Supplementary information : Assessing uncertainty space for long-term flexibility needs in future European sector-coupled energy system

Table of Contents

1 Additional Results

1.1 Additional results - electricity demand and electricity production and installed capacity

Electricity demand is increasing towards 2050, driven by electrification of other sectors e.g. heating, transport. This drives the deployment of renewable and sharp decrease of fossil fuels to produce electricity. In 2050, electricity is mainly provided by renewable energy e.g. solar PV, onshore and offshore wind, hydropower.

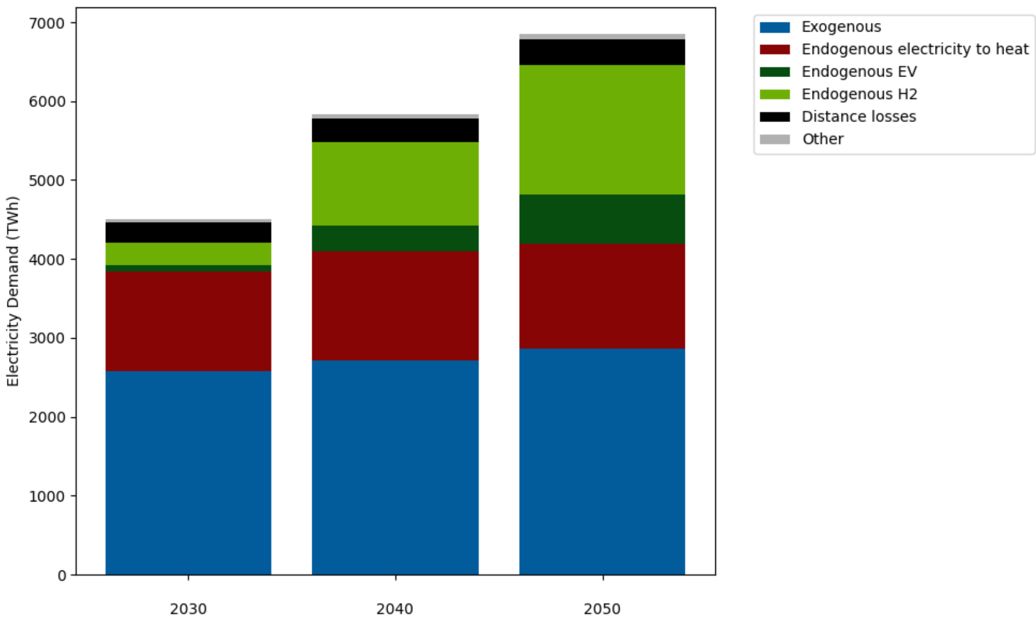


Figure 1: Electricity demand in 2030, 2040 and 2050 disaggregated into exogenous electricity demand, endogenous demand for electricity to heat, electric vehicles and hydrogen production and distance losses.

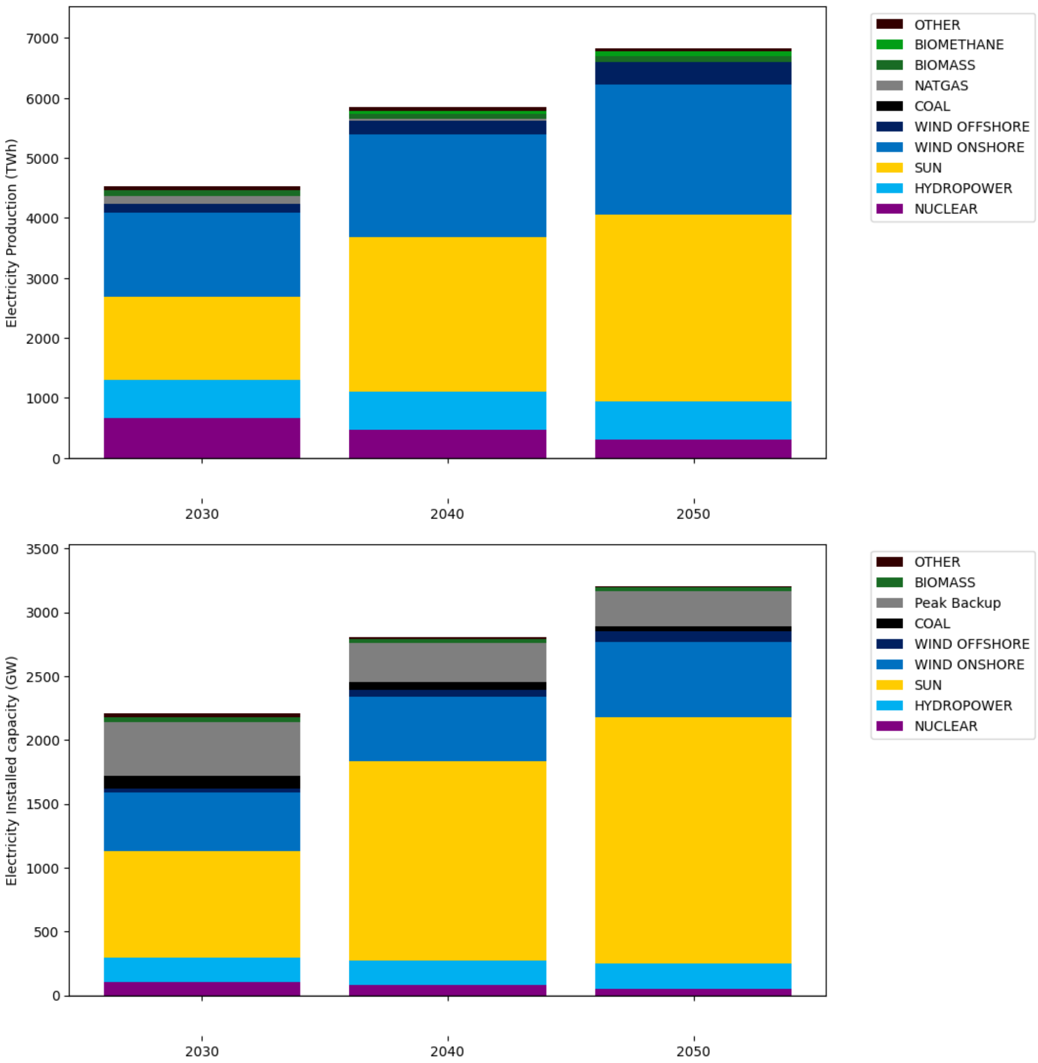


Figure 2: Electricity production mix and installed capacity per technology type in 2030, 2040 and 2050.

1.2 Additional results - heat production and installed capacity

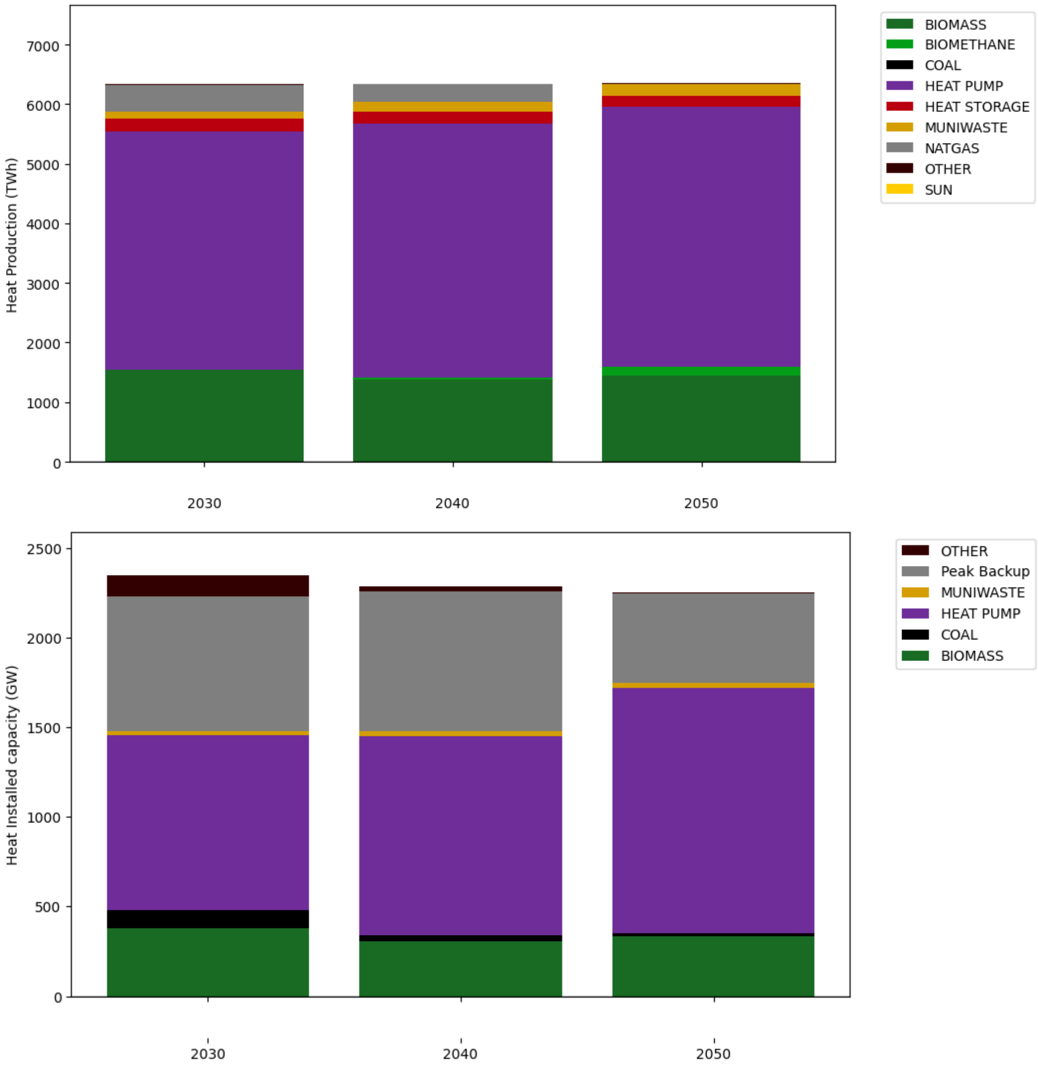


Figure 3: Heat production mix and installed capacity per technology type in 2030, 2040 and 2050.

