KU LEUVEN

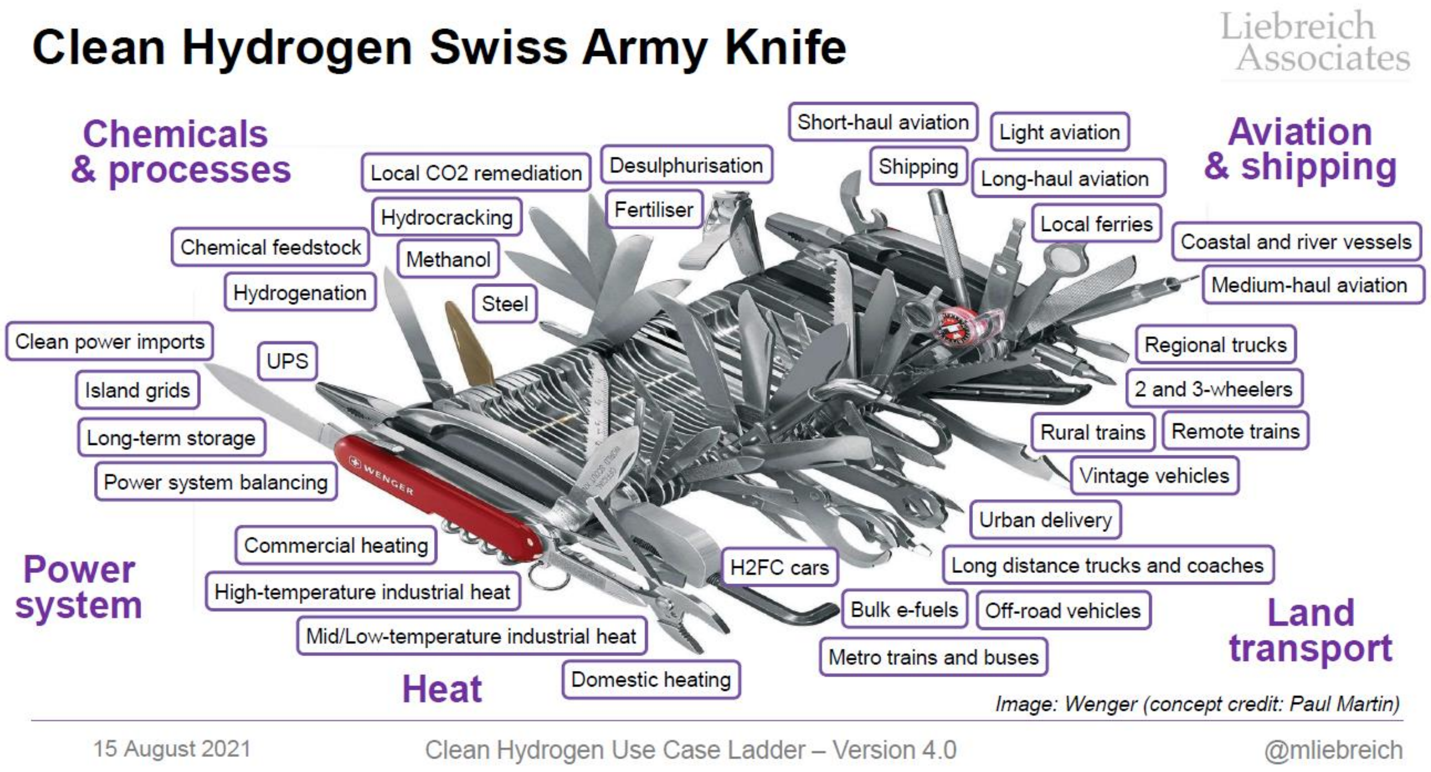
Hydrogen

a new energy carrier, for all means?

William D'haeseleer
ESIG - Tucson - March 21 2022

H_2, an energy carrier for all means?

??



Clean Hydrogen Swiss Army Knife

Liebreich
Associates

Chemicals & processes

Local CO2 remediation
Desulphurisation
Fertiliser
Hydrocracking
Chemical feedstock
Methanol
Hydrogenation
Steel

Aviation & shipping

Short-haul aviation
Light aviation
Shipping
Long-haul aviation
Local ferries
Coastal and river vessels
Medium-haul aviation

Power system

Clean power imports
UPS
Island grids
Long-term storage
Power system balancing

Land transport

Regional trucks
2 and 3-wheelers
Rural trains
Remote trains
Vintage vehicles
Urban delivery
H2FC cars
Long distance trucks and coaches
Bulk e-fuels
Off-road vehicles
Metro trains and buses

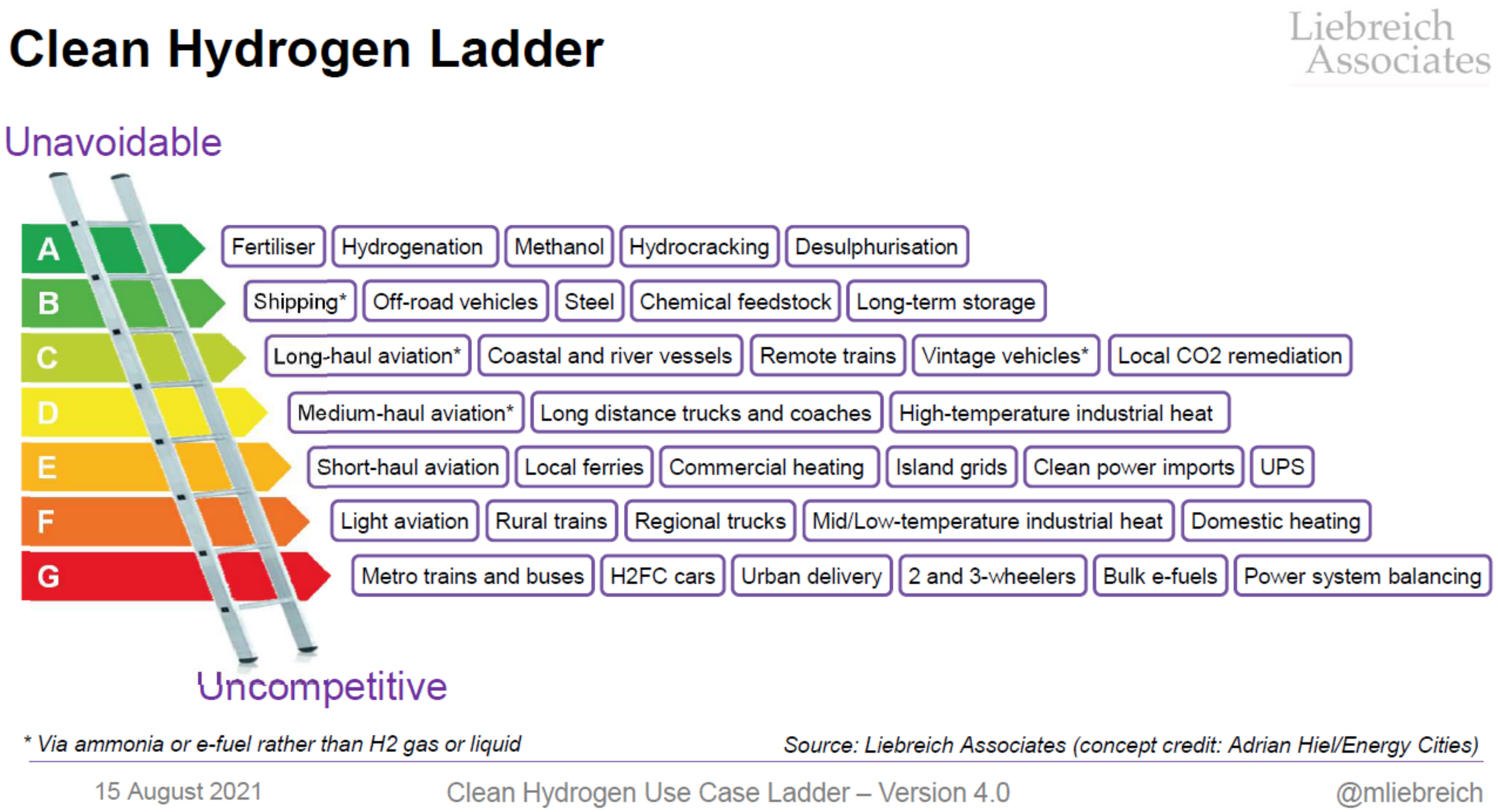
Heat

Commercial heating
High-temperature industrial heat
Mid/Low-temperature industrial heat
Domestic heating

Image: Wenger (concept credit: Paul Martin)

15 August 2021 Clean Hydrogen Use Case Ladder – Version 4.0 @mliebreich

Liebreich’s Hydrogen Ladder



Clean Hydrogen Ladder

Liebreich Associates

Unavoidable

- A: Fertiliser, Hydrogenation, Methanol, Hydrocracking, Desulphurisation
- B: Shipping*, Off-road vehicles, Steel, Chemical feedstock, Long-term storage
- C: Long-haul aviation*, Coastal and river vessels, Remote trains, Vintage vehicles*, Local CO2 remediation
- D: Medium-haul aviation*, Long distance trucks and coaches, High-temperature industrial heat
- E: Short-haul aviation, Local ferries, Commercial heating, Island grids, Clean power imports, UPS
- F: Light aviation, Rural trains, Regional trucks, Mid/Low-temperature industrial heat, Domestic heating
- G: Metro trains and buses, H2FC cars, Urban delivery, 2 and 3-wheelers, Bulk e-fuels, Power system balancing

Uncompetitive

** Via ammonia or e-fuel rather than H2 gas or liquid*

Source: Liebreich Associates (concept credit: Adrian Hiel/Energy Cities)

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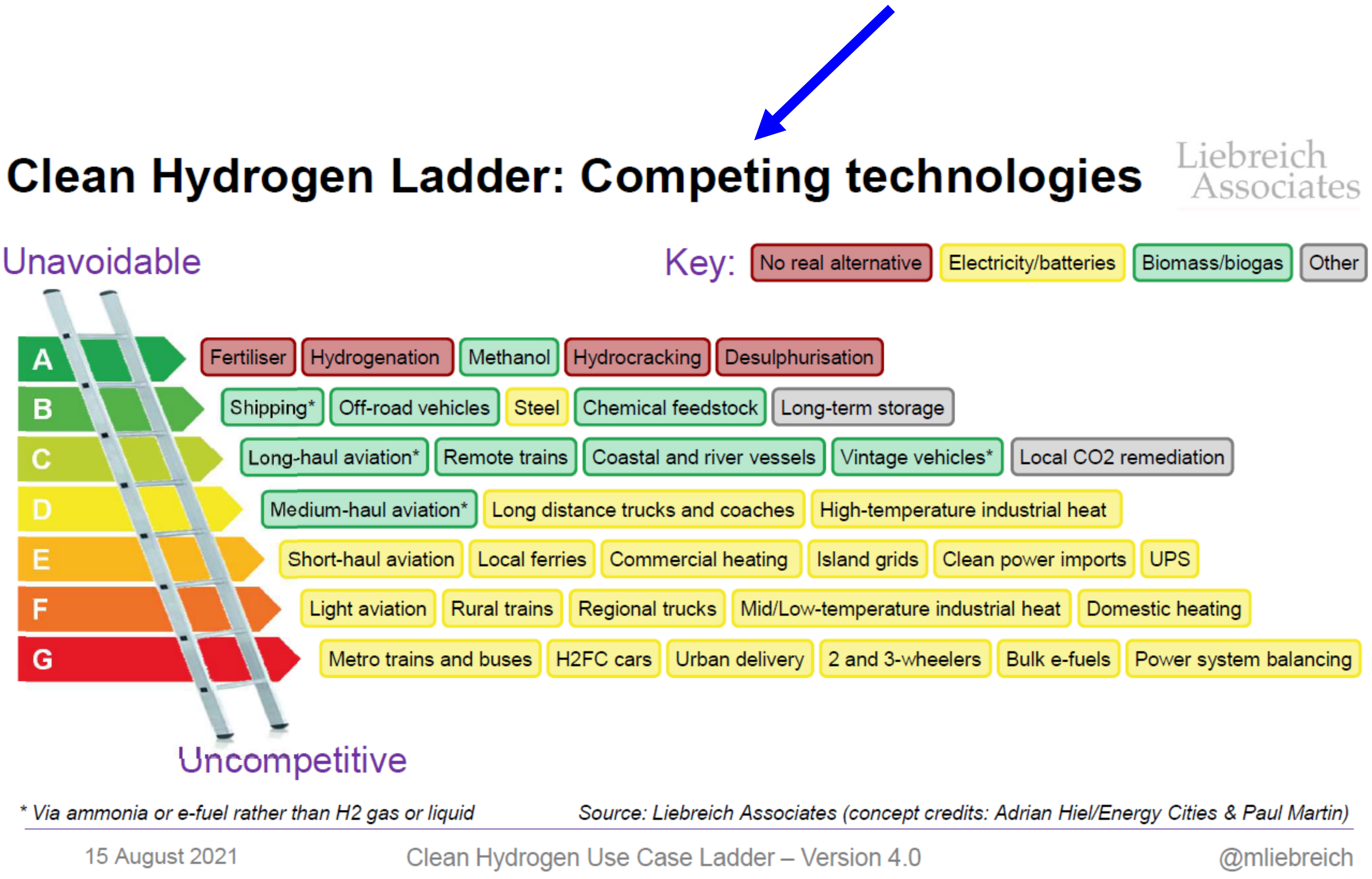
Liebreich's Hydrogen Ladder



Clean Hydrogen Ladder: Competing technologies

Liebreich
Associates

Unavoidable

Key: 🟥 No real alternative | 🟨 Electricity/batteries | 🟩 Biomass/biogas | ⬜ Other

- **A** 🟥 Fertiliser | 🟥 Hydrogenation | 🟩 Methanol | 🟥 Hydrocracking | 🟥 Desulphurisation
- **B** 🟩 Shipping* | 🟩 Off-road vehicles | 🟨 Steel | 🟩 Chemical feedstock | ⬜ Long-term storage
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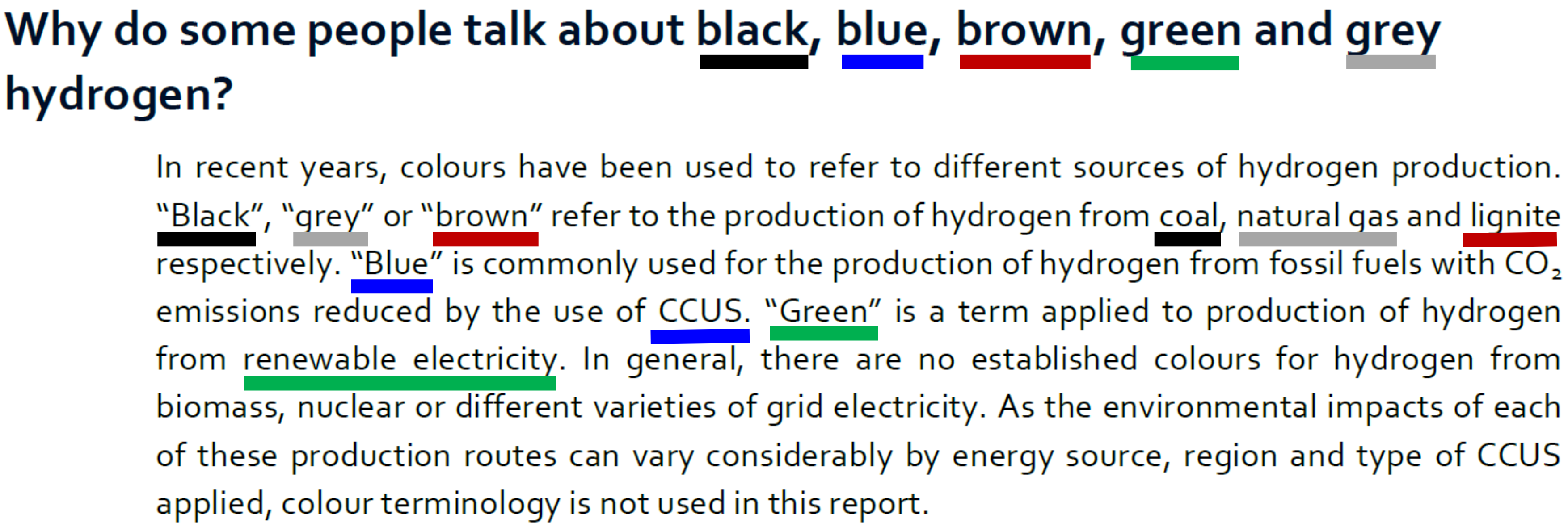
Some preliminaries… Some definitions & conventions

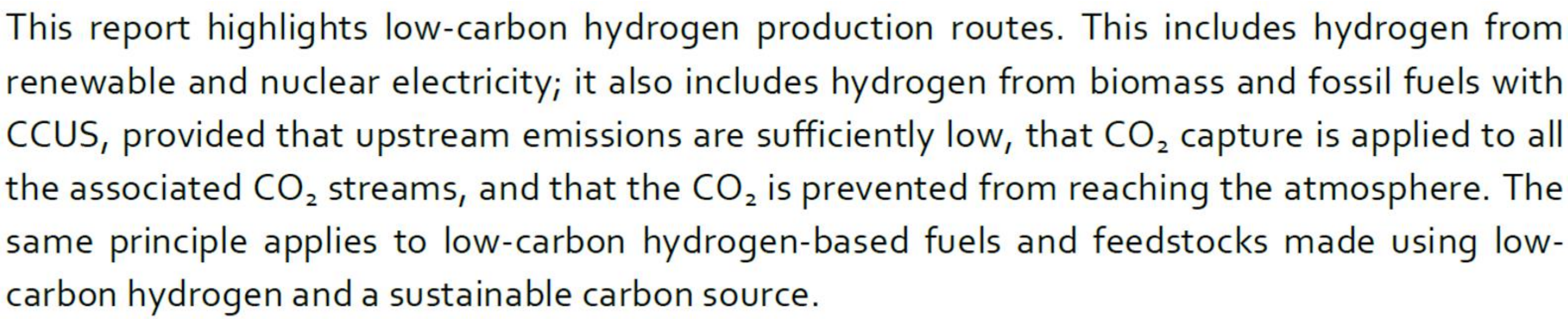
Hydrogen and Energy: a primer *- IEA 'The Future of Hydrogen', 2019*



Why do some people talk about black, blue, brown, green and grey hydrogen?

In recent years, colours have been used to refer to different sources of hydrogen production. "Black", "grey" or "brown" refer to the production of hydrogen from coal, natural gas and lignite respectively. "Blue" is commonly used for the production of hydrogen from fossil fuels with CO_2 emissions reduced by the use of CCUS. "Green" is a term applied to production of hydrogen from renewable electricity. In general, there are no established colours for hydrogen from biomass, nuclear or different varieties of grid electricity. As the environmental impacts of each of these production routes can vary considerably by energy source, region and type of CCUS applied, colour terminology is not used in this report.

