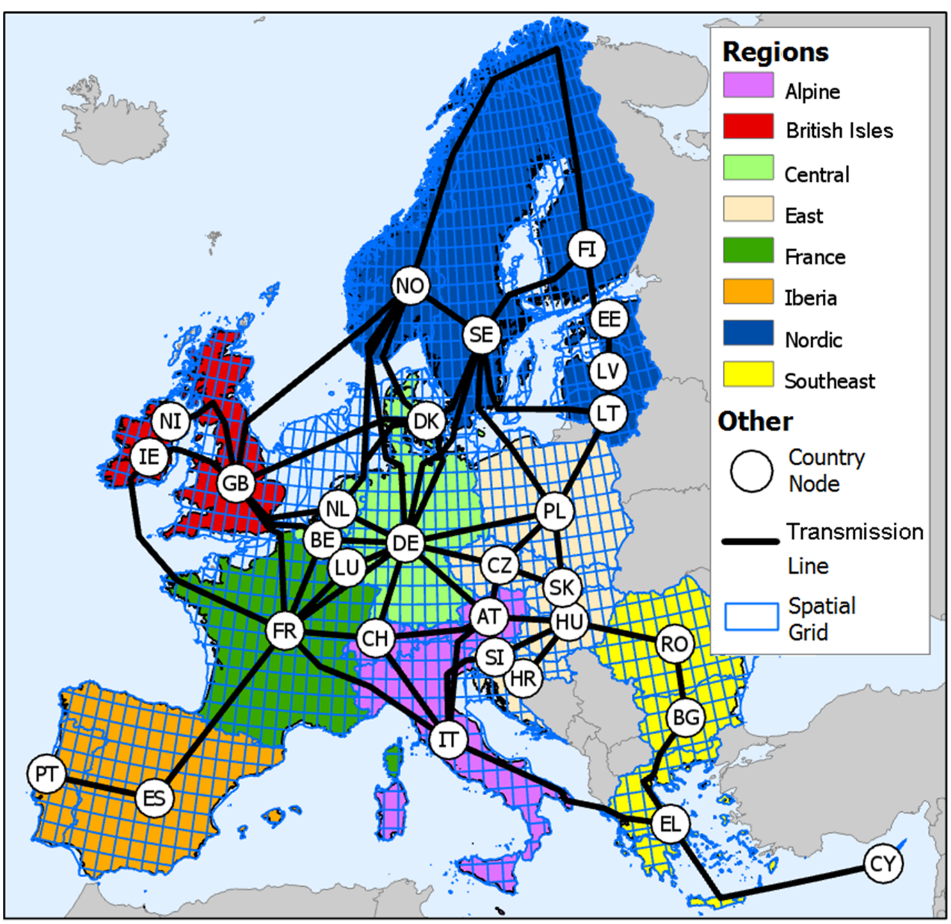

Fig. 2. Countries and transmission lines considered in this study. Countries are labelled according to ISO 3166 except for Greece (EL) and the United Kingdom, which is split into Northern Ireland (NI) and Great Britain (GB). Transmission of electricity occurs between the notional load centres of each country using a centre of gravity approach (see Section 2.2.3). The spatial grid is shown in blue, which includes all land and offshore areas within the exclusive economic zone (EEZ) of each country, up to a maximum water depth of 50 m for offshore wind. Countries not included in the study are shaded grey. The regions are only used to describe results, each country is modelled individually.

Table 3
Assumed techno-economic parameters for generation technologies in 2040.

Generator type		Nominal unit size (MW)	Base CAPEX[a] (€ kW^{-1})	FOM[b] (% y^{-1})	VOM[c] (€ MWh^{-1})	Nom. efficiency (%)[d]	Lifetime (y)[c]	Build time (y)[e]	LCOE[f] (€ MWh^{-1})
Renewable technologies									
Wind	Onshore	–	1320	1.9%	0	–	25	1	67
	Offshore	–	2610	2.8%	0	–	25	1	94
PV[g]	Rooftop	–	950	2%	0	22%	25	< 1	82
	Utility	–	600	1.7%	0	17%	25	1	51
Hydro[h]	Run-of-river (RoR)	70	5720	1.5%	5.0	87%	60	–	214
	Storage (STO)	100	2840	1%	4.0	87%	60	–	105
	Pumped storage (PHS)	400	2840	1.5%	4.0	76%	60	–	105
Bio-electricity	Biomass fluidised bed (Bio-FB)	300	2450	1.8%	3.9	38%	25	3	112
	Open-cycle biogas turbine (Bio-OCGT)	100[l]	600	3%	11.2	42%	25	1	23
Concentrating solar power (CSP)[i]		50	4930	4%	8.1	40%	30	2	119
Geothermal		50	4780	2%	0	24%	30	3	64
Non-renewable and other technologies[j]									
Natural gas	Open-cycle natural gas turbine (Gas-OCGT)	100	600	3%	11.2	42%	30	1	290
	Natural gas combined cycle (Gas-NGCC)	580	1000	2.5%	2.0	63%	30	3	106
	NGCC with CCS (Gas-NGCC-CCS)	485	1860	2.5%	4.1	56%	30	4	96
Coal	Pulverised coal plant (Coal-PC)	750	1980	2.5%	3.7	47%	40	4	151
	PC with CCS (Coal-PC-CCS)	630	3300	2.5%	5.6	41%	40	5	110
Bio-FB with CCS (Bio-FB-CCS)[k]		255	4060	1.8%	5.9	28%	25	4	44
Nuclear (3rd generation)		1500	5330	1.7%	2.6	33%	60	7	77

Abbreviations: CAPEX – Capital expenditure, CCS – Carbon capture and storage, FOM – Fixed operating and maintenance costs, LCOE – Levelised cost of electricity, NGCC – Natural gas combined cycle, PV – Photovoltaic, VOM – Variable operating and maintenance costs.
Note: All costs given in €$_{2016}$ using historical Eurozone inflation rates unless otherwise stated [77].

[a] Base CAPEX represents the total capital requirement (TCR), comprising the overnight capital cost (OCC) in 2040 taken from JRC ETRI 2014 [70] (including grid connection cost), and interest during construction (IDC).

[b] FOM costs given as a percentage of OCC taken from the ETRI [70].

[c] JRC ETRI 2014[70].

[d] Efficiencies and part-load performance are mostly taken from Brouwer et al. [50]. More details can be found in the supplementary material.

[e] Construction time is used to calculate IDC using an 8% discount rate. Taken from [78] apart from nuclear, which is based on more recent data [79]. Plants built within one year have no IDC. IDC is not included for hydro plants as we include no new capacity.

[f] LCOE shown for comparison only, assuming 8% discount rate, average fuel costs and indicative capacity factors of 25% for onshore wind, 38% for offshore wind, 15% for PV, 30% for hydro, 90% for nuclear and geothermal, 5% for gas turbines, and 60% for the remaining technologies.

[g] Future PV cost estimates vary widely in the literature. For this reason, we include both rooftop (< 100 kW) and utility (> 2 MW) scale installations to account not only for their different spatial constraints, but also to include a range of investment costs as an implicit cost sensitivity. Efficiency is based on commercial monocrystalline silicon modules for rooftop PV [71], and polycrystalline modules for utility PV [72].

[h] For hydro, nominal size is based on average plant size per category from ENTSO-E [66]. For hydro-PHP plants, we assume a reservoir size of 45 GWh per plant (4.5 days) based on the mean calculated specific reservoir size of 113 GWh GW^{-1} for existing hydro-PHP plants from ENTSO-E data. As the cost of Hydro-STO plants depends on capacity, we use an average of the costs for plants between 10–100 MW and > 100 MW [70]. The cost for Hydro-STO is used for Hydro-PHS, as the source does not distinguish between plants equipped with reversible turbines, or plants with dedicated pumping capacity. In any case, hydro capacity is exogenous in all scenarios and the costs do not affect the optimisation. Once-through turbine and pumping efficiency are both taken as 87% [50,80].

[i] CSP plant cost includes 8 h of molten salt thermal storage per plant [81]. The peak efficiency of the CSP power block component is 40%, based on electricity generation and total heat input. Overall CSP plant efficiency (output electricity with respect to DNI) is approximately 17% [82]. Most CSP plants are in the order of 200 MW, consisting of several smaller units of around 50 MW each [83].

[j] Fuel costs of 7 € GJ^{-1}, 2 € GJ^{-1} and 1 € GJ^{-1} are taken for natural gas, coal and nuclear fuel respectively based on the 2 Degree Scenario (2DS) for 2050 from the IEA's ETP2016 [84]. A CO_2 price of 120 € t^{-1} is assumed from the IEA's 2015 World Energy Outlook (WEO) 450 Scenario for 2040 [85]. We assume a uniform CO_2 capture rate for CCS technologies of 90% [70], and CO_2 transport and storage costs of 13.5 € t^{-1} CO_2 [50].

[k] No data could be found for Bio-FB-CCS plants, which instead are estimated based on differences between ETRI reported values for Coal-PC with and without CCS: 60% higher CAPEX, 16% lower nominal capacity, 10% (absolute) lower efficiency, and 53% higher VOM than the Bio-FB (non-CCS) plants.

[l] Biogas plants are typically small units (< 1 MW), operating on either gas engine or gas turbine technology. However, modelling with such small units can lead to numerical instabilities. Thus, we use a higher nominal plant size of 100 MW, the same as Gas-OCGTs.

combustion (Bio-FB) plants and open-cycle gas turbines (Bio-OCGT), which are supplied by three categories of biomass fuels (biogas substrates, solid woody biomass and solid waste biomass), based on country-specific cost-supply curves for 14 different biomass feedstocks [73].[13] We assume that solid biomass is combusted in Bio-FBs, while biogas substrates – after conversion to biogas – are combusted in Bio-OCGTs. Raw biomass fuel costs range from 1.4 € GJ^{-1} to 14.4 € GJ^{-1} depending on the fuel type and country of origin, with a total domestic supply potential of 10 EJ y^{-1} in 2050 [73].[14] For biogas substrates, an additional cost of 10.4 € (GJ substrate)$^{-1}$ is included for the conversion by anaerobic digestion (AD) to raw biogas for local use, and a further 3.2 € GJ^{-1} for upgrading to biomethane and injection into the gas grid [74]. In order to avoid infeasible solutions, biomass supply is modelled as a soft constraint by allowing the model to draw on additional biomass, albeit at significantly higher cost.

Run-of-river (RoR) and storage (STO) hydropower capacity is aggregated per country using a nominal unit size, with annual capacity factors limited to historical levels [29,66]. Pumped hydro storage (PHS) capacity is also aggregated for each country but the storage is modelled explicitly, assuming an average storage volume of approximately five days at nominal load.[15]

While wind turbines and PV panels can in principle be located almost anywhere, hydro and geothermal power plants require sites with specific geological features, and CSP plants should be installed in locations which receive high direct normal irradiance (DNI). For these reasons, the installed capacity and spatial distribution of hydro, geothermal and CSP are specified exogenously:

- We assume that total hydro capacity in 2050 remains unchanged from today at approximately 200 GW, with the same geographical distribution and split between RoR (31%), STO (48%) and PHS (21%) capacity [75].
- Geothermal capacity is set at 50 GW to reflect deployment levels assumed in previous high-RES studies [32,33] (see Table 1), and allocated to countries in proportion to their economic geothermal potential [76].
- CSP capacity is fixed at 200 GW, reflecting levels found in the most ambitious high-RES scenarios [32,33] (see Table 1). However, many of these studies locate considerable CSP capacity in the MENA countries where higher annual DNI levels are available. In order to fit this capacity into Europe, we allocate CSP capacity to grid cells in order of decreasing DNI, while adjusting both the minimum allowed DNI and assumed availabilities of suitable land classes until 200 GW is reached – with a preference for sparsely inhabited areas to minimise impacts on local communities. As a result, CSP is allocated to grid cells with average DNI levels of 1600 kWh m^{-2} y^{-1} or higher, located mostly in Spain (158 GW), Portugal (22 GW), Italy (16 GW), Greece (5 GW) and Cyprus (0.8 GW). Thus, the availability of land for CSP is not taken as a hard constraint as for PV and wind, but indicates the area which would be required to accommodate 200 GW of CSP in Europe.

