Assumptions and input parameters for modelling of the European energy system

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1. General boundary conditions

The scenario definition in Deliverable D5.1 provides general storylines for further energy system analyses. The objective of the present deliverable is to underpin the scenario definition with concrete assumptions and data. As illustrated in Figure 1 the major configuration of the power and hydrogen system in the four scenarios evolves in different directions in respect to hydrogen production pathways (mainly domestic/ limited imports vs. larger imports/ moderate domestic) and spatial distribution of H_2 storage technologies across Europe (centralized vs. distributed storage). In each scenario the total hydrogen demand increases over time and the target to reduce GHG emissions becomes stricter. To ensure comparability, the annual hydrogen and power demand in each sector as well as the CO_2 emission cap (CAP_n^{CO2}) are identical for all scenarios.

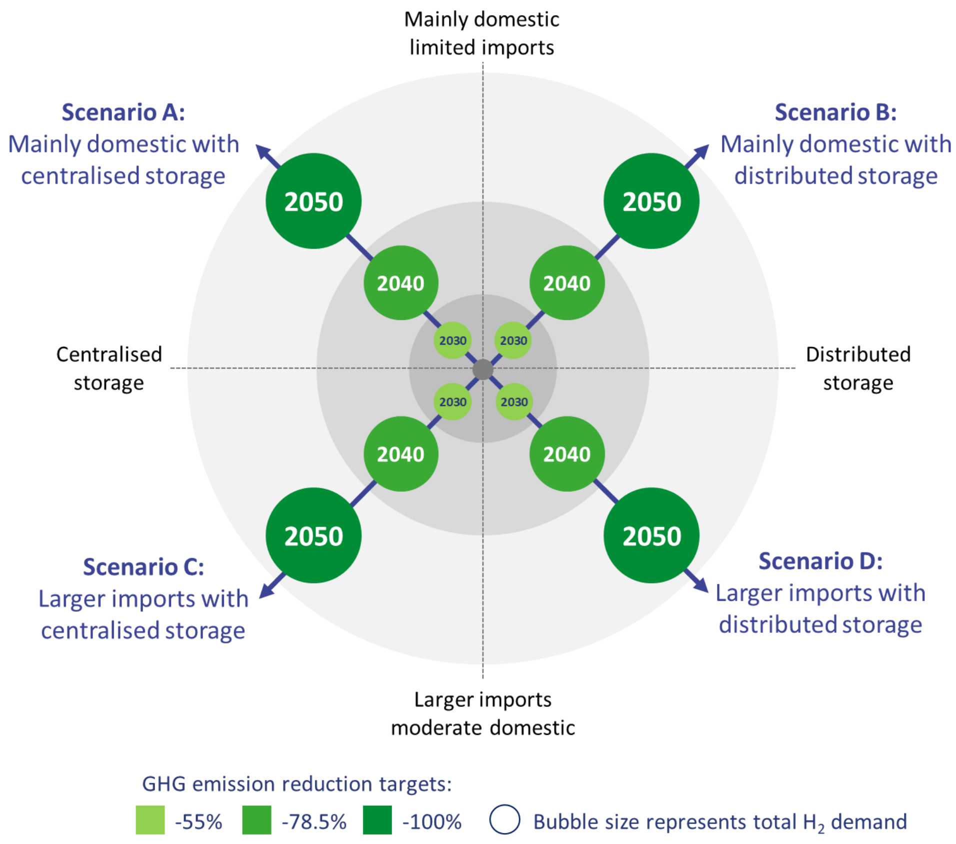

Figure 1: Evolution of the power and hydrogen system in the four scenarios of this study

The annual power and hydrogen demand in EU-27 in each sector is taken from various sources. For 2030, the power demand is based on the “Global Ambition” scenario in ENTSO-E/ENTSOG (2021a), whereas hydrogen demand is an average from the “High” and “Low” scenarios reported in Trinomics/LBST (2020) enhanced by today’s H_2 demand from industry provided by Fuel Cell & Hydrogen Observatory (2021). For 2050, both power and hydrogen demand figures are average values from the “Scenario 1: Electric” and “Scenario 3: Hydrogen” in Trinomics/LBST/E3M (2019) again enhanced by today’s conventional H_2 demand as reported by Fuel Cell & Hydrogen Observatory (2021). The values for 2025 and 2040 are extra- respectively interpolated.

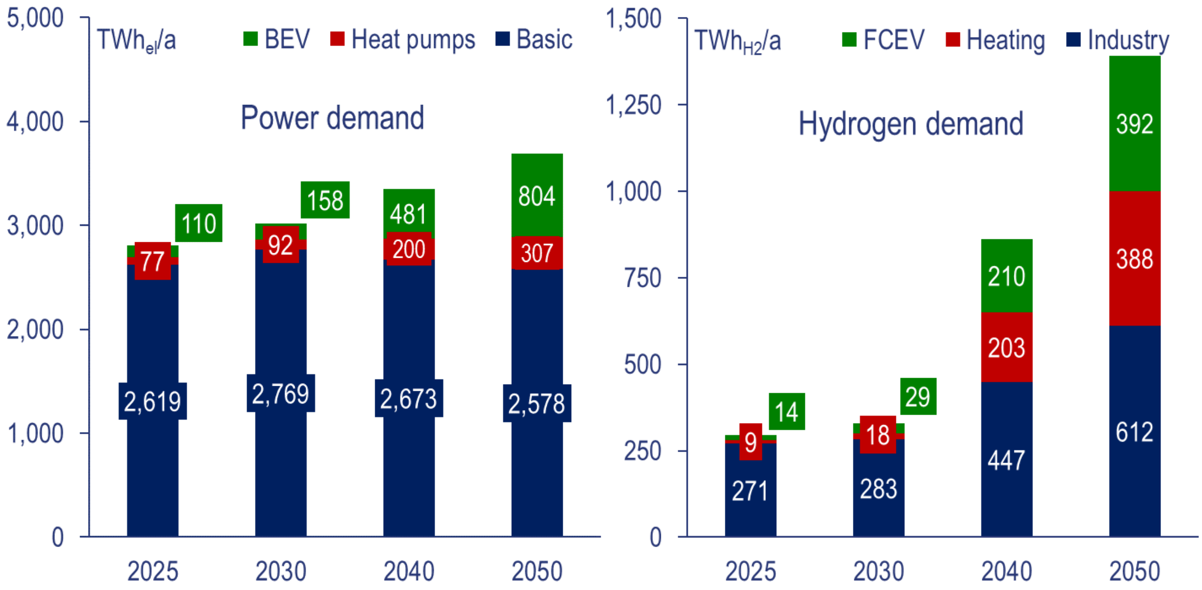

Figure 2: Assumed final power and hydrogen demand excluding power sector in EU-27

On the one hand, the basic power demand (i.e., for white appliances etc.) goes down slightly from ca. 2,620 TWh/a in 2025 to ca. 2,580 TWh/a in 2050 due to improved efficiency in end-use applications (see Figure 2). On the other hand, the power demand of electric heat pumps and mobility sectors increases significantly up to 1,100 TWh/a in 2050. Hence, the study assumes an increase in overall power demand by 30% up to almost 3,700 TWh/a in 2050. The overall hydrogen demand rises significantly by a factor of ca. 4.5 from less than 300 TWh/a in 2025 to more than 1,300 TWh/a in 2050. The increase is significant for all sectors due to the expected strong role of hydrogen in all end-use applications. As depicted in Figure 3, the assumed values are within the corresponding ranges of several other publications. At this point it is important to mention that both power and hydrogen demand assumed in this study increase over time but the overall final energy consumption decreases as renewable electricity and hydrogen replace fossil fuels which are excluded from this analysis.