By 2050, the heating sector is largely electrified through the deployment of individual heat pumps and large-scale district heating heat pumps, while the remaining heat demand is met primarily by biomass and natural gas/biomethane.

1.3 Additional results - hydrogen production and installed capacity

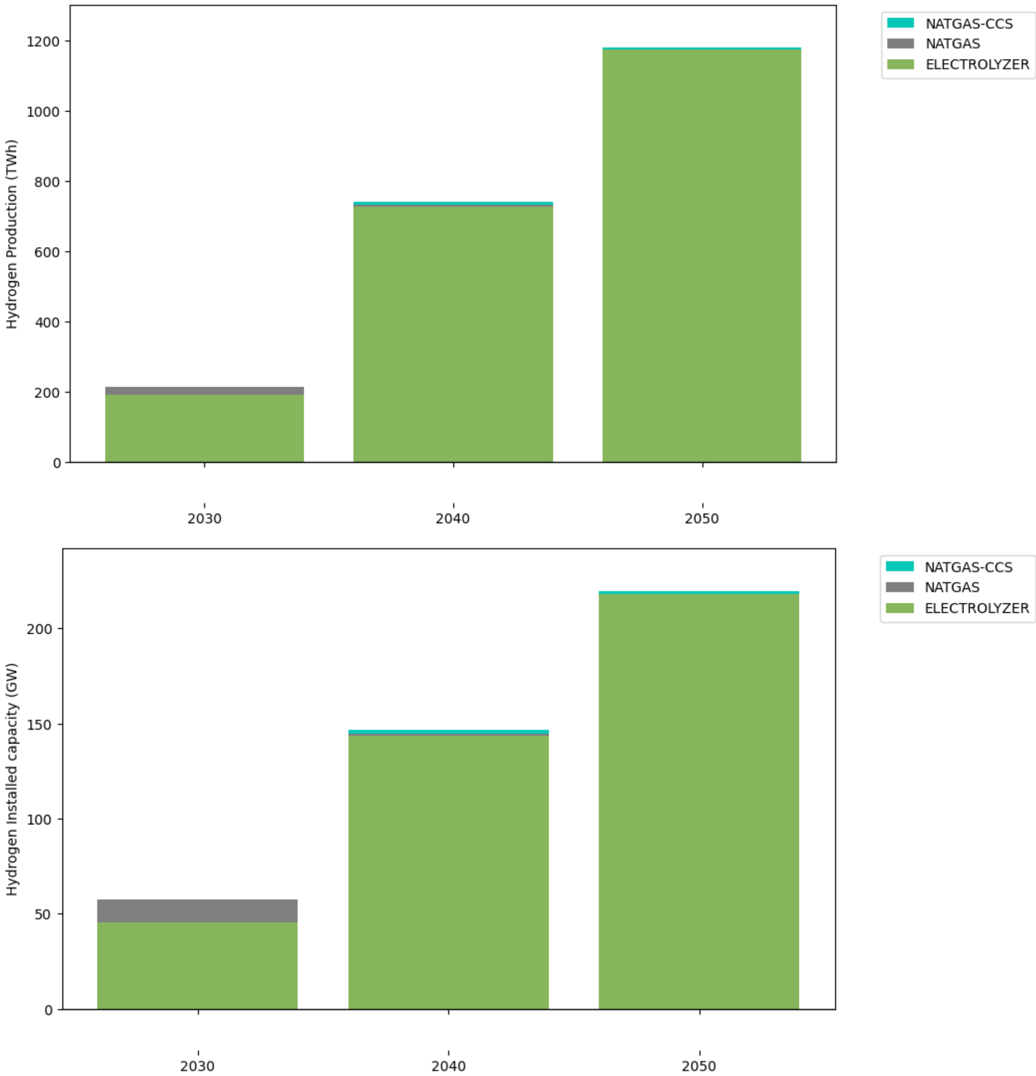


Figure 4: Hydrogen production mix and installed capacity per technology type in 2030, 2040 and 2050.

Hydrogen demand increases substantially towards 2050, with most of the demand being met by electrolyzers producing green hydrogen. A small share of grey hydrogen remains in 2030.

1.4 Additional results - electricity, heat and hydrogen production in 2050 for specific countries highlighted in Figure 2d of the frequency-based approach

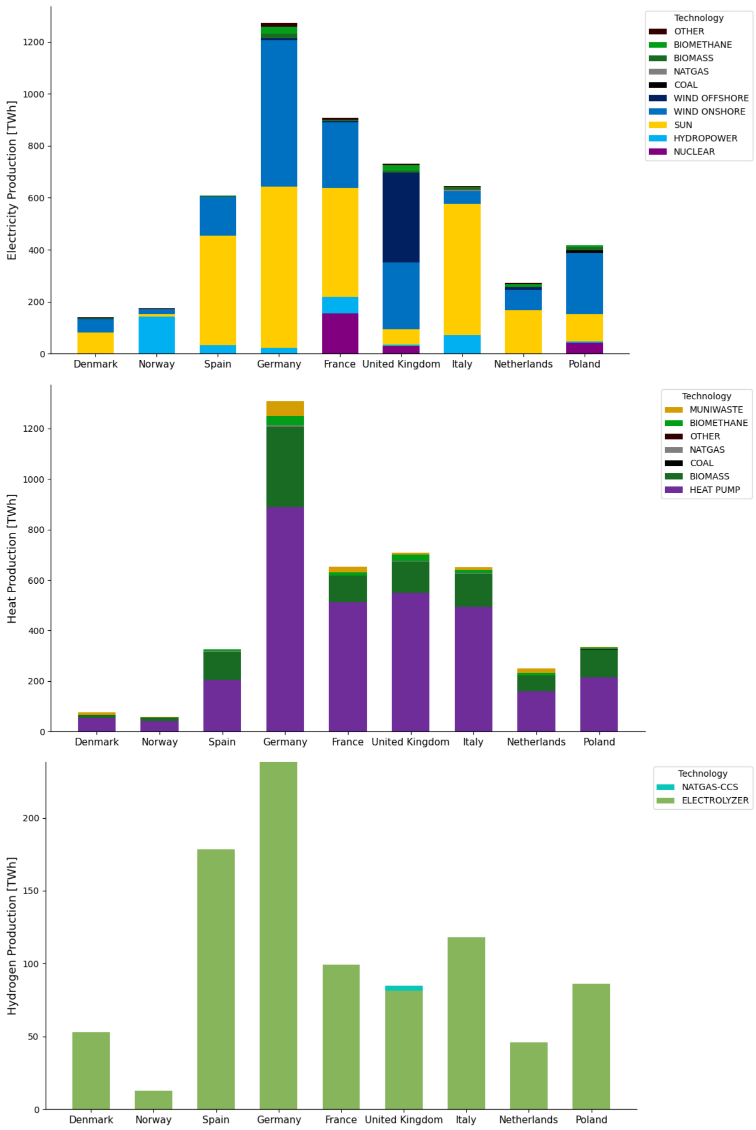


Figure 5: Electricity, heat and hydrogen production in 2050 in Denmark, Norway, Spain, Germany, France, Italy, United Kingdom, Netherlands and Poland.

1.5 Demand response flexibility per type

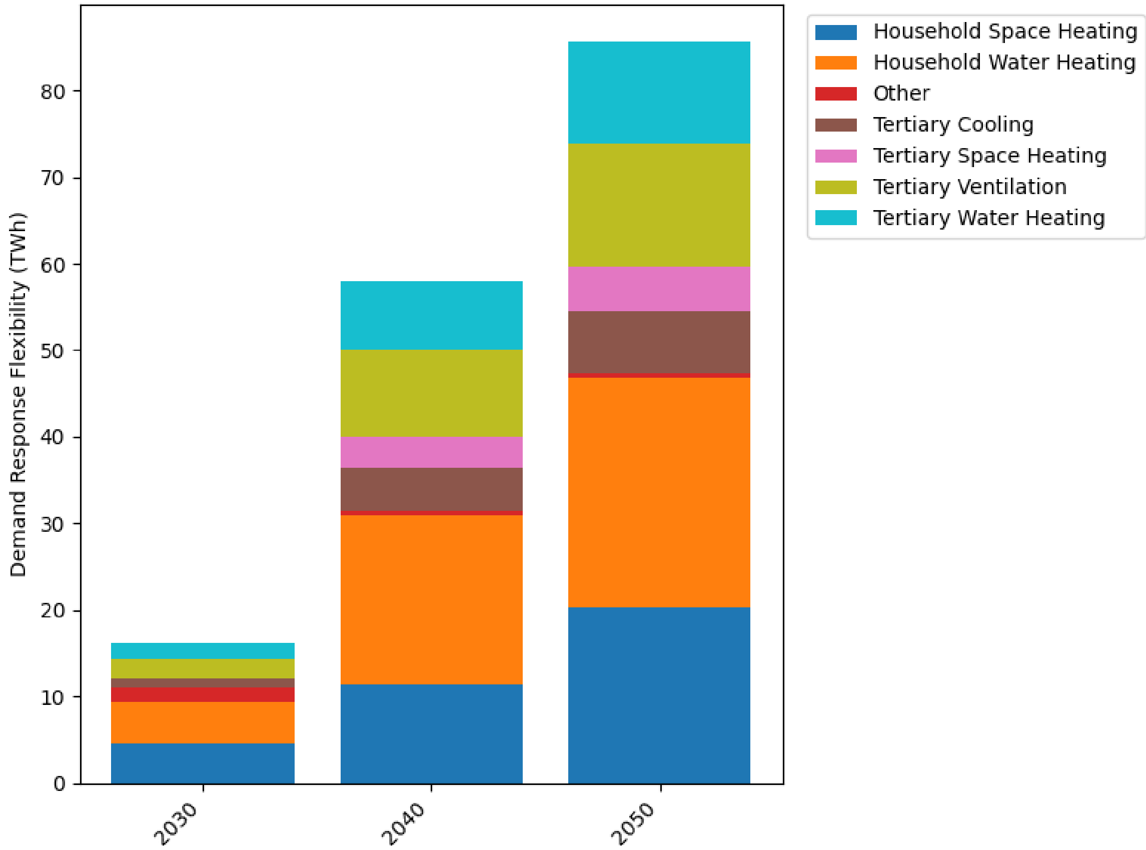


Figure 6: Demand response flexibility per type in 2030, 2040 and 2050.