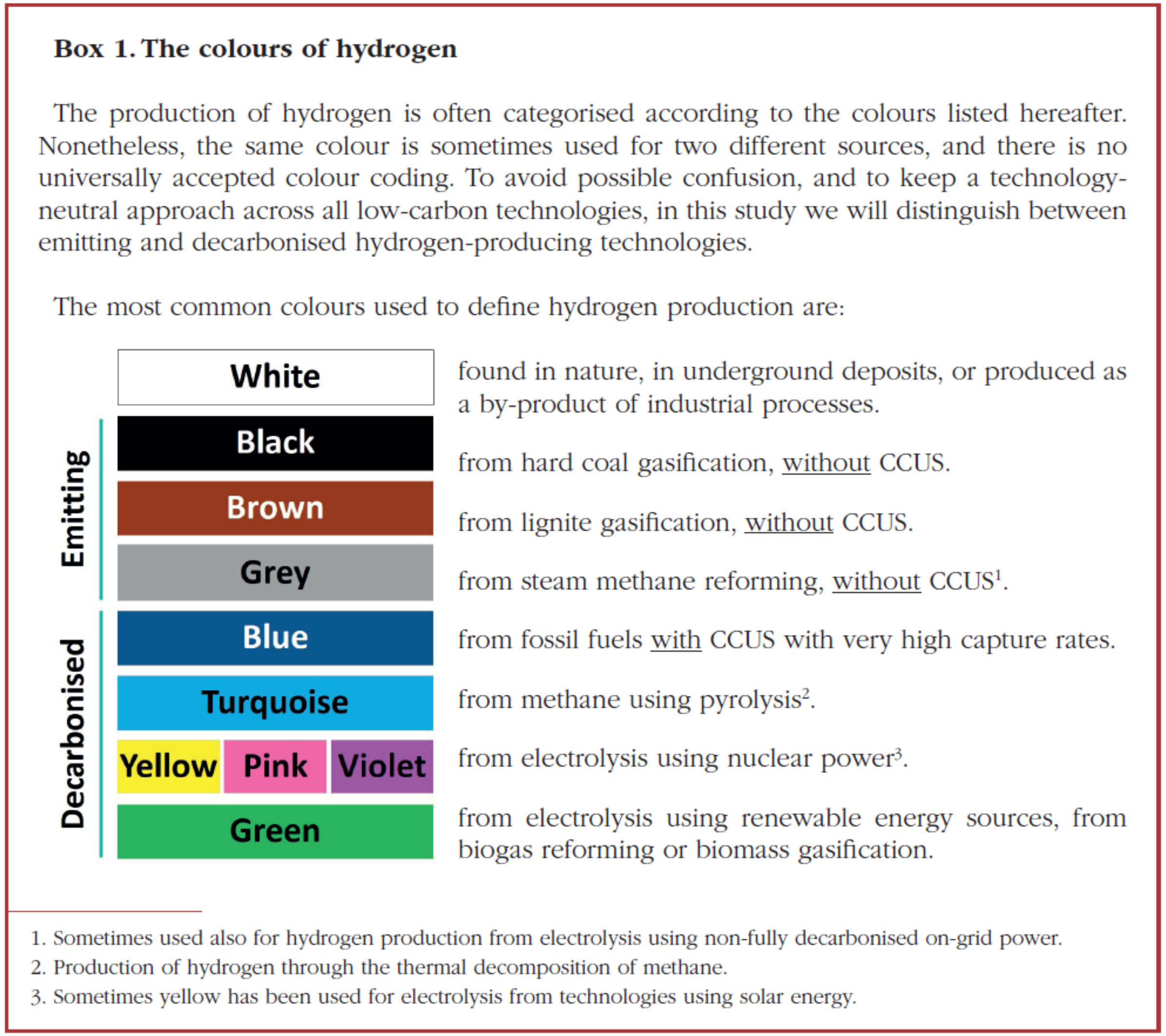
- Recently also: **turquoise H_2** via pyrolysis of CH_4 → H_2 + solid carbon and no CO_2 (cfr FSR/EUI report Piebalgs et al)
- How about nuclear-electrolysis-produced H_2? → pink H_2? (Interest of France)



This report highlights low-carbon hydrogen production routes. This includes hydrogen from renewable and nuclear electricity; it also includes hydrogen from biomass and fossil fuels with CCUS, provided that upstream emissions are sufficiently low, that CO_2 capture is applied to all the associated CO_2 streams, and that the CO_2 is prevented from reaching the atmosphere. The same principle applies to low-carbon hydrogen-based fuels and feedstocks made using low-carbon hydrogen and a sustainable carbon source.

Rather than colors, one should concentrate on **CO_2 content.**

Hydrogen and Energy: a primer



Box 1. The colours of hydrogen

The production of hydrogen is often categorised according to the colours listed hereafter. Nonetheless, the same colour is sometimes used for two different sources, and there is no universally accepted colour coding. To avoid possible confusion, and to keep a technology-neutral approach across all low-carbon technologies, in this study we will distinguish between emitting and decarbonised hydrogen-producing technologies.

The most common colours used to define hydrogen production are:

	White	found in nature, in underground deposits, or produced as a by-product of industrial processes.
Emitting	Black	from hard coal gasification, without CCUS.
	Brown	from lignite gasification, without CCUS.
	Grey	from steam methane reforming, without CCUS[1].
Decarbonised	Blue	from fossil fuels with CCUS with very high capture rates.
	Turquoise	from methane using pyrolysis[2].
	Yellow Pink Violet	from electrolysis using nuclear power[3].
	Green	from electrolysis using renewable energy sources, from biogas reforming or biomass gasification.

---

1. Sometimes used also for hydrogen production from electrolysis using non-fully decarbonised on-grid power.
2. Production of hydrogen through the thermal decomposition of methane.
3. Sometimes yellow has been used for electrolysis from technologies using solar energy.

LA REVUE DE L'ÉNERGIE

Octobre 2021

Decarbonised hydrogen imports
into the European Union:
challenges and opportunities

Foreword
Introduction

1. Setting the scene

Hydrogen production and consumption in Europe
Technologies and costs
Implications

2. Hydrogen imports

Drivers of hydrogen imports
How to make imports possible?
Conditions for mutual success

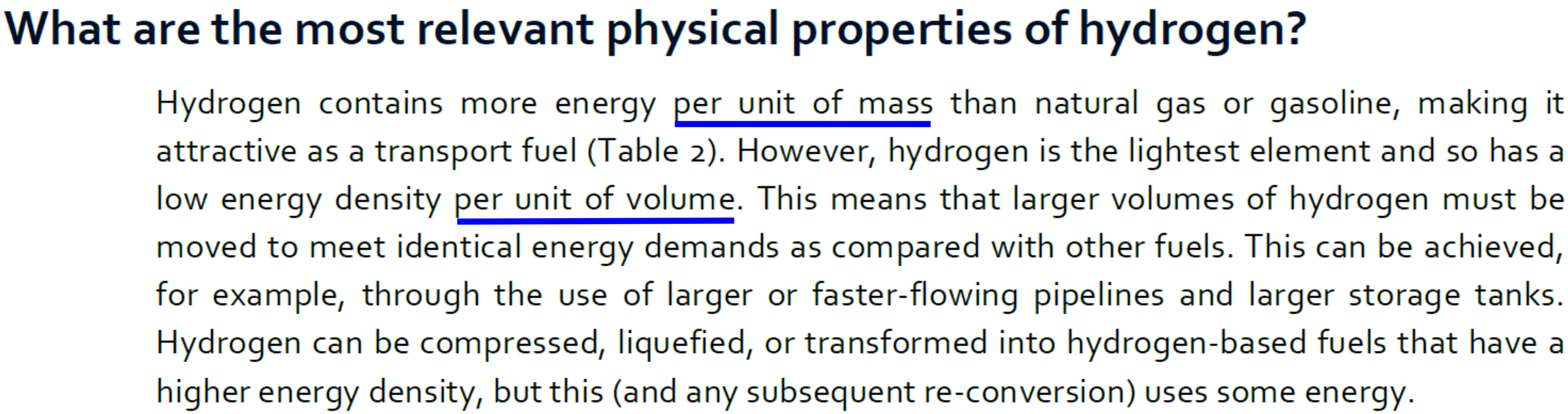
3. Country profiles

Austria
France
Germany
Italy
Spain

Conclusions

WORLD ENERGY COUNCIL | EUROPE

Hydrogen and Energy: a primer *- IEA 'The Future of Hydrogen', 2019*



What are the most relevant physical properties of hydrogen?

Hydrogen contains more energy per unit of mass than natural gas or gasoline, making it attractive as a transport fuel (Table 2). However, hydrogen is the lightest element and so has a low energy density per unit of volume. This means that larger volumes of hydrogen must be moved to meet identical energy demands as compared with other fuels. This can be achieved, for example, through the use of larger or faster-flowing pipelines and larger storage tanks. Hydrogen can be compressed, liquefied, or transformed into hydrogen-based fuels that have a higher energy density, but this (and any subsequent re-conversion) uses some energy.

Hydrogen and Energy: a primer *- IEA ‘The Future of Hydrogen’, 2019*

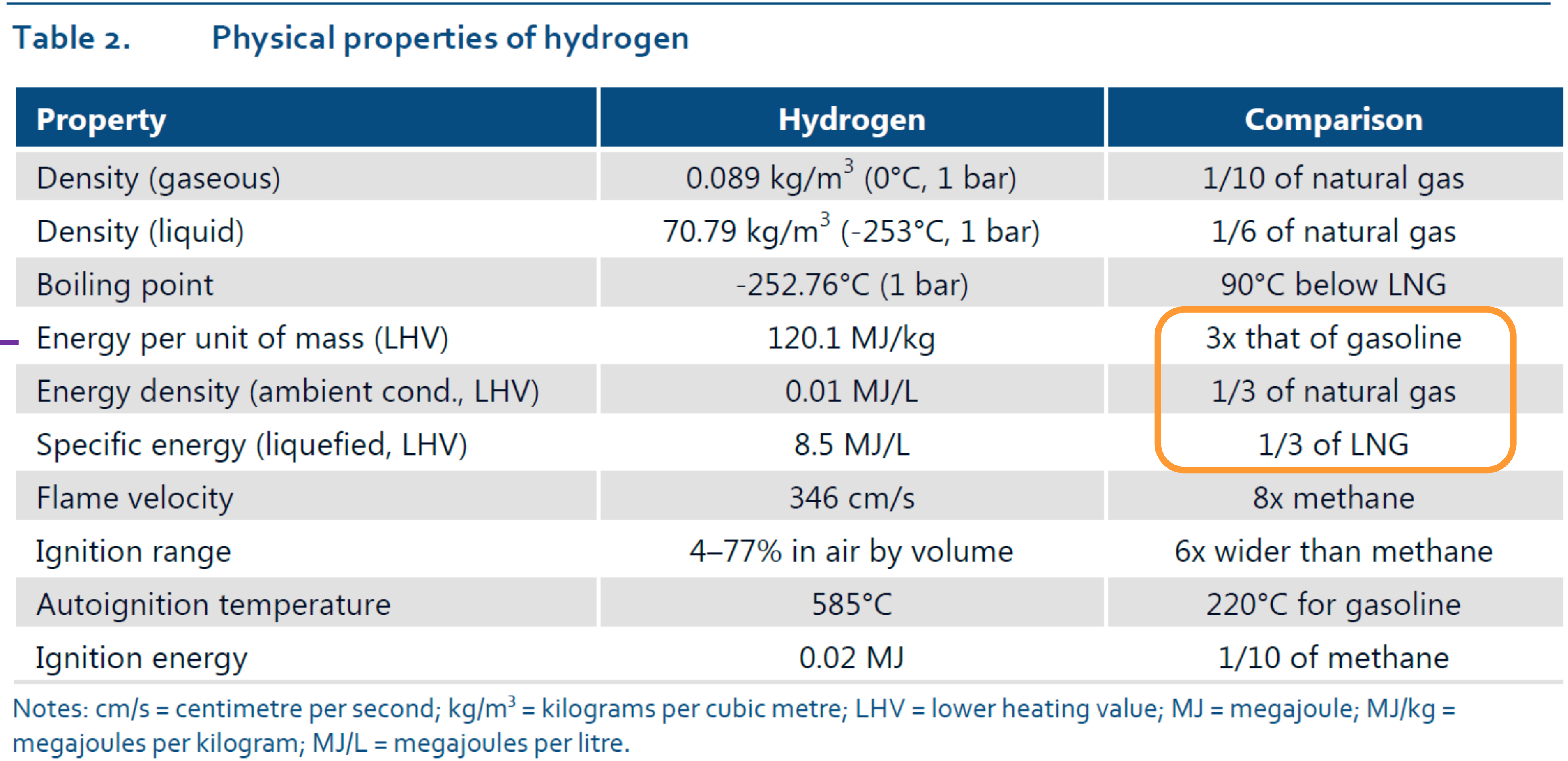


Table 2. Physical properties of hydrogen

Property	Hydrogen	Comparison
Density (gaseous)	0.089 kg/m^3 (0°C, 1 bar)	1/10 of natural gas
Density (liquid)	70.79 kg/m^3 (-253°C, 1 bar)	1/6 of natural gas
Boiling point	-252.76°C (1 bar)	90°C below LNG
Energy per unit of mass (LHV)	120.1 MJ/kg	3x that of gasoline
Energy density (ambient cond., LHV)	0.01 MJ/L	1/3 of natural gas
Specific energy (liquefied, LHV)	8.5 MJ/L	1/3 of LNG
Flame velocity	346 cm/s	8x methane
Ignition range	4–77% in air by volume	6x wider than methane
Autoignition temperature	585°C	220°C for gasoline
Ignition energy	0.02 MJ	1/10 of methane

Notes: cm/s = centimetre per second; kg/m^3 = kilograms per cubic metre; LHV = lower heating value; MJ = megajoule; MJ/kg = megajoules per kilogram; MJ/L = megajoules per litre.

Important extra note: **Energy per unit mass $H_2 \simeq 0.033\ MWh_{LHV}/kg$** → cost/price of **$1\ \$/kg \simeq 30\ \$/MWh_{prim,\ LHV}$**

Hydrogen and Energy: more characteristics

D. Haeseldonckx PhD Thesis

Hence:

HHV: 141/(3.6x1000)=**0.0392 MWh/kg** → 1/ 0.0392 = **25.5 kg/MWh**

LHV: 120/(3.6x1000)=**0.033 MWh/kg** → 1/0.33 = **30 kg/MWh**

Energy per unit mass $H_2 \simeq 0.039\ MWh_{HHV}/kg$

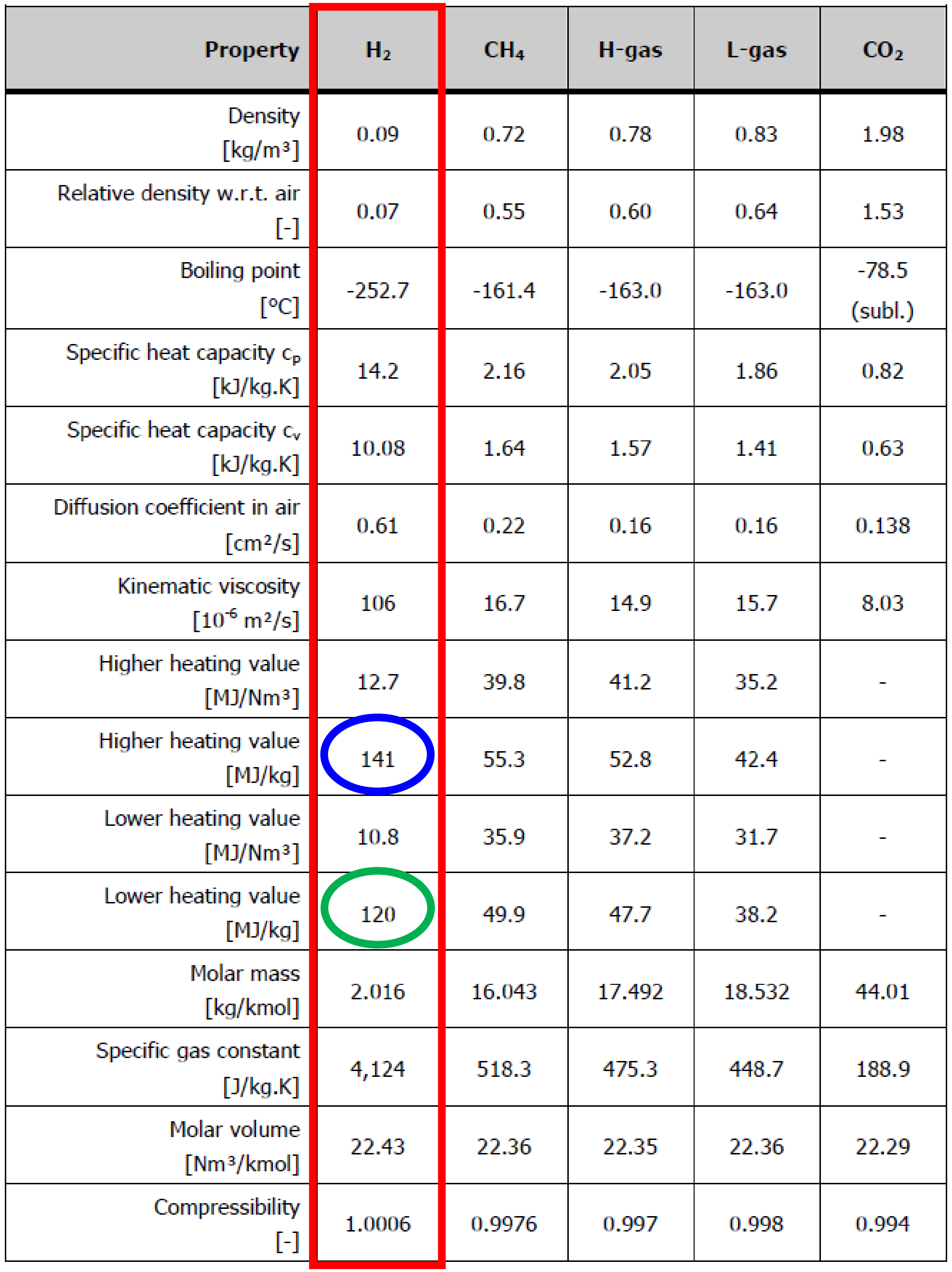
→ cost/price of ***1 \$/kg*** $\simeq$ ***25 \$/MWh***$_{prim,\ HHV}$