Following the assumptions in ENTSO-E/ENTSOG (2021a) and overall GHG emission reduction targets postulated in scenario definition[1], the CO_2 emission cap in 2025 amounts to 800 Mt_{CO2}/a, whereas for 2050 the modelling exercise assumes climate neutrality with only 2 Mt_{CO2}/a (see Figure 4). In contrast, the carbon price increases significantly from 40 €/t_{CO2} in 2025 by more than 300% up to ca. 170 €/t_{CO2} in 2050.

[1] See Deliverable D5.1 “Scenario definition for modelling of the European energy system”.

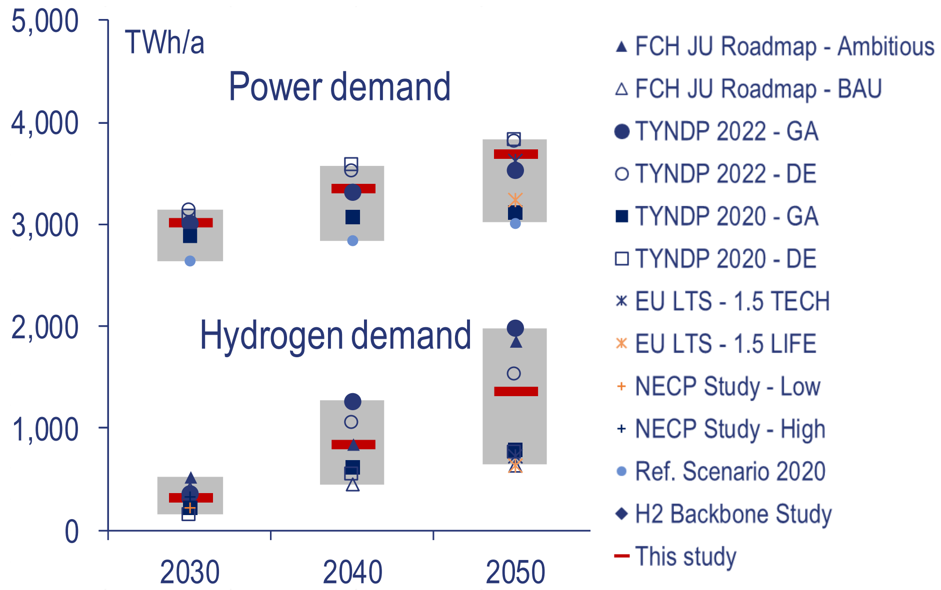

Figure 3: Annual hydrogen and power demand of this study in comparison to other publications:

- FCH JU Roadmap: "Ambitious" and "Business as usual (BAU)" scenarios in FCH JU (2019);
- TYNDP 2022: "Global Ambition (GA)" and "Distribute Energy (DE)" scenarios in ENTSO-E/ENTSOG (2021a);
- TYNDP 2020: ENTSO-E/ENTSOG (2020a);
- EU LTS: "1.5 TECH" and "1.5 LIFE" scenarios of the EU long-term strategy (LTS) vision in EC (2018);
- NECP Study: "Low" and "High" scenarios in Trinomics/LBST (2020);
- Ref. Scenario 2020: EU Reference Scenario 2020 in E3M/IIASA/EuroCAREI (2021);
- H2 Backbone study: scenario of the European Hydrogen Backbone study in Guidehouse (2021a).

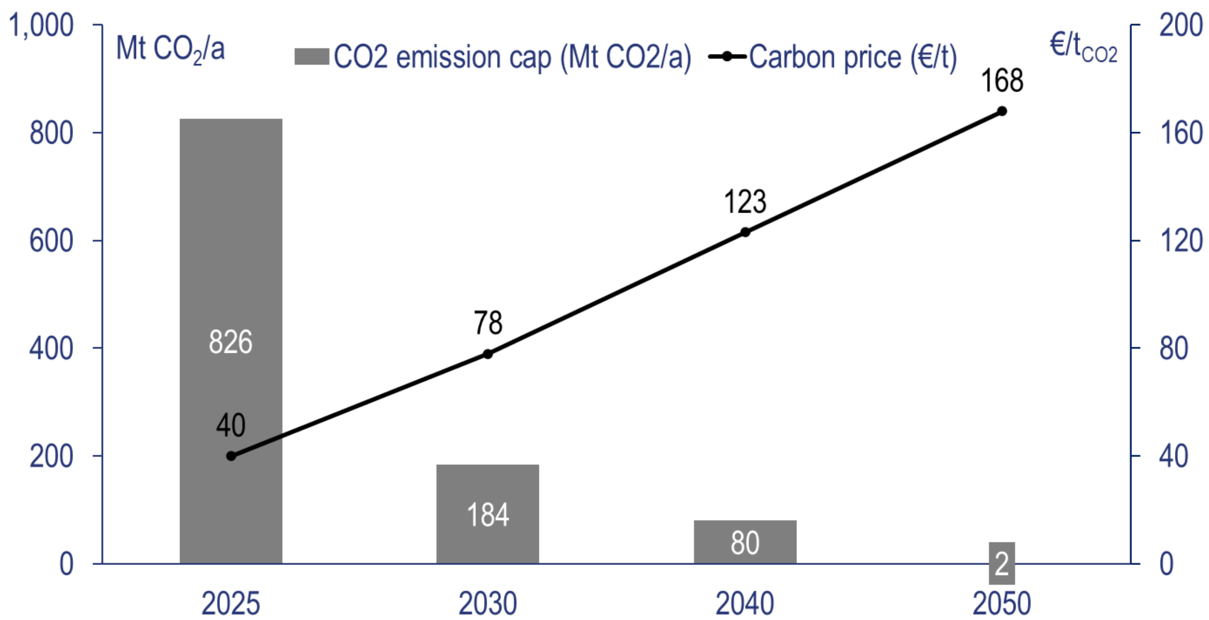

Figure 4: Annual CO_2 emission cap for energy supply and expected carbon price in EU-27

In order to achieve the GHG emission targets, the analysis assumes a minimum share of intermittent renewable electricity in power supply (including power provision for hydrogen production via electrolysis) in all scenarios from 30% in 2025 up to 85% in 2050 (as reported in ENTSO-E/ENTSOG (2021a); see Table 1). The split between three major technologies for intermittent power generation (i.e., wind onshore, wind offshore and PV) presented in Table 2 is mainly based on ENTSO-E/ENTSOG (2021a) and adapted on country-by-country basis to account for country-specific policies and trajectories. In all timesteps wind onshore has the largest share followed by PV. However, over time above-average growth in wind offshore capacities is expected until 2050. At this point it is worth mentioning that the presented figures are European averages. For individual countries the technology split is different taking country-specific conditions into account. Moreover, abovementioned figures apply to the predefined final power and hydrogen demand from the different end-use sectors. The optimal structure of the overall energy supply including storage operation and hydrogen re-electrification (i.e., including hydrogen consumption in the power sector and thus efficiency losses through conversion of renewable power generation) are modelling results. Hence, the overall share of intermittent power supply might be higher. Following the approach in Trinomics/LBST/E3M (2019) and according to the data provided by IHA (2022) the study assumes constant supply from run-of-river power plants of ca. 370 TWh/a due to their limited potential for capacity expansion.

Table 1: General energy supply assumptions

Parameter	2025	2030	2040	2050
Minimum share of intermittent renewable electricity in power supply in all scenarios	30%	50%	75%	85%
Maximum share of imports in hydrogen supply in Scenario A and B	0%	5%	10%	15%
Minimum share of imports in hydrogen supply in Scenario C and D	0%	5%	25%	50%

Table 2: Average split of intermittent renewable power generation in Europe

Power generation	2025	2030	2040	2050
Wind onshore*	59%	59%	57%	55%
Wind offshore*	12%	12%	14%	15%
PV*	29%	29%	29%	30%
Run-of-river	371 TWh/a			

* On average in Europe: higher wind shares in Central and Northern Europe and higher PV shares in Southern Europe.