The firm capacity for all dispatchable generators is taken as 90%, assuming 5% unavailability due to unplanned outages, and a further 5% for planned maintenance [86].[16] The firm capacity for vRES technologies is estimated per grid cell following the approach of Milligan [87] as the average capacity factor during the peak 1% of demand hours per year. As a result, PV receives a capacity credit of zero in all grid cells, onshore wind has a median capacity credit of 12%, and offshore wind a median of 10%. Further details can be found in the supplementary material.

2.2.3. Transmission

We use a 'centre-of-gravity' approach to model transmission flows between countries, with the urban-area-weighted centres of each country serving as nodes (see Fig. 2). Taking the existing capacity in 2016 as a starting point [66], new transmission capacity can be built if this lowers total costs, based on the costs given in Table 4. Subsea lines are assumed to be high voltage direct current (HVDC), while land-based lines are high voltage alternating current (HVAC). Transmission and distribution within countries is modelled as copper plate.

For the wind and PV technologies, we also estimate the amount of grid reinforcement required to bring this electricity to the main transmission grid by calculating the shortest transmission distance (across either land or sea) to the nominal load centre of the country in which it is deployed, and add the cost of this additional transmission to the base CAPEX from Table 3.[17]

2.2.4. Demand response

Demand response, also known as demand side management (DSM), is the willingness of electricity consumers to shift or even curtail their load during times of peak system residual demand [95]. In this study, we consider 16 GW of load shedding capacity from heavy industrial processes, and 82 GW of load shifting capacity from various commercial and residential appliances based on the technical potentials reported by Gils [95], and assumed deployment levels (as a percentage of technical potential) from Bertsch et al. [96]. Demand shedding costs vary from 100 € kWh^{-1} to over 2000 € kWh^{-1} depending on the industry, which is activated whenever electricity prices exceed these levels. Limits are imposed on the volume and activation of residential and commercial DSM, depending on the appliance and the season.[18]

2.2.5. Reserves

Power systems require operating reserves in order to balance out

[13] Currently, most large-scale bioelectricity plants in Europe are the result of the partial (e.g. co-firing) or complete conversion of existing pulverised coal plants to biomass. However, as many existing coal plants will have been decommissioned by 2050, we do not consider the conversion of existing plants. Instead, we model future large-scale biomass as fluidised bed combustion plants as their projected 2050 costs are similar to coal plants with added costs for biomass co-firing (based on [70]). The alternative would be to assume future biomass plants use more efficient integrated gasification combined cycle (IGCC) technology (as done by [142]), however these are approximately 40% more expensive, potentially less flexible, and no large-scale units are currently operating.

[14] We do not include sugar, starch and oil crops (which we reserve for liquid biofuel production), roundwood fuel wood (which we reserve for firewood), nor black liquor. We include the transport of solid woody biomass between countries [143], while for practical reasons we assume that solid waste biomass must be used in its country of origin.

[15] Based on an in-house database of Europe's 120 largest hydro plants and their associated reservoirs incorporating data from various open-source databases (e.g. [80,144,145]), we calculate average specific reservoir sizes of 60, 1608 and 113 MWh MW^{-1} for RoR, STO and PHP plants respectively. Multiplying these values by the average plant sizes from ENTSO-E [66] gives total European hydro storage capacity of approximately 160 TWh. This total matches quite well with the 180 TWh reported by [75]. Also, the value of 60 MWh MW^{-1} for RoR storage shows that most RoR plants also have several hours of storage, and thus capable of some level of dispatchability [146]. The resulting 56 GW of PHS capacity is equipped with 6.4 TWh of storage.

[16] Firm capacity, also known as capacity credit or capacity value, represents the contribution a generator makes to system adequacy. Put simply, it indicates the share of installed capacity which can be relied upon during times of peak demand. For dispatchable generators, a value of 90% is typical and allows for forced and unforced offline periods. While CSP generation depends on intermittent sunlight, the capacity credit of CSP plants can exceed 90% when equipped with at least four hours of storage, thus we assume this value [147].

[17] These notional 'reinforcement lines' are not modelled explicitly as part of the transmission network, and only serve to include the cost of bringing electricity from more remote vRES sites to load centres.

[18] For example, the potential of DSM from space heating is zero in summer.

mismatches between demand and generation due to (i) demand forecast errors, (ii) vRES generation forecast errors, and (iii) unplanned generator outages [97]. In this study, we include fast-responding spinning reserves (both up and down regulation) available within five minutes, as well as standing reserves available within one hour. We assume a single Europe-wide reserve market in which all generation technologies are capable of providing reserves, including wind and PV.[19]

2.3. Define scenarios

We consider eight scenarios in order to understand the impact of assumptions made in this study and uncertainties involved in modelling a future 100% RES power system (Table 5). Seven of these scenarios focus on uncertainty in final demand and technological developments in a 100% RES power system, while the eighth scenario includes non-RES capacity as explained below:

- In the ***Base*** scenario, all RES technologies are modelled as previously explained with CSP, geothermal and hydro capacities specified exogenously, assuming the *Base* demand level of 4409 TWh y^{-1}.
- In the ***High Demand*** scenario, demand is scaled up by 36% to 6020 TWh y^{-1} keeping the underlying demand profile the same, to see the impact of further growth in demand[20];
- In the ***Alternative Demand Profile*** scenario, we test how sensitive our results are to the base hourly demand profile by using the less peaky 'Vision 4' hourly demand profile from ENTSO-E, scaled up to the *Base* annual demand (4409 TWh y^{-1});
- In the ***No CSP or Geothermal*** scenario, we exclude these two dispatchable technologies to see how critical their future deployment is for a fully renewable European power system;
- In the ***No Biomass*** scenario, we do not allow any power generation from biomass, reflecting possible social opposition to the technology, or complete prioritisation of biomass for other end-use sectors (e.g. heating, chemicals, industry);
- In the ***Storage*** scenario, we allow the model to build additional grid-scale storage capacity in the form of compressed-air energy storage (CAES)[21];
- In the ***Free RES*** scenario, we specify no exogenous CSP or geothermal capacity and leave the model free to optimise all RES capacity (excluding hydro); and
- In the ***Allow non-RES*** scenario, we allow all low-carbon (but not necessarily renewable) technologies to be built, so that the costs of a fully renewable system can be compared with one which includes non-renewable alternatives.

2.4. Perform model runs

With hydro, geothermal, and CSP the only technologies exogenously defined, we first run PLEXOS' LT Plan module in order to find the cost-optimum deployment of the remaining generation capacity and transmission investments which can reliably meet demand (Section 2.4.1). Then, we test how this system performs at hourly resolution by running detailed UCED calculations with the ST Schedule module (Section 2.4.2).[22]

Table 4
Techno-economic parameters for HVAC and HVDC transmission infrastructure.

Component		CAPEX		FOM[c] (% CAPEX y^{-1})	Losses[d] (% 100 km^{-1})
		Lines (€ MW^{-1} km^{-1})	Substations/ Converters (€ MW^{-1})		
HVAC[a]	Overhead	330	38,800	3.5%	0.7%
	Underground (Direct buried)	3370			0.45%
HVDC[b]	Subsea	240	121,000	3.5%	0.35%

Note: All costs given in €$_{2016}$ unless otherwise stated. Abbreviations: CAPEX – Capital expenditure, FOM – Fixed operating and maintenance costs. A lifetime of 40 years is assumed for all transmission system components. A 6% outage rate is assumed for transmission lines, with a mean time to repair of 14 h [88,89].

[a] Based on a study for the UK [90], specific costs range from 333 to 605 € MW^{-1} km^{-1} for overhead HVAC lines and 3370 to 4780 € MW^{-1} km^{-1} for direct-buried lines respectively, depending on the line length and carrying capacity. The quoted values correspond to a double circuit 400 kV 75 km line with 6930 MVA carrying capacity. Given we consider mainly long-distance transmission, we assume a 90%/10% split between onshore overhead lines and underground cables. HVAC converter costs taken from [91].

[b] A complete HVDC line includes the cable length and two converter stations. HVDC line and converter costs taken from [91].

[c] Annual FOM costs equivalent to 3.5% of the base CAPEX [70,90].

[d] HVAC losses taken from [92], HVDC losses from [93]. We also include losses of 0.65% per HVDC converter station (average of values from [92,94]).

2.4.1. Long-term capacity optimisation

One aspect of system adequacy is ensuring that enough generation capacity is available to meet demand reliably. Ideally, this would involve optimising the generation portfolio and transmission network considering all available weather data (i.e. from 1979 to 2015) simultaneously, to ensure that the risk of short supply is acceptable even in the most challenging weather year, and that the generation portfolio is not sensitive to any individual year. However, optimising the installed capacity of two biomass and four vRES technologies across more than 2000 grid cells – for 37 years of weather data – is not feasible with available computing power. Furthermore, due to the model complexity, it is not amenable to probabilistic methods. Thus, we take the simpler approach of deterministically optimising capacity for the most challenging weather year experienced by Europe in the period 1979–2015. Based on the historical data, we determine 2010 as the year with the overall lowest potential wind and PV generation, and run the capacity expansion optimisation for this year (see the supplementary material for additional details). In performing the capacity expansion optimisation, we make the following assumptions:

- Europe is modelled as a single integrated power system in which capacity can be shared between countries.
- Apart from a reference level of transmission (60 GW) and hydro plant capacity (200 GW), we take Europe as a clean slate and include no legacy generation capacity. Nor do we consider any government policies which may preclude technologies in any given country.
- Transmission is modelled as simple active power transport, rather than a full optimal power flow (OPF) problem.[23]

[19] Several countries already require that wind farms must be able to supply primary (and in some cases secondary) reserves, which is possible by operating in de-loaded mode or being equipped with storage capacity (e.g. flywheels) [148]. PV plants can also provide primary reserves [149].

[20] This is to match demand in the Energy [R]evolution study (see Table 1), which assumed extensive use of electricity for the production of hydrogen for use in other sectors [33].

[21] We assume storage investment costs of 700 € kW^{-1} (including 8 kWh of storage for every kW capacity installed), round trip efficiency of 63%, FOM costs of 35 € kW^{-1} y^{-1} and lifetime of 35 years, based on [50]. Equivalent to 88 € kWh^{-1}, we acknowledge this is rather optimistic given expectations for grid-level storage costs are 340 USD kWh^{-1} (290 € kWh^{-1}) in 2040 [150]. However, with this scenario we want to see the potential role of storage in the power system at a given cost, not provide an accurate cost assessment.

[22] The commercial optimisation package Gurobi [151] is used to solve the system of MILP equations generated by PLEXOS.

[23] OPF calculations enforce active and reactive power balance constraints at

Table 5
Scenario runs performed.