Energy per unit mass $H_2 \simeq 0.033\ MWh_{LHV}/kg$

→ cost/price of ***1 \$/kg*** $\simeq$ ***30 \$/MWh***$_{prim,\ LHV}$

HHV

LHV

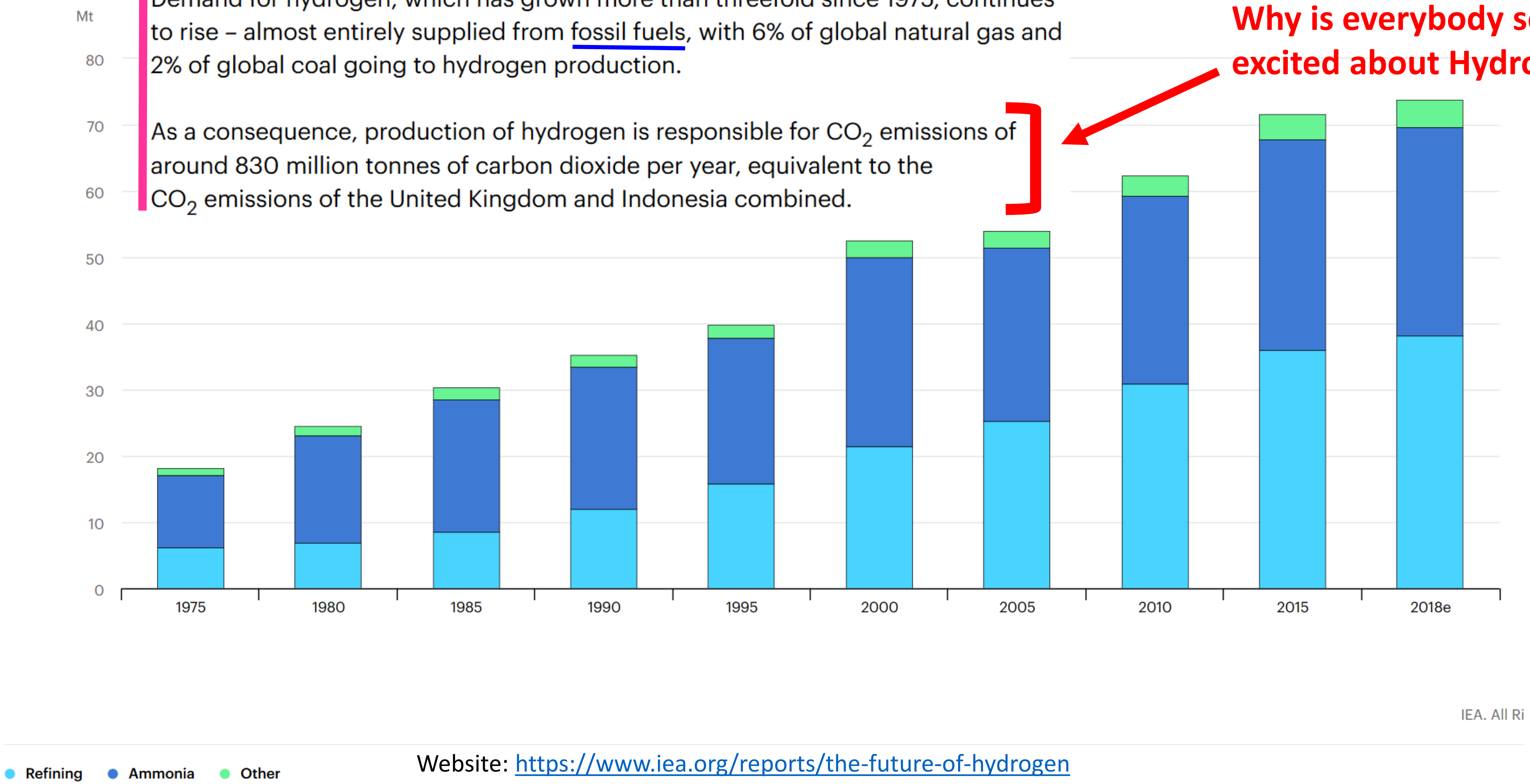


Property	H_2	CH_4	H-gas	L-gas	CO_2
Density [kg/m^3]	0.09	0.72	0.78	0.83	1.98
Relative density w.r.t. air [-]	0.07	0.55	0.60	0.64	1.53
Boiling point [°C]	-252.7	-161.4	-163.0	-163.0	-78.5 (subl.)
Specific heat capacity c_p [kJ/kg.K]	14.2	2.16	2.05	1.86	0.82
Specific heat capacity c_v [kJ/kg.K]	10.08	1.64	1.57	1.41	0.63
Diffusion coefficient in air [cm^2/s]	0.61	0.22	0.16	0.16	0.138
Kinematic viscosity [10^{-6} m^2/s]	106	16.7	14.9	15.7	8.03
Higher heating value [MJ/Nm^3]	12.7	39.8	41.2	35.2	-
Higher heating value [MJ/kg]	141	55.3	52.8	42.4	-
Lower heating value [MJ/Nm^3]	10.8	35.9	37.2	31.7	-
Lower heating value [MJ/kg]	120	49.9	47.7	38.2	-
Molar mass [kg/kmol]	2.016	16.043	17.492	18.532	44.01
Specific gas constant [J/kg.K]	4,124	518.3	475.3	448.7	188.9
Molar volume [Nm^3/kmol]	22.43	22.36	22.35	22.36	22.29
Compressibility [-]	1.0006	0.9976	0.997	0.998	0.994

Table 1: Physical and chemical properties of hydrogen, methane, H-gas, L-gas and carbon dioxide. All properties are given for normal conditions, i.e. 0 °C and 1 atm. The use of a capital 'N', as in Nm³, refers to these normal conditions. (Perry [8], Lide [9], Cerbe [10]).

Some preliminaries… Current use of hydrogen

Worldwide pure H_2 demand 1975-2018



> Supplying hydrogen to industrial users is now a major business around the world. Demand for hydrogen, which has grown more than threefold since 1975, continues to rise – almost entirely supplied from fossil fuels, with 6% of global natural gas and 2% of global coal going to hydrogen production.
>
> As a consequence, production of hydrogen is responsible for CO_2 emissions of around 830 million tonnes of carbon dioxide per year, equivalent to the CO_2 emissions of the United Kingdom and Indonesia combined.

Why is everybody so excited about Hydrogen??


The Future of Hydrogen

Seizing today's opportunities

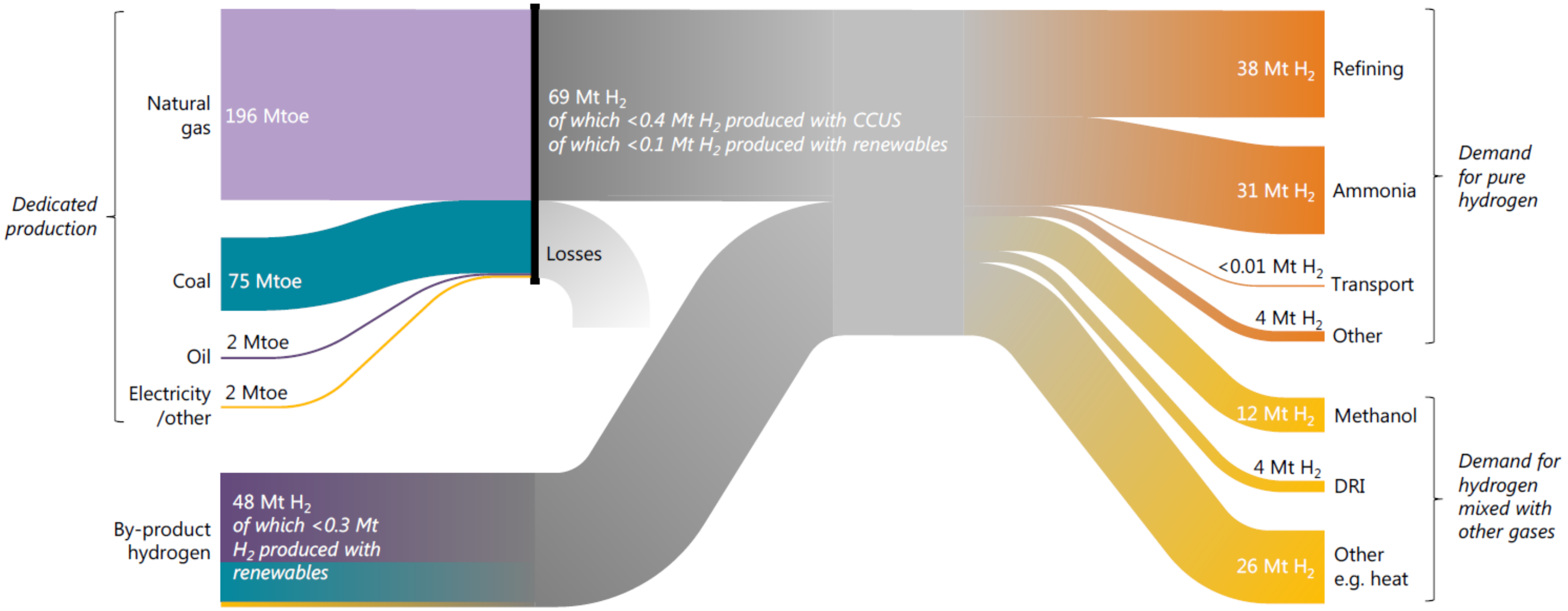
Report prepared by the IEA for the G20, Japan

June 2019

Website: https://www.iea.org/reports/the-future-of-hydrogen

Hydrogen and Energy: a primer *- IEA 'The Future of Hydrogen', 2019*

Figure 6. Today's hydrogen value chains



Notes: Other forms of pure hydrogen demand include the chemicals, metals, electronics and glass-making industries. Other forms of demand for hydrogen mixed with other gases (e.g. carbon monoxide) include the generation of heat from steel works arising gases and by-product gases from steam crackers. The shares of hydrogen production based on renewables are calculated using the share of renewable electricity in global electricity generation. The share of dedicated hydrogen produced with CCUS is estimated based on existing installations with permanent geological storage, assuming an 85% utilisation rate. Several estimates are made as to the shares of by-products and dedicated generation in various end uses, while input energy for by-product production is assumed equal to energy content of hydrogen produced without further allocation. All figures shown are estimates for 2018. The thickness of the lines in the Sankey diagram are sized according to energy contents of the flows depicted.

Source: IEA 2019. All rights reserved.

The Future of Hydrogen

Seizing today's opportunities

Why the interest in hydrogen for energy?

The issue…Very-Long-Term Energy Storage

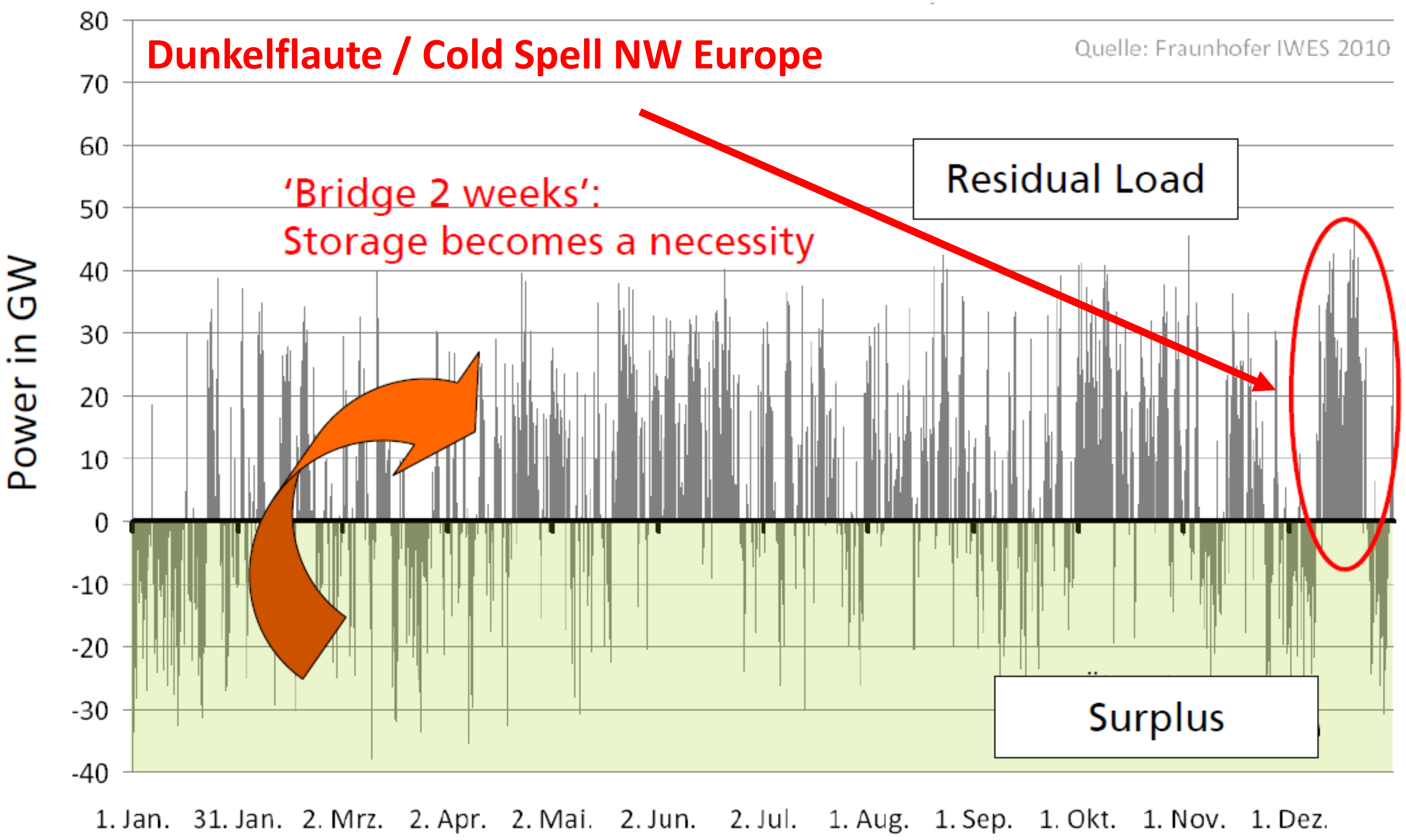
- Major issue: fluctuating electric power delivery from PV and wind generation
  - Need good ‘integration’ in electric grid / flexibility
  - Storage of electricity?

- Electricity storage (in large quantities) remains difficult issue and costly
  - Future short-term storage likely via electric batteries (Li-ion)?
  - Medium-term storage: Indirect storage via pump/turbine hydro (if geography allows).
  - But long-term / seasonal storage? Via hydrogen (electrolysis/fuel cells) or electric power to synthetic methane (P2G)

Long-Term Storage - Power to ‘Gas’ (H_2 & CH_4)

Energy scenario of the German govt. for 2050 (80% RES)

80% in annual electrical energy share



Why the Excitement for Hydrogen? – A long story (with twists & turns)

- ❑ Current H_2 usage basically as feedstock for industry
- ❑ But H_2 could be a clean fuel
  - for climate
    - ○ no CO_2 emitted by 'end use'
    - ○ no CO_2 if 'carefully' produced
  - no local emissions (transportation & combustion in boilers or prime movers)
- ❑ ~ 2000: To aid problem electricity storage – mainly for HEV (Hydrogen Electric Vehicles)

  → *electricity* → *electrolysis* → H_2 → *Fuel Cells* → *electricity*
- ❑ Now: To resolve 'overgeneration' due to VRE in elec pwr sector & LT (indirect) electric storage problem
- ❑ Now: Realization that 'all' electric society is not likely; still molecules needed
  - Ships, aircrafts, long-haul trucks… but need liquid fuels based on hydrogen (and CCSU)
  - Sector coupling to help decarbonize transportation & heating sectors (incl industry) – H_2 based liquid fuels

Why the Excitement for Hydrogen? – A long story (with twists & turns)

❑ But current recent insights…

❑ Overall objective is decarbonization

❑ Different countries/regions pur different constraints on the overall energy system

❑ Assume in many places close renewables penetration between 70%...100%

❑ Three-level objective:

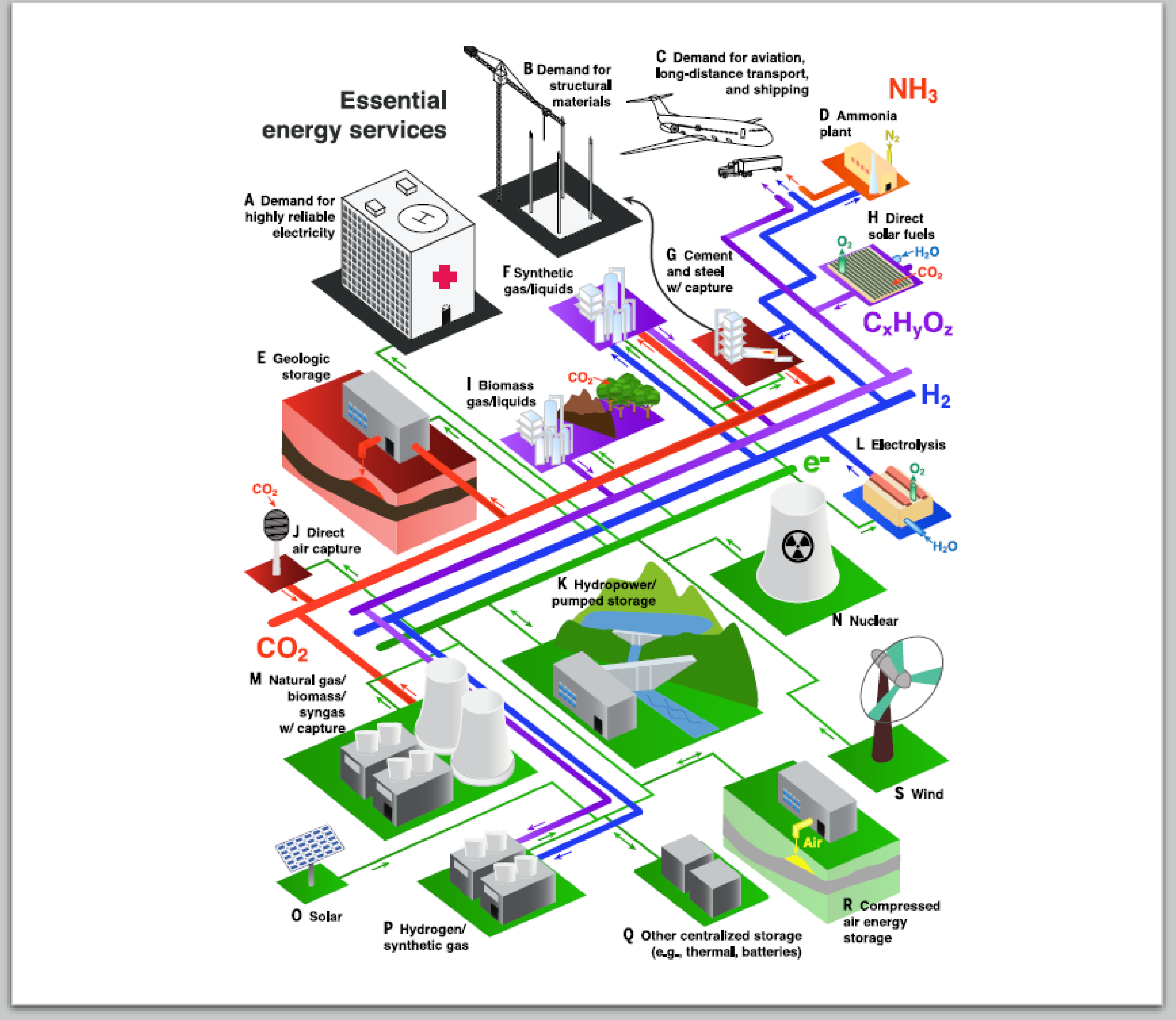
1. Energy efficiency
2. Electrification where possible
3. Molecules for hard to electrify applications → **H_2 or H_2-derived fuels (HDF)**

❑ BUT: the future of hydrogen will vary geograpgically (meteo), regulation, cost, and competition with other technologies (especially batteries)