According to their definition, the scenarios in this study differ, among others, in terms of hydrogen imports from outside the EU. Therefore, as reported in Table 1, in Scenarios A and B the maximum share of imports in hydrogen supply can achieve 15% until 2050. In contrast, in Scenario C and D the minimum share of hydrogen imports ranges from 5% to 50% between 2030 and 2050.

Table 3 summarizes the expected market prices for different fuels taken from ENTSO-E/ENTSOG (2021b). The potential for renewable and low-carbon hydrogen imports from different non-EU countries as well as the corresponding H_2 import price in Table 4 are derived from ENTSO-E/ENTSOG (2021b) and Guidehouse (2021a). Major import potential for renewable hydrogen (i.e., based on renewable power sources) is expected especially in the long-term from Ukraine and North Africa with decreasing prices down to 1.2 €/kg_{H2} in 2050. In contrast, the potential for low-carbon hydrogen (i.e., H_2 produced via steam methane reforming combined with carbon capture and storage or via methane pyrolysis) is low and limited to Norway and Russia with a remaining emission factor of 0.026 t_{CO2}/MWh_{H2} as reported in ENTSO-E/ENTSOG (2021b). Moreover, in line with the EU hydrogen strategy provided by European Commission (2020), low-carbon hydrogen imports after 2040 are excluded from this analysis. The emission data for other fuel types summarized in Table 5 comes from ENTSO-E/ENTSOG (2021b).

Table 3: Assumed market prices for different fuels

Fuel	Unit	2025	2030	2040	2050
Nuclear	€/MWh	1.7	1.7	1.7	1.7
Lignite	€/MWh	6.5	6.5	6.5	6.5
Hard coal	€/MWh	8.3	7.1	6.9	6.7
Oil	€/MWh	46.3	36.3	34.6	32.8
Natural gas	€/MWh	20.1	14.5	14.7	14.7
Biomethane	€/MWh	86.0	74.7	61.0	50.3

Table 4: Expected potential (TWh_{H2}/a) and prices (€/kg_{H2}) for renewable and low-carbon hydrogen imports from non-EU countries

Region	Unit	2030	2040	2050
Renewable hydrogen				
North Africa	TWh_{H2}/a	86	330	1,000
Ukraine	TWh_{H2}/a	15	170	700
Low-carbon hydrogen				
Norway	TWh_{H2}/a	217	217	
Russia	TWh_{H2}/a		189	
H_2 import price				
H_2 price	€/kg_{H2}	1.8	1.6	1.2

The analysis applies a constant social discount rate *r* of 4% based on the low-risk rate taken from the EU reference scenario 2020 in E3M/IIASA/EuroCARE (2021).

Table 5: Emission data for different fuel types

Fuel	Unit	Value
Nuclear	t_{CO2}/MWh	0.000
Lignite	t_{CO2}/MWh	0.364
Hard coal	t_{CO2}/MWh	0.354
Oil	t_{CO2}/MWh	0.267
Natural gas	t_{CO2}/MWh	0.202
Biomethane	t_{CO2}/MWh	0.000
Low-carbon H_2 imports	t_{CO2}/MWh	0.026
Renewable H_2 imports	t_{CO2}/MWh	0.000

2. Techno-economic data

This chapter describes in more detail the input parameters related to different production, storage and transport technologies for power and hydrogen covering all relevant techno-economic data such as expected cost, efficiencies, lifetime etc. Note that each technology represents an average of all units of the same type in a given node, i.e., e.g., wind onshore technology represents all wind farms in a selected country or node. In addition, the techno-economic parameters are identical for all grid nodes as similar technological development is expected for all countries across Europe.

In general, the annuity *a* for different technologies is calculated based on the discount rate *r*, lifetime *lt* and specific investment cost *ic* using following formula[2]:

$$a = \frac{(1+r)^{lt} - 1}{r(1+r)^{lt}} \cdot ic$$

Moreover, each technology's fixed cost *fc* result from investment cost *ic* multiplied by the fixed cost share *cs.* Variable production cost vc_p for all production technologies are calculated as follows:

$$vc_p = \frac{mp_p + cp \ \cdot e_p}{\eta_p} + nc_p$$

where mp_p is the market price of the respective fuel type (in €/MWh),
cp stands for the carbon price (in €/t_{CO2}),
e_p is the emission factor of the corresponding fuel type (in t_{CO2}/MWh),
η_p represents the efficiency of the technology (in %) and
nc_p stands for variable non-fuel cost (in €/MWh).

Table 6 to Table 9 summarize major techno-economic parameters including specific investment cost *ic*, fixed cost share *cs*, variable non-fuel cost nc_p, efficiency η_p and lifetime *lt* for different renewable and conventional power as well as H_2-based technologies. The data is based on E3M/IIASA/EuroCARE (2021), ASSET (2020) and Trinomics/LBST/E3M (2019). In order to calibrate the model following further assumptions are needed:

- Intermittent power production (i.e., wind onshore, wind offshore, PV and run-of-river) in Table 6 has no fuel-related cost or emissions (i.e., $mp_p = 0$ and $e_p = 0$) and the efficiency $\eta_p = 1$, the remaining variable cost equal variable non-fuel cost nc_p.

[2] For more details on the use of input parameters in the model see Deliverable D5.3 "Model description".

- For power production technologies based on fossil fuels the specific CO_2 emission factor ε_p is based on fuel emission data reported in Chapter 1 divided by the efficiency η_p .
- For all power production technologies in Table 6 to Table 8 power consumption coefficients $pf_p^{EL} = 1$ and the electrical efficiency $\eta_p^{EL} = 1$ to ensure electricity input into the power grid.
- In case of H_2-based power production (i.e., H_2-based CCGT, gas turbine and fuel cell) in Table 8 $pf_p^{H2} = -1$ and $\eta_p^{H2} = \eta_p$ to account for hydrogen consumption and for all other power generation technologies (i.e., not related to hydrogen) $pf_p^{H2} = 0$ and $\eta_p^{H2} = 1$ to exclude them from the hydrogen grid.
- For electrolysis the variable cost refer to water consumption represented by variable non-fuel cost nc_p. There are no other fuel-related cost or emissions (i.e., $mp_p = 0$ and $e_p = 0$). Moreover, $pf_p^{EL} = -1$ and $\eta_p^{EL} \leq \eta_p$ to account for power consumption based on the electrical efficiency η_p , whereas $pf_p^{H2} = 1$ and $\eta_p^{H2} = 1$ to include hydrogen supply into the hydrogen grid.