Demand response flexibility contribution increases towards 2050. In 2030, demand response is primarily provided by residential water heating and space heating. Towards 2050, these end uses remain the main contributors to demand response flexibility; however, additional sources, including tertiary-sector ventilation, cooling, and space heating, become increasingly deployed.

1.6 National VRE installed capacities and potentials

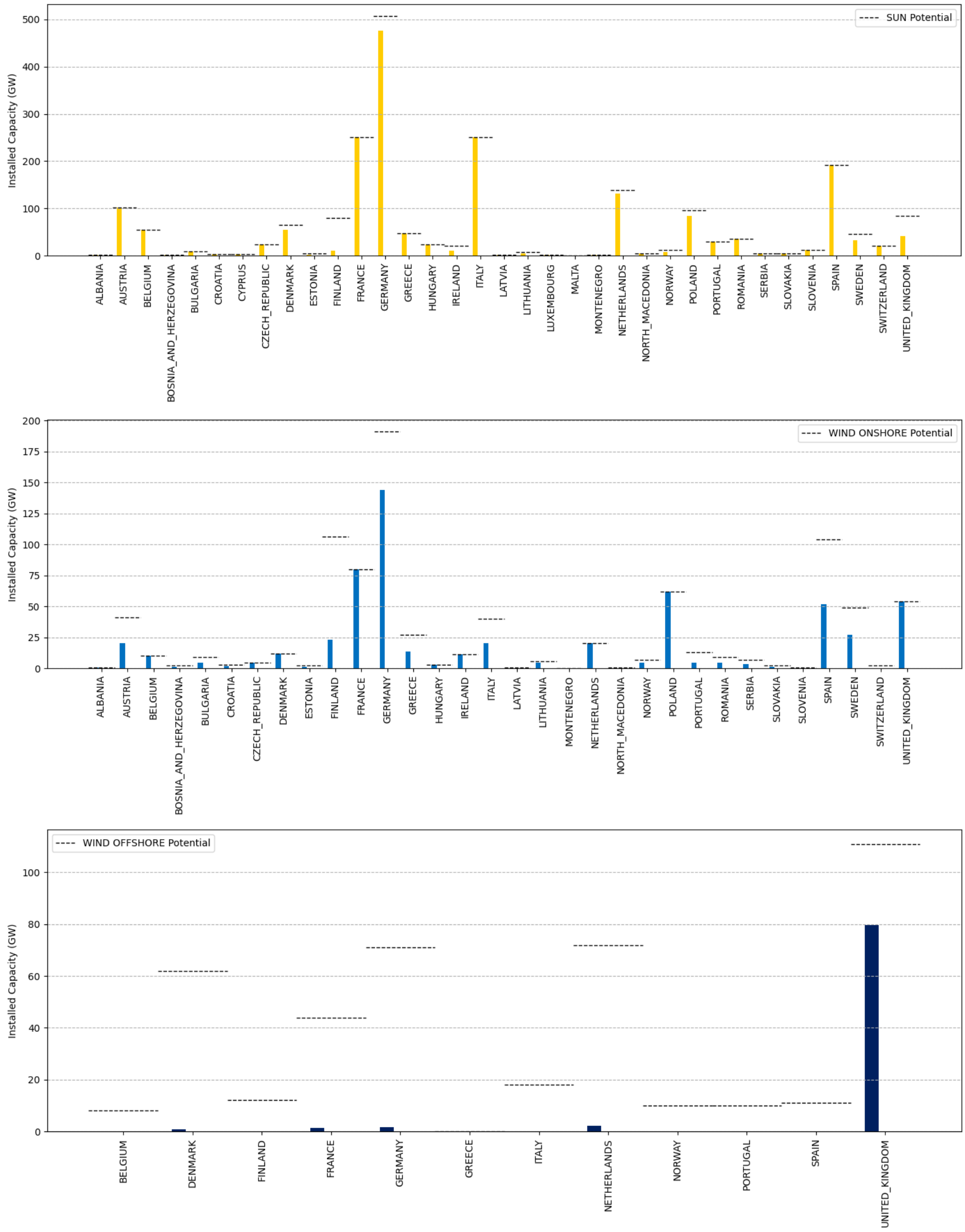


Figure 7: Installed capacity compared to the potential, per country, for Solar PV, onshore wind and offshore wind, in Net Zero scenario 2050

Maximum deployment potentials for variable renewable energy (VRE) are implemented in Balmorel for each country and renewable technology, to reflect technical limitations, social acceptance and land availability. Thus, some VRE can reach a technical limit in some countries. Indeed, the results of the baseline simulation for 2050 show that solar PV and onshore wind potentials are frequently fully exploited, whereas offshore wind deployment remains below its maximum potential. National potentials for VRE are defined according to the installed capacity projected din the Distributed Energy scenario for 2050.

In addition, to consider renewable variability within each region, we split the potential of investments into sub-areas, named resource grades. In each resource grade, full load hours and capacity factors are different whereas investment costs remain the same. Resource grade 1 accounts of the 10% locations with the best wind or irradiation, resource grade 2 considers 40% of second-best locations and resource grade 3 the remaining 50%. For solar PV and onshore wind, For offshore wind, we mostly assume assets to be deployed within resource grade 2, that considers investments in offshore wind with an AC connection.

To generate full load hours and variable time series of VRE, this study uses the Correlations in renewable energy sources (CorRES) model. We use the most recent CorRES dataset [1], containing Pan-European hourly wind and solar time series. CorRES previous datasets have been used in many publications including TYNDP 2024 [2].

1.7 Additional results - operational CO2 emissions

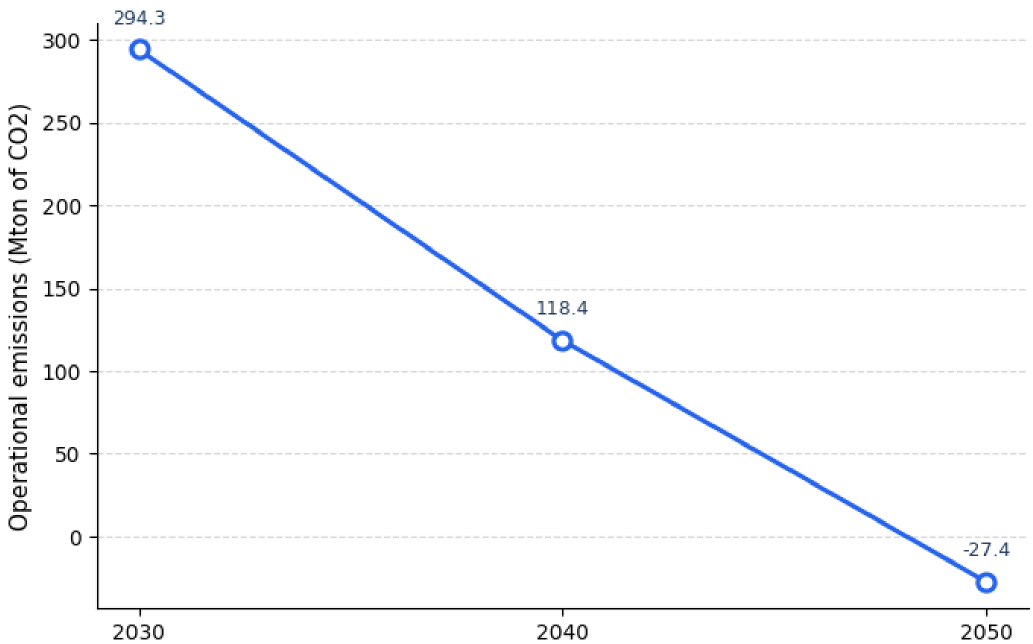


Figure 8: CO_2 operational emissions in 2030, 2040 and 2050 of the European energy system for a Net Zero system in 2050.

Operational CO_2 emissions from the energy system are decreasing from 2030 to 2050, reaching a negative value of -27 million ton of CO_2eq in 2050. This corresponds to a Net Zero energy system and could support economy-wide net-zero emissions, provided that the remaining emissions from hard-to-abate sectors do not exceed the available negative emissions. Indeed, if a hydrogen demand of 1000 TWh is insufficient to fully decarbonize these hard-to-abate sectors, additional mitigation measures would be required e.g. additional electrification or green fuel production, reduction of demand in specific sectors.