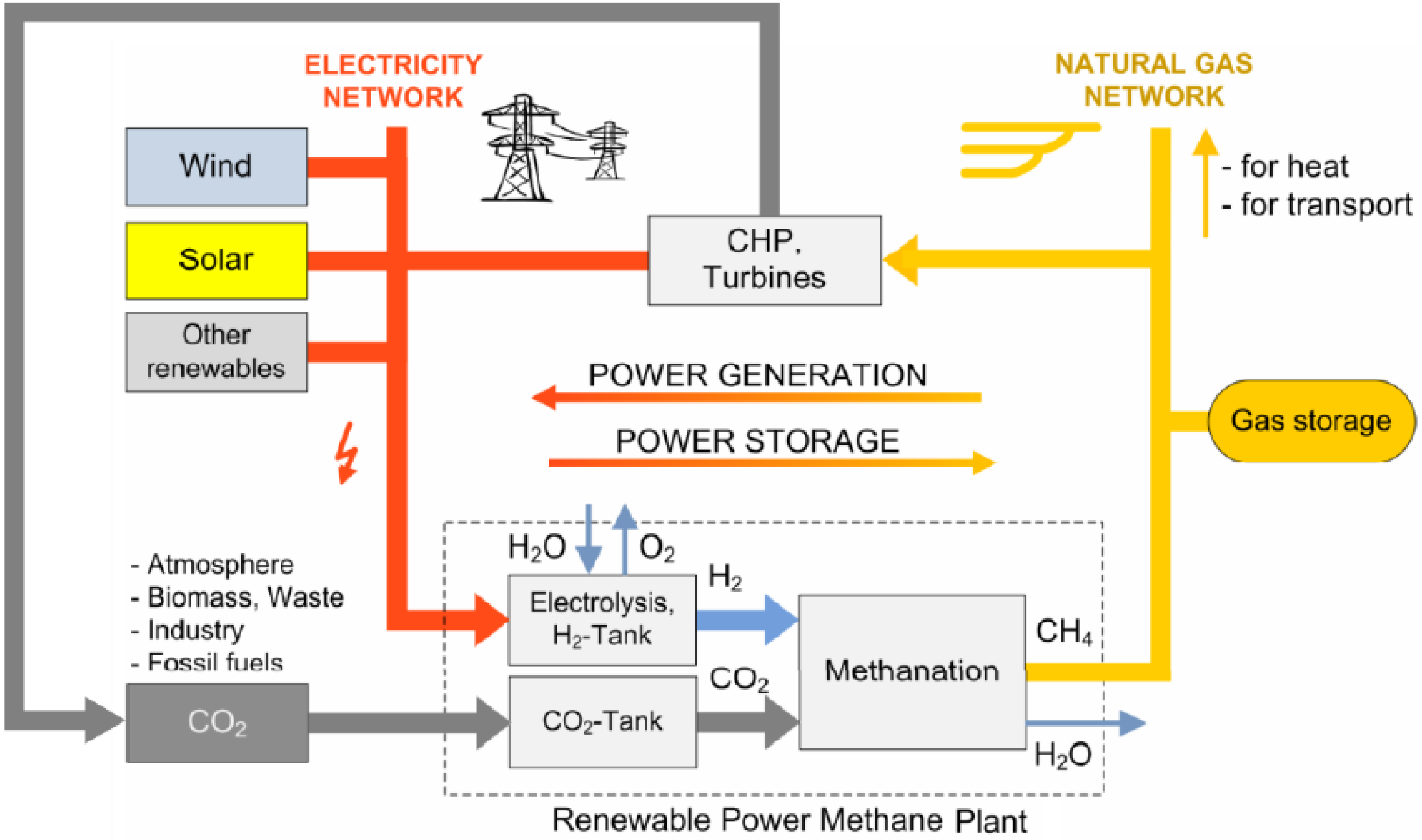
Future energy system with electrons & molecules

- Ref: Steven J. Davis, et al., “Net-zero emissions energy systems”, *Science* 29 Jun 2018: Vol. 360, Issue 6396, eaas9793 https://science.sciencemag.org/content/360/6396/eaas9793/tab-pdf

- Fig. 1. Schematic of an integrated system that can provide essential energy services without adding any CO2 to the atmosphere. (A to S) Colors indicate the dominant role of specific technologies and processes. Green, electricity generation and transmission; blue, hydrogen production and transport; purple, hydrocarbon production and transport; orange, ammonia production and transport; red, carbon management; and black, end uses of energy and materials.



Power to Gas (P2G) – elec to H_2 to CH_4 to elec



Ref: Adapted from M. Sterner, 2011, 2013

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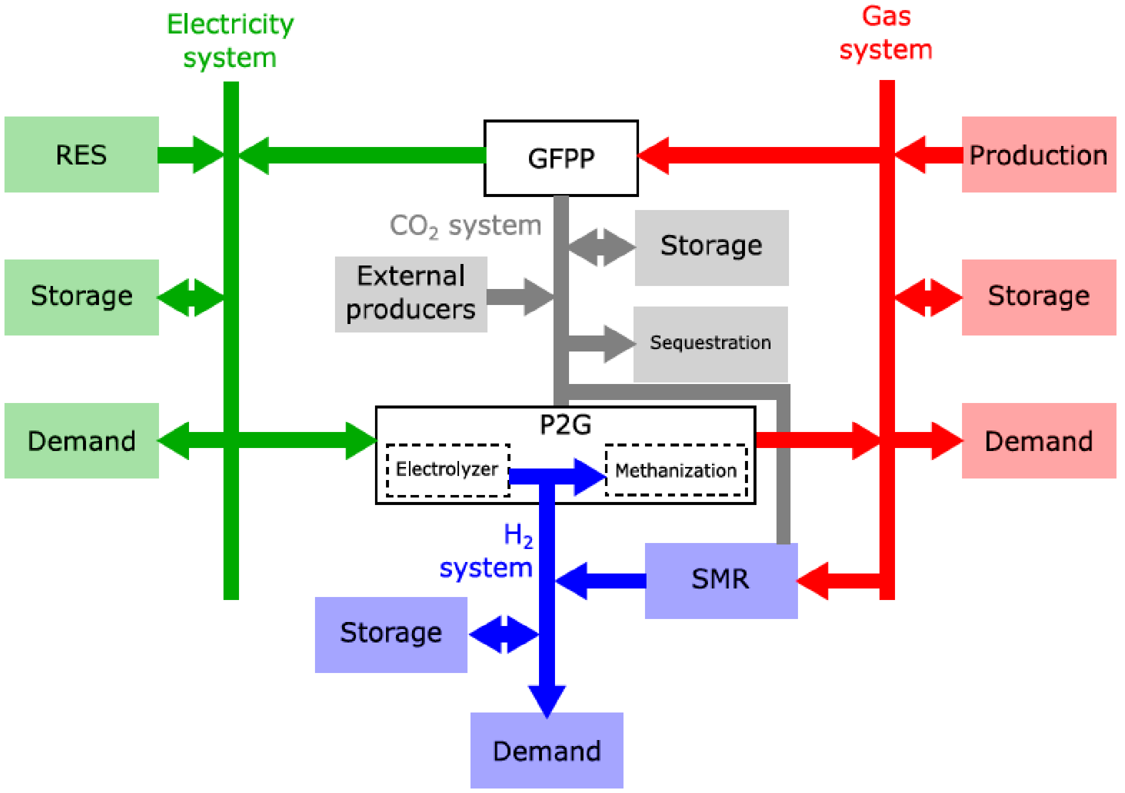


Figure 4.2: overview of the different energy systems accounted for in the investment model. RES = renewable energy source, GFPP = gas-fired power plant, SMR = steam methane reformer.

G could be CH_4
G could be H_2

If H_2, then GFPP is fuel cell or H_2 gas turbine

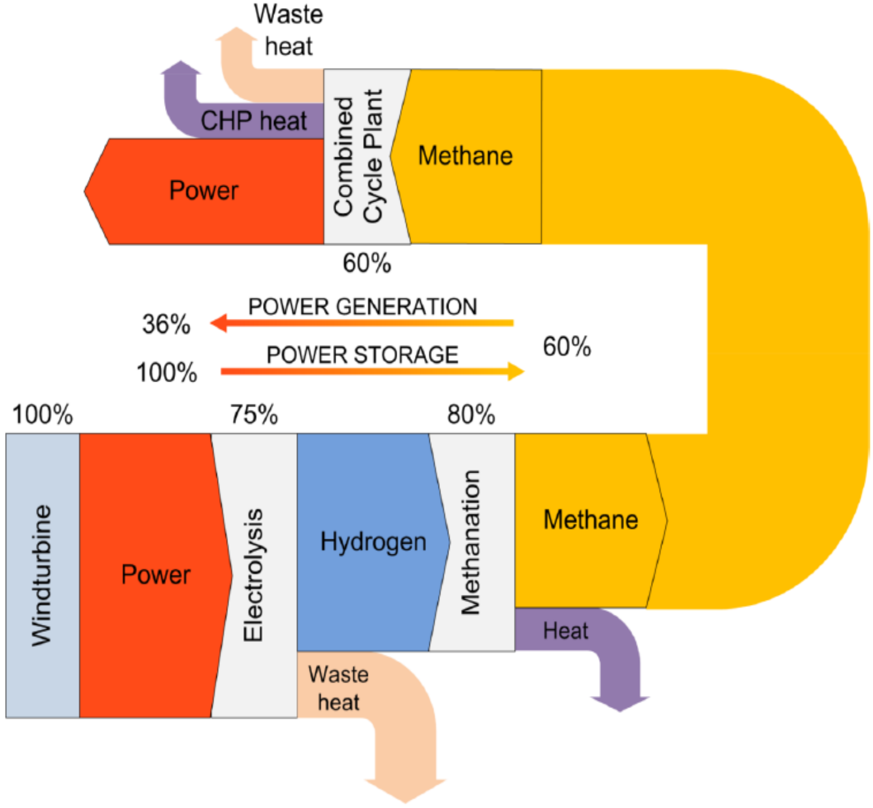
Advantage CH_4 is that current NG infrastructure can be used

Disadvantage CH_4 is lower efficiency

[Ref: Belderbos, PhD Thesis, 2019]

Power to Gas (P2G) – elec to H_2 to CH_4 to elec

Renewable power (to) methane / SNG
Efficiency



60-65% SNG

35-40% Power

50-60% CHP

Vs. 0% due to power cut off / power curtailment

Typical efficiencies:

Electrolysis ~70%-75%

Methanation ~ 78%

But combined electrolysis (SOEC) & Sabatier … expected to reach ~ 80%

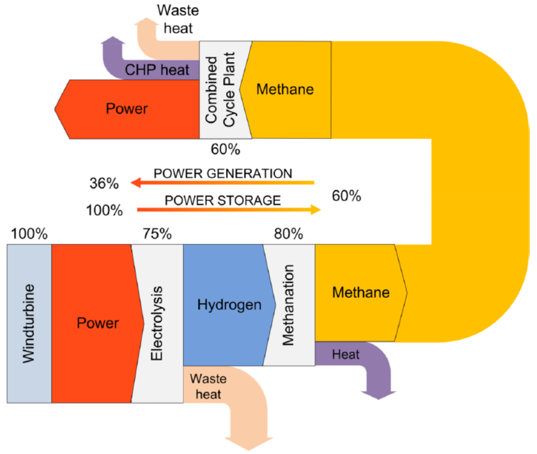
Ref: Michael Sterner

http://www.uni-kassel.de/upress/online/frei/978-3-89958-798-2.volltext.frei.pdf

Power to Gas (P2G) – elec to H_2 to CH_4 to elec

Pfad	Wirkungsgrad	
Strom-zu-Gas	2/3	
Strom → Wasserstoff	54 – 72%	
Strom → Methan (SNG)	49 – 64%	
Strom → Wasserstoff	57 – 73%	
Strom → Methan (SNG)	50 – 64%	
Strom → Wasserstoff	64 – 77%	
Strom → Methan (SNG)	51 – 65%	
Strom-zu-Gas-zu-Strom	1/3	
Strom → Wasserstoff → Strom	34 – 44%	bei Verstromung mit 60% und Kompression auf 80 bar
Strom → Methan → Strom	30 – 38%	
Strom-zu-Gas-zu-KWK (Wärme und Strom)	1/2	
Strom → Wasserstoff → KWK	48 – 62%	bei 40% Strom & 45% Wärme und Kompression auf 80 bar
Strom → Methan → KWK	43 – 54%	

Renewable power (to) methane / SNG
Efficiency



60-65% SNG
35-40% Power
50-60% CHP
Vs. 0% due to power cut off / power curtailment

vs. Norwegische Pumpspeicher mit 65-68% (75% vor Ort + 7-10% Verlust durch Stromtransport)

vs. 0% durch Abregelung oder vs. effizientere aber kapazitätslimitierte Speicheralternativen

Ref: M. Sterner, 2011, 2013

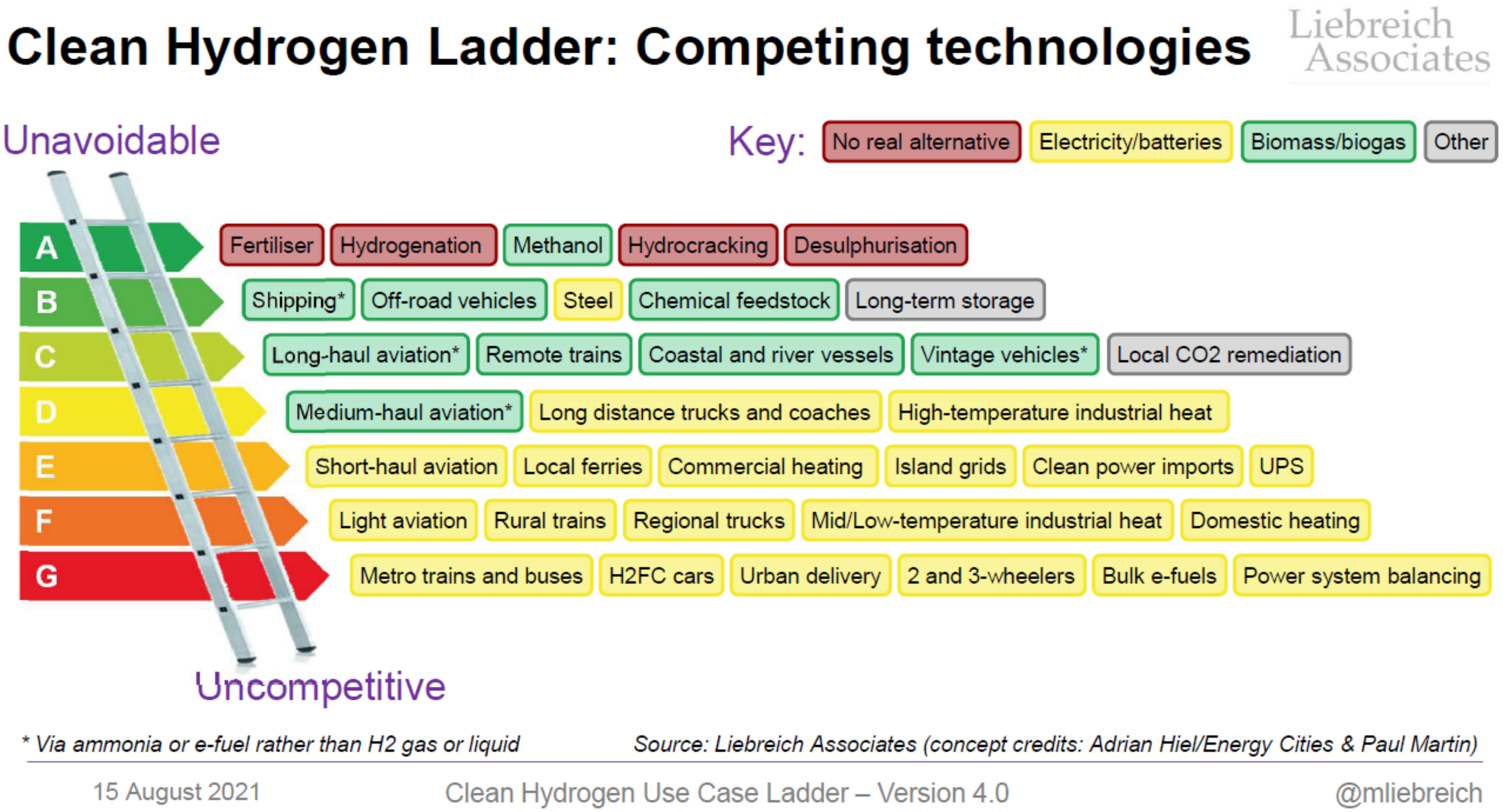
Where will H_2 or HDF be used?

- Transportation:
  - Light-duty: most likely Batteries: BEV
  - Only H_2 or HDF for shipping, long-haul aviation and long-distance trucks
- Industry

- Electric power generation???

Liebreich's Hydrogen Ladder

Recall



Clean Hydrogen Ladder: Competing technologies

Liebreich Associates

Unavoidable

Key: 🟥 No real alternative 🟨 Electricity/batteries 🟩 Biomass/biogas ⬜ Other

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* Via ammonia or e-fuel rather than H2 gas or liquid

Source: Liebreich Associates (concept credits: Adrian Hiel/Energy Cities & Paul Martin)

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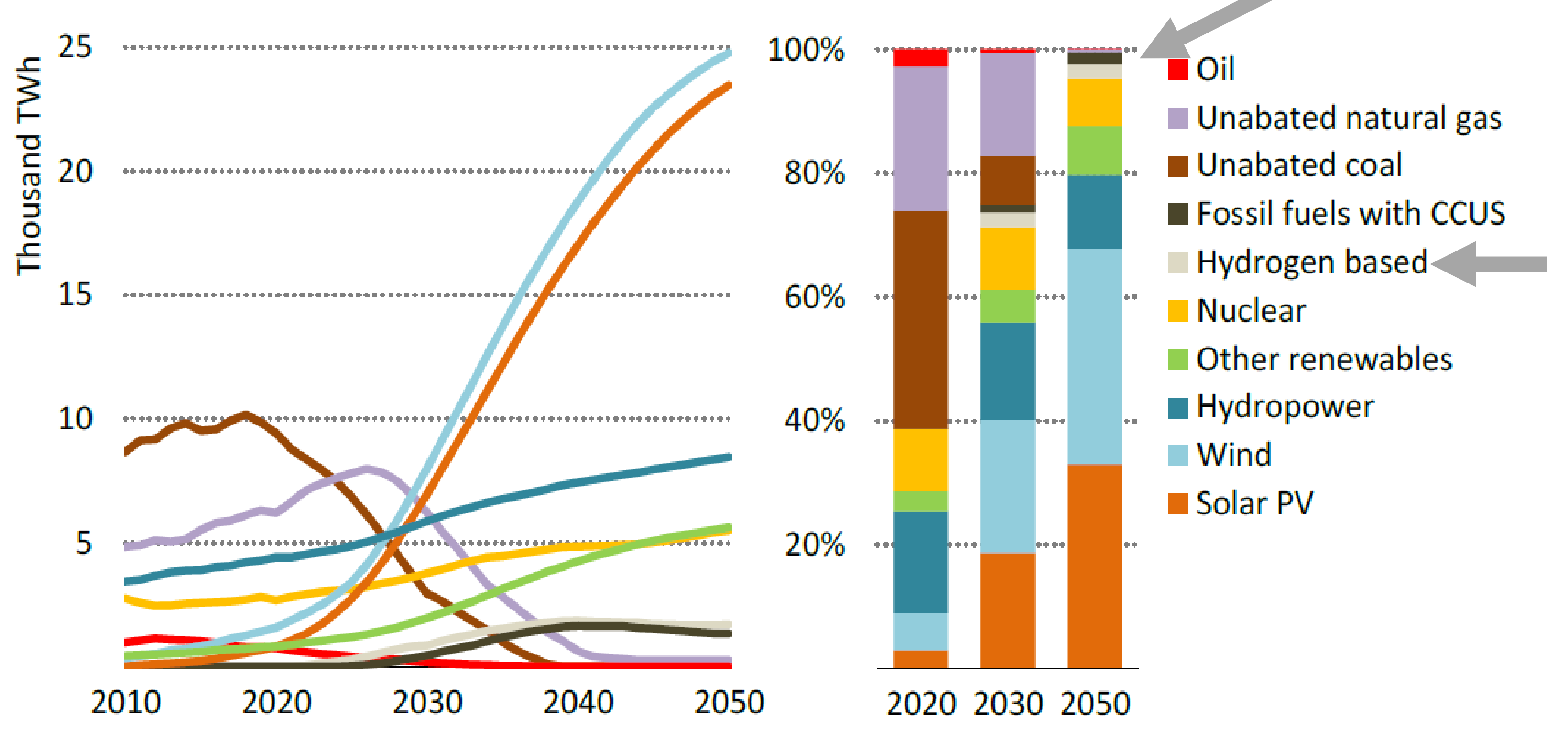
H_2 for power generation?