Table 6: Techno-economic data for intermittent renewable power generation technologies

Technology	Parameter	Unit	2025	2030	2040	2050
Wind onshore	Investment cost	€/kW	1,024	1,001	961	933
	Fixed cost share	% of invest./a	1.6%	1.6%	1.6%	1.6%
	Variable non-fuel cost	€/MWh	0.20	0.20	0.20	0.20
	Lifetime	a	30	30	30	30
Wind offshore	Investment cost	€/kW	2,131	2,067	1,999	1,929
	Fixed cost share	% of invest./a	1.9%	1.7%	1.6%	1.6%
	Variable non-fuel cost	€/MWh	0.39	0.39	0.39	0.39
	Lifetime	a	30	30	30	30
Photo-voltaics (PV)	Investment cost	€/kW	501	461	443	426
	Fixed cost share	% of invest./a	3.1%	3.0%	2.3%	2.0%
	Variable non-fuel cost	€/MWh	0.00	0.00	0.00	0.00
	Lifetime	a	30	30	30	30
Run-of-river	Investment cost	€/kW	1,692	1,670	1,660	1,650
	Fixed cost share	% of invest./a	0.5%	0.5%	0.5%	0.5%
	Variable non-fuel cost	€/MWh	0.00	0.00	0.00	0.00
	Lifetime	a	50	50	50	50
Bioenergy	Investment cost	€/kW	483	465	458	450
	Fixed cost share	% of invest./a	5.5%	5.2%	5.2%	5.2%
	Variable non-fuel cost	€/MWh	2.56	2.56	2.56	2.56
	Efficiency	%	38%	38%	39%	39%
	Lifetime	a	25	25	25	25

Table 7: Techno-economic data for conventional dispatchable power generation technologies

Technology	Parameter	Unit	2025	2030	2040	2050
Nuclear	Investment cost	€/kW	5,325	5,250	5,250	5,250
	Fixed cost share	% of invest./a	2.2%	2.2%	2.1%	2.0%
	Variable non-fuel cost	€/MWh	6.90	7.40	7.60	7.80
	Efficiency	%	38%	38%	38%	38%
	Lifetime	a	60	60	60	60
Lignite	Investment cost	€/kW	1,867	1,867	1,867	1,867
	Fixed cost share	% of invest./a	2.1%	2.1%	2.0%	2.0%
	Variable non-fuel cost	€/MWh	3.83	3.81	3.42	3.37
	Efficiency	%	39%	39%	40%	41%
	Lifetime	a	40	40	40	40
Hard coal	Investment cost	€/kW	1,667	1,667	1,667	1,667
	Fixed cost share	% of invest./a	2.0%	1.9%	1.8%	1.8%
	Variable non-fuel cost	€/MWh	2.94	2.92	2.87	2.86
	Efficiency	%	42%	43%	44%	44%
	Lifetime	a	40	40	40	40
Oil	Investment cost	€/kW	1,200	1,200	1,200	1,200
	Fixed cost share	% of invest./a	1.7%	1.7%	1.7%	1.7%
	Variable non-fuel cost	€/MWh	2.76	2.76	2.76	2.76
	Efficiency	%	35%	35%	35%	35%
	Lifetime	a	40	40	40	40
Combined cycle gas turbine (CCGT)	Investment cost	€/kW	566	558	554	550
	Fixed cost share	% of invest./a	3.7%	3.7%	3.6%	3.6%
	Variable non-fuel cost	€/MWh	2.13	2.11	2.06	2.02
	Efficiency	%	59%	60%	61%	61%
	Lifetime	a	30	30	30	30
Gas turbine	Investment cost	€/kW	393	386	383	380
	Fixed cost share	% of invest./a	3.0%	3.0%	3.0%	3.0%
	Variable non-fuel cost	€/MWh	2.10	2.10	2.10	2.10
	Efficiency	%	36%	37%	39%	40%
	Lifetime	a	25	25	25	25

Table 8: Techno-economic data for H_2-based power production technologies

Technology	Parameter	Unit	2025	2030	2040	2050
H_2-based combined cycle gas turbine CCGT	Investment cost	€/kW	566	558	554	550
	Fixed cost share	% of invest./a	3.7%	3.7%	3.6%	3.6%
	Variable non-fuel cost	€/MWh	2.13	2.11	2.06	2.02
	Efficiency	%	59%	60%	61%	61%
	Lifetime	a	30	30	30	30
H_2-based gas turbine	Investment cost	€/kW	393	386	383	380
	Fixed cost share	% of invest./a	3.0%	3.0%	3.0%	3.0%
	Variable non-fuel cost	€/MWh	2.10	2.10	2.10	2.10
	Efficiency	%	36%	37%	39%	40%
	Lifetime	a	25	25	25	25
Fuel cell	Investment cost	€/kW	3,295	3,090	2,871	2,668
	Fixed cost share	% of invest./a	1.7%	1.5%	1.5%	1.5%
	Variable non-fuel cost	€/MWh	1.04	1.04	1.04	1.04
	Efficiency	%	68%	68%	68%	69%
	Lifetime	a	20	20	20	20

Table 9: Techno-economic data for hydrogen production via electrolysis

Technology	Parameter	Unit	2025	2030	2040	2050
Electrolysis	Investment cost	€/kW_{el}	1,638	761	559	358
	Fixed cost share	% of invest./a	3.75%	4.50%	4.75%	5.00%
	Variable non-fuel cost	€/MWh_{H2}	0.41	0.41	0.41	0.41
	Electrical efficiency	%	68%	69%	71%	74%
	Lifetime	a	25	25	25	25

Table 10 and Table 11 summarize input parameters related to electricity and hydrogen storage technologies, respectively. The data for electricity storage is derived from Danish Energy Agency/Energinet (2021) and Michalski (2016), whereas the data for hydrogen storage is based on results and assumptions from KBB/Shell/E.ON (2013), Trinomics/LBST/E3M (2019) and Guidehouse (2021c) as well as on input from Work Package 7 in Task 7.2 on cost analysis and LCCA for large-scale underground hydrogen storage in porous media. To calibrate the model following additional assumptions are necessary:

- Variable storage cost occur only for hydrogen storage technologies and are related to compressor and dehydration power consumption plus the gas treatment consumption in the case of porous media storage assuming an average power price of 60 €/MWh. There are no other variable storage cost.
- Volume over flow rate ratio in Table 10 and Table 11 corresponds to ratio between storage volume and flow rate $\theta_{s,n}$. For pumped hydro, batteries and above-ground

pressurized H_2 storage it is the maximum value whereas for underground hydrogen storage in salt caverns and porous media it is the minimum value.

- For electricity storage technologies in Table 10 $\eta_S^{EL\ out}$ corresponds to the reported output efficiency, while $\eta_S^{EL\ in}$ equals the reciprocal of reported input efficiency. Additionally, $\eta_S^{H2\ in}$ and $\eta_S^{H2\ out}$ are set zero to exclude them from the hydrogen grid.
- Analogously, for hydrogen storage technologies in Table 11 $\eta_S^{H2\ out}$ corresponds to the reported output efficiency while $\eta_S^{H2\ in}$ equals the reciprocal of reported input efficiency. $\eta_S^{H2\ in} = 0$ and $\eta_S^{H2\ out}$=0 to exclude these technologies from the power grid.

Table 10: Techno-economic data for electricity storage technologies

Technology	Parameter	Unit	2025	2030	2040	2050
Pumped hydro storage	Investment cost in/out	€/kW	600	600	600	600
	Investment volume	€/kWh	10	10	10	10
	Fixed cost share in/out	% invest/a	1.50%	1.50%	1.50%	1.50%
	Fixed cost share volume	% invest/a	1.50%	1.50%	1.50%	1.50%
	Variable input cost	€/MWh	0.00	0.00	0.00	0.00
	Variable output cost	€/MWh	0.00	0.00	0.00	0.00
	Input efficiency	%	89%	89%	89%	89%
	Output efficiency	%	90%	90%	90%	90%
	Lifetime in/out	a	50	50	50	50
	Lifetime volume	a	50	50	50	50
	Volume over flow rate ratio	MWh/MW	6	6	6	6
Stationary batteries	Investment cost in/out	€/kW	215	160	100	60
	Investment volume	€/kWh	187	142	94	75
	Fixed cost share in/out	% invest/a	3.87%	3.29%	3.28%	3.24%
	Fixed cost share volume	% invest/a	3.87%	3.29%	3.28%	3.24%
	Variable input cost	€/MWh	0.00	0.00	0.00	0.00
	Variable output cost	€/MWh	0.00	0.00	0.00	0.00
	Input efficiency	%	98%	98%	98%	98%
	Output efficiency	%	97%	97%	97%	97%
	Lifetime in/out	a	25	25	25	25
	Lifetime volume	a	25	25	25	25
	Volume over flow rate ratio	MWh/MW	0.33	0.33	0.33	0.33

Following Trinomics/LBST/E3M (2019) demand side management (DSM) is assumed only for the power grid, as DSM related to hydrogen is intrinsically included in the operation of hydrogen grid and different H_2 storage technologies. The variable cost for power-related DSM amount to 50 €/MWh and the delay time δ_{DSM} is set to 8 hours corresponding to overnight shifting in power consumption e.g., by flexible charging of battery electric vehicles. Redispatch cost related to electricity and hydrogen, $rc_{n,m}^{EL}$ and $rc_{n,m}^{H2}$, respectively, amount to 100 €/MWh$_{el}$ and 200 €/MWh$_{H2}$, respectively.