1.8 Additional Results - Frequency-based approach assessment

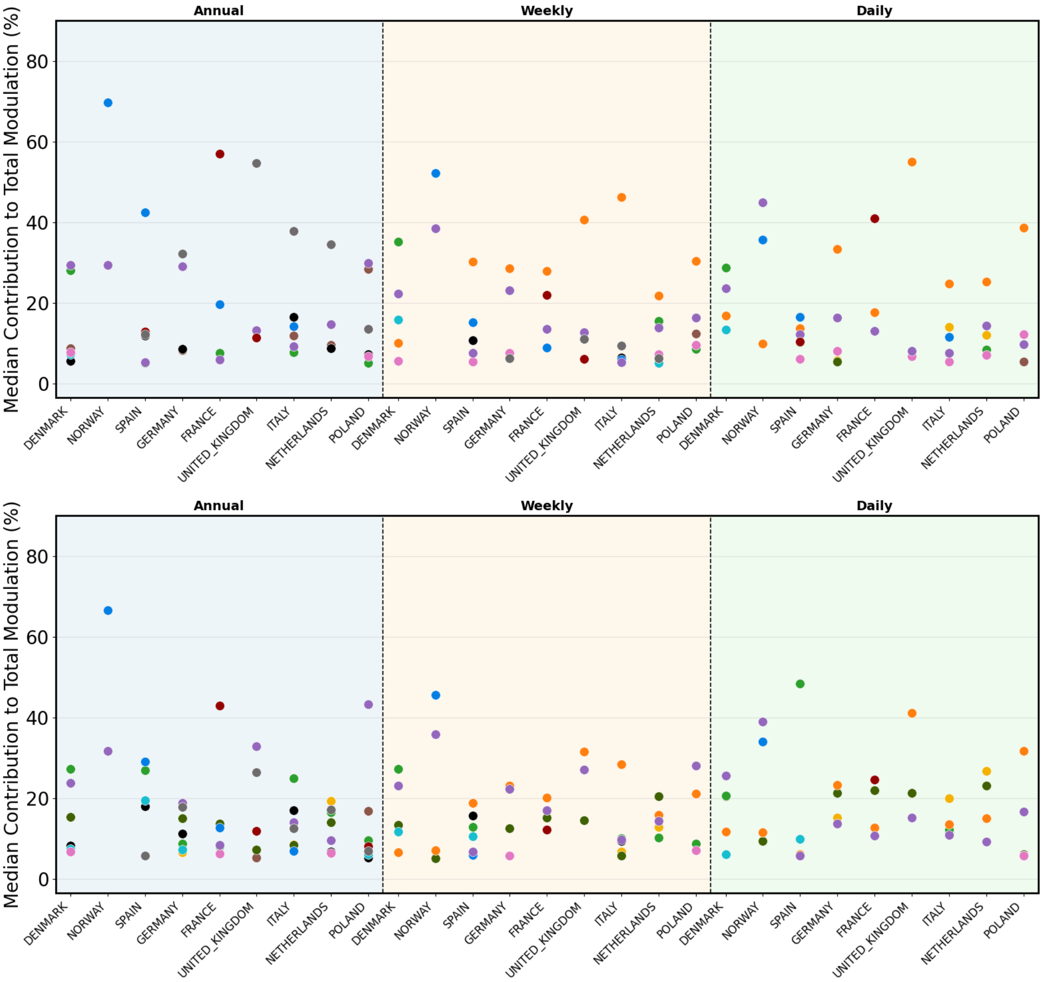


Figure 9: Country specific flexibility contribution median value in 2030 (a) and 2040 (b).

1.9 Additional Results - Multiple weather year assessment

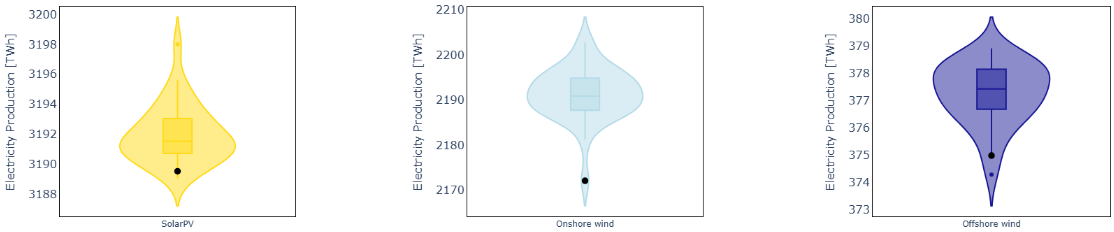


Figure 10: Electricity production of solar PV, onshore and offshore wind across the different weather years. Results for the baseline weather year 2012 are shown as a black dot.

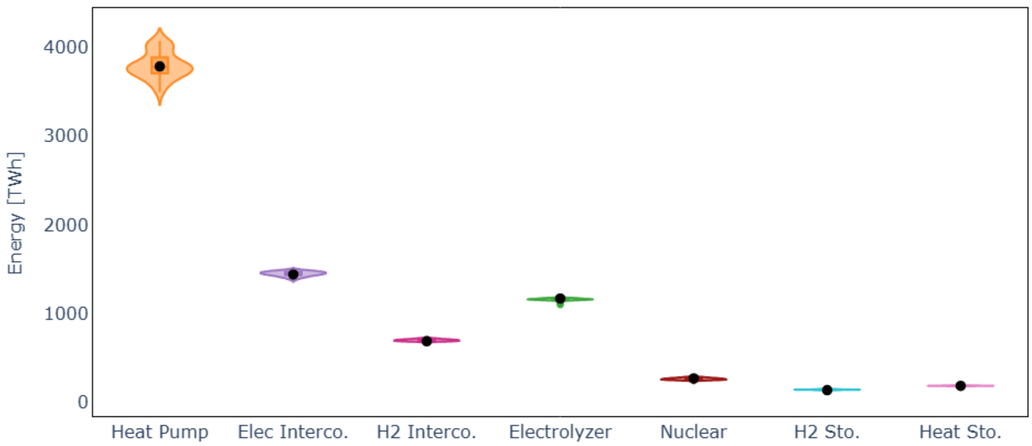
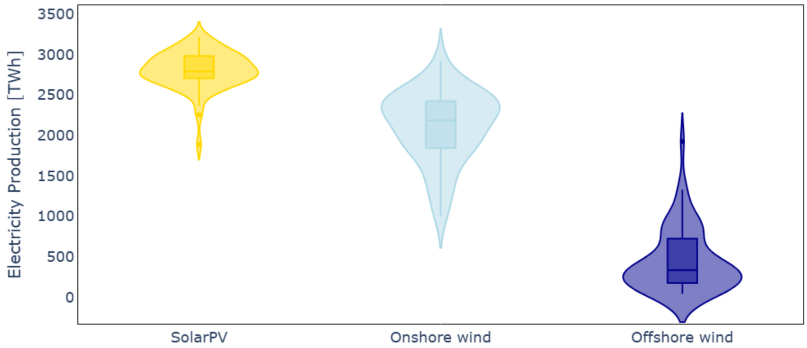


Figure 11: Flexibility amount provided by various assets across the different weather years.

The multiple weather year assessment highlight that VRE yearly production is changing across weather years, as well as the amount of heat delivered by heat pumps. Other assets shown in the previous plot remain stable across weather years.

1.10 Additional Results - Monte Carlo



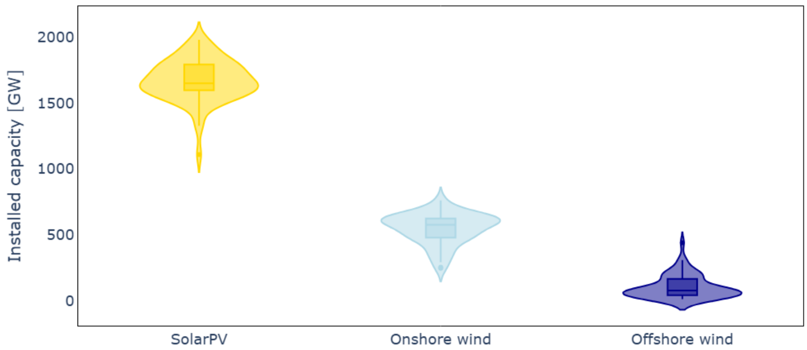


Figure 13: Electricity production and installed capacity distributions in the 100 scenarios for solar PV, onshore wind and offshore wind.

Solar PV installed capacity exhibits higher uncertainty than onshore and offshore wind capacities. However, onshore and offshore wind technologies show a wider distribution of electricity production compared with solar PV.

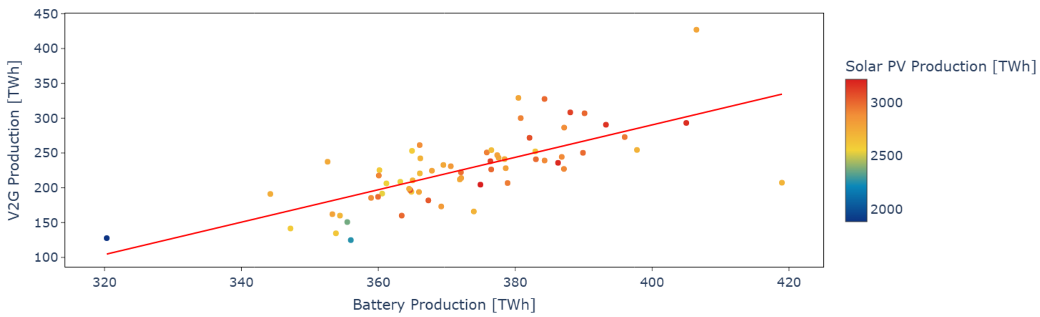
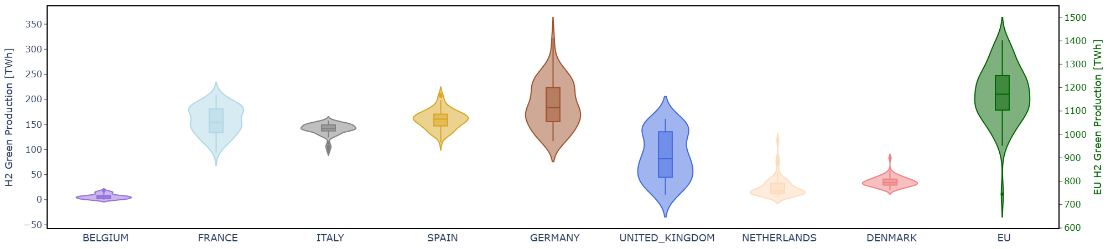


Figure 14: Correlation plot between V2G output, battery output and solar PV production across the 100 scenarios of the Monte Carlo simulation.

An increase of Solar PV production goes along with an increase of both V2G and battery output.