Scenario	Varied parameters							
	Demand profile	Available technologies[a] (O: optimised, X: excluded)						
		Hydro[b]	CSP	Geo	vRES[c]	Bio[d]	CAES	Non-RES[e]
Base	Base (4409 TWh y^{-1})	200	200	50	O	O	X	X
High demand	High demand (6020 TWh y^{-1})	200	200	50	O	O	X	X
Alternative demand profile	Alternative demand (4409 TWh y^{-1})	200	200	50	O	O	X	X
No CSP or Geothermal	Base	200	X	X	O	O	X	X
No Biomass	Base	200	200	50	O	X	X	X
Storage	Base	200	200	50	O	O	O	X
Free RES	Base	200	O	O	O	O	X	X
Allow non-RES	Base	200	O	O	O	O	X	O

[a] A numerical value indicates the exogenous specified capacity in GW. Transmission is freely optimised in all scenarios. DSM is also included in all scenarios; however, demand shedding (16 GW) is included in both the LT Plan and ST Schedule modules, while demand shifting (82 GW) is only included in the ST Schedule runs to minimise computational time.
[b] Includes STO, RoR and PHS hydro.
[c] Includes all wind and PV technologies.
[d] Includes Bio-FB and Bio-OCGT.
[e] Includes all '*Non-renewable and other technologies' listed in* Table 3.

- Generator flexibility parameters and operational reserves are not considered.[24]
- To ensure comparability with the 100% RES scenarios, in the *Allow non-RES scenario* we constrain total GHG emissions to 45 Mt y^{-1} in 2050.[25] This represents a reduction of 96% compared with 1990, the level required to ensure that the EU goal of reducing total CO_2 emissions by 80–95% by 2050 can be achieved [4,98,99].

In assessing system adequacy, most countries allow for a Loss of Load Expectation (LoLE) between 3 h y^{-1} (e.g. BE, GB, FR) and 8 h y^{-1} (e.g. NI, IE, PT) [100]. However, in our study it is not possible to target such a specific LoLE level as we cannot include reserve requirements in the LT Plan, and our vRES firm capacity estimates are not perfect.[26] Assuming that each country must have sufficient capacity to cover its peak demand – provided either by its own generators or exchange with neighbouring countries – we instead increase the capacity margin in each country until no unserved energy is observed in the LT Plan results.[27]

2.4.2. Short-term hourly dispatch

With the optimum generation portfolios and transmission networks determined from the LT Plan, we then perform detailed UCED simulations for each scenario with PLEXOS' ST Schedule module for the same weather year 2010, including both generator flexibility constraints and operating reserve requirements. Simulations are run at hourly resolution for one typical week per month, in order to reduce solution time.[28] In assessing system adequacy, we consider a maximum acceptable level of unserved energy of 0.0003% of total annual demand, based on the expected unserved energy for Europe's electricity system in 2020 from ENTSO-E's 2016 Mid-Term Adequacy Forecast [88].

3. Results

3.1. System adequacy

Based on the results of the LT Plan optimisations, feasible solutions are found for all scenarios, with the exception of the *No Biomass* scenario. This shows that with CSP, geothermal, and hydro capacity at their assumed levels, and in the absence of seasonal storage, a 100% RES power system is not feasible without biomass. Hence, we do not consider this scenario any further.[29] After simulating the remaining scenarios at hourly resolution, feasible solutions are found with less than 0.0003% unserved energy. From this, we conclude that a 100% RES European power system can achieve the same level of system adequacy as today's power system.

(footnote continued)
each node, and would provide better estimates for losses and reactive power compensation requirements (e.g. capacitor banks, synchronous condensers) [152,153]. However, this is beyond the scope of our paper.

[24] For computational reasons, the LT plan does not simulate each hour. Instead, we slice the year into 12 monthly blocks and optimise based on a simplified 12-step load duration curve in each block. As a consequence, chronology is only maintained between the blocks and not within them, thus ramping constraints are not considered [59]. However, both generator flexibility and reserves are included in the ST Schedule.

[25] We assume direct GHG emission factors of 56, 101 and 100 kg CO_2 equivalent GJ^{-1} (NCV) for natural gas, coal and biomass fuels respectively [154]. Note that emissions for biomass are only considered when coupled with CCS in Bio-FB-CCS plants to calculate sequestered CO_2. Otherwise, biomass is considered carbon-neutral as we assume that sufficient new biomass is grown (and CO_2 absorbed) to offset that which is burned.

[26] Reserve requirements depend on vRES generation profiles, which are not known until after the LT Plan is solved. The vRES capacity credit is estimated based on the hours in which total European-wide demand is highest, however these hours do not necessarily coincide with the peak demand hours in each country. For this reason, we must ensure that some over-capacity is included in the LT Plan so that sufficient capacity is available to cover both reserve requirements and vRES firm capacity inaccuracies in the subsequent hourly simulations.

[27] Due to the temporal simplifications and relaxation of some constraints in the LT Plan, some unserved energy is often observed in the hourly ST Schedule results, even if none appears in the LT Plan. Thus, several iterations are usually required increasing the capacity margin until the level of unserved energy in the ST runs is acceptable. This required a capacity margin of around 8%. Even if this approach is rather conservative and more capacity is installed by the model than actually required, this capacity will come in the form of OCGTs (the cheapest capacity providers) which ultimately contribute a relatively minor amount to total costs (see Section 3.7).

[28] Performing hourly simulations for one week for one scenario can take more than 4 h to solve using integer programming with a target MIP gap of 0.1%. Thus, simulating a full year could take more than 200 h, or more than 60 days for all eight scenarios. Instead, we limit the solver time to two hours and solve only the first week of each month.

[29] We also attempted another scenario excluding biomass but including daily (8 h) storage; however, this also returned an infeasible solution.

3.2. Generation portfolio

The optimised generation portfolio for each scenario is shown in Fig. 3, while Fig. 4 shows the annual generation. All 100% RES scenarios show a significant expansion of generation capacity compared to today, with total installed capacity ranging from 1.9 TW in the *Alternative Demand Profile* scenario to 3.1 TW in the *High Demand* scenario. Aside from the higher assumed demand, this increase in capacity is due to the low capacity credit of wind and PV, which must be backed up by dispatchable capacity. With the capacity of geothermal, CSP and hydro set exogenously in most scenarios, the only remaining dispatchable RES technology is biomass, which is installed in significant quantities. Compared to the *Base* scenario, allowing non-RES technologies in the portfolio in the *Allow non-RES* scenario reduces the size of the total portfolio to 1.4 TW, primarily due to the rollout of some 200 GW of dispatchable zero-carbon nuclear capacity, and 200 GW of Gas-NGCC capacity. Approximately 50 GW of Bio-FB-CCS capacity is also installed as the net negative emissions it generates allow this lower-cost Gas-NGCC capacity to be included in the portfolio without CCS.

In the 100% RES scenarios, onshore wind deployment ranges between 50% (*Base*) and 64% (*No CSP or Geothermal*) of its maximum potential (543 GW). Due to its higher cost, offshore wind deployment is modest in most RES scenarios at about 17% of its maximum potential (754 GW); however, deployment increases when demand is higher or CSP is excluded from the portfolio. With 65% (*Base*) to 85% (*High Demand*) of its total potential deployed (895 GW), utility PV represents the largest share of installed capacity in all 100% RES scenarios – despite making no contribution to firm capacity. Due to its higher cost, rooftop PV is only installed in appreciable amounts in the *High Demand* and *No CSP or Geothermal* scenarios, once the best utility PV sites are exploited.

Turning to the dispatchable technologies, biomass plays a critical role in providing peak and load-following capacity in all 100% RES scenarios. This is evidenced by comparing the installed Bio-OCGT capacities in the *Base* (~470 GW) and *Alternative Demand Profile* (~220 GW) scenarios, showing that with a lower peak demand and smoother demand profile, Bio-OCGT capacity is approximately 50% lower in the *Alternative Demand Profile* scenario. Meanwhile, Bio-FBs provide between 160 GW and 230 GW of load-following capacity in the 100% RES scenarios. When CSP capacity is optimised, only 38 GW of CSP is installed in the *Free RES* scenario and no capacity at all is installed in the *Allow non-RES* scenario. By contrast, geothermal capacity is fully exploited in all scenarios as, with lower VOM costs and a higher capacity factor, it is more competitive than CSP.

At the assumed cost of 700 € kW^{-1} (88 € kWh^{-1}), just under 80 GW of CAES is installed in the *Storage* scenario, which displaces an equivalent amount of Bio-OCGT capacity. Total installed generation capacity increases by 30 GW (mostly PV) compared to the *Base* scenario in order to provide additional electricity for charging the storage, as there is no surplus (curtailed) vRES generation in any scenario which can be used to charge the storage.[30]

3.3. Spatial capacity distribution

Fig. 5 shows how the optimised generation capacity from the *Base* scenario is deployed across Europe. For the spatially optimised vRES technologies (wind and PV), Fig. 6 shows how this capacity is distributed within each country. Onshore wind capacity is mainly installed in countries bordering the North and Baltic Seas in a band stretching from the British Isles to the Baltic countries. These locations are preferred due to their favourable wind speeds, and central location in Europe which minimises transmission losses. Offshore wind is mainly installed in the North Sea due to the higher wind speeds, and central location. PV capacity is spread across most countries. Within countries, PV capacity is typically installed either in southerly locations, or close to the load centre to reduce costs. Less utility PV capacity is installed in the Iberian Peninsula than might be expected, as much of the suitable land area for vRES is needed to accommodate the exogenous CSP capacity. Furthermore, any additional PV capacity in this region would further increase the transmission needs between Spain and France (see Section 2.2.3).

3.4. Transmission requirements

The optimised transmission grid reinforcements (on top of the reference capacity of 60 GW) for each scenario are shown in Fig. 7. In the scenarios including the 200 GW exogenous CSP capacity, reinforcements range from 321 GW to 416 GW, as the transmission corridors FR-ES, FR-DE, FR-BE, and IT-FR must be significantly reinforced to bring CSP generation from the Iberian peninsula to the rest of Europe. However, when CSP capacity is optimised in the *Free RES* scenario, reinforcements fall to 142 GW due to the more optimal (lower) deployment of CSP. Thus, the exogenously defined CSP capacity has a significant impact on the configuration of the transmission network.[31]

Very little additional transmission is built in the *Allow non-RES* scenario due to the lower vRES capacity and absence of CSP. In the *Storage* scenario, transmission reinforcements fall by 10 GW (3%) compared to the *Base* scenario. Thus, large-scale transmission expansion appears more cost effective than utility-scale daily (8 h) energy storage in balancing supply and demand, even when assuming optimistic reductions in future storage costs.

One consequence of a fully interconnected power system is that the reliability of transmission becomes critical for ensuring system adequacy as, with a higher dependence on generators in neighbouring countries, the reliability of generators depends not only on availability, but also on the reliability of the transmission lines which deliver their electricity.

3.5. Hourly dispatch

Fig. 8 shows the results of the ST Schedule hourly dispatch from the *Base* scenario for a typical summer week, while Fig. 9 shows the hourly dispatch for a typical winter week. Comparing these two figures, we find that:

- Geothermal, Hydro-STO and Hydro-RoR provide baseload capacity throughout the year due to their high investment but relatively low marginal cost.
- Variable PV and wind generation fluctuates hourly, daily, and seasonally. While PV can usually be relied upon for significant daytime generation in summer, wind production is less reliable. While average wind generation tends to be higher in winter, Fig. 9 shows

[30] We observe no curtailment in our study as with both transmission and vRES siting optimised simultaneously, transmission bottlenecks are avoided, and it is more cost-effective to balance the portfolio with firm non-vRES capacity than install additional vRES capacity. Furthermore, as we do not model the transmission or distribution grids within countries, any internal bottlenecks requiring vRES curtailment are neglected. Also, we model and optimise the system for the worst weather year available.