Table 11: Techno-economic data for hydrogen storage technologies

Technology	Parameter	Unit	2025	2030	2040	2050
H_2 salt caverns	Investment cost in/out	€/kW	260	260	260	260
	Investment cost volume	€/kWh	0.55	0.55	0.55	0.55
	Fixed cost share in/out	% invest/a	3.8%	3.8%	3.8%	3.8%
	Fixed cost share volume	% invest/a	0.5%	0.5%	0.5%	0.5%
	Variable input cost	€/MWh	2.37	2.37	2.37	2.37
	Variable output cost	€/MWh	0.66	0.66	0.66	0.66
	Input efficiency	%	100%	100%	100%	100%
	Output efficiency	%	100%	100%	100%	100%
	Lifetime in/out	a	30	30	30	30
	Lifetime volume	a	50	50	50	50
	Volume over flow rate ratio	MWh/MW	268	268	268	268
Under-ground H_2 storage in porous media	Investment cost in/out	€/kW	1,060	1,060	1,060	1,060
	Investment cost volume	€/kWh	0.35	0.35	0.35	0.35
	Fixed cost share in/out	% invest/a	4.0%	4.0%	4.0%	4.0%
	Fixed cost share volume	% invest/a	2.0%	2.0%	2.0%	2.0%
	Variable input cost	€/MWh	1.86	1.86	1.86	1.86
	Variable output cost	€/MWh	2.67	2.67	2.67	2.67
	Input efficiency	%	100%	100%	100%	100%
	Output efficiency	%	97%	97%	97%	97%
	Lifetime in/out	a	30	30	30	30
	Lifetime volume	a	50	50	50	50
	Volume over flow rate ratio	MWh/MW	800	800	800	800
Above-ground pressurized H_2 storage	Investment cost in/out	€/kW	458	458	458	458
	Investment cost volume	€/kWh	10	10	10	10
	Fixed cost share in/out	% invest/a	1.00%	1.00%	1.00%	1.00%
	Fixed cost share volume	% invest/a	1.00%	1.00%	1.00%	1.00%
	Variable input cost	€/MWh	1.20	1.20	1.20	1.20
	Variable output cost	€/MWh	0.00	0.00	0.00	0.00
	Input efficiency	%	100%	100%	100%	100%
	Output efficiency	%	100%	100%	100%	100%
	Lifetime in/out	a	30	30	30	30
	Lifetime volume	a	30	30	30	30
	Volume over flow rate ratio	MWh/MW	48	48	48	48

Input data for power transport is derived from 50Hertz et al. (2021) taking into account the split between AC/DC and overhead lines/ underground cables as reported in ENTSO-E (2021) and assuming a utilisation rate of 80% to account for the n-1 criterion as proposed by Egerer (2016). For hydrogen pipelines average data is taken from Guidehouse (2021b) accounting for different pipeline diameters and share of new and repurposed pipelines. Variable H_2 transport costs are based on compressors' electricity consumption at 2% of energy content of transported H_2 at an average power price of 50 €/MWh as stated in Guidehouse (2020). For both transport technologies the analysis assumes an average lifetime of 30 years and neglects transmission losses (i.e., $\eta_{n,m}^{EL}$=1 and $\eta_{n,m}^{H2}$=1) for the sake of simplicity. At this point it is important to mention that in order to analyse the role of the future power and hydrogen transmission infrastructure the presented cost figures are minimum values depending on the expected development of required capacities. In particular, the analysis in scenarios B and D with distributed storage capacities across Europe is based on the assumption of limited interconnector capacity between individual Member States. This might be due to lower public acceptance for large infrastructure projects as well as concerns in respect to security of supply in national energy policies. Therefore, the specific infrastructure costs are higher in scenario B and D in comparison to scenarios A and C with centralised energy storage in Europe. The actual costs values for scenarios B and D depend on the modelling results and are estimated in an iterative approach. Table 12 summarizes major techno-economic data for power and hydrogen transport including the minimum cost values for scenario A and C.

Table 12: Techno-economic data for power and hydrogen transport

Parameter	Unit	Power lines	H_2 pipelines
Investment cost (minimum)	€/(km*MW)	1,846	252
Fixed cost (minimum)	% of investment	1.00%	1.25%
Variable cost (minimum)	€/(1,000 km*MWh)	0.0	1.0
Lifetime	a	30	30

3. Country-specific data

The country-specific data on power and hydrogen demand as well as installed capacities and investment limits for different technologies per country is derived from Trinomics/LBST/E3M (2019). As depicted in Figure 5, the “six big” countries (Germany, France, Italy, United Kingdom (UK), Spain and Poland) account for almost 70% of the overall final power and hydrogen demand in Europe. Significant hydrogen demand can be also observed for the Netherlands with its strong hydrogen industry. At this point it is important to mention that this study focuses on EU-27 but includes a detailed analysis also for the UK as a large economy with significant energy demand and impact on power and gas infrastructure. All other European non-EU countries are smaller and thus considered in less detail (see also Chapter 4 on power and hydrogen grid topology).

Table 13 provides an overview of the initial capacities $K_{p,n}$ of dispatchable power and hydrogen production technologies. The analysis assumes a gradual phase out of lignite, hard coal and oil power plants until 2050 for climate protection reasons.

Table 13: Initially installed capacities for power and hydrogen production technologies in EU-27

Fuel	Unit	2025	2030	2040	2050	Investment candidate
Nuclear*	GW	79	79	74	67	yes*
Lignite**	GW	32	32	0	0	no
Hard coal**	GW	53	53	0	0	no
Oil**	GW	52	52	26	0	no
Bioenergy**	GW	32	32	32	32	no
CCGT (natural gas)***	GW	68	68	34	0	yes
CCGT (hydrogen)***	GW	0	0	0	0	yes
Gas turbines (natural gas)***	GW	72	72	36	0	yes
CCGT (hydrogen)***	GW	0	0	0	0	yes
Fuel cells***	GW	0	0	0	0	yes
Electrolysis***	GW	0	0	0	0	yes

* Potential investments in nuclear power are included “manually” on a country-by-country basis following the political debate in the selected country.

** Maximum capacity based on historical values after decommissioning without the possibility to invest in new capacities.

*** Minimum capacity taking into account decommissioning of historically installed capacities which, however, can be increased by investments in the given time step.