H2 Green Production [TWh]
EU H2 Green Production [TWh]
BELGIUM
FRANCE
ITALY
SPAIN
GERMANY
UNITED_KINGDOM
NETHERLANDS
DENMARK
EU

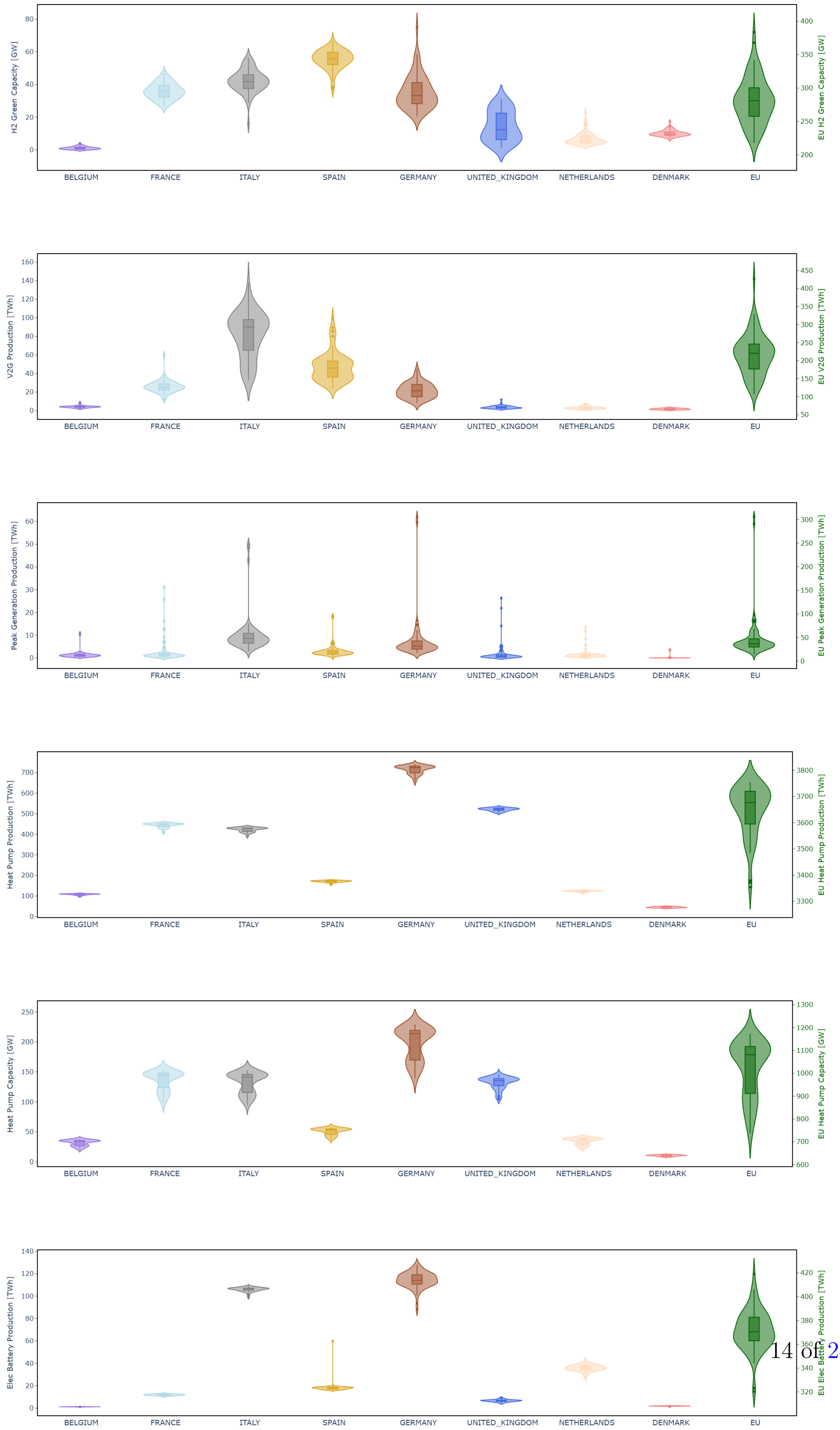


Figure 16: Distribution of various flexible system components for the 100 runs of the Monte Carlo

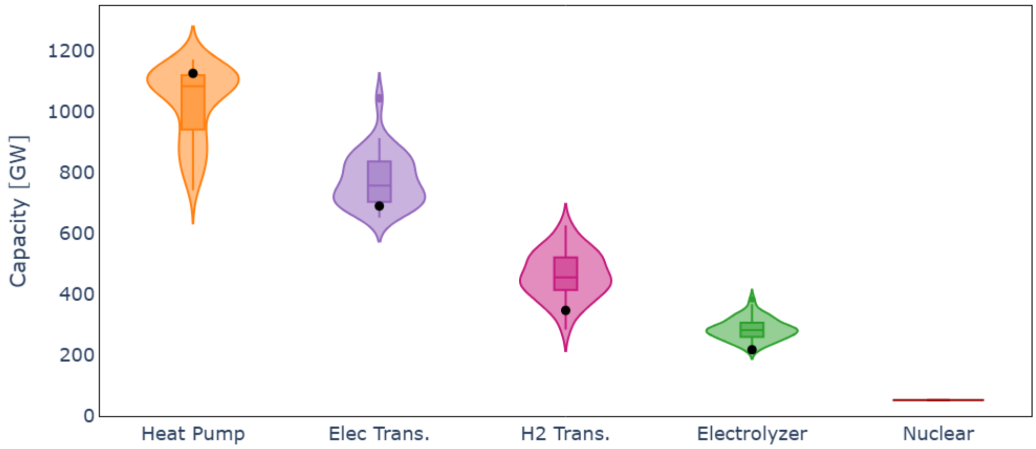


Figure 17: Distribution of installed capacity of various flexibility assets across the 100 scenarios of the Monte Carlo simulation

Flexibility assets distribution and uncertainty is country specific. Green hydrogen production and capacity uncertainty is mainly driven by countries with high hydrogen demand e.g. Germany, United Kingdom, Spain and France. V2G output uncertainty is highly correlated with the number of EV in the country, therefore more important in more populated countries. It is also more important in countries whose electricity production relies significantly on solar PV e.g. Italy, Spain. Peak Gas production uncertainty is more important in countries with high peak demands such as Italy, Germany and Spain. Heat pump and battery production uncertainties are mainly occurring in Germany.

Regarding installed capacity, heat pump deployment, electricity and hydrogen transmissions are highly uncertain across scenario.

1.11 Additional cross-sectoral trade-off

As highlighted in Section 2.8, flexibility options deployment can be impacted by cross-sectoral effects. Another example is related to the interplay between V2G and the heat sector. Higher EV deployment and improved V2G characteristics and lower charging infrastructure increase G2V charging and V2G discharging peak capacities, reducing the use of heat storage and, to some extent, the deployment of heat pumps (Fig. 5 of the main article). By providing greater peak flexibility and enabling greater utilization of VRE, V2G reduces the system's reliance on heat infrastructure for flexibility provision. This suggests competition between cross-sectoral flexibility options and indicates that the model prioritizes power-sector flexibility options when they provide a more cost-effective alternative to cross-sectoral solutions.

Additionally, higher hydrogen demand primarily increases hydrogen infrastructure deployment and its contribution to system flexibility, while also increasing heat storage output.

2 Extended Data

€$_{2016}/GJ$	**2030**	**2040**	**2050**
Nuclear	1.54	1.54	1.54
Natural Gas	5.8	5.8	5.8
Coal	1.5	1.5	1.8
Lignite	1.28	1.28	1.28
Straw	7.16	9.0	9.5
Wood Chips	6.2	6.2	6.2
Wood Pellets	10.65	12.44	13.0
Biogas	16.5	16.5	17.2

Table 1: Fuel price assumptions for 2030, 2040 and 2050.

Natural gas price value is assumed to reach a plateau from 2030, thus we assume a constant value being the 2030 projection of ENTSO-E in the TYNDP 2024 report [2]. Coal, lignite and nuclear prices are taken from World Energy Outlook 2025 report for Europe [3]. Other fuel prices have not been updated and are extracted from Balmorel main model, which reflect the assumptions of the World Energy Outlook scenario Net Zero from 2022.

	2030	2040	2050
GERMANY	6,4	30,4	44,2
UNITED KINGDOM	4,1	19,2	42,8
FRANCE	4,0	19,1	36,3
ITALY	1,3	6,0	28,1
SPAIN	0,9	4,4	20,7
NETHERLANDS	1,8	8,5	11,5
BELGIUM	1,2	5,7	6,5
SWEDEN	1,4	6,0	6,3
POLAND	0,3	1,2	5,7
PORTUGAL	0,5	2,1	5,4
AUSTRIA	0,6	2,7	4,6
NORWAY	2,3	3,4	3,8
DENMARK	0,8	3,4	3,5
FINLAND	0,6	2,7	3,2
GREECE	0,1	0,4	2,0
SWITZERLAND	0,5	0,5	0,5
Total	26,7	115,7	225,1

Table 2: Millions of available EVs for each countries considered in the study. Some countries included in the study do not have EVs.

The total amount of EVs is based on Balanza et al. [4] methodology. Number of EVs for each region considers 2024 EV statistics and projections towards 2035 [5]. Then, from 2035 to 2050, projections are based on the yearly projected increment from 2030 to 2035 [5], with an upper limit set to 55% of the regions's forecasted population. This leads to around 225 millions electric vehicles in 2050, accounting for approximately 95%

of the European passenger car fleet, assuming a constant amount of personal vehicles as today.

Year	LB	UB
CO_2 tax	0.5	2
Natural gas price	0.75	1.5
Solar PV CAPEX	0.5	2
Onshore wind CAPEX	0.5	2
Offshore wind CAPEX	0.75	2
Heat pump CAPEX	0.5	1.5
Heat storage CAPEX	0.5	1.5
Electrolyser CAPEX	0.75	2
Hydrogen storage CAPEX	0.5	1.5
Batteries CAPEX	0.5	1.5
Electricity Transmission CAPEX	0.75	1.5
Hydrogen Transmission CAPEX	0.75	1.5
Hydrogen Demand	0.5	1.5
V2G share	0.75	1.25
Number of EVs [6]	0.64	1.18
V1G and V2G charging infrastructure costs [7]	0.63	1.38
EV charger capacity [5]	0.32	1
Batteries OPEX	0.75	1.5
Adoption rate demand response [8]	0.4	1

Table 3: Uncertainty parameter distributions for 2050. Bounds -Lower Bound (LB), Upper Bound (UB) are expressed as multipliers on the base-case value. Distribution are all truncated normal.