[31] If this CSP capacity was instead located in the MENA countries, the required network topology would be similar as HVDC connections bringing electricity to central Europe from the MENA countries must go through Spain, Italy, or Greece. For example, the SAPEI HVDC cable linking Sardinia with mainland Italy is the deepest in the world, with some sections reaching 1650 m [93], while significant portions of the Mediterranean Sea exceed 2500 m depth. Attempting to lay cables at greater depths involves significant technical and cost limitations which are unlikely to be overcome before 2030, leaving only 20 years for a trans-Mediterranean HVDC network to be developed [155,156]. This leaves Spain, Italy or Greece as the only alternatives.

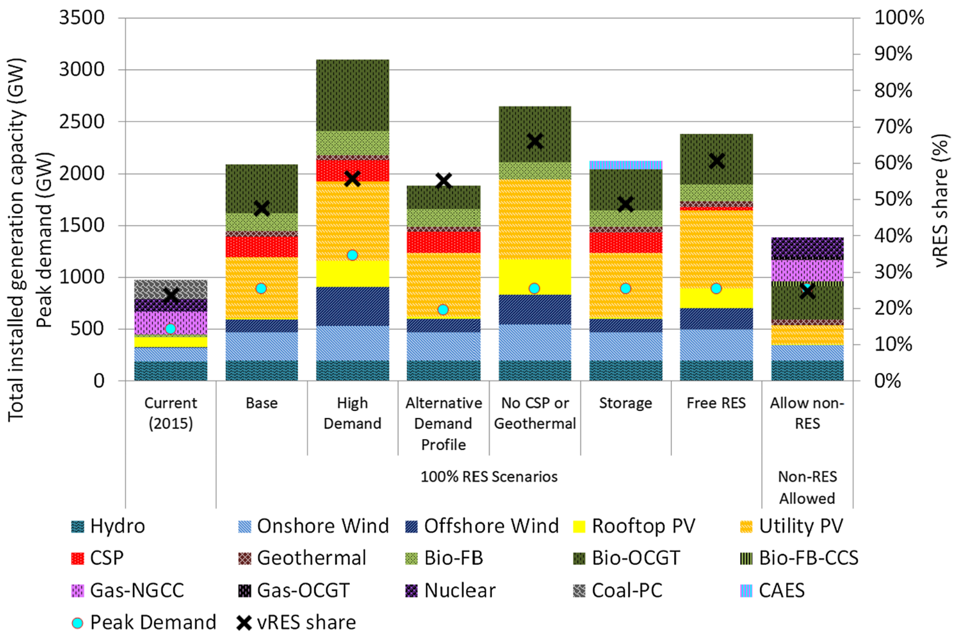

Fig. 3. Installed capacity of each technology per scenario in 2050, based on weather year 2010 (the lowest PV and wind supply). For comparison, the current (2015) installed capacity is also shown with coal, natural gas, PV and biomass shown as Coal-PC, Gas-NGCC, Rooftop PV, and Bio-FB respectively, based on ENTSO-E data [66]. Demand shedding capacity of 16 GW is not shown. The peak total system demand in each scenario is indicated by the '●' symbols (left axis) and the share of vRES capacity indicated by the '×' symbols (right axis).

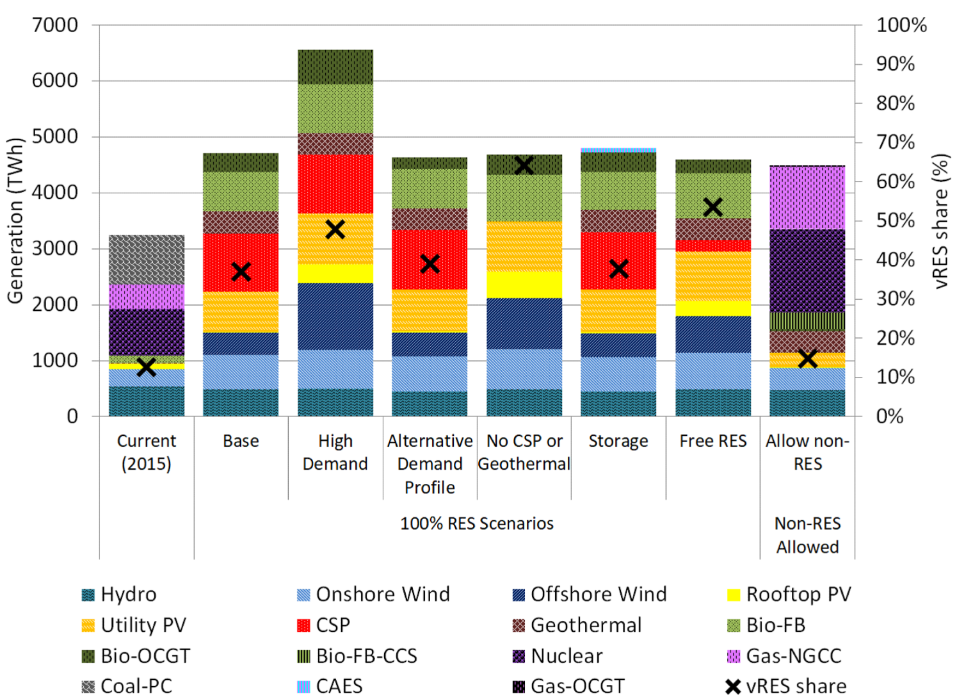

Fig. 4. Total generation by technology per scenario in 2050, based on weather year 2010 (the lowest PV and wind supply). For comparison, the current (2015) generation is also given with coal, natural gas, PV (total), wind (total) and biomass shown as Coal-PC, Gas-NGCC, Rooftop PV, Onshore Wind and Bio-FB respectively, based on ENTSO-E data [66]. The share of vRES generation is indicated by the '×' symbols (right axis).

that there can be periods of low wind generation, even in winter.

- CSP plays a significant role in covering night-time demand during the summer, but cannot provide the same level of coverage in winter due to the lower DNI received.
- Biomass plays quite different roles in summer and winter. In summer, Bio-FB and Bio-OCGT capacity is cycled daily in order to meet peak evening demand, once generation from PV and CSP has ceased. In winter, Bio-FBs are used to provide baseload capacity while day- and night-time peaks – mainly caused by EVs – are met by Bio-OCGTs.
- DSM is used extensively to both shift and curtail demand during peak evening hours, particularly in winter. Hydro-PHS plays a similar role tas Bio-OCGTs in providing flexible peak generation during evening hours, especially during summer when electricity from PV can be used for pumping during the day.

Due to the imperfect forecasting of demand and vRES generation, operating reserve requirements in a 100% RES power system with a high vRES share would be significant. An example of this is given in Fig. 10, which shows the provision of operating reserves by each generator type during the same typical summer week as shown in Fig. 8. Spin-up reserves are mainly provided by hydro and CSP, with Bio-OCGTs providing the majority of stand-up reserves. Down-regulation reserves are provided mainly by CSP and vRES, though practically all technologies contribute some down-regulation during the year.

3.6. Biomass utilisation

Total demand for biomass in the 100% RES scenarios ranges from 8.5 EJ in the *Base* scenario up to 12.9 EJ in the *High Demand* scenario. In 2015, Europe produced approximately 5 EJ of biomass for energy

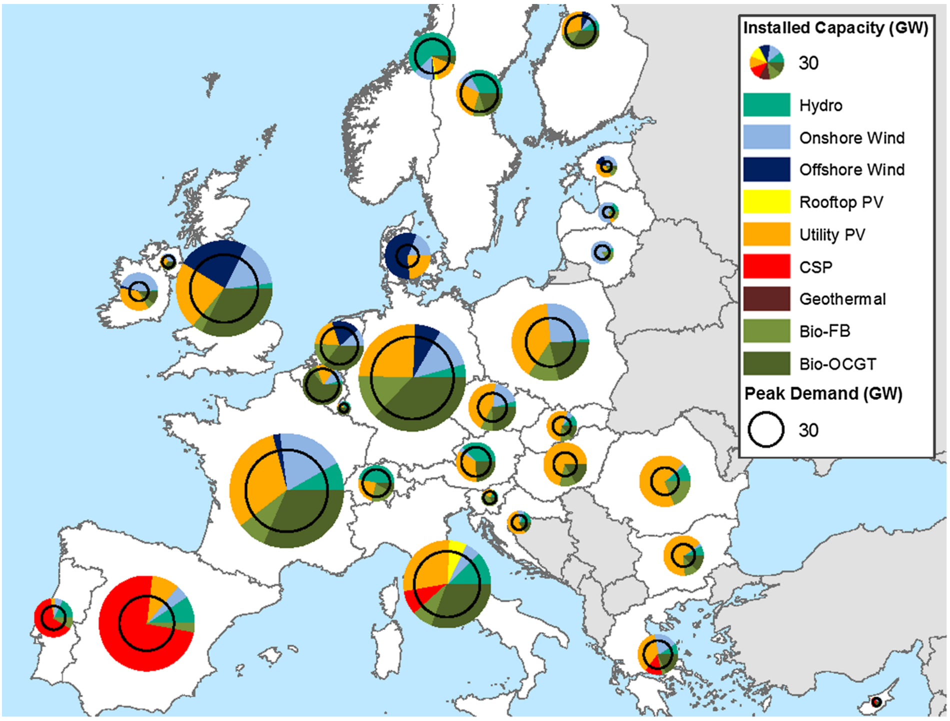

Fig. 5. Optimised generation capacity per technology in 2050 per country in the *Base* scenario, based on weather year 2010. The pie charts show the share of capacity per generation technology, while the size (area) of the pie chart is proportional to the total installed capacity. The circles within each pie chart show the peak demand per country.

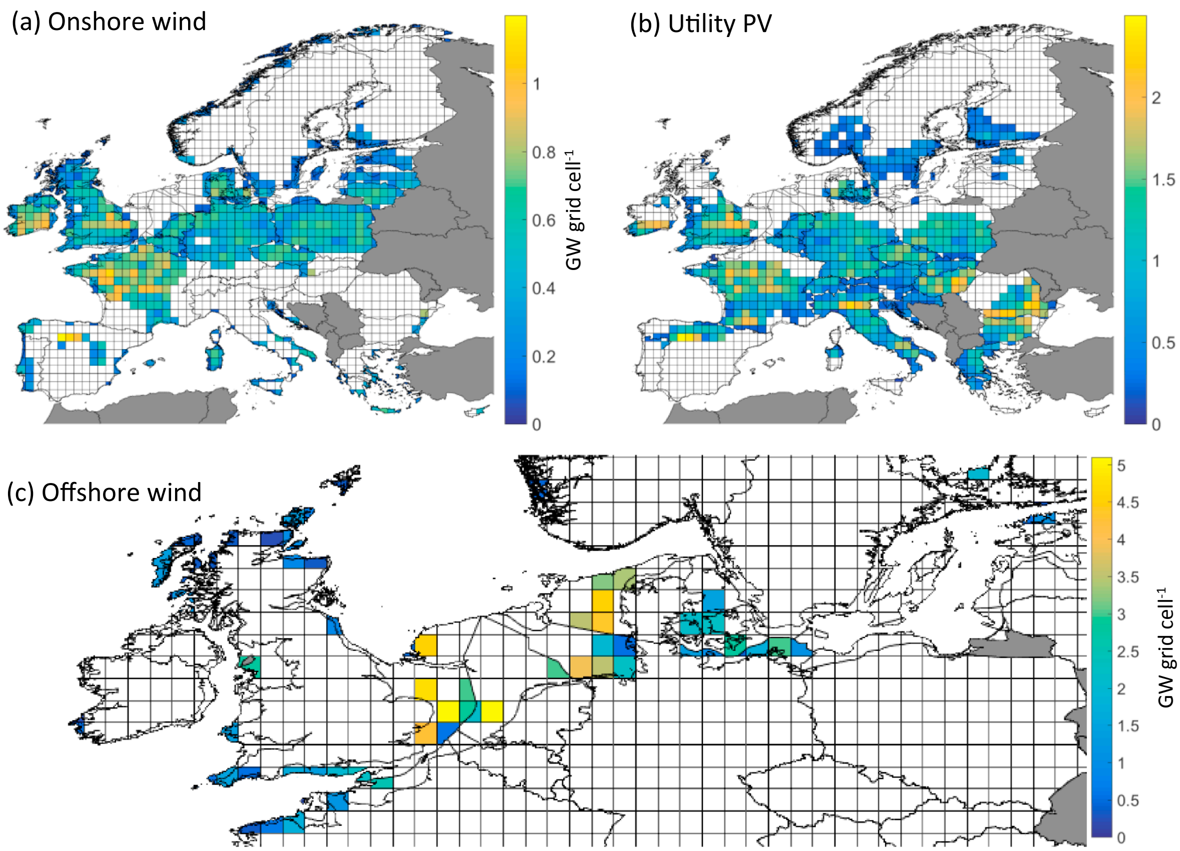

Fig. 6. Optimised 2050 spatial deployment of vRES generation capacity in the *Base* scenario in GW (grid cell)$^{-1}$ for (a) Onshore wind and (b) Utility PV, and (c) Offshore wind, based on the most challenging weather year 2010. Only a small amount of rooftop PV is installed in the *Base* scenario, and hence not shown.