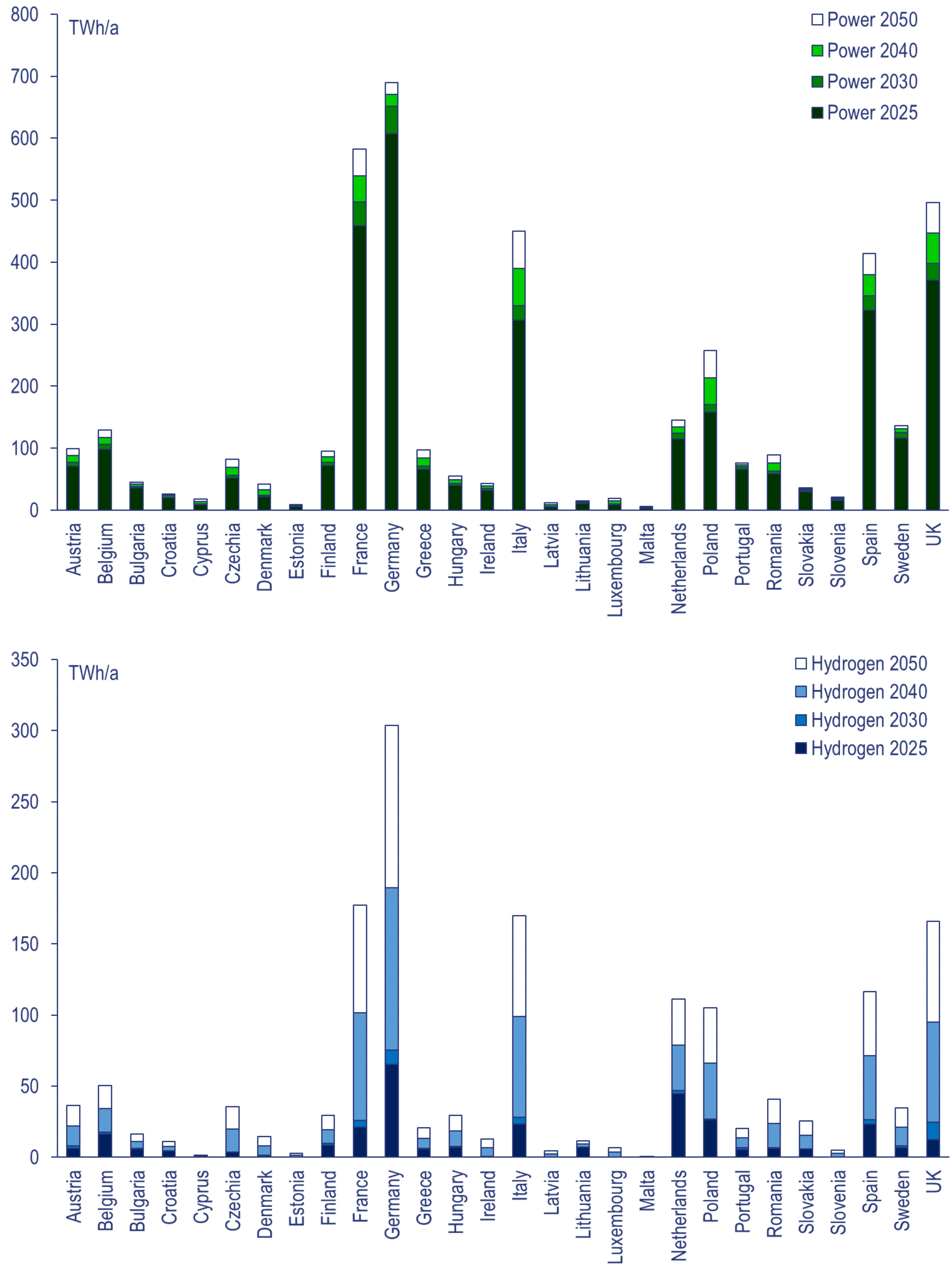

Figure 5: Power (top) and hydrogen (bottom) demand per country between 2025 and 2050

For nuclear power plants investments in new capacities are included “manually” on a country-by-country basis following the political debate in the selected country. For bioenergy power plants the model excludes investments in new capacities beyond the historical values due to limited economic and technical potential. This means that the figures for the aforementioned technologies in Table 13 represent maximum capacity based on historical values after decommissioning without the possibility to invest in new capacities (i.e., $\bar{I}_{p,n} = 0$).

In contrast, the capacities for production units based on natural gas (CCGT and gas turbines) and hydrogen (CCGT, gas turbines, fuel cells and electrolysis) are identified as investment candidates in the model. Hence, the figures in Table 13 stand for minimum capacity taking into account decommissioning of historically installed capacities which, however, can be increased by investments in the given time step (i.e., $\bar{I}_{p,n} \gg 0$). This also means that the model results on capacity investments from a given year increase the initially installed capacity $K_{p,n}$ in the next year. The initial capacities for intermittent renewable power generation (wind onshore, wind offshore, PV and run-of-river) follow the assumption on minimal renewables shares and split between the technologies from Table 1 and Table 2 in Chapter 1. The regional split between the countries is based on national renewables targets, potential normalised trajectories presented in the EU reference scenario in E3M/IIASA/EuroCARE (2021) and EUCO3232.5 scenario in EC (2019) as well as the respective share of each country’s potential in the overall European potential. In order to account for hydrogen demand from the power sector and storage efficiency losses, the model allows investments in intermittent power generation of up to 20% above the initial capacities (i.e., $\bar{I}_{p,n} = K_{p,n} \cdot 1.20$).

Table 14: Potential for demand side management in the power sector and initially installed capacities for electricity and hydrogen storage technologies in EU-27

Technology	Unit	2025	2030	2040	2050	Investment candidate
Demand side management	GW_{el}	17	20	38	55	no
Pumped hydro storage	GW_{el}	45	45	45	45	no
Stationary batteries	GW_{el}	0	0	0	0	yes
H_2 salt caverns	GWh_{H2}	0	0	0	0	yes
Underground H_2 storage in porous media	GWh_{H2}	0	0	0	0	yes
Above-ground pressurized H_2 storage	GWh_{H2}	96	192	1,318	2,444	yes

The country-specific CO_2 emission cap is based on the overall target as described in Chapter 1, distributed according to each country's share in overall final power and hydrogen demand. Geographical distribution of hydrogen imports follows the assumptions on import shares and potential as assumed in Chapter 1 and gas grid topology as described in Chapter 4.

Table 14 summarizes the potential for demand side management in the power sector and initial capacities for energy storage technologies. Note that the demand side management includes the predefined potential from ENTSO-E (2020a) and additional DSM from the transport sector assuming that 25% of the peak power demand of battery electric vehicles is available for flexible charging. Similar, the initial capacities for above-ground pressurized H_2 storage are based on expected capacities of hydrogen refuelling stations in the transport sector assuming a two-day-storage at each station. The analysis assumes limited potential for pumped hydro storage and, therefore, excludes investments in this technology (i.e., $\bar{I}_{s,n}^{V} = \bar{I}_{s,n}^{F} = 0$).