Hydrogen demand is varied between 500 and 1500 TWh to capture uncertainty in future hydrogen system development. EV charging capacity is varied from 3.7 kW, corresponding to typical single-phase residential charging, to 11 kW, representing widespread three-phase charging infrastructure in Europe. The number of electric vehicles is varied between a upper case where the current European passenger vehicle fleet is fully electrified and a lower electrification level corresponding to 60% of the vehicle fleet being converted to electric vehicles. V1G and V2G charging infrastructure costs, the lower and upper thresholds correspond respectively to the scenarios Low and High in Sanvito et al. [7]. For the remaining uncertain technology parameters, ranges from the DEA Technology Catalogue are used to define plausible uncertainty bounds. These ranges are interpreted as indicative of potential technological trends and developments, rather than exact predictions of future values. For instance, the lower uncertainty bounds for electrolysers and offshore wind are higher than those for solar PV, reflecting the higher cost levels associated with these technologies, as reported in the DEA Technology Catalogue. This difference accounts for the distinct maturity levels and cost trajectories expected across technologies.

Technology assumptions

The technology data (see Supplementary Table 4) are mainly extracted from the Danish Energy Agency (DEA) technology catalogues [9]. All the financial data is given in

€$_{2016}$ level. Offshore wind, onshore wind, solar PV (tracking and non tracking) costs have been updated in April 2026 based on the DEA technology catalogues updates from 2025. This account for the latest increase cost - around 20% compared to DEA value from 2024 technology catalogue- in offshore wind.

Table 4: Technology assumptions

Name	Parameter	2020	2030	2040	2050	Unit	Source
Biogas internal combustion backpressure	Fuel efficiency	0.930	0.939	0.960	0.940	0-1	[9]
	Cb	0.86	0.92	0.92	1	-	[9]
	Investment cost	0.931	0.882	0.858	0.833	M€/MW	[9]
	FOM	0.860	0.920	0.920	1.000	k€/MW	[9]
	VOM	3.161	3.087	2.930	2.764	€/MWh	[9]
	Economic lifetime	25	25	25	25	years	[9]
Biogas internal combustion condensing	Fuel efficiency	0.430	0.450	0.460	0.470	0-1	[9]
	Investment cost	0.791	0.750	0.729	0.708	M€/MW	[9]
	FOM	9.555	9.114	8.722	8.330	k€/MW	[9]
	VOM	7.350	6.860	6.370	5.880	€/MWh	[9]
	Economic lifetime	25	25	25	25	years	[9]
Coal steam Supercritical condensing	Fuel efficiency	0.49	0.52	0.53	0.54	0-1	[9]
	Investment cost	1.69099	1.65767	1.61602	1.57437	M€/MW	[9]
	FOM	60.368	60.368	60.368	60.368	k€/MW	[9]
	VOM	2.156	2.156	2.156	2.156	€/MWh	[9]
	Economic Lifetime	40	40	40	40	years	[9]
Coal steam Supercritical extraction	Fuel efficiency	0.49	0.52	0.53	0.54	0-1	[9]
	Cb	0.84	1.01	1.01	1.01	-	[9]
	Cv	0.15	0.15	0.15	0.15	-	[9]
	Investment cost	1.9894	1.9502	1.9012	1.8522	M€/MW	[9]
	FOM	60.368	60.368	60.368	60.368	k€/MW	[9]
	VOM	1.05644	1.12112	1.14268	1.16424	€/MWh	[9]
	Economic Lifetime	40	40	40	40	years	[9]
Electric boiler	Fuel efficiency	0.993	0.993	0.993	0.993	0-1	[9]
	Investment cost	0.388	0.370	0.352	0.334	M€/MW	[9]
	FOM	3.312	3.171	3.029	2.888	k€/MW	[9]
	VOM	0.588	0.653	0.653	0.653	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Electric battery storage	Fuel efficiency	0.86	0.9	0.950	0.950	0-1	[9]
	Investment cost	0.420	0.336	0.252	0.168	M€/MW	[9]
	FOM	2.660	2.123	1.596	1.064	k€/MW	[9]
	VOM	0	0	0	0	€/MWh	[9]
	Economic Lifetime	20	20	20	20	years	[9]
Air to air heat pump	Fuel efficiency	4.9	4.9	4.9	4.9	0-1	[9]
	Investment cost	0.431	0.431	0.431	0.431	M€/MW	[9]
	FOM	63.374	41.774	39.782	37.789	k€/MW	[9]
	VOM	0	0	0	0	€/MWh	[9]
	Economic Lifetime	12	12	12	12	years	[9]
Air to water heat pump	Fuel efficiency	3.240	3.377	3.442	3.607	0-1	[9]
	Investment cost	1.212	1.068	0.990	0.912	M€/MW	[9]
	FOM	35.067	32.249	31.269	30.289	k€/MW	[9]
	VOM	1.012	0.910	0.885	0.860	€/MWh	[9]
	Economic Lifetime	22	22	25	25	years	[9]
Water to water heat pump	Fuel efficiency	6.000	7.600	7.600	10.467	0-1	[9]
	Investment cost	0.645	0.580	0.580	0.522	M€/MW	[9]
	FOM	1.960	1.960	1.960	1.960	k€/MW	[9]
	VOM	1.764	1.666	1.666	1.568	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Ground water heat pump	Fuel efficiency	3.650	3.800	3.913	4.025	0-1	[9]
	Investment cost	1.056	0.975	0.911	0.848	M€/MW	[9]
	FOM	10.173	9.244	8.828	8.413	k€/MW	[9]
	VOM	0.882	0.833	0.809	0.784	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Pump hydro reservoir	Fuel efficiency	0.800	0.800	0.800	0.800	0-1	[9]
	Investment cost	0.285	0.285	0.285	0.285	M€/MW	[9]
	FOM	0.735	0.735	0.735	0.735	k€/MW	[9]
	VOM	0.000	0.000	0.000	0.000	€/MWh	[9]
	Economic Lifetime	60	60	60	60	years	[9]
Pit heat storage seasonal	Fuel efficiency	0.7	0.7	0.7	0.7	0-1	[9]
	Investment cost	0.00094	0.00090	0.00085	0.00079	M€/MW	[9]
	FOM	0.00300	0.00300	0.00300	0.00300	k€/MW	[9]
	VOM	0	0	0	0	€/MWh	[9]
	Economic Lifetime	20	20	20	20	years	[9]
Watertank heat storage	Fuel efficiency	0.965	0.965	0.965	0.965	0-1	[9]
	Investment cost	0.20235	0.20235	0.20235	0.20235	M€/MW	[9]
	FOM	8.17088	8.17088	8.17088	8.17088	k€/MW	[9]
	VOM	0.343	0.343	0.343	0.343	€/MWh	[9]
	Economic Lifetime	35	35	35	35	years	[9]
Municipal waste heat only boiler	Fuel efficiency	1.060	1.060	1.060	1.060	0-1	[9]
	Investment cost	1.903	1.814	1.762	1.710	M€/MW	[9]
	FOM	79.765	74.764	71.291	67.818	k€/MW	[9]
	VOM	6.215	6.230	6.245	6.260	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Municipal waste subcritical steam backpressure	Fuel efficiency	1.014	1.040	1.047	1.054	0-1	[9]
	Cb	0.293	0.300	0.300	0.300	-	[9]
	Investment cost	8.946	8.383	7.934	7.485	M€/MW	[9]
	FOM	261.333	241.733	225.400	209.067	k€/MW	[9]
	VOM	5.661	5.737	5.700	5.662	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Municipal waste subcritical steam condensing	Fuel efficiency	0.230	0.240	0.242	0.243	0-1	[9]
	Investment cost	7.604	7.126	6.744	6.362	M€/MW	[9]
	FOM	261.333	241.733	225.400	209.067	k€/MW	[9]
	VOM	24.613	23.903	23.590	23.276	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Natural gas heat only boiler	Fuel efficiency	0.987	0.992	0.996	1.002	0-1	[9]