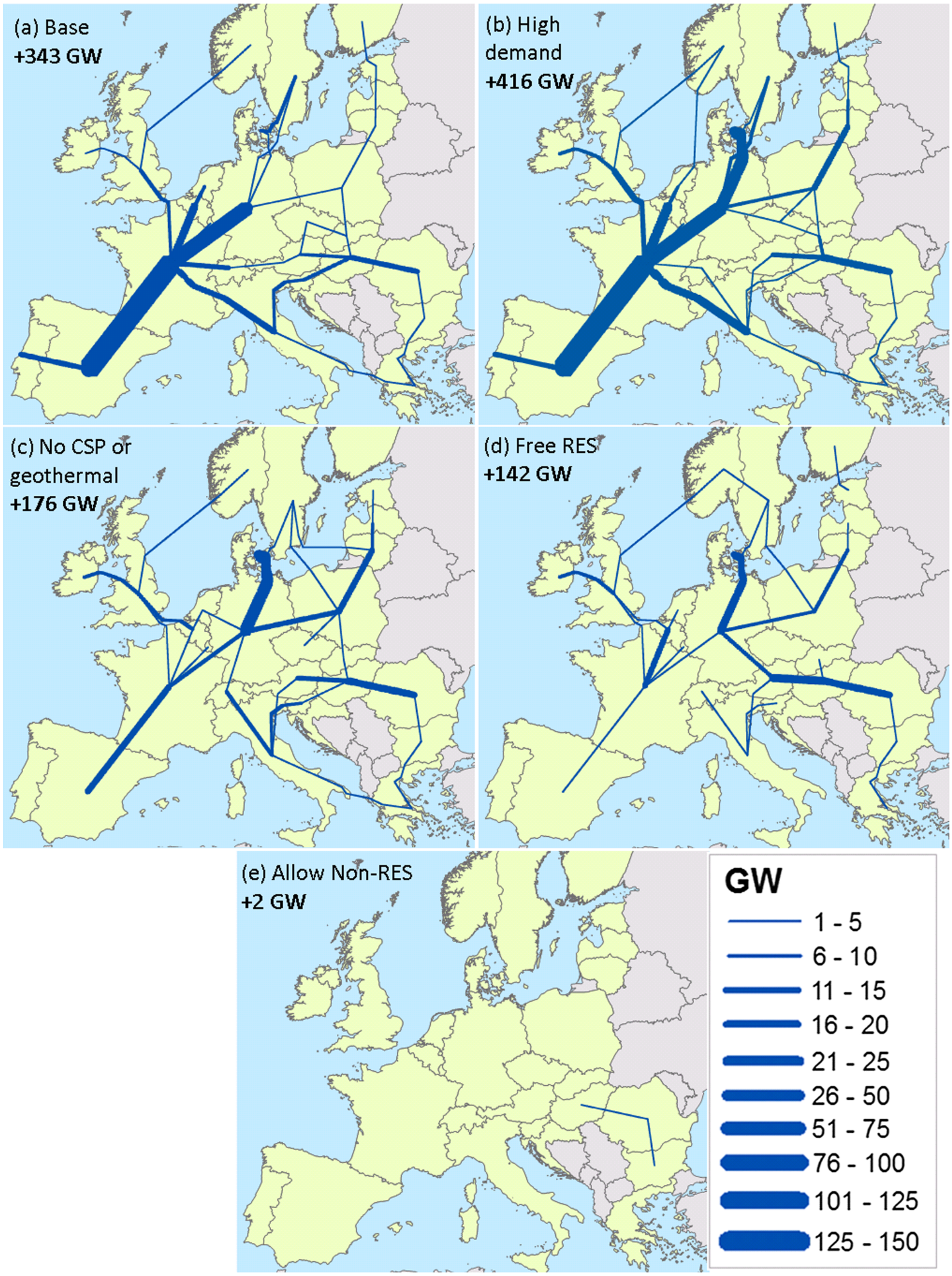

Fig. 7. Transmission grid reinforcements (on top of current capacity) for the (a) *Base*, (b) *High demand*, (c) *No CSP or Geothermal*, (d) *Free RES* and (e) *Allow non-RES* scenarios. Although the total installed capacities are lower, the grid topologies for the *Storage* (+334 GW) and *Alternative Demand Profile* (+321 GW) scenarios are similar to the *Base* scenario and hence not shown. The reference current transmission capacity (60 GW) is not included in the figures.

purposes, of which only 1.9 EJ (38%) was used in the production of electricity [101].[32] Thus, a 100% RES system would require a significant increase in biomass use compared with today.

Fig. 11 gives the consumption of biomass by fuel type for the *Base* and *High Demand* scenarios, showing that it is mainly lower-cost residues which are exploited, with minimal use of more costly energy crops like willow and poplar. By contrast, all available biogas substrates are used, and the model is forced to draw on additional high-cost biogas feedstock – beyond the maximum potential – in order to achieve feasible solutions. The quantity of additional biogas substrate varies from 0.13 EJ in the *Base* scenario, up to 3.4 EJ in the *High Demand* scenario. While the additional 0.13 EJ of substrate used in the *Base* scenario is relatively small and total biogas feedstock use (1.5 EJ) lies within the

[32] The total of 5 EJ includes 3.9 EJ of solid biomass, 0.7 EJ of biogas, and 0.4 EJ of renewable municipal waste. The 38% used for electricity includes use in combined heat and power plants. 'Energy purposes' includes both electricity and heat. The remaining biomass not used for electricity production (62%, 3.1 EJ) was used for residential heating or in district heating plants.

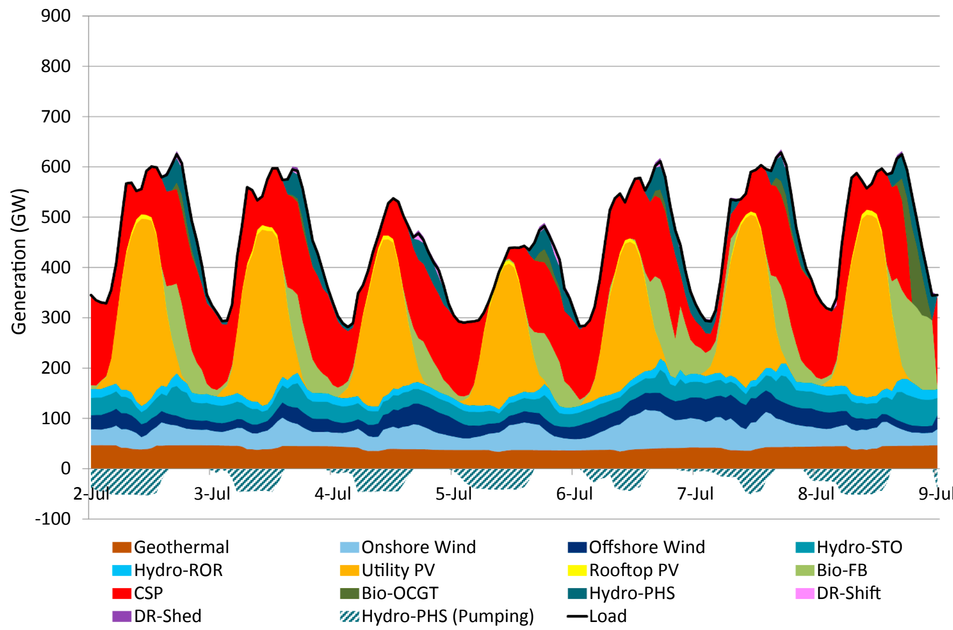

Fig. 8. Hourly dispatch for a typical summer week from the *Base* scenario, based on weather year 2010. Electricity demand for hydro pumping is shown as negative below the horizontal axis.

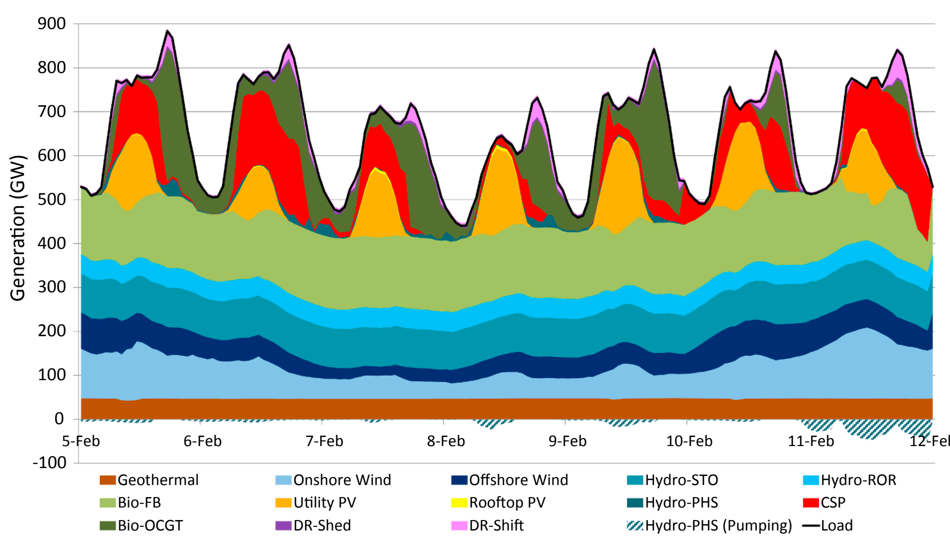

Fig. 9. Hourly dispatch for a typical winter week from the *Base* scenario, based on weather year 2010. Electricity demand for hydro pumping is shown as negative below the horizontal axis.

range of potentials reported in the literature,[33] the 4.7 EJ of additional biogas substrate required in the *High Demand* scenario far exceeds reported potentials.[34]

3.7. Total costs

In terms of total system costs, Fig. 12 shows how each scenario performs on an annualised basis, and in terms of the specific cost of electricity.[35]

Comparing the costs of all scenarios we draw several conclusions:

- Total annualised system costs in the *Base* scenario, and indeed most of the 100% RES scenarios, are similar at approximately 560 €bn y^{-1}.
- The exogenous CSP capacity of 200 GW is not optimal as it forces transmission costs up, and squeezes lower-cost wind and PV capacity out of the portfolio. As shown by the *Free RES* scenario, a lower capacity (~40 GW) would require far less land area and would be more cost effective, with costs falling to 530 €bn y^{-1}.