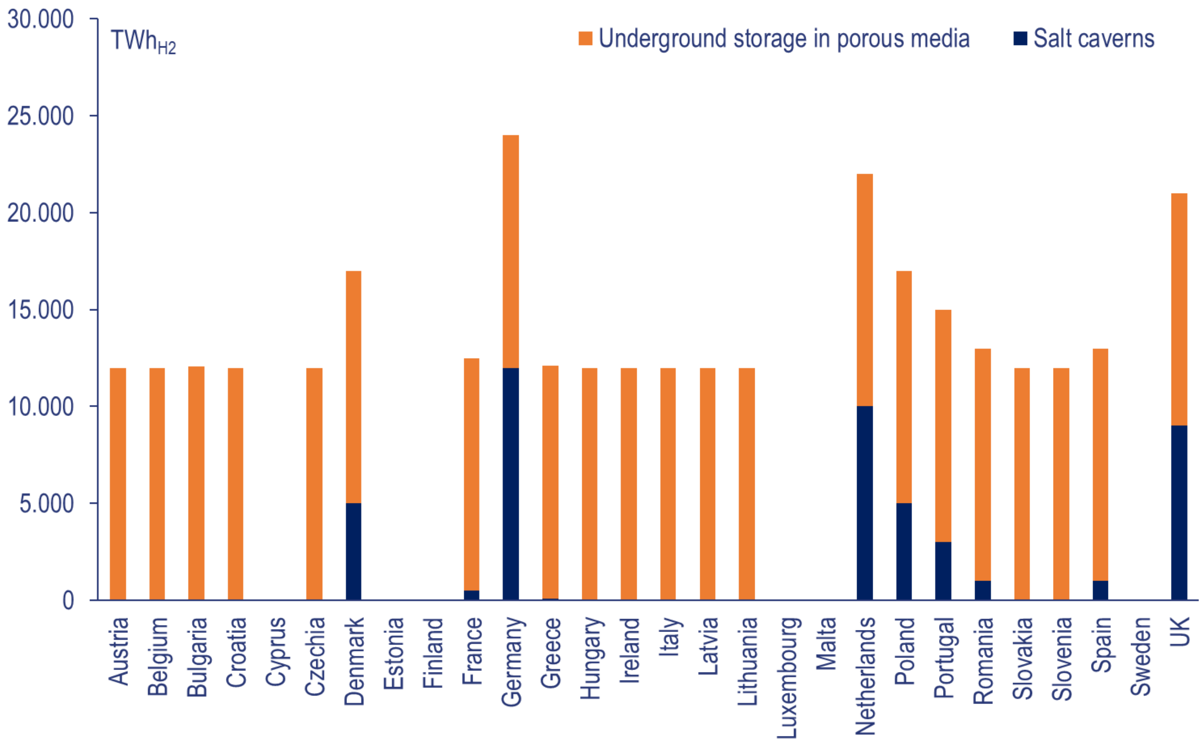

Figure 6: Technical potential for underground hydrogen storage. Note that the porous media figure is a hypothetical value, a priori not limiting possible deployment.

Following the data provided by Caglayan et al. (2020) and Albes et al. (2014) and based on the experience of Geostock, the overall hydrogen storage technical potential for in salt caverns in Europe is very large, amounting to more than 70,000 TWh, but limited to 11 countries in Europe, namely Bulgaria, Denmark, France, Germany, Greece, the Netherlands, Poland, Portugal, Romania, Spain and the UK. For porous media there is no equivalent public estimate of a technical storage capacity for hydrogen in Europe to date and it will be provided by Work Package 1 and 2 within the Hystories project. Hence, estimations have been proposed based on the hypothesis of the conversion of existing natural gas facilities, providing figures that tend to show a larger potential of hydrogen storage in porous media. However, this is not a technical potential but rather a reflection of how natural gas storage has developed (Guidehouse, 2021c). Thus, as illustrated in Figure 6, the Hystories project assumes a hydrogen storage potential in porous media of 12,000 TWh for each country except for 6 Member States, namely Cyprus, Estonia, Finland, Luxembourg, Malta and Sweden for which early results from Work Package 1 and 2 have identified that there is no, or no public, porous media storage potential. The figure of 12,000 TWh is not a preliminary result of these Work Packages. It corresponds to the maximum of what was found for salt caverns and is chosen as a very high value that should not limit the porous media storage deployment. In this context it is important to mention that the abovementioned figures on storage potential in porous media are a strong assumption. In reality, the ability of different geological formations to store hydrogen in an economic way depends on a number of site-specific criteria (e.g., microbiologic conditions) and might differ significantly for the individual countries which will become an outcome in the course of the Hystories project. Therefore, this uncertainty might be further assessed within a dedicated sensitivity analysis. The investments in stationary batteries and above-ground pressurized H_2 storage do not undergo any limitations (i.e., $\bar{I}_{s,n}^{V} \gg 0$ and $\bar{I}_{s,n}^{F} \gg 0$).

4. Topology power and gas grid

Modelling of both power and hydrogen grids follows the country approach, i.e., each country is represented by one grid node. In this context, the grid captures all EU-27 Member States plus some additional non-EU countries including:

- the UK as large economy with significant impact on the European energy system,
- Norway with its power storage and low-carbon H_2 export potential,
- Switzerland with pumped hydro storage potential and as energy transit country,
- Western Balkan countries (i.e., Albania, Bosnia and Herzegovina, Kosovo, North Macedonia, Montenegro and Serbia) as energy transit countries within the EU and
- other potential H_2 export countries such as Russia, Ukraine as well as Morocco, Algeria and Libya (all three considered as North Africa).

Figure 7 depicts assumed power grid topology. Corresponding initial power line capacities $K_{n,m}^{EL}$ are derived from the reference grid provided by ENTSO-E (2020b).

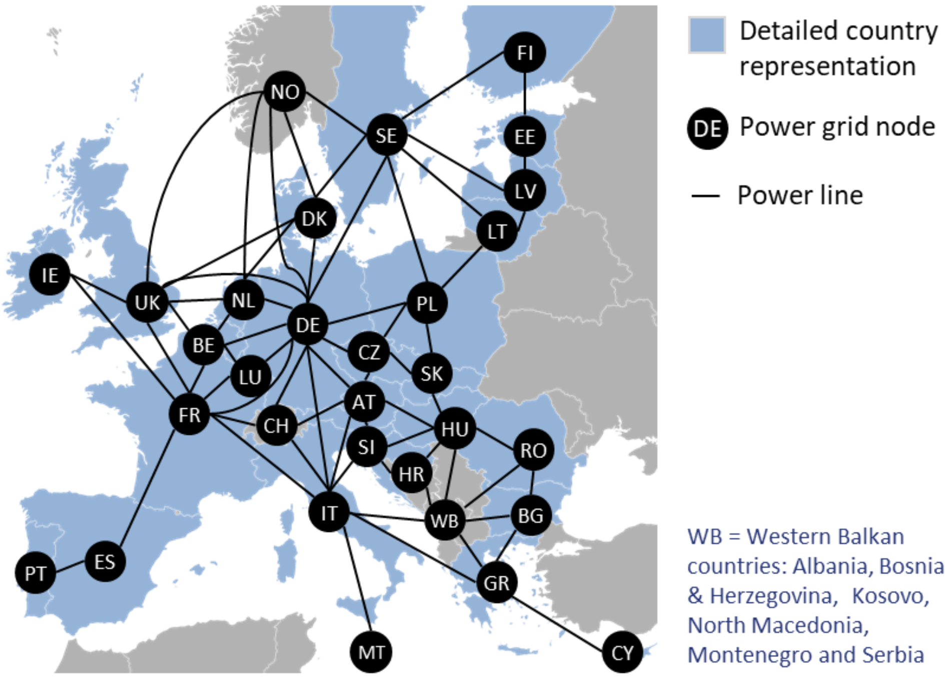

Figure 7: Assumed power grid topology

In line with the Hydrogen Backbone Study in Guidehouse (2021b), analysis provided in van Wijk & Chatzimarkakis (2020) and expected early interconnector projects the hydrogen grid develops gradually based on the existing gas grid. In 2025, only today's hydrogen grid between the Netherlands and Belgium is taken into account. It would be an upgrade of the existing feedstock network for petrochemical industries to a mixed feedstock and energy system network. As the study excludes H_2 imports from non-EU countries in 2025, hydrogen supply in almost all nodes is isolated from each other. In 2030, a first rudimentary hydrogen grid is expected to occur in Europe, mainly in Central and South Europe connecting Portugal, Spain, France, Belgium, the Netherlands, Germany, Denmark, Poland, Austria and Slovakia. Limited imports are possible from Norway (to the Netherlands), Ukraine (to Slovakia) and North Africa (to Italy and Spain). In 2040, the hydrogen grid is further developed connecting most grid nodes and allowing for renewable and low-carbon H_2 imports from different non-EU regions. Finally in 2050, the hydrogen grid replaces the methane infrastructure achieving its maximal extent. Only renewable hydrogen imports are allowed, i.e., from Ukraine and North Africa. Figure 8 illustrates the expected development of the hydrogen grid until 2050.