Figure 3.10 ▹ Global electricity generation by source in the NZE

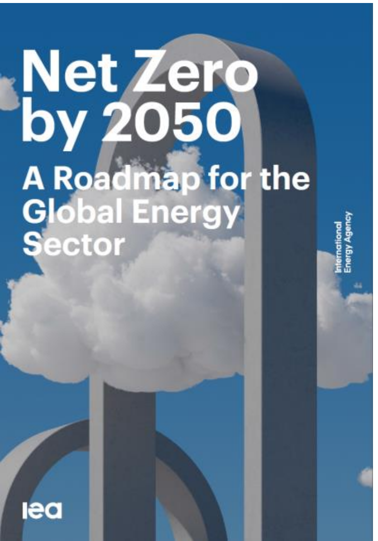


IEA. All rights reserved.

Solar and wind power race ahead, raising the share of renewables in total generation from 29% in 2020 to nearly 90% in 2050, complemented by nuclear, hydrogen and CCUS

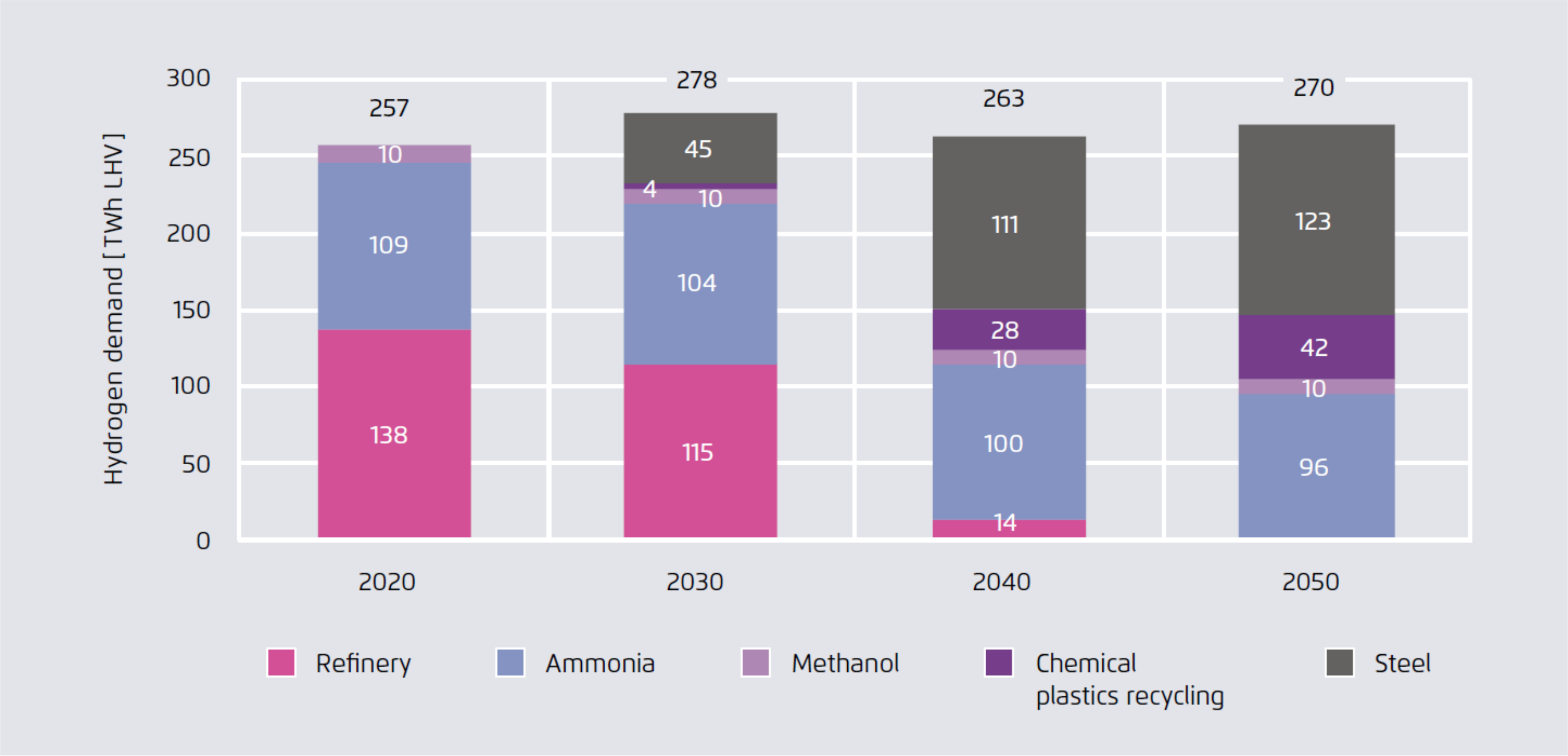
H_2 fuel for elec pwr gen very limited.

Perhaps need high installed capacity for H_2 GFPP, but limited usage.



H_2 for industry – starting point for H_2 development

Industrial hydrogen demand from 2020 to 2050 within the specific demand sectors in TWh per year Figure 1



AFRY (2021).

Projected hydrogen demand in industry in the EU-28 from 2020 through 2050.

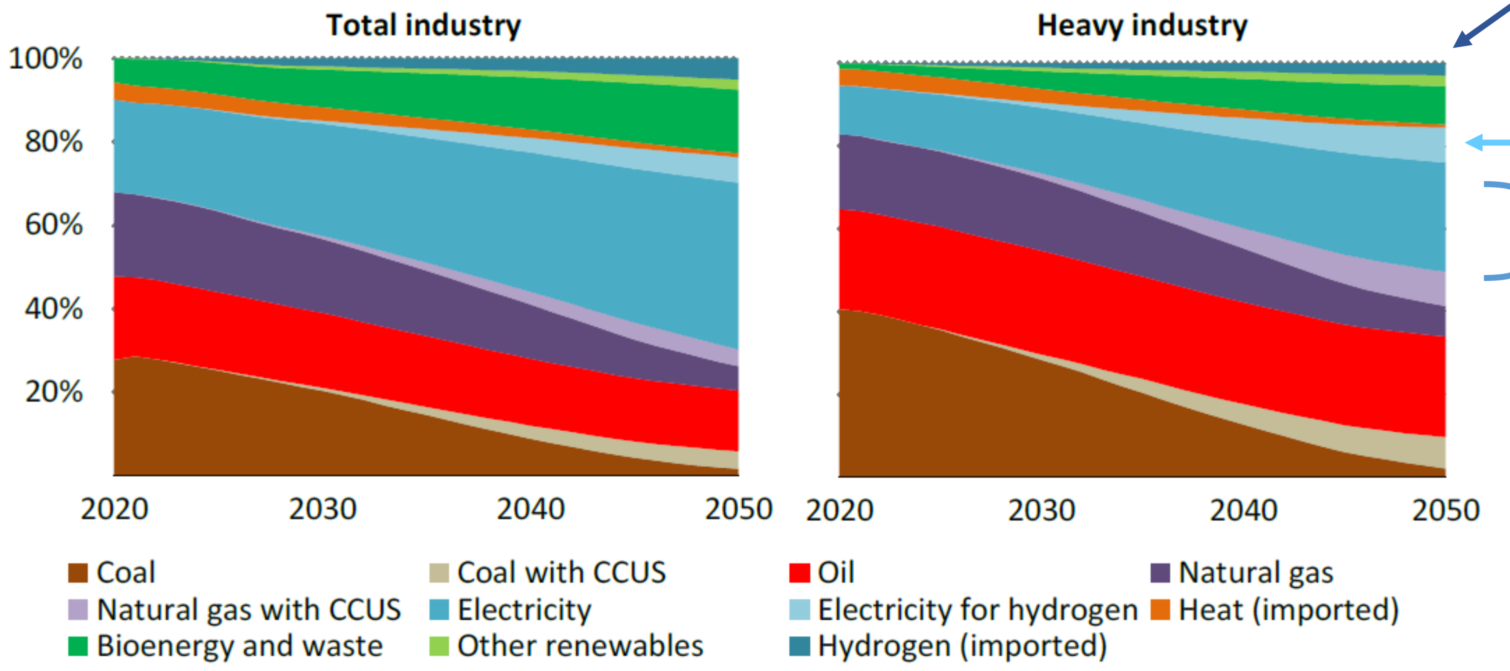
Industry will sign for the demand side of hydrogen and be the trigger for H_2 economy and infrastructure

Oil refinery ↘

Steel ↗

H_2 for industry – starting point for H_2 development

Figure 3.18 ▹ Global final industrial energy demand by fuel in the NZE



Hydrogen (imported)

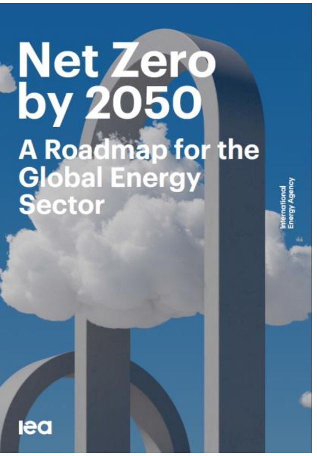
Electricity for H_2

electrification

IEA. All rights reserved.

Fossil fuel use in industry is halved by 2050, replaced primarily by electricity and bioenergy

Notes: Industrial energy consumption includes chemical feedstock and energy consumed in blast furnaces and coke ovens. Hydrogen refers to imported hydrogen and excludes captive hydrogen generation. Electricity for hydrogen refers to electricity used in the production of captive hydrogen via electrolysis.



Projected industrial final energy demand by fuel through 2050 in the NZE scenario. 'Captive hydrogen' refers to hydrogen consumed on the same site where produced. NZE = Net zero emissions (by 2050)

Electricity demand – worldwide evolution

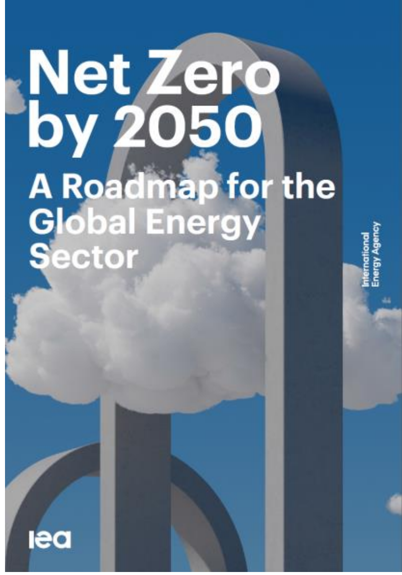
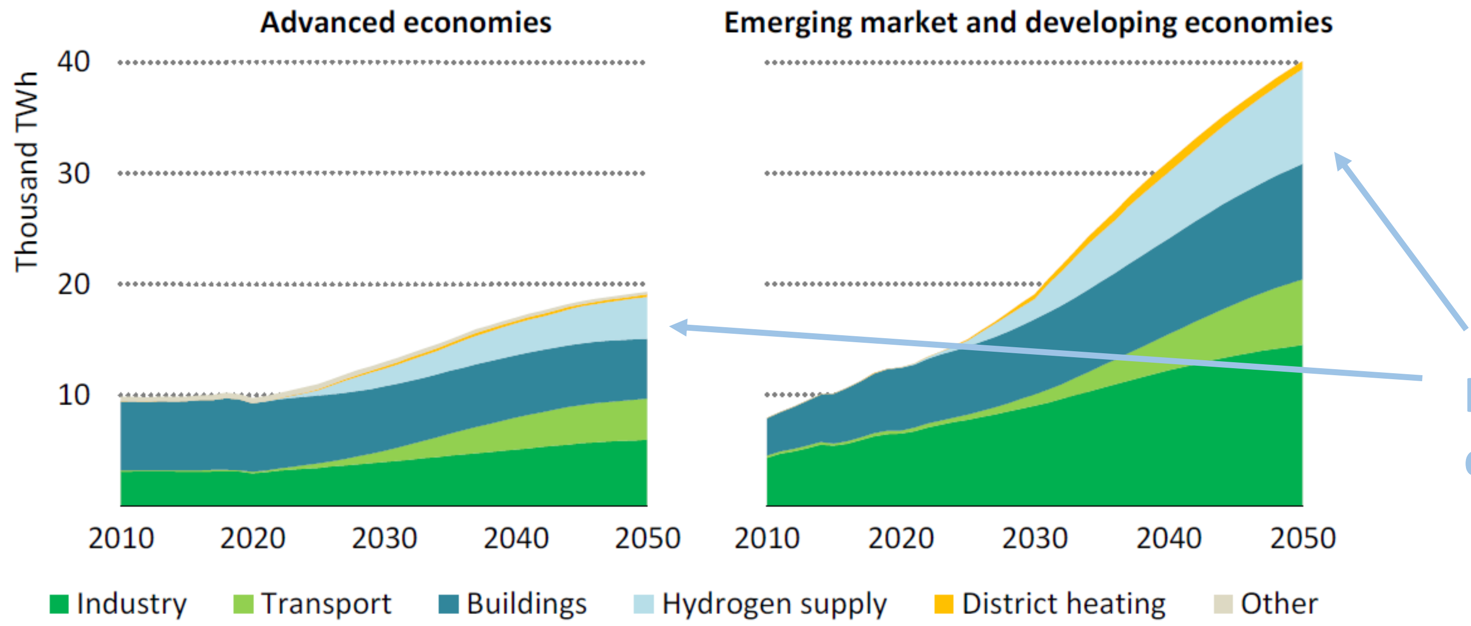


Figure 3.9 ▷ Electricity demand by sector and regional grouping in the NZE



IEA. All rights reserved.

Electrification of end-uses and hydrogen production raise electricity demand worldwide, with a further boost to expand services in emerging market and developing economies

H_2 production via electrolyzers

Projected overall electricity demand and hydrogen production via electrolyzers worldwide through 2050.

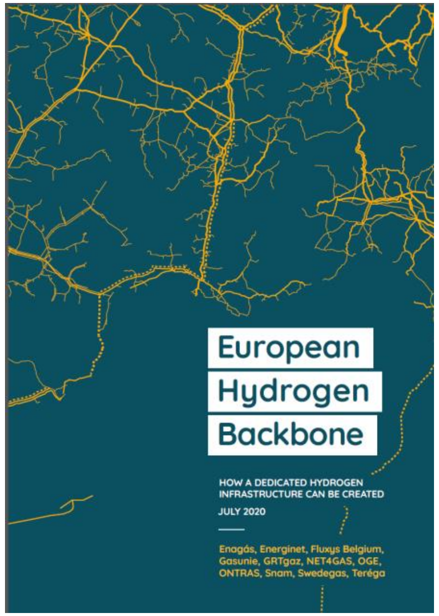
[Ref: IEA, 2021, Net zero by 2050]

Development H_2 economy – worldwide evolution

- Industrial H_2 demand likely best starting point for developing H_2 economy
  - Gradual decarbonization of industrial H_2 demand
- Parallel expansion of H_2 infrastructure
  - Pipelines (new or repurposed)
  - H_2 storages (long term)
  - Refrigeration & regasification facilities, ships, …
- Will be different for different regions (meteorological & spatial conditions)
- Unwise regulation may delay or kill the hydrogen or HDF future
- Start from blue hydrogen, gradually develop green hydrogen and let competition work. (Stiff CO_2-emission penalties – price– desirable)

Development H_2 infrastructure – contrasting ideas

European Example (EU-28)

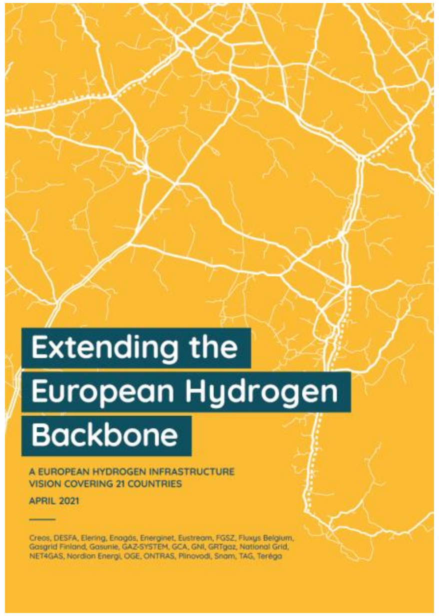


European
Hydrogen
Backbone

HOW A DEDICATED HYDROGEN
INFRASTRUCTURE CAN BE CREATED

JULY 2020

Enagás, Energinet, Fluxys Belgium,
Gasunie, GRTgaz, NET4GAS, OGE,
ONTRAS, Snam, Swedegas, Teréga

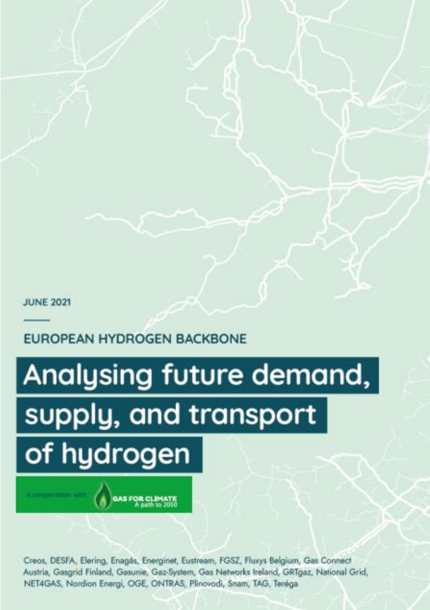


Extending the
European Hydrogen
Backbone

A EUROPEAN HYDROGEN INFRASTRUCTURE
VISION COVERING 21 COUNTRIES

APRIL 2021

Creos, DESFA, Elering, Enagás, Energinet, Eustream, FGSZ, Fluxys Belgium,
Gasgrid Finland, Gasunie, GAZ-SYSTEM, GCA, GNI, GRTgaz, National Grid,
NET4GAS, Nordion Energi, OGE, ONTRAS, Plinovodi, Snam, TAG, Teréga