[33] Potential biogas production for the EU28 in 2030 is reported to range between 28.8 Mtoe and 40.2 Mtoe (1.2 EJ to 1.7 EJ) [157]. Thus, the 2050 potential may be higher than the base levels assumed in our study.

[34] This additional biogas is only required by the model in the hourly ST Schedule runs, not in the LT Plan. This highlights the importance of accounting for generator flexibility limitations and reserve requirements by performing detailed hourly simulations: neglecting them can underestimate the utilisation of peak generators.

[35] Calculated as the total annualised system costs divided by the total annual generation. Note that these are the 'worst case' costs, as generation is based on the most challenging weather year.

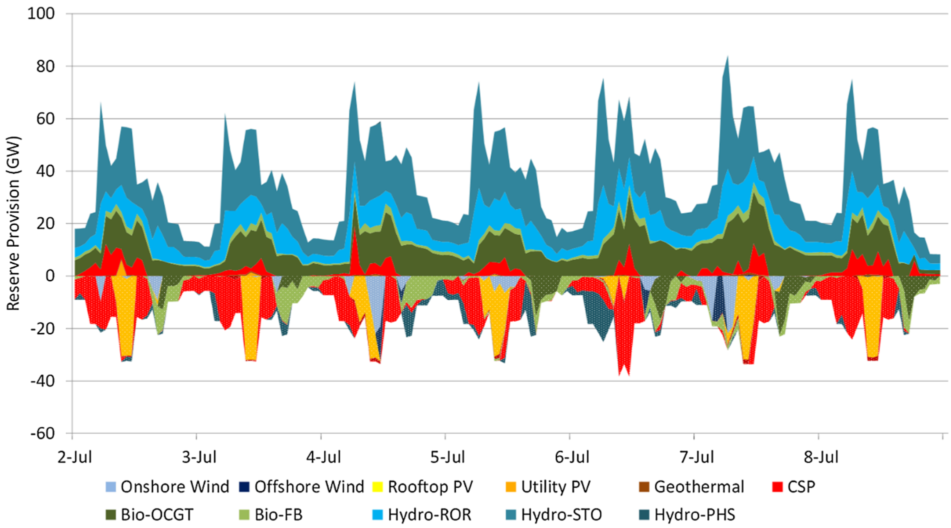

Fig. 10. Hourly reserve provision by generator type for a typical summer week from the *Base* scenario, based on weather year 2010. Positive values indicate total up-regulation reserves (spin-up plus stand-up), while negative values indicate down-regulation (spin-down) reserves.

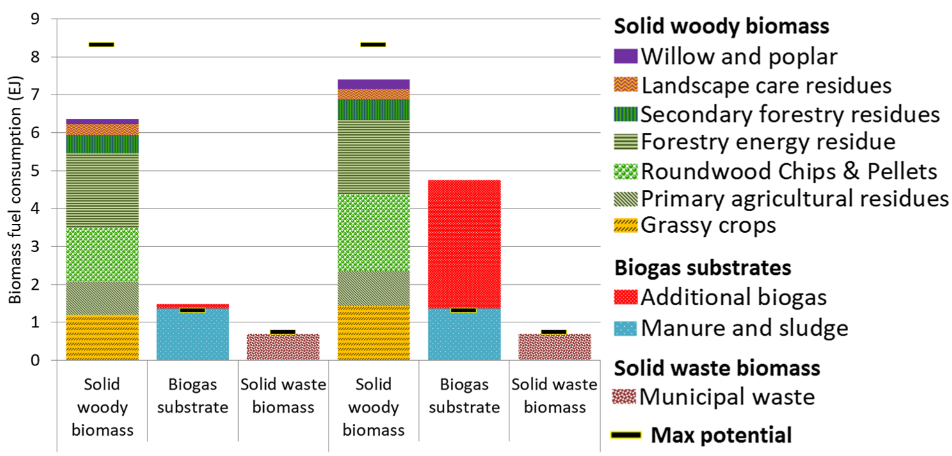

Fig. 11. Breakdown of biomass consumption by fuel type for the *Base* and *High Demand* scenarios for weather year 2010. The maximum potential per fuel category is indicated by black horizontal bars. The graph shows that while solid biomass availability is sufficient, 0.13 EJ of additional biogas is required in the *Base* scenario, rising to 3.4 EJ in the *High Demand* scenario.

- Allowing non-RES technologies in the portfolio sees costs fall to approximately 410 €bn y^{-1}: 22% cheaper than the lowest-cost 100% RES scenario.
- The costs of a 100% RES power system increase relatively more (approximately 1.4×) with higher demand, as a 36% increase in demand in the *High Demand* scenario leads to a 50% increase in costs compared with the *Base* scenario. This is due to the higher capacity required, use of more costly biomass sources, a greater need for more costly peaking generators, a shift to offshore wind, and the need to install wind and PV at less optimal sites.[36]
- A 100% RES system is possible without CSP and geothermal, but may be more expensive.
- At a cost of 700 € kW^{-1} (88 € kWh^{-1}), daily storage results in negligible cost benefits compared to the *Base* scenario as the savings in Bio-OCGT and transmission costs are offset by the investment costs for the storage and additional generation capacity.
- Given that Europe currently spends in the order of 300–400 €bn y^{-1} for an electricity demand of some 3100 TWh y^{-1} [43], a 100% RES power system costing 530 €bn y^{-1} and delivering 4400 TWh y^{-1} would be more expensive than the current system, but not unaffordable.[37]

3.8. Sensitivity analysis

So far, we have shown what different demand levels and technology availability would mean for a 100% RES power system. To provide a cost comparison, we also present one scenario in which non-RES technologies are allowed in the portfolio. However, given uncertainty in future fuel costs, and the fact that based on data from two nuclear plants currently under construction in Europe, the cost of nuclear may be significantly higher, comparing the costs of a 100% RES system with this single non-RES scenario may not be realistic.[38] Thus, we perform some additional model runs based on the *Allow non-RES* scenario with:

[36] From a single data point it is not possible to determine exactly how costs increase with increasing demand. However, for the reasons given, the relation is likely to be non-linear.

[37] 300 €bn y^{-1} to 400 €bn y^{-1} is approximately 2% to 3% of Europe's 2015 gross domestic product (GDP) [43]. Assuming moderate GDP growth (1.5% y^{-1}), 530 €bn y^{-1} would still represent 2% to 3% of GDP in 2050 [30].

[38] Hinkley Point C will have a capacity of 3200 MW at a cost of 19.6 £bn [158], while Olkiluoto-3 will have a capacity of 1600 MW at a cost of 8.5 £bn [159]. On this basis, the investment cost for nuclear could be in the range of ~5300 € kW^{-1} to ~6800 € kW^{-1}. However, it is not clear whether the reported costs include IDC, thus including IDC would increase the costs further.

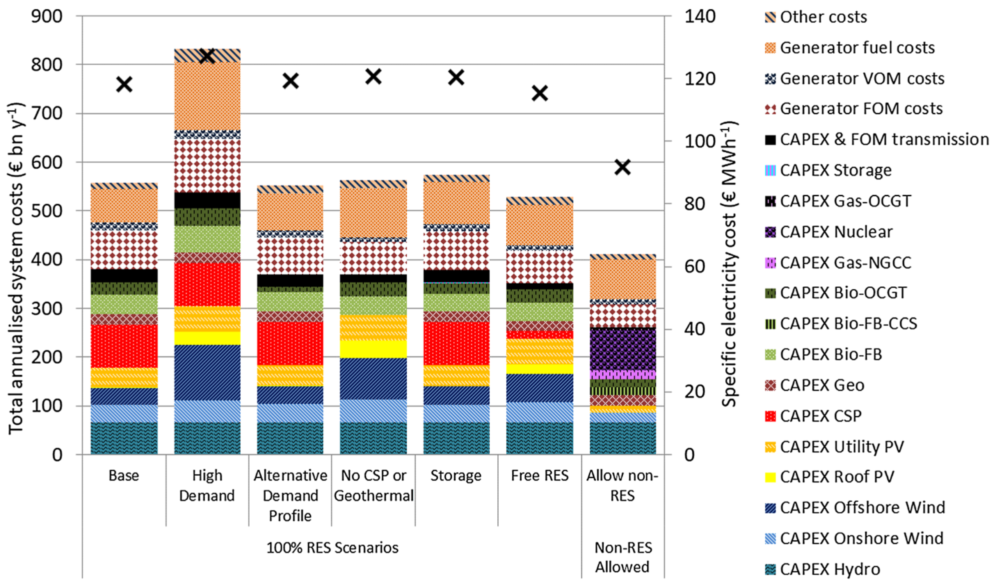

Fig. 12. Total annualised power system costs in 2050 for each scenario, based on weather year 2010. The total annualised costs for each scenario are shown on the left axis, while the specific electricity cost is indicated by the '×' symbols on the right axis. 'Other costs' includes demand curtailment costs, generator start-up costs, reserve costs, DSM costs, unserved energy costs, and for the *Allow Non-RES scenario*, emission costs and CO_2 capture and storage costs. Transmission costs from deployed vRES sites to the country node centres are included in the vRES CAPEX costs. While existing hydro is specified exogenously in all scenarios and not built by the model, we include the costs here for completeness.

- 27% higher nuclear CAPEX (6800 € kW^{-1});
- a higher CCS carbon capture rate of 100%, in the event that the assumed 90% CO_2 capture rate may be a limiting factor for CCS deployment at high decarbonisation levels;
- a 50% lower coal price (1 € GJ^{-1});
- a 50% lower natural gas price (3.5 € GJ^{-1}); and
- a 53% higher natural gas price (10.7 € GJ^{-1}).[39]

Fig. 13 shows the optimised generation portfolios for these sensitivity runs, as well as the original *Allow-Non-RES* scenario for comparison. With a higher nuclear CAPEX, nuclear disappears from the portfolio and is replaced by a mix of vRES, natural gas (OCGT, NGCC and NGCC-CCS) and additional Bio-FB-CCS capacity, which offsets the additional emissions from gas. Lower coal and natural gas prices also see nuclear disappear from the portfolio, to be replaced by Coal-PC-CCS and Gas-NGCC-CCS capacity. Assuming 100% CO_2 capture for CCS technologies sees some nuclear capacity replaced by Gas-NGCCs, and approximately 50% of Bio-OCGTs replaced by Gas-OCGTs. In all sensitivity runs, Bio-FB-CCS plays an important role in offsetting CO_2 emissions from natural gas and coal plants, both with and without CCS.

In terms of total annualised costs, Fig. 14 shows that almost all sensitivity runs have similar costs to the *Allow Non-RES* scenario of approximately 410 €bn y^{-1}, despite their different generation portfolios. The reason for this is that under a tight emission constraint, trying to replace high-cost (but zero-carbon) baseload nuclear capacity from the portfolio with lower-cost Coal-PC-CCS, Gas-NCCC or Gas-NCCC-CCS is not cost effective, as some higher-cost Bio-FB-CCS must also be installed to offset the higher emissions from gas or coal (even when equipped with CCS), and any additional CCS capacity leads to a concomitant increase in CO_2 transport and storage costs. As a result, total costs are not sensitive to the makeup of the portfolio, and we conclude that 410 €bn y^{-1} is a reasonable figure for benchmarking the cost of a 100% RES power system with a non-RES alternative.