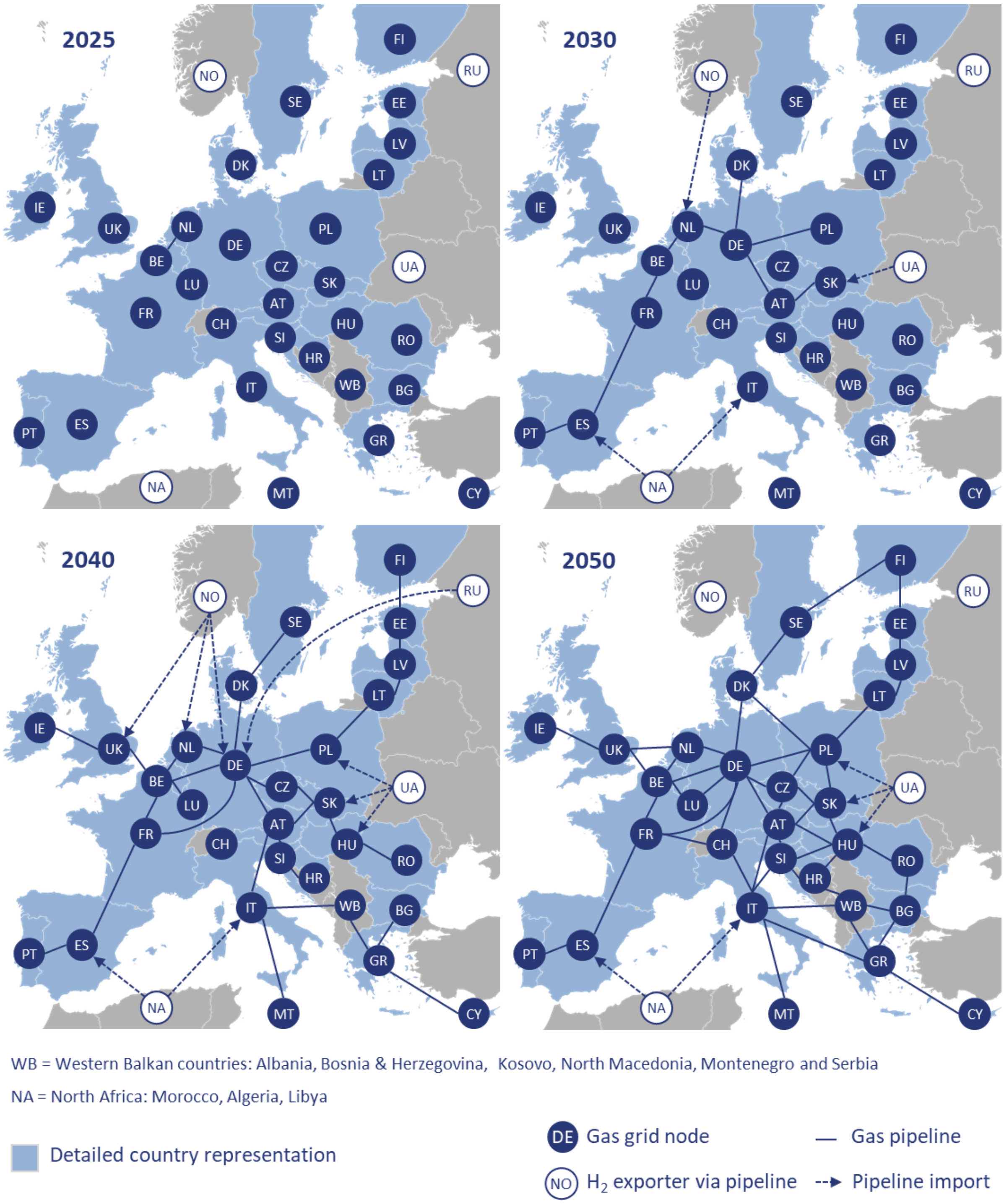

Figure 8: Expected development of hydrogen grid until 2050

Initial pipeline capacities $K_{n,m}^{H2}$ correspond to existing gas grid capacity taken from ENTSOG (2020). The length of power lines and hydrogen pipelines is calculated as distance between the geographical centre of each country derived from the e-Highways project provided by ENTSO-E (2015).

5. Time-dependent profiles

Time-dependent profiles characterize hourly constraints related to the operation of the energy system. They are based on different sources and normalised to allow for scaling the absolute time series depending on the intermediate results of each modelling step. In the first modelling steps (capacity expansion model) the resolution is reduced to 120 time steps each representing an average of 73 hours (i.e., load duration *ld = 73*) or 5 days. Based on model testing such temporal resolution provides an acceptable trade-off between computational time and results accuracy. The temporal resolution in the second and third modelling steps, i.e., within the unit commitment model as well as the power and gas grid model, respectively, is one hour and the representative year contains 8,760 time steps.

For most production units the maximal production profile ($p_{p,n,t}^{max}$) is set to 1 and the minimal production profile ($p_{p,n,t}^{min}$) to 0 in order to allow for the full operational range of the dispatchable units. Following exceptions are made to the above rule:

- For intermittent renewable power plants (wind onshore, wind offshore, PV and run-of-river) the maximal production profile corresponds to the renewable feed-in (see below).
- Curtailment of intermittent renewable feed-in is limited to 10%.
- Nuclear and lignite power plants have a minimal production of 60% (i.e., $p_{p,n,t}^{min} = 0.6$).

The profiles are based on historical data from 2015. According to TYNDP 2022 in ENTSO-E/ENTSOG (2021b) this weather year represents rather favourable climatic conditions in terms of severity of the so-called “Dunkelflaute” (low renewable feed-in during a two-week period of high energy demand typically in winter with low temperatures). Hence, the modelling results based on the selected time series can be interpreted as the lower bound for storage requirements. The impact of other climatic conditions on H_2 storage needs can be assessed in additional sensitivity analyses. In line with Trinomics/LBST/E3M (2019) following sources are used for the different profiles:

- Renewable feed-in (wind onshore, wind offshore, PV and run-of-river) and basic power demand ($p_{n,t}^{Basic}$) are taken from ENTSO-E Transparency Platform.
- Power demand in the mobility sector ($p_{n,t}^{BEV}$) is based on expected charging patterns as described by Malling et al. (2015) and Element Energy (2019).
- Electricity demand by heat pumps ($p_{n,t}^{HP}$) is derived from temperature data Iowa State University (2021) taking into account a variable coefficient of performance based on the outdoor temperature.
- H_2 demand in the mobility sector ($p_{n,t}^{FCEV}$) refers to end-user refuelling behaviour taken from Bünger et al. (2018), Bünger et al. (2019) and Michalski et al. (2019).
- H_2 demand for heating ($p_{n,t}^{Heat}$) is also based on outdoor temperatures from the data base provided by Iowa State University (2021).
- H_2 ($p_{n,t}^{Ind}$) demand in industry is assumed to remain constant for all time steps.

6. Abbreviations

a	Annum (year)
AC	Alternating current
CCGT	Combined cycle gas turbine
DC	Direct current
DSM	Demand side management
EU	European Union
LCCA	Life-cycle cost analysis
O&M	Operation & maintenance
TYNDP	Ten-year network development plan
UK	United Kingdom

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