JUNE 2021

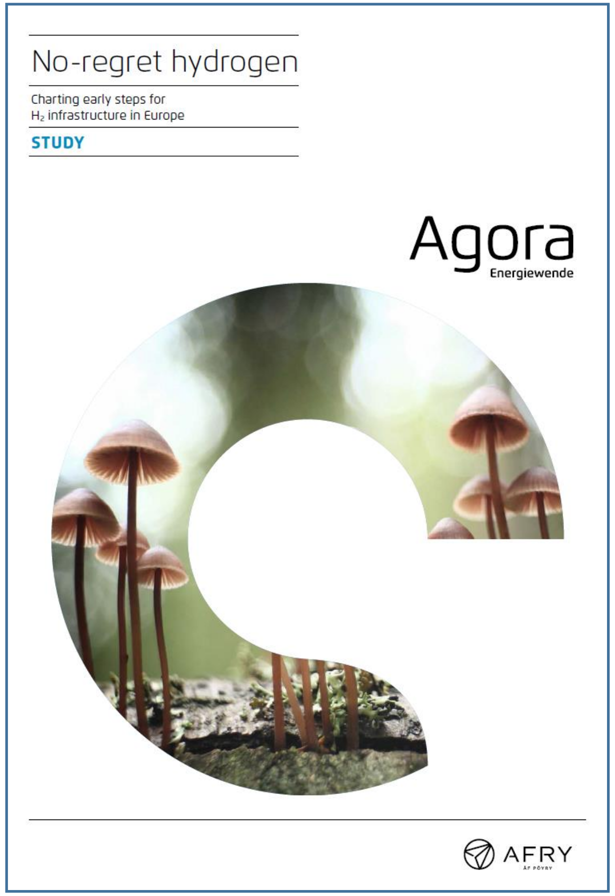
EUROPEAN HYDROGEN BACKBONE

Analysing future demand,
supply, and transport
of hydrogen

A cooperation with GAS FOR CLIMATE A path to 2050

Creos, DESFA, Elering, Enagás, Energinet, Eustream, FGSZ, Fluxys Belgium, Gas Connect
Austria, Gasgrid Finland, Gasunie, Gaz-System, Gas Networks Ireland, GRTgaz, National Grid,
NET4GAS, Nordion Energi, OGE, ONTRAS, Plinovodi, Snam, TAG, Teréga

Group of 11 & 23 European Gas Transmission Operators



No-regret hydrogen

Charting early steps for
H_2 infrastructure in Europe

STUDY

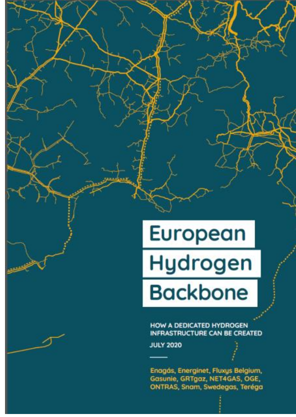
Agora Energiewende

AFRY

German RES-supporting Think Tank

Important note:
Studies date from before February 24, 2022 – Geopolitics NOT accounted for.

Development H_2 infrastructure – 11 EUR Gas TSOs


European Hydrogen Backbone

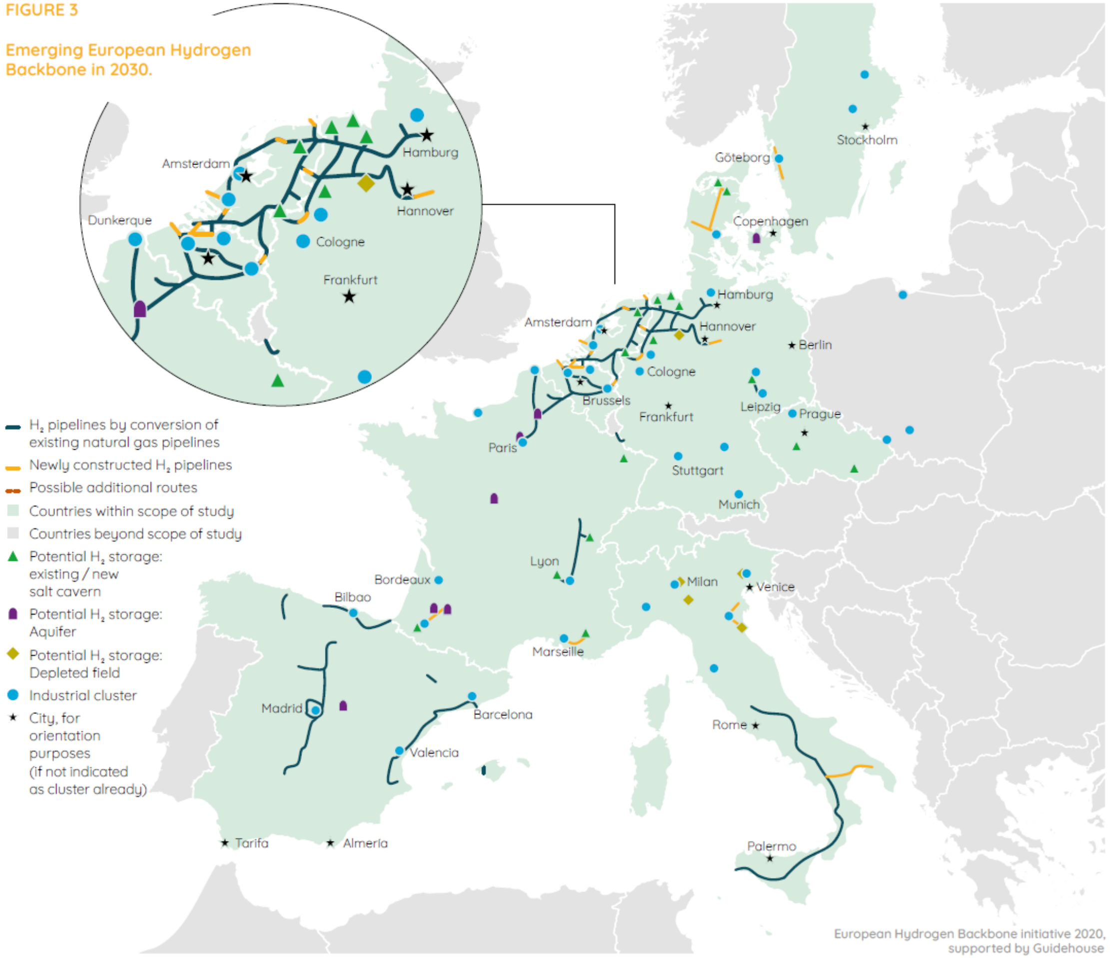
HOW A DEDICATED HYDROGEN INFRASTRUCTURE CAN BE CREATED

JULY 2020

Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas, Teréga

FIGURE 3

Emerging European Hydrogen Backbone in 2030.



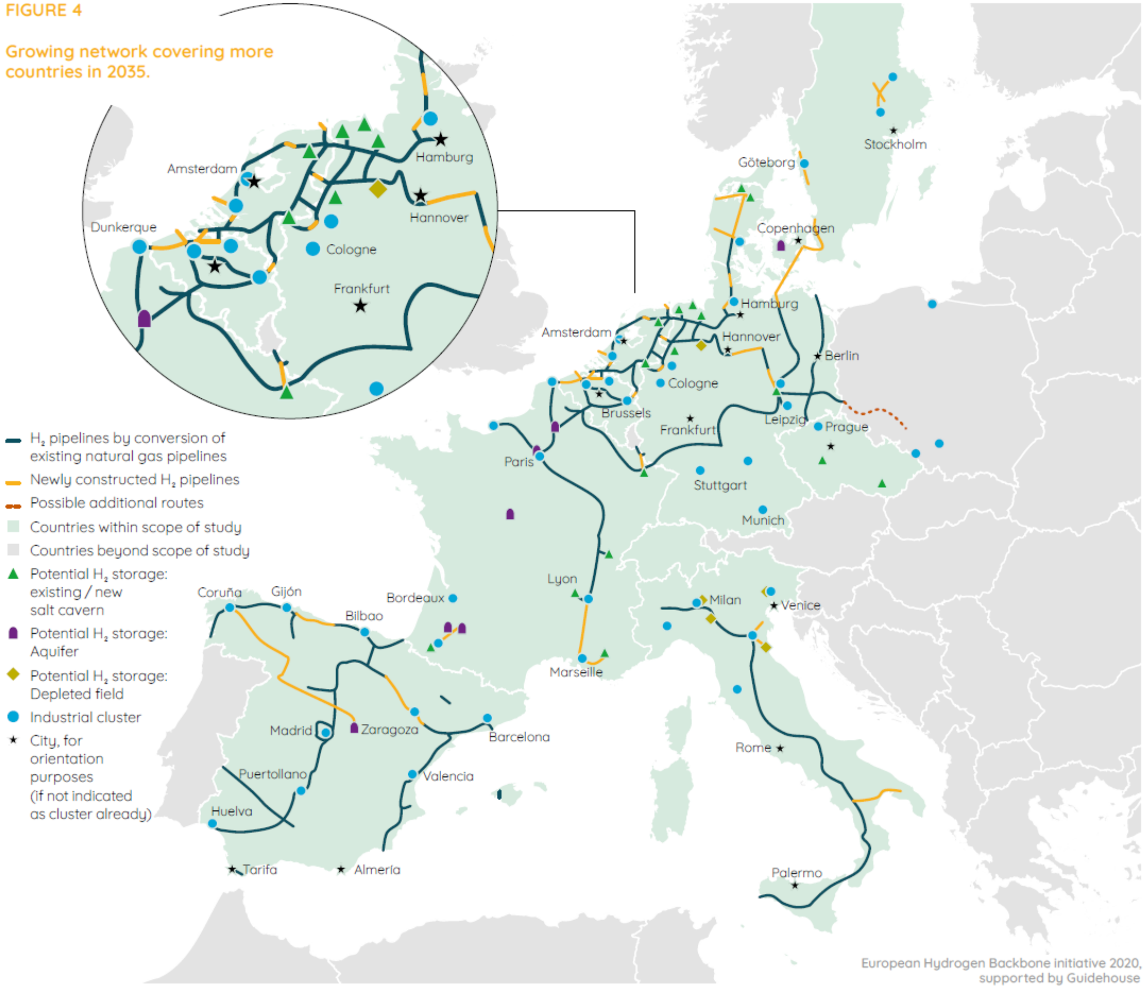
European Hydrogen Backbone initiative 2020, supported by Guidehouse

2030

2035

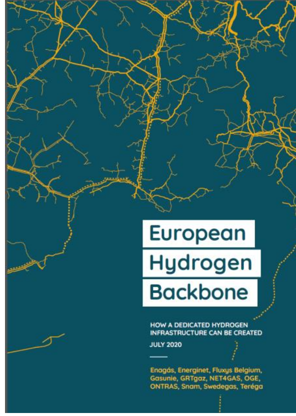
FIGURE 4

Growing network covering more countries in 2035.



European Hydrogen Backbone initiative 2020, supported by Guidehouse

Development H_2 infrastructure – 11 EUR Gas TSOs



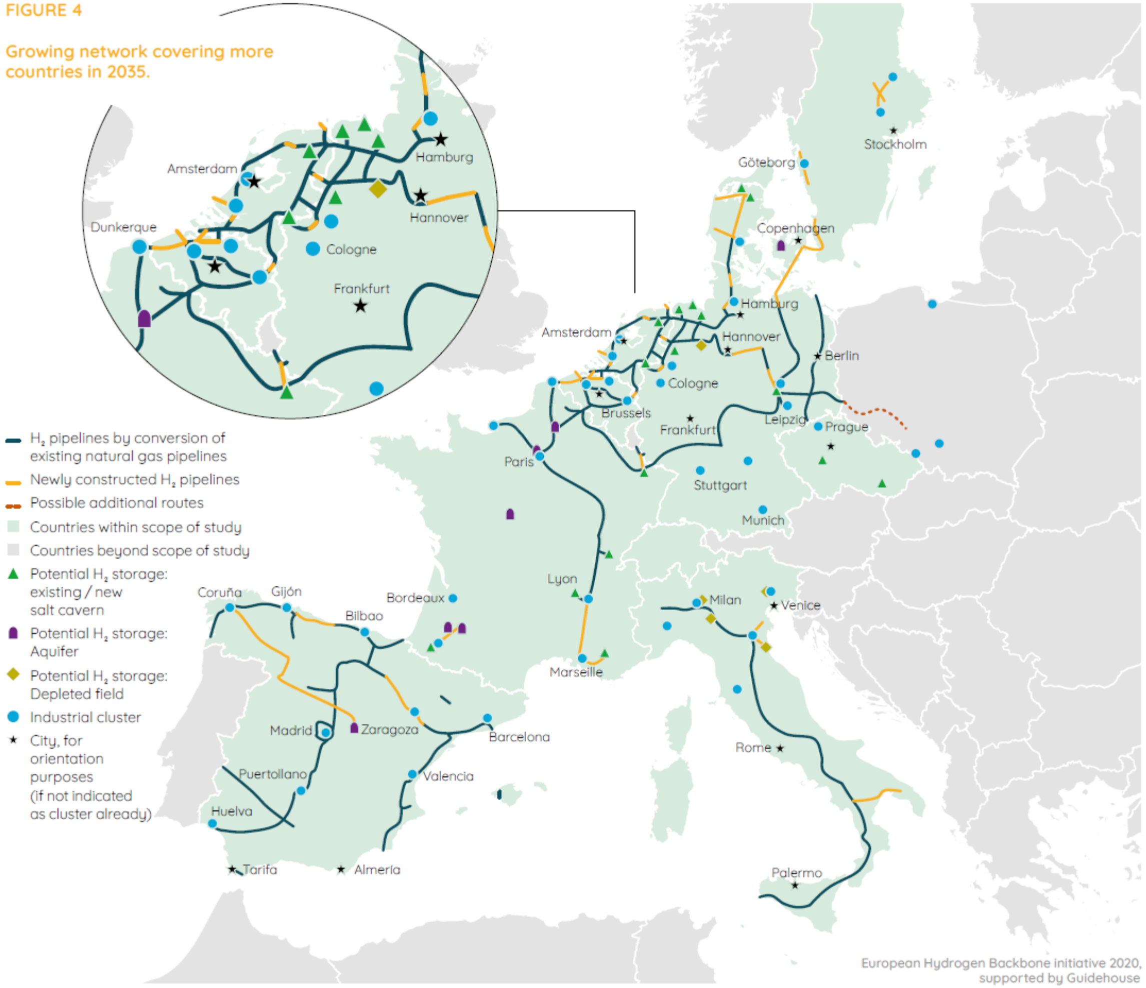
European
Hydrogen
Backbone

HOW A DEDICATED HYDROGEN INFRASTRUCTURE CAN BE CREATED
JULY 2020

Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas, Teréga

FIGURE 4

Growing network covering more countries in 2035.



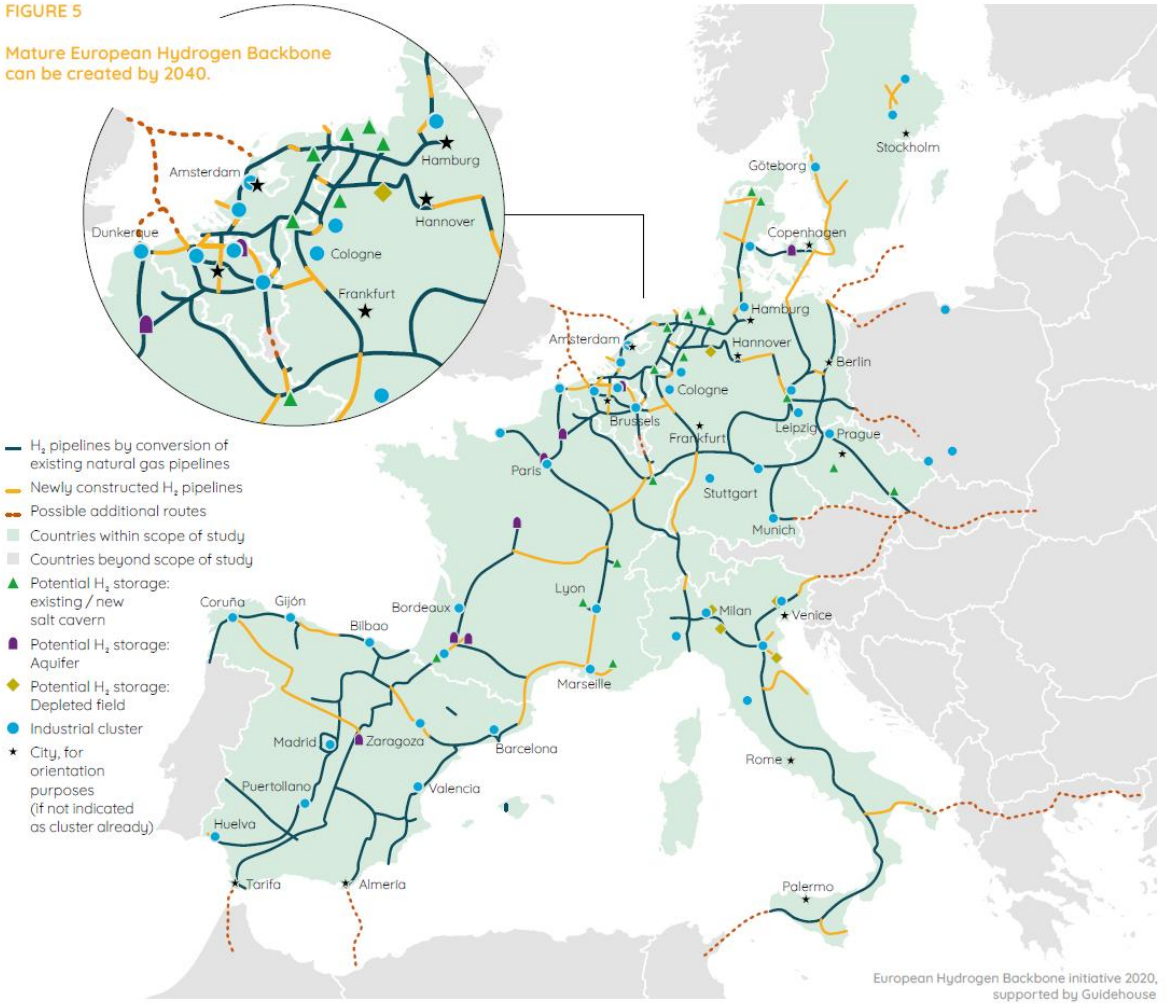
European Hydrogen Backbone initiative 2020, supported by Guidehouse

2035

2040

FIGURE 5

Mature European Hydrogen Backbone can be created by 2040.