4. Discussion

4.1. Deployment trajectories to 100% RES

In this paper we demonstrate that in 2050, Europe's electricity needs could be met by a 100% RES power system with the same level of system adequacy as today. However, we have not considered whether such a transformation would be possible by 2050.

Fig. 15 shows the historical deployment of wind capacity in the EU28 countries, as well as linear deployment trajectories required to reach the 2050 installed capacity in each of the 100% RES scenarios from this study.[40] For comparison, the installed capacities in 2030 and 2040 for three future scenarios from ENTSO-E's TYNDP 2018 are also shown, as well as the JRC's EU Reference Scenario 2016. From a starting capacity of 141 GW in 2016, if the current level of net wind deployment continues at approximately 10.5 GW y^{-1} (based on the average annual installations between 2007 and 2016), the installed capacity in 2050 would be sufficient for the majority of the 100% RES scenarios.[41] In fact, the 2050 levels for the *Base*, *Alternative Demand Profile* and *Storage* scenarios could even be achieved with a lower deployment of 7.5 GW y^{-1}. Only in the absence of CSP and Geothermal, or a significant increase in demand, would installations need to rise to 14 GW y^{-1} or 17 GW y^{-1} respectively. Given that nearly 13 GW of wind was installed in 2015, even these higher levels seem achievable.

A similar graph for PV is given in Fig. 16, showing that recent deployment levels in the EU have been erratic and in 2016, the 6.1 GW of capacity installed was far below the 22 GW achieved in 2011. If the installed capacity from the period 2008 to 2016 is extrapolated (an average of 10.5 GW y^{-1}), the installed capacity in 2050 would not be sufficient for any of the 100% RES scenarios considered in this study. In order to achieve the 2050 capacity in the *Base* (lowest) scenario, average annual PV deployment would need to increase to 15 GW y^{-1} for every year until 2050, rising to 25 GW y^{-1} for the *Free RES* scenario, and 30 GW y^{-1} for the *No CSP or Geothermal* scenario. While ambitious, given that 22 GW of PV was installed in Europe in 2011, it appears that these levels could be achievable [102]. Thus, we assert that sufficient wind and PV capacity could be deployed by 2050 to support a 100% RES power system.

However, unlike wind and PV which have significant capacity already installed and are currently experiencing growth, the total installed capacities of solid biomass, biogas, CSP and geothermal in 2015 were only 18 GW, 10 GW, 2.3 GW and 0.8 GW respectively, with recent deployment rates not exceeding 1 GW y^{-1} for any technology [105]. In

[39] The higher nuclear CAPEX is based on the calculated cost of Olkiluoto-3 [159]. The higher gas price is based on the 4 Degree Scenario (4DS) for 2050 from the IEA's ETP2016 [84].

[40] While the deployment trend would not necessarily be linear, this demonstrates that exponential growth would not be required to reach the 2050 installed wind and PV capacities for most scenarios.

[41] Net deployment includes the replacement of retired capacity.

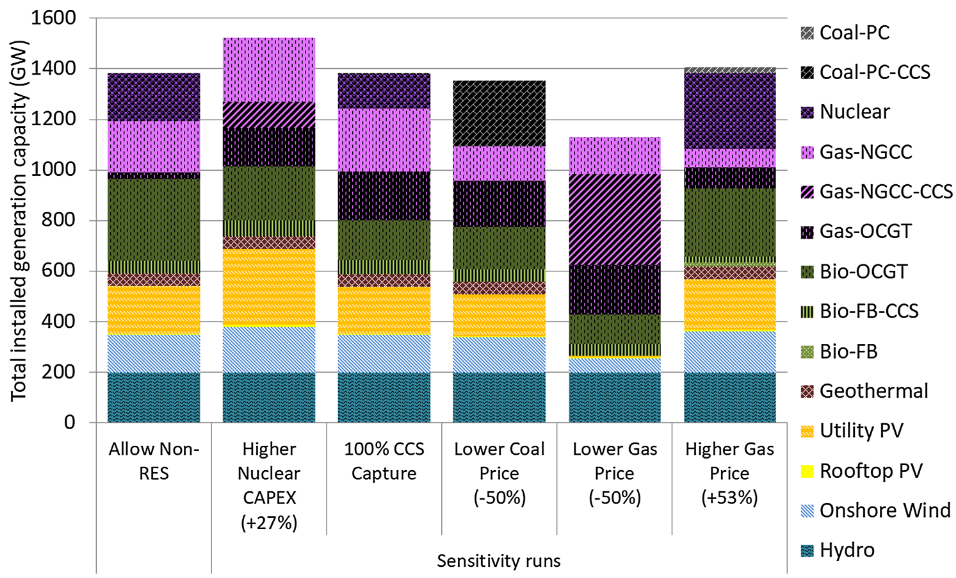

Fig. 13. Total installed generation capacity in 2050 in the sensitivity analysis runs, based on weather year 2010. The optimised portfolio from the *Allow Non-RES* scenario is shown again for comparison.

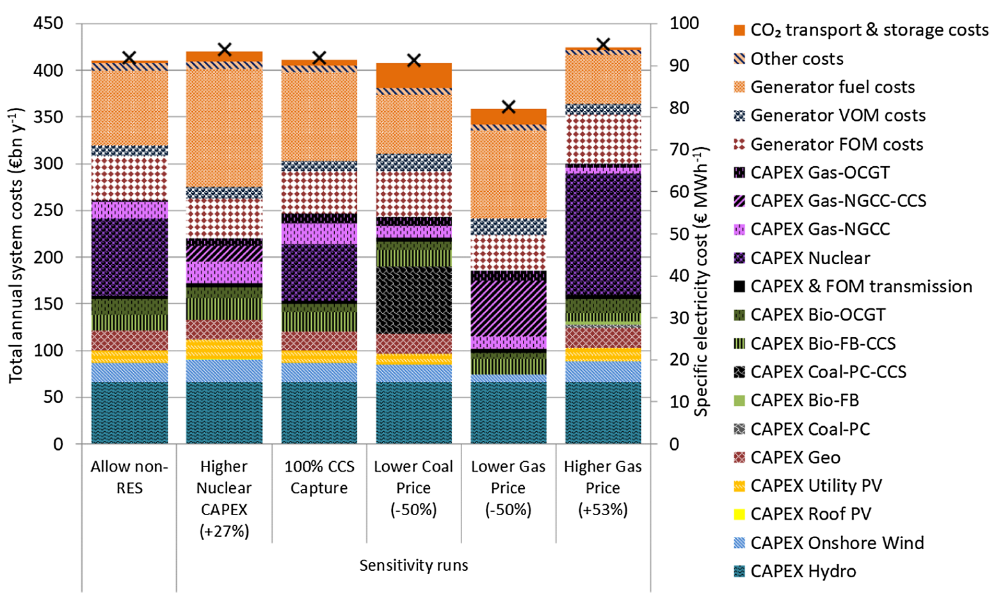

Fig. 14. Total annualised power system costs in 2050 for each sensitivity run, based on weather year 2010. The optimised portfolio from the *Allow non-RES* scenario is shown again for comparison. 'Other costs' includes demand curtailment costs, generator start-up costs, reserve costs, DSM costs, unserved energy costs, and emission costs. The total annualised costs for each run are shown on the left axis, while the specific electricity cost is indicated by the '×' symbols on the right axis.

order to reach the installed 2050 capacities in the *Base* scenario, installations of CSP and geothermal capacity would need to average 6 GW y^{-1} and 1.4 GW y^{-1} respectively every year from 2016 to 2050, which has never been demonstrated. Biomass presents an even greater challenge, with capacity additions needing to average between 4 GW y^{-1} (*Free RES*) and 6 GW y^{-1} (*High Demand*) for solid biomass, and between 6 GW y^{-1} (*Alternative Demand*) and 19 GW y^{-1} (*High Demand*) for biogas.[42] Even though we show that a 100% RES system is possible without CSP or geothermal, the infeasibility of the *No Biomass* scenario and large-scale deployment of biomass in the remaining scenarios demonstrate the vital role of bioelectricity in a 100% RES power system as a provider of flexible firm capacity, in the absence of significant seasonal storage.

In addition to generation capacity, we showed in Section 3.4 that cross-border transmission capacity would need to increase by between 142 GW (*Free RES*) and 416 GW (*High Demand*) from the 60 GW installed today, in order to support a 100% RES power system. Given that ENTSO-E expects a further 58 GW of cross-border transmission to be commissioned by 2030, installing an additional 84 GW between 2031 and 2050 to meet the requirements of the *Free RES* scenario should be plausible by 2050. However, realising the transmission network in the *High Demand* scenario would require 10 GW y^{-1} of new transmission capacity to be installed every year from 2016 until 2050, double the currently planned rate.[43]

4.2. Caveats and limitations

By modelling alternative scenarios in our study and performing selected sensitivity analysis, we explore how other demand and

[42] Rather than new biomass installations, existing coal and natural gas plants could also be converted to run on 100% biomass or upgraded biogas.

[43] According to ENTSO-E's TYNDP 2016 [67], 58 GW of new transmission capacity is expected to be commissioned between 2018 and 2030, implying an average deployment rate of 4.8 GW y^{-1}. Commissioning a further 84 GW between 2031 and 2050 would require a deployment rate of 4.4 GW y^{-1}.

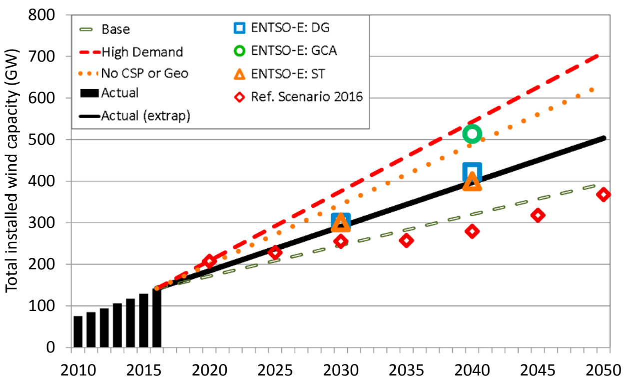

Fig. 15. Historical deployment of total (onshore and offshore) installed wind capacity in the EU28 (excluding NO and CH) based on data from the GWEC [102]. The solid line shows a linear extrapolation of the current deployment rate until 2050, assuming annual installations based on average deployment between 2007 and 2016 of 10.6 GW y^{-1}. The dashed lines show the linear deployment trajectories required to reach the installed 2050 capacity in the 100% RES scenarios from this study. The *Storage* and *Alternative Demand Profile* trajectories (not shown) are very similar to the *Base* scenario, while the *Free-RES* trajectory (not shown) is similar to the extrapolation of current deployment. For comparison, the hollow markers show the installed capacity from ENTSO-E's TYNDP 2018 [103] (O) *Global Climate Agreement* (□) *Distributed Generation* and (Δ) *Sustainable Transition* scenarios, and (◊) the JRC's *EU Reference Scenario 2016* [30].