	Investment cost	0.089	0.107	0.107	0.101	M€/MW	[9]
	FOM	4.011	5.390	3.557	4.880	k€/MW	[9]
	VOM	0.694	0.784	0.823	0.862	€/MWh	[9]
	Economic Lifetime	21.4286	24	24	24	years	[9]
Natural gas combined cycle backpressure	Fuel efficiency	0.902	0.909	0.926	0.905	0-1	[9]
	Cb	1.300	1.400	1.400	1.550	-	[9]
	Investment cost	1.880	1.735	1.663	1.590	M€/MW	[9]
	FOM	28.714	27.244	26.362	25.480	k€/MW	[9]
	VOM	2.199	2.181	2.170	2.156	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Natural gas combined cycle condensing	Fuel efficiency	0.550	0.570	0.580	0.590	0-1	[9]
	Investment cost	1.340	1.247	1.207	1.168	M€/MW	[9]
	FOM	28.714	27.244	26.362	25.480	k€/MW	[9]
	VOM	4.312	4.116	4.018	3.920	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Natural gas combined cycle extraction	Fuel efficiency	0.590	0.610	0.620	0.630	0-1	[9]
	Cb	1.800	2.000	2.000	2.200	-	[9]
	Cv	0.150	0.150	0.150	0.150	-	[9]
	Investment cost	1.272	1.200	1.178	1.157	M€/MW	[9]
	FOM	28.714	27.244	26.362	25.480	k€/MW	[9]
	VOM	2.544	2.511	2.491	2.470	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Natural gas internal combustion backpressure	Fuel efficiency	0.965	0.965	0.985	0.981	0-1	[9]
	Cb	0.950	0.990	0.990	1.040	-	[9]
	Investment cost	1.374	1.301	1.265	1.229	M€/MW	[9]
	FOM	9.555	9.114	8.722	8.330	k€/MW	[9]
	VOM	2.487	2.399	2.401	2.401	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Natural gas internal combustion condensing	Fuel efficiency	0.470	0.480	0.490	0.500	0-1	[9]
	Investment cost	1.168	1.106	1.075	1.045	M€/MW	[9]
	FOM	9.555	9.114	8.722	8.330	k€/MW	[9]
	VOM	5.292	4.998	4.900	4.802	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Natural gas Turbine Generator backpressure	Fuel efficiency	0.811	0.842	0.852	0.862	0-1	[9]
	Cb	0.950	0.950	0.950	0.950	-	[9]
	Investment cost	0.954	0.911	0.889	0.868	M€/MW	[9]
	FOM	19.110	18.228	17.934	17.640	k€/MW	[9]
	VOM	1.885	1.860	1.813	1.764	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Natural gas Turbine Generator condensing	Fuel efficiency	0.395	0.410	0.415	0.420	0-1	[9]
	Investment cost	0.811	0.774	0.756	0.737	M€/MW	[9]
	FOM	19.110	18.228	17.934	17.640	k€/MW	[9]
	VOM	4.802	4.557	4.386	4.214	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Natural gas steam Subcritical Turbine backpressure	Fuel efficiency	0.763	0.763	0.763	0.763	0-1	[9]
	Cb	0.101	0.101	0.101	0.101	-	[9]
	Investment cost	0.868	0.868	0.868	0.868	M€/MW	[9]
	FOM	12.051	12.051	12.051	12.051	k€/MW	[9]
	VOM	0.318	0.318	0.318	0.318	€/MWh	[9]
	Economic Lifetime	30	30	30	30	years	[9]
Natural gas steam Subcritical Turbine condensing	Fuel efficiency	0.470	0.470	0.470	0.470	0-1	[9]
	Investment cost	0.909	0.909	0.909	0.909	M€/MW	[9]
	FOM	37.240	37.240	37.240	37.240	k€/MW	[9]
	VOM	0.804	0.804	0.804	0.804	€/MWh	[9]
	Economic Lifetime	30	30	30	30	years	[9]
Natural gas steam Subcritical Turbine extraction	Fuel efficiency	0.470	0.470	0.470	0.470	0-1	[9]
	Cb	0.700	0.700	0.700	0.700	-	[9]
	Cv	0.170	0.170	0.170	0.170	-	[9]
	Investment cost	1.069	1.069	1.069	1.069	M€/MW	[9]
	FOM	37.240	37.240	37.240	37.240	k€/MW	[9]
	VOM	0.378	0.378	0.378	0.378	€/MWh	[9]
	Economic Lifetime	30	30	30	30	years	[9]
Peat steam Subcritical Turbine backpressure	Fuel efficiency	1.151	1.151	1.151	1.151	0-1	[9]
	Cb	0.250	0.250	0.250	0.250	-	[9]
	Investment cost	4.788	4.547	4.368	4.190	M€/MW	[9]
	FOM	205.800	200.900	193.550	186.200	k€/MW	[9]
	VOM	1.083	1.081	1.086	1.091	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Straw heat only boiler	Fuel efficiency	1.020	1.020	1.020	1.020	0-1	[9]
	Investment cost	0.872	0.823	0.784	0.745	M€/MW	[9]
	FOM	50.274	47.432	44.933	42.434	k€/MW	[9]
	VOM	0.588	0.588	0.588	0.588	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Straw steam Subcritical Turbine backpressure	Fuel efficiency	0.956	0.956	0.956	0.956	0-1	[9]
	Cb	0.363	0.363	0.363	0.363	-	[9]
	Investment cost	3.779	3.614	3.442	3.270	M€/MW	[9]
	FOM	169.867	160.067	155.167	150.267	k€/MW	[9]
	VOM	0.553	0.554	0.554	0.554	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Straw steam Subcritical Turbine condensing	Fuel efficiency	0.243	0.243	0.243	0.243	0-1	[9]
	Investment cost	3.212	3.072	2.926	2.780	M€/MW	[9]
	FOM	169.867	160.067	155.167	150.267	k€/MW	[9]
	VOM	2.434	2.439	2.439	2.439	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Solar heating	Fuel efficiency	1	1	1	1	0-1	[9]
	Investment cost	0.560	0.490	0.467	0.443	M€/MW	[9]
	FOM	0.016	0.016	0.016	0.016	k€/MW	[9]
	VOM	0.103	0.147	0.159	0.172	€/MWh	[9]
	Economic Lifetime	27.5	30	30	30	years	[9]
Solar PV non tracking	Fuel efficiency	1	1	1	1	0-1	[9]
	Investment cost	0.527	0.358	0.301	0.273	M€/MW	[9]
	FOM	10.640	8.945	7.627	6.968	k€/MW	[9]
	VOM	0	0	0	0	€/MWh	[9]
	Economic Lifetime	30	30	30	30	years	[9]
Solar PV tracking	Fuel efficiency	1	1	1	1	0-1	[9]
	Investment cost	0.612	0.424	0.358	0.330	M€/MW	[9]
	FOM	11.394	9.793	8.851	8.475	k€/MW	[9]

	VOM	0	0	0	0	€/MWh	[9]
	Economic Lifetime	30	30	30	30	years	[9]
Offshore wind	Fuel efficiency	1	1	1	1	0-1	[9]
	Investment cost	2.133	2.133	1.888	1.728	M€/MW	[9]
	FOM	47.081	32.094	28.318	26.430	k€/MW	[9]
	VOM	4.708	3.257	2.822	2.624	€/MWh	[9]
	Economic Lifetime	30	30	30	30	years	[9]
Onshore wind	Fuel efficiency	1	1	1	1	0-1	[9]
	Investment cost	1.711	1.711	1.563	1.453	M€/MW	[9]
	FOM	15.690	15.690	15.033	14.691	k€/MW	[9]
	VOM	1.860	1.860	1.782	1.741	€/MWh	[9]
	Economic Lifetime	26.3	29	29	29	years	[9]
Woodchips heat only boiler	Fuel efficiency	1.017	1.025	1.025	1.025	0-1	[9]
	Investment cost	0.516	0.637	0.608	0.578	M€/MW	[9]
	FOM	22.115	30.576	29.645	28.714	k€/MW	[9]
	VOM	0.761	0.980	0.882	0.784	€/MWh	[9]
	Economic Lifetime	21.6667	25	25	25	years	[9]
Woodchips subcritical steam backpressure	Fuel efficiency	1.149	1.149	1.149	1.149	0-1	[9]
	Cb	0.280	0.280	0.280	0.280	-	[9]
	Investment cost	4.273	4.056	3.888	3.721	M€/MW	[9]
	FOM	156.800	150.267	145.367	140.467	k€/MW	[9]
	VOM	1.084	1.081	1.085	1.088	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Woodchips Subcritical steam condensing	Fuel efficiency	0.247	0.247	0.247	0.247	0-1	[9]
	Investment cost	3.632	3.448	3.305	3.162	M€/MW	[9]
	FOM	156.800	150.267	145.367	140.467	k€/MW	[9]
	VOM	4.745	4.736	4.747	4.759	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Woodpellets heat only boiler	Fuel efficiency	0.891	0.901	0.901	0.926	0-1	[9]
	Investment cost	0.686	0.736	0.713	0.690	M€/MW	[9]
	FOM	40.719	44.860	44.327	41.136	k€/MW	[9]
	VOM	0.250	0.250	0.225	0.200	€/MWh	[9]
	Economic Lifetime	22.5	22.5	22.5	22.5	years	[9]
Woodpellets subcritical steam backpressure	Fuel efficiency	0.993	0.993	0.993	0.993	0-1	[9]
	Cb	0.383	0.383	0.383	0.383	-	[9]
	Investment cost	3.523	3.352	3.209	3.066	M€/MW	[9]
	FOM	151.573	144.060	139.960	135.861	k€/MW	[9]
	VOM	0.506	0.505	0.380	0.507	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Woodpellets subcritical steam condensing	Fuel efficiency	0.267	0.267	0.267	0.267	0-1	[9]
	Investment cost	2.919	2.773	2.654	2.534	M€/MW	[9]
	FOM	143.733	137.200	133.933	130.667	k€/MW	[9]
	VOM	2.047	2.044	2.047	2.051	€/MWh	[9]
	Economic Lifetime	25	25	25	25	years	[9]
Alkaline water electrolysis district heating	Fuel efficiency	0.656	0.672	0.707	0.741	0-1	[9]
	Investment cost	1.001	0.801	0.651	0.501	MEuro/MW	[10, 11]
	FOM	12.740	8.820	5.880	4.900	kEuro/MW	[9]
	VOM	-	-	-	-	Euro/MWh	[9]
	Economic lifetime	25	30	32	35	years	[9]
Alkaline water electrolysis	% to DH	6.100	6.840	9.540	15.770	%	[9]
	Fuel efficiency	0.656	0.672	0.707	0.742	0-1	[9]
	Investment cost	1.000	0.800	0.650	0.500	MEuro/MW	[10]
	FOM	12.740	8.820	5.880	4.900	kEuro/MW	[9]
	VOM	-	-	-	-	Euro/MWh	[9]
	Economic lifetime	25	30	32	35	years	[9]
Hydrogen to electricity (fuel cells)	Fuel efficiency	0.550	0.600	0.615	0.630	0-1	[9]
	Investment cost	1.470	0.784	0.637	0.490	MEuro/MW	[9]
	FOM	0.010	0.010	0.010	0.010	kEuro/MW	[9]
	VOM	9.800	3.920	3.430	2.940	Euro/MWh	[9]
	Economic lifetime	15	20	20	20	years	[9]
Hydrogen storage steel tank (140 bar)	Fuel efficiency	0.990	0.990	0.990	0.990	0-1	[9]
	Investment cost	0.056	0.044	0.026	0.021	MEuro/MW	[9]
	FOM	0.003	0.003	0.002	0.002	kEuro/MW	[9]
	VOM	-	-	-	-	Euro/MWh	[9]
	Economic lifetime	25	30	30	30	years	[9]
Hydrogen storage underground salt cavern	Fuel efficiency	0.990	0.990	0.990	0.990	0-1	[9]
	Investment cost	0.003	0.002	0.001	0.001	MEuro/MW	[9]
	FOM	0.059	0.039	0.029	0.024	Euro/MW	[9]
	VOM	0.000	0.000	0.000	0.000	Euro/MWh	[9]
	Economic lifetime	100	100	100	100	years	[9]
Hydrogen to biomethane + Direct air capture	Fuel efficiency	0.800	0.800	0.800	0.800	0-1	[12]
	Investment cost	1.250	1.250	1.250	1.250	MEuro/MW	[12]
	FOM	0.010	0.010	0.010	0.010	kEuro/MW	[12]
	VOM	-	-	-	-	Euro/MWh	[12]
	Economic lifetime	25	25	25	25	years	[12]
Steam methane reforming	Fuel efficiency	0.700	0.700	0.700	0.700	0-1	[9]
	Investment cost	0.571	0.571	0.571	0.571	MEuro/MW	[9]
	FOM	19.479	19.479	19.479	19.479	kEuro/MW	[9]
	VOM	-	-	-	-	Euro/MWh	[9]
	Economic lifetime	25	25	25	25	years	[9]
Steam methane reforming + CCS	Fuel efficiency	0.7	0.7	0.7	0.7	0-1	[9]
	Investment cost	1.019	1.09	1.09	1.09	MEuro/MW	[9]
	FOM	28.316	28.316	28.316	28.316	kEuro/MW	[9]
	VOM	-	-	-	-	Euro/MWh	[9]
	Economic lifetime	25	25	25	25	years	[9]
Biogas upgrading	Fuel efficiency	0.99	0.99	1	1	0-1	[9]
	Investment cost	0.419	0.373	0.355	0.336	MEuro/MW	[9]
	FOM	10.388	9.310	8.869	8.428	kEuro/MW	[9]
	VOM	-	-	-	-	Euro/MWh	[9]
	Economic lifetime	15	15	15	15	years	[9]
Biogas methanation	Fuel efficiency	1.679	1.679	1.679	1.679	0-1	[9]
	Investment cost	0.889	0.741	0.593	0.445	MEuro/MW	[9]
	FOM	35.562	29.635	23.708	17.781	kEuro/MW	[9]
	VOM	4.2336	3.528	2.8224	2.1168	Euro/MWh	[9]
	Economic lifetime	25	25	25	25	years	[9]