European Hydrogen Backbone initiative 2020, supported by Guidehouse

Development H_2 infrastructure – 23 EUR Gas TSOs

Emerging European Hydrogen Backbone in

2030

European Hydrogen Backbone initiative 2021, supported by Guidehouse

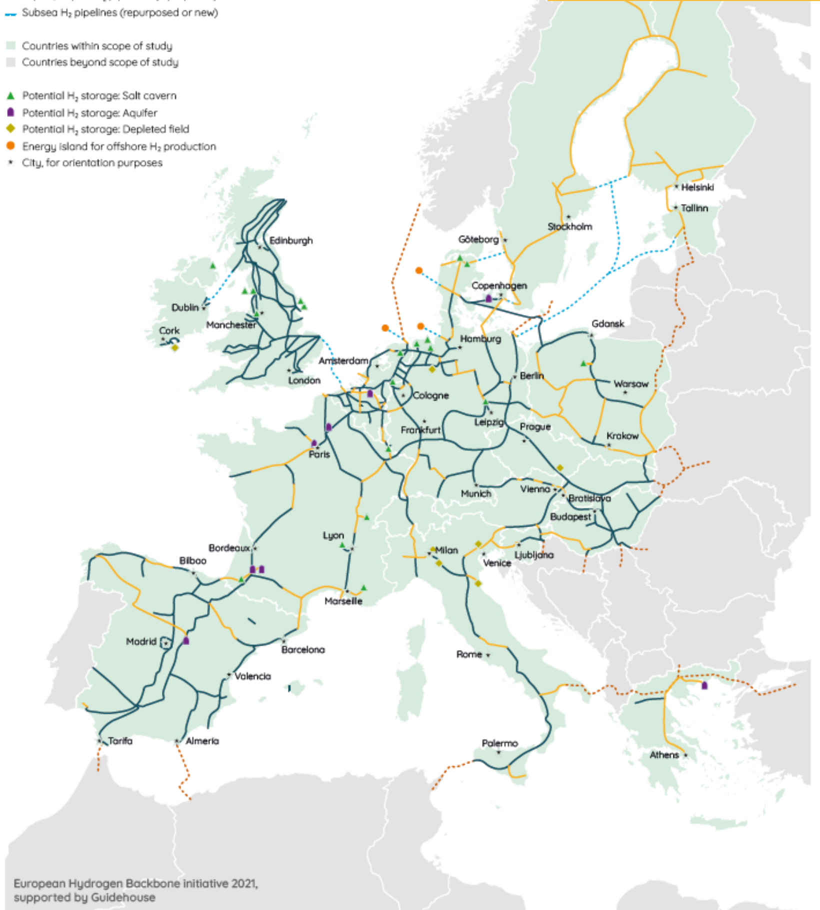
Growing network covering more countries in

2035

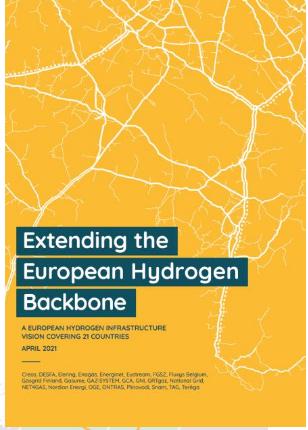
European Hydrogen Backbone initiative 2021, supported by Guidehouse

Mature European Hydrogen Backbone can be created by

2040



European Hydrogen Backbone initiative 2021, supported by Guidehouse



Extending the European Hydrogen Backbone

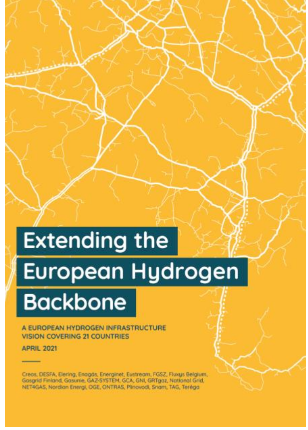
A EUROPEAN HYDROGEN INFRASTRUCTURE VISION COVERING 21 COUNTRIES

APRIL 2021

Creos, DESFA, Elering, Enagás, Energinet, Eustream, FGSZ, Fluxys Belgium, Gasgrid Finland, Gasunie, GAZ-SYSTEM, GCA, GNI, GRTgaz, National Grid, NET4GAS, Nordion Energi, OGE, ONTRAS, Plinovodi, Snam, TAG, Teréga

Proposed future Hydrogen backbone by 2030, 2035, 2040 – updated version. [Ref: Guidehouse, 2020a & 2021a,b]

Development H_2 infrastructure – 23 EUR Gas TSOs



Extending the European Hydrogen Backbone

A EUROPEAN HYDROGEN INFRASTRUCTURE VISION COVERING 21 COUNTRIES

APRIL 2021

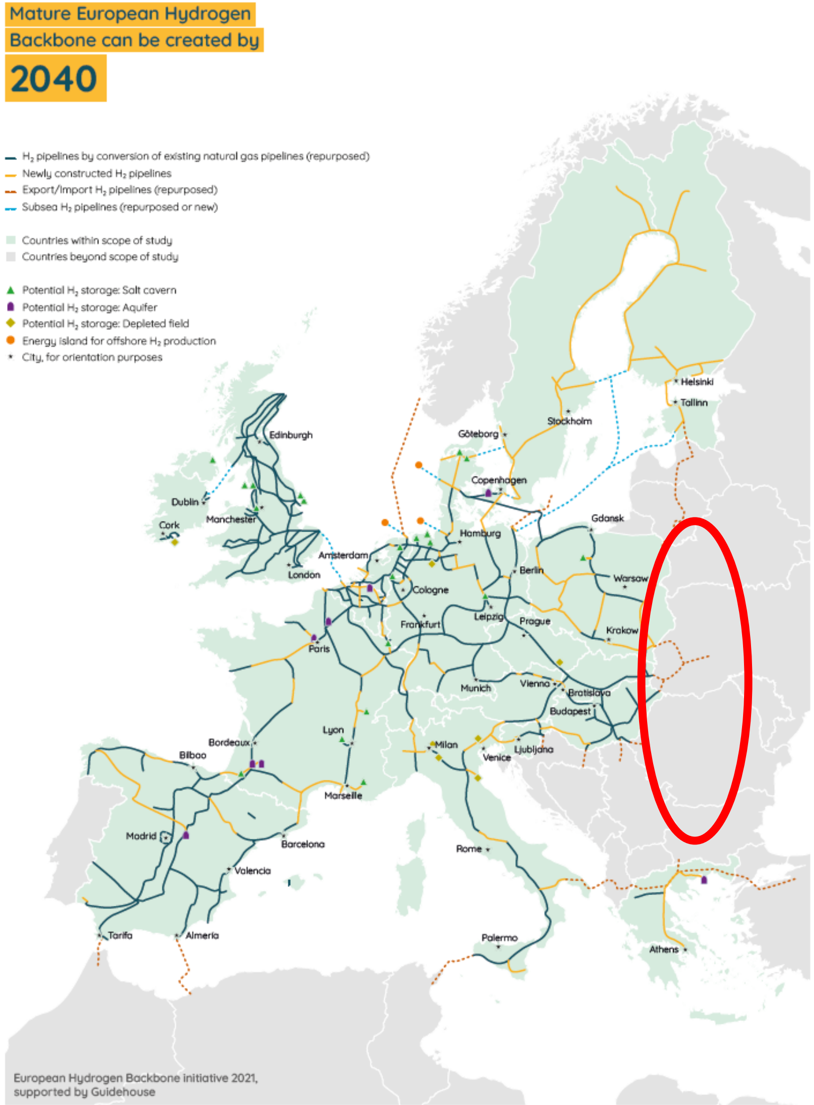
Creos, DESFA, Elering, Enagás, Energinet, Eustream, FGSZ, Fluxys Belgium, Gasgrid Finland, Gasunie, GAZ-SYSTEM, GCA, GNI, GRTgaz, National Grid, NET4GAS, Nordion Energi, OGE, ONTRAS, Plinovodi, Snam, TAG, Teréga

Total length ~40,000 km

Cost ~ €40 bn - €80 bn
or ~ €0.1-0.2 / kg H_2

Compared to desired future H_2 production cost of ~ €1-2 / kg H_2

Recall:
1 \$/kg ≃ 25 \$/MWh$_{\text{prim, HHV}}$
1 \$/kg ≃ 30 \$/MWh$_{\text{prim, LHV}}$



Mature European Hydrogen Backbone can be created by 2040

European Hydrogen Backbone initiative 2021, supported by Guidehouse

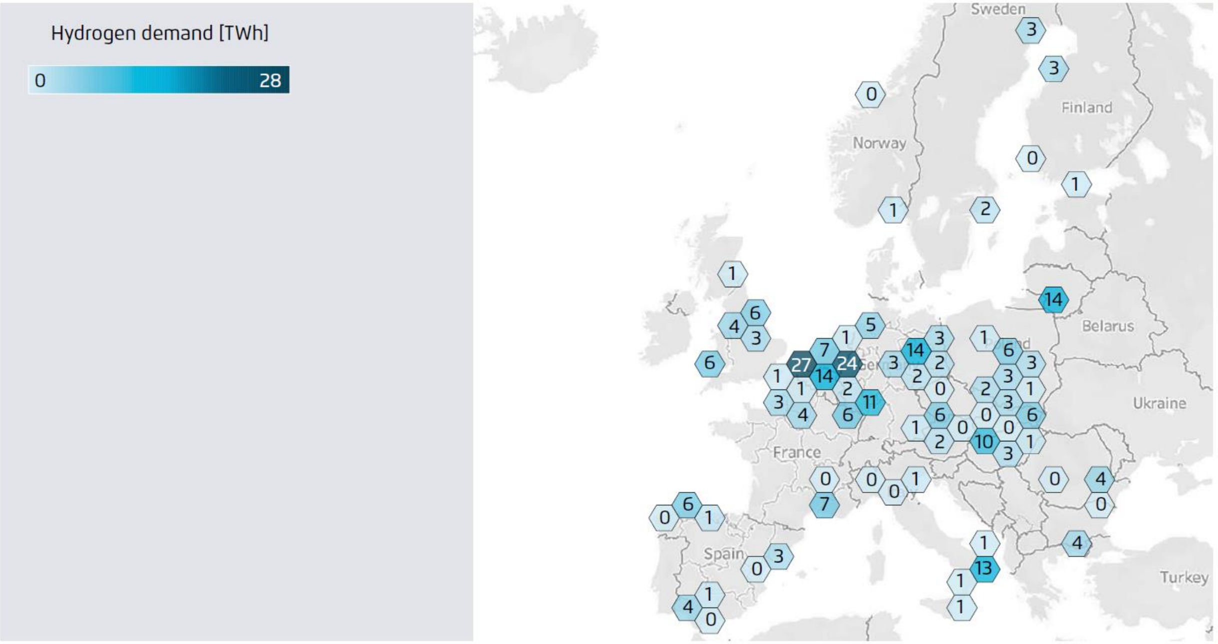
But… post Feb 24 2022…

Inflow & trade from the far-east side of Europe becomes questionable…

Proposed future Hydrogen backbone by 2030, 2035, 2040 – updated version. [Ref: Guidehouse, 2020a & 2021a,b]

No-regret development H_2 infrastructure

Distribution of industrial hydrogen demand projected for 2050 in TWh per year Figure 2



AFRY (2021). Demand in 2050 is mainly driven by ammonia and steel production.

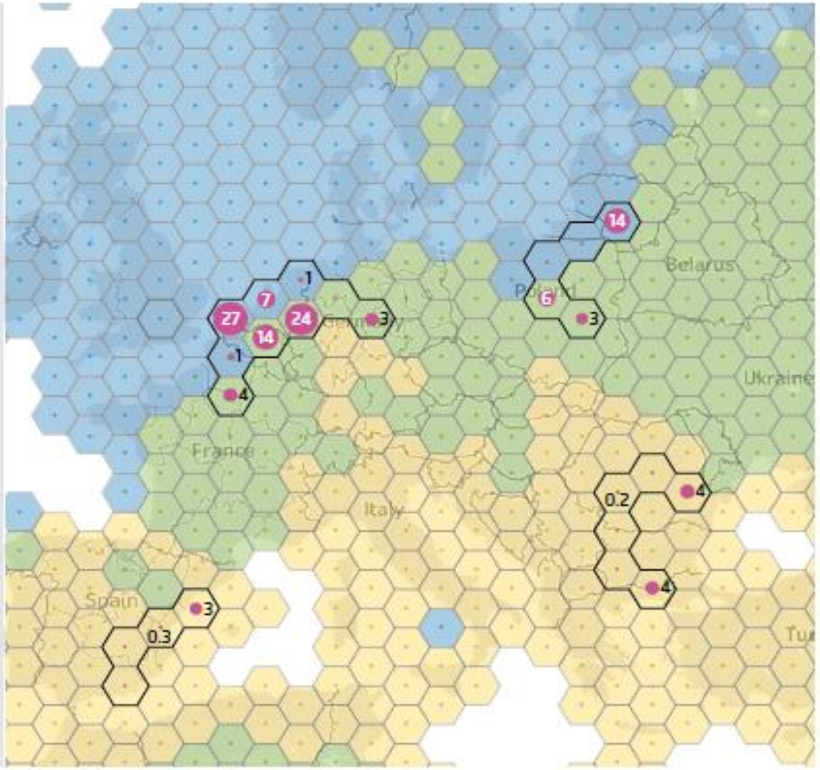
Follow EU priority:

1) Efficiency
2) Electrification
3) Molecules where needed

No-regret pipeline corridors with industrial hydrogen demand in TWh per year in 2050 Figure 7

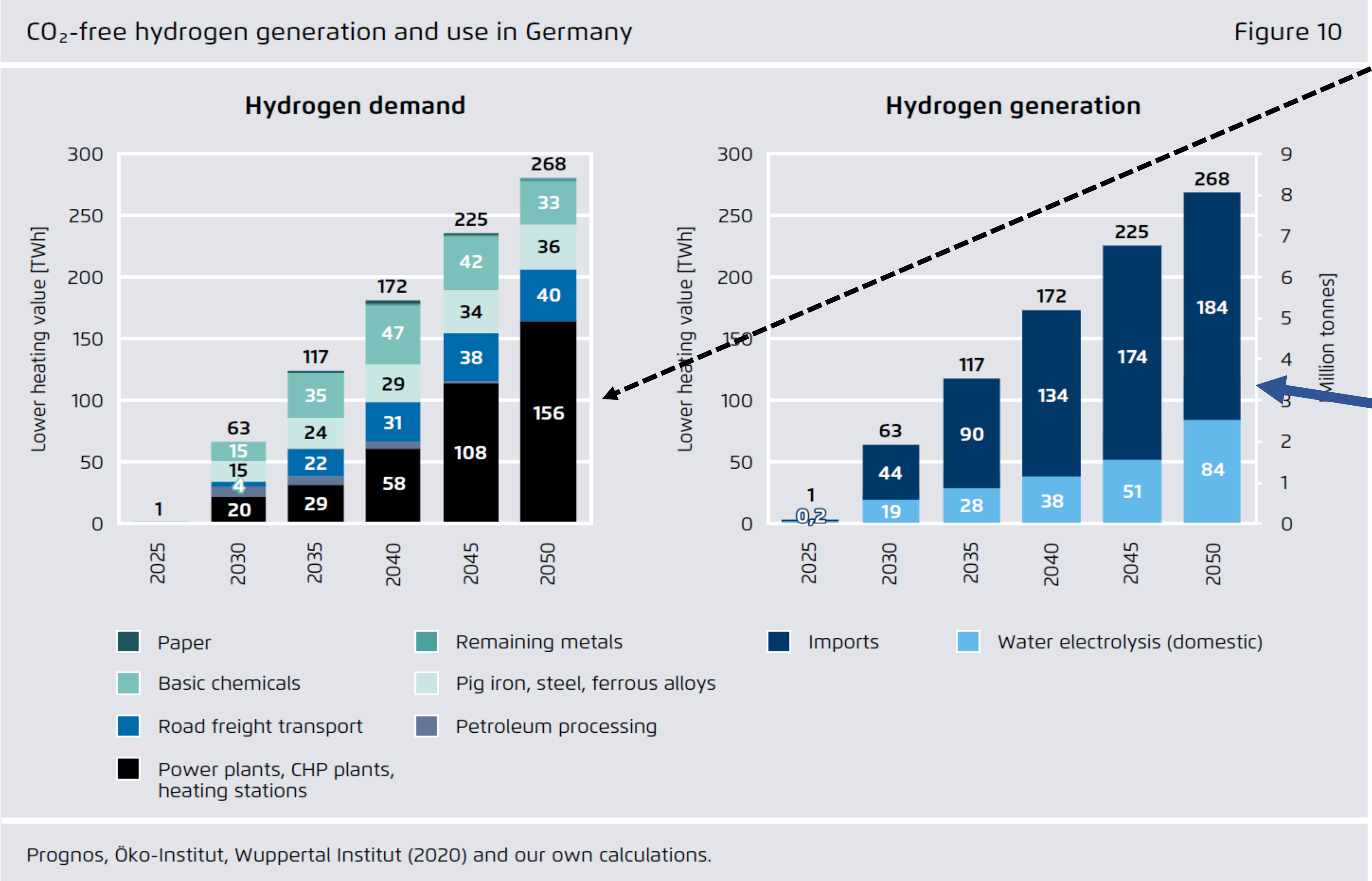
Best LCOH 2050

- 🟩 Hybrid
- 🟨 Solar
- 🟦 Wind
- 🟥 Industrial hydrogen demand 2050 in TWh per year



Note: Only those hydrogen pipelines that are resilient to the future levels of hydrogen demand and the technology assumptions used here have been considered to be "no-regret". See section 4.2.5.1 for more details and the annex for further results.

No-regret development H_2 infrastructure



CO_2-free hydrogen generation and use in Germany

Figure 10

Prognos, Öko-Institut, Wuppertal Institut (2020) and our own calculations.

In DE quite some H_2 used for electricity generation

Massive import of H_2 anticipated

Towards a Climate-Neutral Germany

Three Steps for Achieving Climate Neutrality by 2050 and an Intermediate Target of -65% in 2030 as Part of the EU Green Deal

EXECUTIVE SUMMARY

"Based on industrial demand, no justification for a larger pan-Eurpean H_2 backbone."

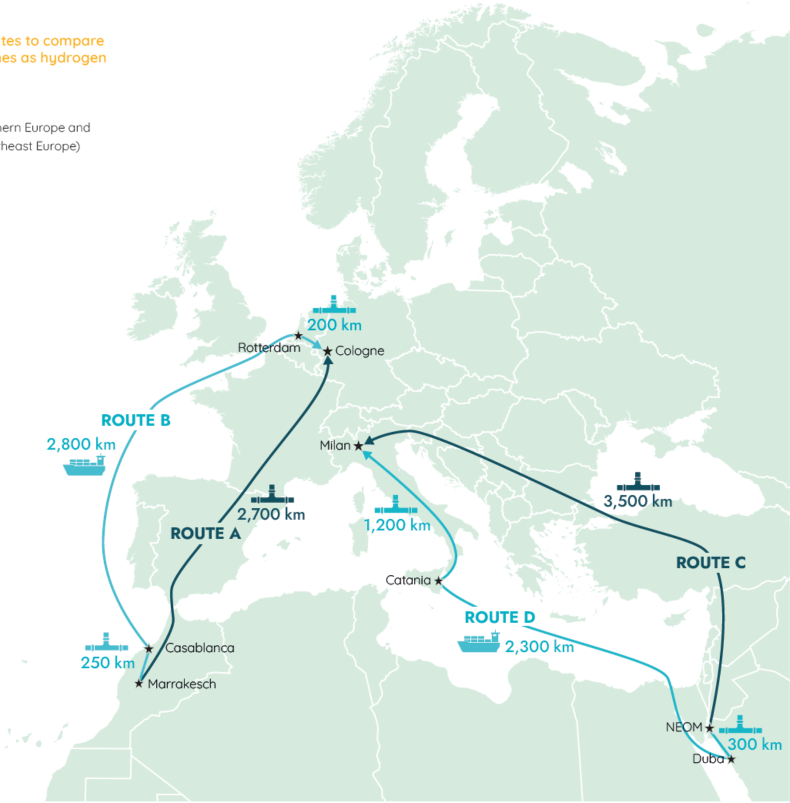
Projected hydrogen demand (LHS) versus hydrogen production (RHS) for Germany from 2025 through 2050. From the RHS it is clear that much hydrogen will have to be imported.