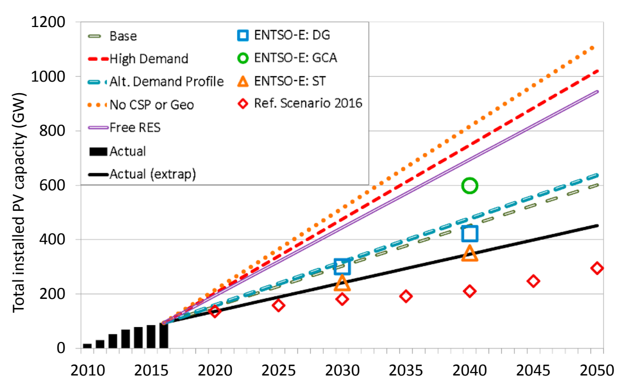

Fig. 16. Historical deployment of total installed PV capacity in the EU28 (excluding NO and CH) based on data from EurObservER [104]. The solid line shows a linear extrapolation of current deployment until 2050, assuming annual installations based on average deployment between 2008 and 2016 of 10.5 GW y^{-1}. The dashed lines show the linear deployment trajectories required to reach the installed 2050 capacity in the 100% RES scenarios from this study. The *Storage* trajectory (not shown) is very similar to the *Base* scenario. For comparison, the hollow markers show the installed capacity from ENTSO-E's TYNDP 2018 [103] (O) *Global Climate Agreement (GCA)* (□) *Distributed Generation (DG)* and (Δ) *Sustainable Transition* (ST) scenarios, and (◊) the JRC's *EU Reference Scenario 2016* [30].

technology developments would affect our results. Nevertheless, modelling the future is inherently uncertain and our results should be seen in the context of the following uncertainties:

- Different **cost developments** for the different generation technologies would affect both the makeup of the optimised RES portfolios, and their competitiveness with non-RES alternatives. While the costs of vRES have fallen rapidly in recent years, vRES CAPEX costs would need to fall by a further 70% from the base levels (which already assume significant reductions compared to today), in order for the total costs in the *Free RES* scenario to reach parity with the *Allow non-RES* scenario in 2050.
- Our results show that biomass would play a critical role in 100% RES power system in 2050. However, the **future cost and potential supply of biomass** in 2050 are uncertain, and will depend on future rainfall patterns, agricultural practices, and biomass demand from other sectors. Biomass imports from outside Europe, precluded from this study, would also be possible; however, a 100% RES power system relying on biomass for firm capacity would be vulnerable to what is ultimately a scarce and relatively expensive fuel.
- The quality of our results is underpinned by the quality of the **vRES generation profiles**, which depend first on the accuracy of the underlying weather dataset, and secondly on the methods used to derive generation profiles from the raw meteorological parameters. Both may have resulted in an overestimation of system adequacy:
  - o Firstly, the period covered by ERA-Interim (1979-present) is one in which the winter North Atlantic Oscillation (NAO) more often exhibited a positive phase than a negative phase, resulting in above-average wind speeds and temperatures in most of Europe [106–108]. However, as our study is based on the worst-case year with the NAO in its negative phase, our results are not affected.
  - o Secondly, linearly interpolating the 3-hourly temporal resolution of ERA-Interim to hourly values may make wind and PV generation profiles smoother than they would be in reality. However, the impact of this is likely to be small in comparison to the local smoothing which occurs at individual sites [109], and large-scale spatial smoothing across Europe [110].
- The long-term impact of **climate change** on Europe's weather patterns is also uncertain. However, recent studies suggest that, at the continental scale, these impacts are likely to be small [111,112].
- As shown by the significant expansion in cross-border transmission infrastructure, a cost-effective 100% RES European power system would be contingent upon deep **multi-lateral cooperation on energy policy** and integration of national power markets across the European continent, with harmonised rules for how generation and transmission capacity is dispatched and shared between countries. However, the realisation of such a 'supergrid' is by no means certain, and geopolitical developments may cause individual governments to resist increasing their reliance on interconnectors and electricity imports from other countries.

Due to time and research constraints, the following aspects could not be considered and remain areas for further research:

- Our assessment of reliability considers only **system adequacy**, not system security. Thus, without performing transient stability analysis, we do not know how a 100% RES system would perform under transient conditions, or what facilities would be required to maintain security (e.g. synthetic inertia, Flexible Alternating Current Transmission Systems (FACTS) [43,70,113]). However, by modelling reserves we do ensure that sufficient capacity is available to cover forecast errors and unplanned generator outages.
- We do not consider the low-voltage **distribution grid** which would need to be upgraded to bring electricity from PV and biogas plants to the wider power system.[44] Enhanced self-consumption with local storage could reduce distribution upgrades for PV [114], but biogas must provide peak supply and balancing for the wider system.
- We consider only snapshots of plausible 100% RES power systems in 2050, **without considering the transition** from the existing system in detail.[45] Thus, we do not consider whether the cumulative

[44] While large wind farms and centralised power plants (e.g. CSP, biomass) would most likely be connected to the transmission grid, biogas plants are usually small decentralised facilities located in agricultural areas, more likely to be connected to the transmission grid. For example, the most economical size of a biomethane plant ranges between 1 and 2 million Nm^3 biomethane per year (approximately 500 kWe to 1 MWe), depending on availability of feedstock and transport costs [160].

[45] This would require detailed data on Europe's fleet of existing power plants which was not available.

emissions trajectories to reach the 100% RES scenarios in 2050 would fit within Europe's allowable carbon budget to limit global warming to 2 °C, nor do we explore more ambitious decarbonisation efforts in light of the Paris Agreement. However, any of the 100% RES scenarios could be made net-carbon-negative by equipping (some of) the Bio-FB capacity with CCS.

- We assume constant **availability of biomass**, while in fact biomass availability fluctuates with the seasons, harvest times, and rainfall.[46] Security of biomass supply could be improved by importing or stockpiling biomass, but this would incur some costs for additional storage and treatment (e.g. torrefaction [115]) to stabilise the biomass, minimise degradation and methane emissions during storage [116,117].
- We model **biogas production and supply** as fully flexible, while in fact current AD processes have limited flexibility [118]. Flexibility can be improved with storage (either on-site storage, or upgraded gas which is injected and stored in the gas network) or more flexible AD processes [119]. However, storage can be limited for safety reasons, and not all countries have an extensive gas pipeline network.[47]
- We do not account for a potential increase in **indirect GHG emissions**, particularly from biomass. However, rough calculations suggest that indirect emissions from most 100% RES scenarios would be approximately 100 Mt $CO_{2eq}\,y^{-1}$: 70% higher than the indirect emissions from the current power system, or approximately 9% of the direct GHG emissions saved by converting to a 100% RES system. These could be offset by equipping approximately 10% of the Bio-FB capacity with CCS.[48]
- **Additional technology options** such as hybrid generators, co-firing biomass in existing coal plants, and seasonal storage (e.g. power-to-gas) to reduce total costs and dependence on biomass have not been considered.[49] However, adding seasonal storage would also require more vRES capacity in order to charge the storage which, as shown by the *High Demand* scenario, would be incrementally more expensive.
- In power systems with high penetrations of vRES generators, an energy-only market based on marginal-cost pricing may not provide sufficient revenues for generators to cover their costs [50]. Thus, any 100% RES power system would need to be supported by an open **electricity market environment** which ensured generators were remunerated adequately.[50] Scarcity pricing and capacity remuneration mechanisms are two possible ways to make up for this revenue shortfall [120,121], but neither have been proven at the European scale.
- Lastly, we do not consider the impacts of **social acceptance on costs**. For example, public opposition to overhead transmission lines and onshore wind could be mitigated by using underground cables, and shifting wind turbines offshore [122–124].[51] Shifting nuclear and CCS offshore could also make these technologies more palatable for the public [125,126]; however, offshore real estate is limited, and the cost and environmental consequences of shifting so much infrastructure offshore are likely to be significant.

5. Conclusion

In this study, we model seven scenarios for a fully renewable European power system in 2050 and explore the impact of uncertainties in future demand and technology availability. We find that a 100% renewable European power system could operate with the same level of system adequacy as the current power system, even when relying only on domestic European sources in the most challenging weather year. However, based on our scenarios, realising such a system by 2050 would entail:

- expanding generation capacity to at least 1.9 TW (based on the *Alternative Demand Profile* scenario), compared to the 1 TW installed today;
- expanding cross-border transmission capacity by at least ~140 GW (based on the *Free RES* scenario) from current levels (60 GW), with the consequence that Europe becomes much more dependent on the reliability of cross-border transmission capacity;
- the well-managed integration of heat pumps and electric vehicles into the power system through smart charging and other demand-side technologies, in order to reduce peak demand and required biogas turbine capacity;
- the implementation of energy efficiency measures to prevent a massive increase in electricity demand (on top of that expected from HPs and EVs) in order to reduce demand for biomass, and keep the deployment rate of new transmission and generation capacity manageable through to 2050;
- wind deployment levels of at least 7.5 GW y^{-1} to be maintained (currently 10.6 GW y^{-1}) while PV deployment to increase to at least 15 GW y^{-1} (currently 10.6 GW y^{-1}) until 2050 (based on the *Base* scenario);
- the large-scale mobilisation of Europe's biomass resources, with power sector biomass use reaching at least 8.5 EJ (4.5 times higher than today's 1.9 EJ) in the most challenging year (based on the *Base* scenario*)*;
- increasing solid biomass and biogas capacity deployment to at least 4 GW y^{-1} and 6 GW y^{-1} respectively every year until 2050 (based on the *Alternative Demand Profile* scenario); and,
- additional costs, as even when wind and PV are placed in the optimum locations, the total annualised costs of a 100% renewable power system would be at least 530 €bn y^{-1} (based on the *Free RES* scenario), approximately 30% higher than for a system in which nuclear or carbon capture and storage are included. Moreover, these costs would increase relatively more with higher demand.

This study shows that even when wind and PV capacity is spatially optimised and electricity can be transmitted across a fully integrated European grid, a 100% renewable power system would still require significant flexible zero-carbon firm capacity to balance variable wind and PV generation, and cover demand when wind and solar supply is low. This capacity could be provided by hydropower, CSP, geothermal, biomass, or seasonal storage, yet none of these technologies are currently being deployed at the level necessary to support a 100% renewable power system by 2050. However, we find that even a 100% renewable system may not deliver the level of emission reductions necessary to achieve Europe's climate goals, as negative emissions from biomass with carbon capture and storage may still be required; either to offset an increase in indirect greenhouse gas emissions, or to realise more ambitious decarbonisation pathways. Thus, in steering the transition to a reliable, cost-effective power system that is consistent with Europe's climate ambitions, policymakers should ensure that all

[46] For example, the annual European supply of agricultural residues can vary by as much as +23% and −28% from the long-term average [161].

[47] For example, in the Nordic countries gas is only available in a few major cities, not in rural areas where biogas is likely to be produced.

[48] These indirect emission calculations can be found in the supplementary material.

[49] For example, biomass-CSP hybrid generators which can burn biomass during winter and on cloudy days when DNI is low [162]. Also, co-firing of solid biomass in coal plants (possibly retrofitted CCS) could allow existing coal plants to remain in operation up to (or even beyond) 2050, reducing costs by avoiding stranded assets.

[50] In Germany for example, tertiary balancing power can only be provided by plants above 5 MW [119]. This would be a major limitation for biogas plants which are typically small. However, aggregators could be used to pool generation capacity for provision of ancillary services.

[51] As shown in Tables 3 and 4, the cost of offshore wind is twice that of onshore wind, while underground cables are up to 10 times more expensive than overhead transmission lines.

technology options are on the table including biomass, nuclear and carbon capture and storage.

Future research should investigate the flexibility of biogas production, system adequacy under different rainfall years, the dispatchability of run-of-river hydro generators and seasonal availability of water, the potential role of seasonal storage, heat-electricity sector coupling, system security, and the market conditions necessary to support power systems with high shares of variable renewables.

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Appendix A. Supplementary material

Supplementary data associated with this article can be found, in the online version, at https://doi.org/10.1016/j.apenergy.2018.08.109.

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