Balmorel optimisation model

The objective function in Balmorel minimises discounted costs over the years y, considering investment costs c_y^{inv}, variable operation costs c_y^{vo} and fixed operation costs c_y^{fom} (Equation 1). Costs are discounted using a discount factor, DF_y, of 4%. Investments costs include the costs for new energy assets and transmission infrastructure. Operational costs include operation and maintenance costs as well as fuel costs and carbon tax.

$$\min \sum_{y} DF_y \left(c_y^{inv} + c_y^{fom} + c_y^{vo} \right) \tag{1}$$

Electricity generation g^{el} needs to satisfy the exogenous electricity demand from Balmorel ($d^{\text{el,exo}}$) as well as the endogenous demand modelled in Balmorel through sector-coupling e.g. electrification of hydrogen, EV ($d^{\text{el,endo,bal}}$) (Equation 2). Electricity balance equation also considers distribution losses from electricity transmission across regions. In a similar way, balance equations are defined for heat, hydrogen and transmission.

$$\begin{aligned} g^{\text{el}}_{r,y,s,t} + \sum_{r'} x^{\text{el}}_{r',r,y,s,t} \left(1 - x^{\text{el,loss}}_{r',r}\right) &= d^{\text{el,exo}}_{r,y,s,t} + d^{\text{el,endo,bal}}_{r,y,s,t} \\ &\quad + \sum_{r'} x^{\text{el}}_{r,r',y,s,t}, \qquad \forall r, y, s, t \end{aligned} \tag{2}$$

More specific information about the modeling of the hydrogen sector can be found in Kountouris et al. [13], about electric vehicle in Balanza et al. [4] and about demand response in Kirkerud et al. [8].

Spearman

The Spearman rank correlation coefficient highlights the correlation between two sets ranks, for instance one input set and one output set. It ranges from -1 to 1, with high value for positive correlation, negative value for negative correlation, and value around 0 for non correlated sets.
For a sample of size n with a set of input (X_i) and outputs (Y_i) paired, each variable is first converted to ranks, $R[X_i]$ and $R[Y_i]$. The Spearman coefficient is then given by:

$$r_s = \rho\big(R[X], R[Y]\big) = \frac{\text{cov}\,\big(R[X], R[Y]\big)}{\sigma_{R[X]}\,\sigma_{R[Y]}} \tag{3}$$

where $\text{cov}(R[X], R[Y])$ is the covariance of the rank variables, and $\sigma_{R[X]}$, $\sigma_{R[Y]}$ are their respective standard deviations. p-value is then calculated to measure the robustness of the result. Weak correlations are then filtered out when $|\rho|$ is lower than 0.1 and p-value is lower than 0.2.

Myopic and perfect foresight

In this study, we use myopic optimisation to run 2030, 2040 and 2050 sequentially. Each year is linked to the previous one, using the results of one year as an input for the following year. This method might overlook the most optimal pathway because it lacks information for the following years. Another option is to consider perfect foresight, where all years are optimised together, allowing the model to have all information from 2030 to 2050 when optimising. This usually enables lower system costs as the system. However, this increases model size and computational time. For our study, that already requires extensive computational resource when using myopic foresight, perfect foresight did not solve.

Frequency-based quantification of flexibility - main algorithm

Algorithm 1 Frequency-based quantification of flexibility - main algorithm

Require:

df raw time series data, indexed by season and time with a value column
$season\_col$ column identifying season
$time\_col$ column identifying time step within a season
$value\_col$ column containing the output values

Aggregate signal across relevant dimension(e.g. countries)
$df_{grouped} \leftarrow$ group df by $(season\_col, time\_col)$, sum $value\_col$ across the grouping dimension

Construct continuous time index
Sort $df_{grouped}$ by $(season\_col, time\_col)$
$time\_index \leftarrow$ sequential integers $[0, 1, \ldots, N-1]$

Extract raw signal
$signal \leftarrow df_{grouped}[value\_col]$

Remove DC offset (annual mean)
$signal_{centered} \leftarrow signal - \text{mean}(signal)$

Compute Discrete Fourier Transform (DFT)
$(fft_{coeffs}, frequencies) \leftarrow \text{FFT}(signal_{centered})$, with time step $\Delta t = 1$ hour
$N \leftarrow \text{length}(signal)$

Define frequency bands corresponding to characteristic timescales with periods expressed in hours:

$$daily_{max} \leftarrow 2 \times 24 \qquad (\approx 2 \text{ days})$$
$$weekly_{min} \leftarrow 2 \times 24$$
$$weekly_{max} \leftarrow 60 \times 24 \qquad (\approx 60 \text{ days})$$
$$annual_{min} \leftarrow 60 \times 24$$

Convert period bounds to frequency bounds (cycles/hour):

$$f_{daily} \leftarrow \left[1/daily_{max},\ 0.5\right]$$
$$f_{weekly} \leftarrow \left[1/weekly_{max},\ 1/weekly_{min}\right]$$
$$f_{annual} \leftarrow \left[1/N,\ 1/annual_{min}\right]$$

Apply band-pass filtering in the frequency domain
for each band $b \in \{daily, weekly, annual\}$ **do**
    $filtered\_fft[b] \leftarrow fft_{coeffs}$ where $|frequency| \in f_b$, else 0
end for

Reconstruct time-domain signal using Inverse FFT
for each band $b \in \{daily, weekly, annual\}$ **do**
    $signal[b] \leftarrow \text{Re}\left[\text{IFFT}(filtered\_fft[b])\right]$
end for

Output gathering
$df_{out} \leftarrow$ DataFrame with columns:

$$S = season\_col$$
$$T = time\_col$$
$$Original = signal_{centered}$$
$$Daily = signal_{daily}$$
$$Weekly = signal_{weekly}$$
$$Annual = signal_{annual}$$

3 References

[1] Shubham Nayak, Matti Juhani Koivisto, and Polyneikis Kanellas. *Pan-European wind and solar generation time series*. Technical report. 2025.

[2] ENTSOE. "TYNDP_2024_Scenarios_Report". In: (2024). URL: https://2024.entsos-tyndp-scenarios.eu/foreword/.

[3] International Energy Agency. *World Energy Outlook 2025*. Technical report. 2025. URL: www.iea.org/terms.

[4] Théo Balanza, Alexander Torp Jørgensen, and Rasmus Bramstoft. *The Role of Electric Vehicles and Vehicle-to-Grid in a Future Sector-Coupled European Energy System*. Technical report. URL: https://ssrn.com/abstract=6569982.

[5] International Energy Agency. *Global EV Outlook 2024 Moving towards increased affordability*. Technical report. 2024. URL: www.iea.org.

[6] ENTSOE. *TYNDP ENTSOE 2024*. 2024. URL: https://2024.entsos-tyndp-scenarios.eu/visualisation-platform/.

[7] Francesco Sanvito, Francesco Lombardi, and Stefan Pfenninger-Lee. "Coordinated planning of European charging infrastructure and energy system for optimal V1G and V2G deployment". In: *Nature Energy* (July 2026). ISSN: 2058-7546. DOI: 10.1038/s41560-026-02107-5. URL: https://www.nature.com/articles/s41560-026-02107-5.

[8] J. G. Kirkerud, N. O. Nagel, and T. F. Bolkesjø. "The role of demand response in the future renewable northern European energy system". In: *Energy* 235 (November 2021). ISSN: 03605442. DOI: 10.1016/j.energy.2021.121336.

[9] Danish Energy Agency. *Technology catalogue*. 2024.

[10] Adrian Odenweller, Falko Ueckerdt, Gregory F. Nemet, Miha Jensterle, and Gunnar Luderer. "Probabilistic feasibility space of scaling up green hydrogen supply". In: *Nature Energy* 7.9 (September 2022), pages 854–865. ISSN: 20587546. DOI: 10.1038/s41560-022-01097-4.

[11] Juan Gea-Bermúdez, Rasmus Bramstoft, Matti Koivisto, Lena Kitzing, and Andrés Ramos. "Going offshore or not: Where to generate hydrogen in future integrated energy systems?" In: *Energy Policy* 174 (March 2023). ISSN: 03014215. DOI: 10.1016/j.enpol.2022.113382.

[12] T. Brown, D. Schlachtberger, A. Kies, S. Schramm, and M. Greiner. "Synergies of sector coupling and transmission reinforcement in a cost-optimised, highly renewable European energy system". In: *Energy* 160 (October 2018), pages 720–739. ISSN: 03605442. DOI: 10.1016/j.energy.2018.06.222.

[13] Ioannis Kountouris, Rasmus Bramstoft, Theis Madsen, Juan Gea-Bermúdez, Marie Münster, and Dogan Keles. *Supplementary Material: A unified European hydrogen infrastructure planning to support the rapid scale-up of hydrogen production*. Technical report. 2023.