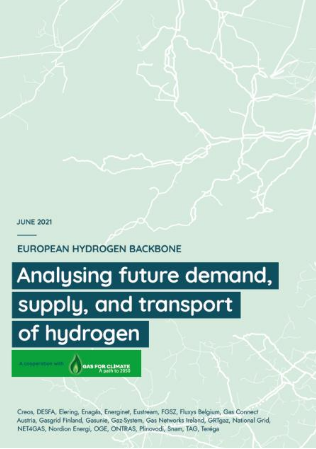
Transport Costs – careful with assumptions

FIGURE 35

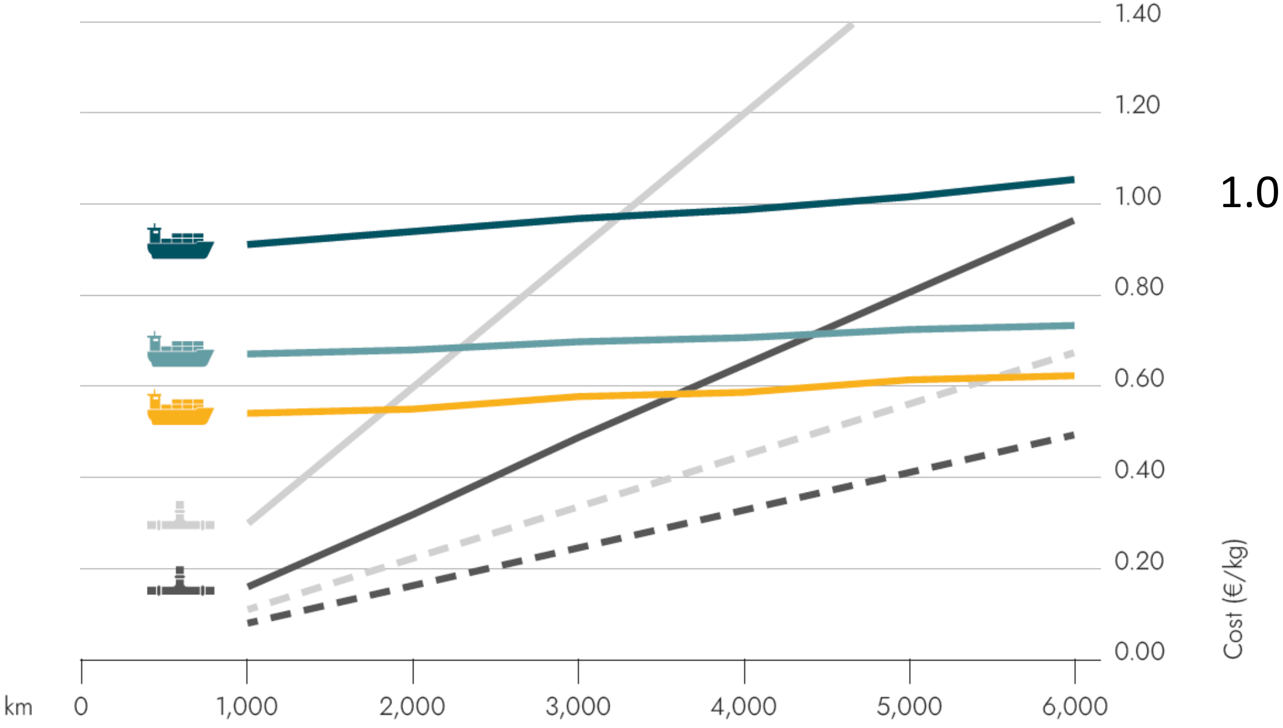
Map of example routes to compare shipping and pipelines as hydrogen transport methods

For imports from
(1) North Africa to Northern Europe and
(2) Saudi Arabia to Southeast Europe)





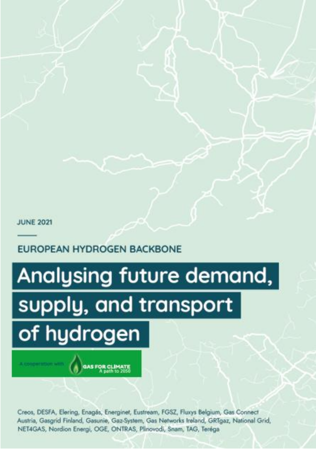
Recall:
$1\ €/\text{kg} \simeq 25\ €/\text{MWh}_{\text{prim, HHV}}$
$1\ €/\text{kg} \simeq 30\ €/\text{MWh}_{\text{prim, LHV}}$



1.0

Source: Guidehouse analysis (see Appendix C for assumptions)

Transport Costs – careful with assumptions


JUNE 2021

EUROPEAN HYDROGEN BACKBONE

Analysing future demand, supply, and transport of hydrogen

Even comparisons with
electric power transmission…

Credible?
To be checked…

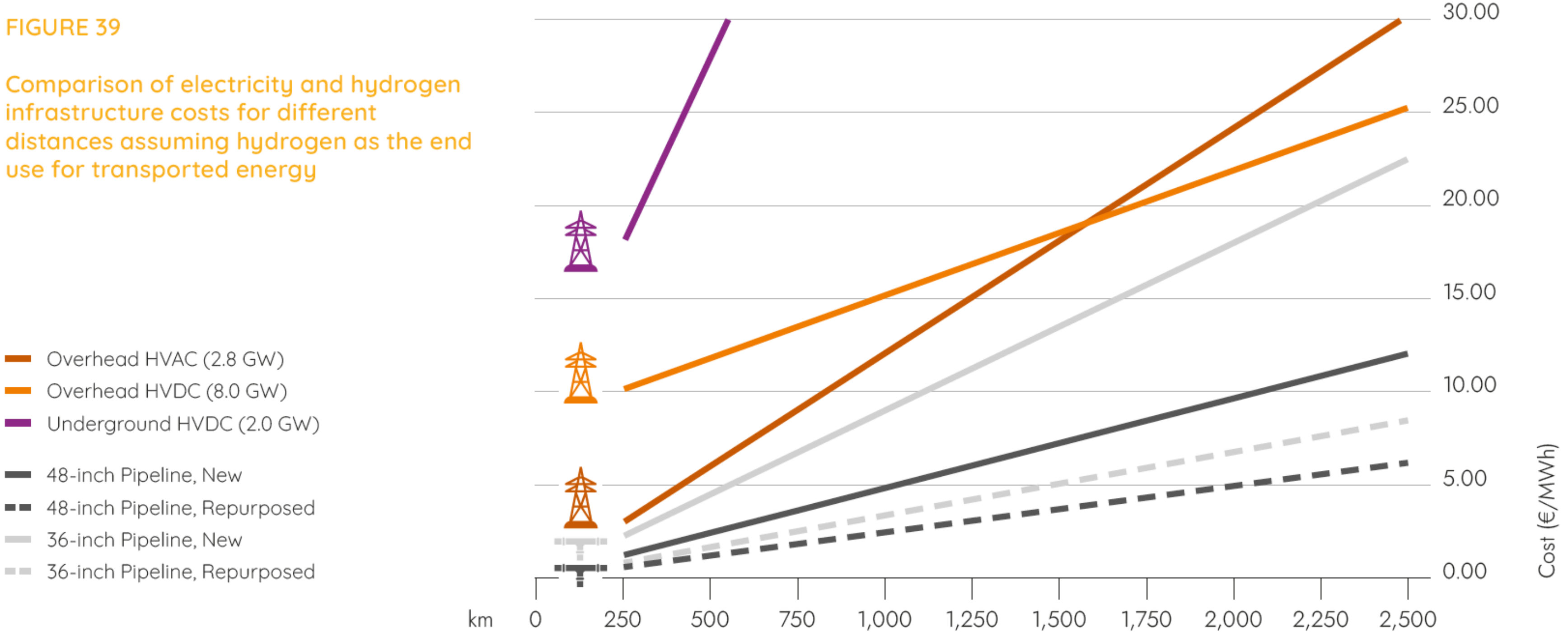


FIGURE 39

Comparison of electricity and hydrogen infrastructure costs for different distances assuming hydrogen as the end use for transported energy

Source: Guidehouse analysis (see Appendix C for assumptions)

Transport Costs – careful with assumptions


LA REVUE DE L'ÉNERGIE

Octobre 2021

Decarbonised hydrogen imports
into the European Union:
challenges and opportunities

Foreword
Introduction

1. Setting the scene

Hydrogen production and consumption in Europe
Technologies and costs
Implications

2. Hydrogen imports

Drivers of hydrogen imports
How to make imports possible?
Conditions for mutual success

3. Country profiles

Austria
France
Germany
Italy
Spain

Conclusions

WORLD ENERGY COUNCIL | EUROPE

In contrast, much higher transport costs

e.g., ~ factor 2 for Liquid H2 Morocco - Germany

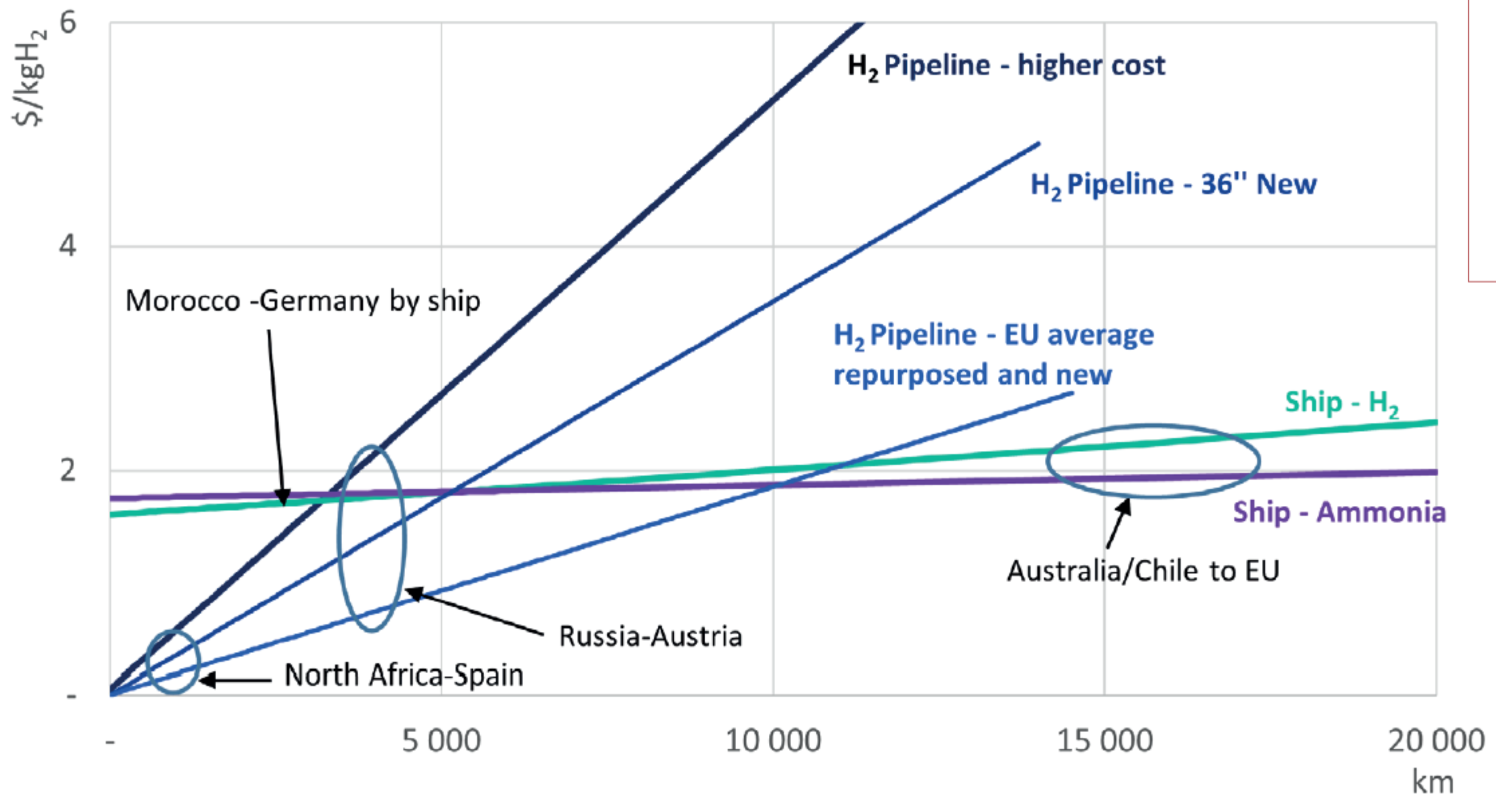
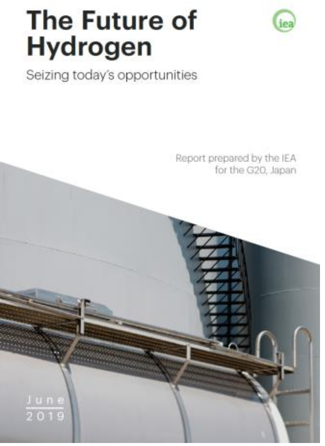


Figure 6. Comparison of hydrogen transport costs via pipeline and seaborne

Sources: IEA, 2019; EHB, 2021a; EWI, 2020; analysis by the authors

Note: Pipeline costs in the figure refer to land pipelines. Submarine pipelines in the analysis of this study are assumed to have a 25-30% higher cost and not to be longer than 1 500-2 000 km. For repurposed pipelines, the costs shown in the graph are those of the EHB costs study; an additional cost for the amortisation of current pipelines might need to be added. See Annex A for cost assumptions.

Hydrogen Production Costs – important factors

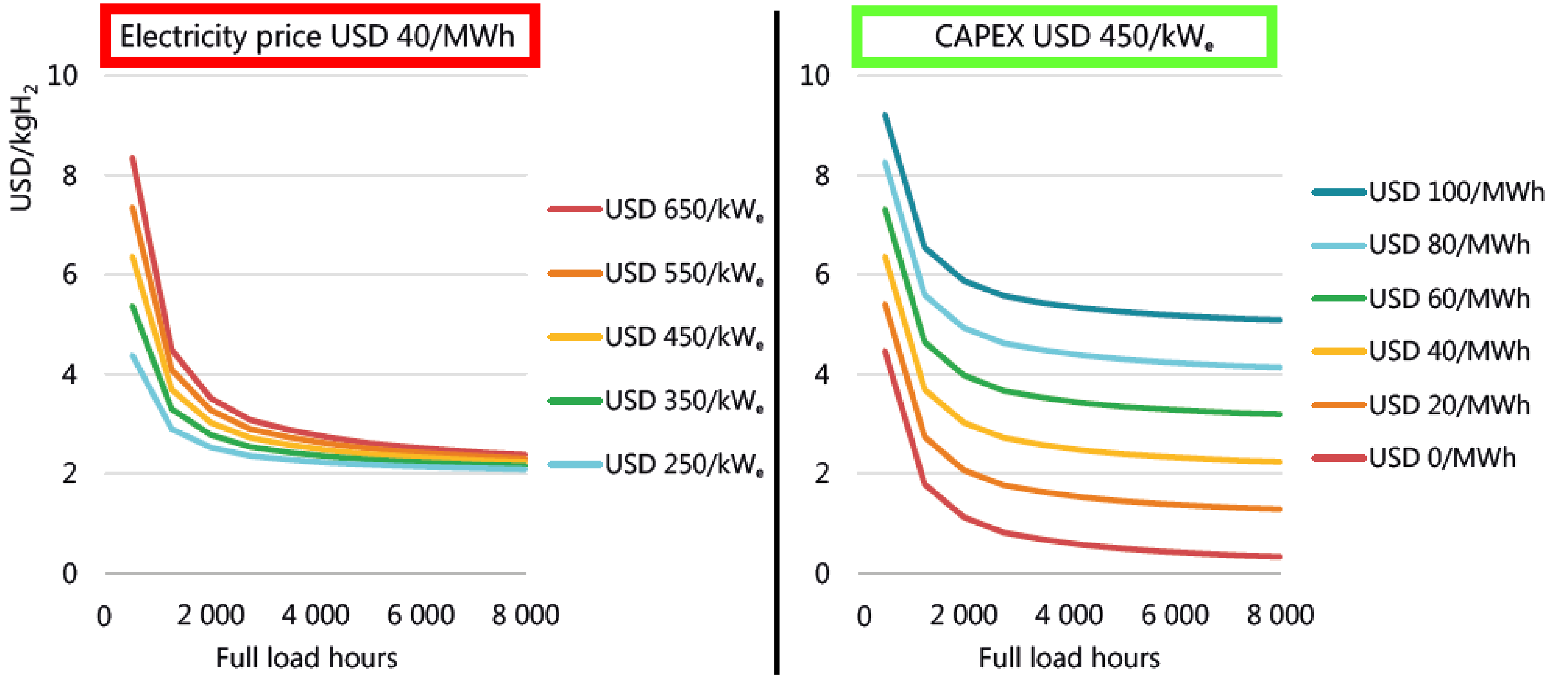

The Future of Hydrogen
Seizing today's opportunities
Report prepared by the IEA for the G20, Japan
June 2019

Important dependencies:

1) **Investment cost**
2) **Full Load Hours (FLH)**
3) **Cost input electric energy**
4) **Efficiency electrolyzers & BOP/BOS**
5) **Discount rate (WACC)**

Recall:
$1\ \$/kg \simeq 25\ \$/MWh_{prim,\ HHV}$
$1\ \$/kg \simeq 30\ \$/MWh_{prim,\ LHV}$

Figure 12. Future levelised cost of hydrogen production by operating hour for different electrolyser investment costs (left) and electricity costs (right)

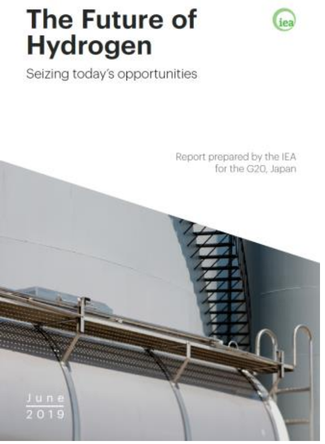


Notes: MWh = megawatt hour. Based on an electrolyser efficiency of 69% (LHV) and a discount rate of 8%.

Source: IEA 2019. All rights reserved.

With increasing full load hours, the impact of CAPEX on hydrogen costs declines and the electricity becomes the main cost component for water electrolysis.

Hydrogen Production Costs – electrolyzers characteristics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June
2019

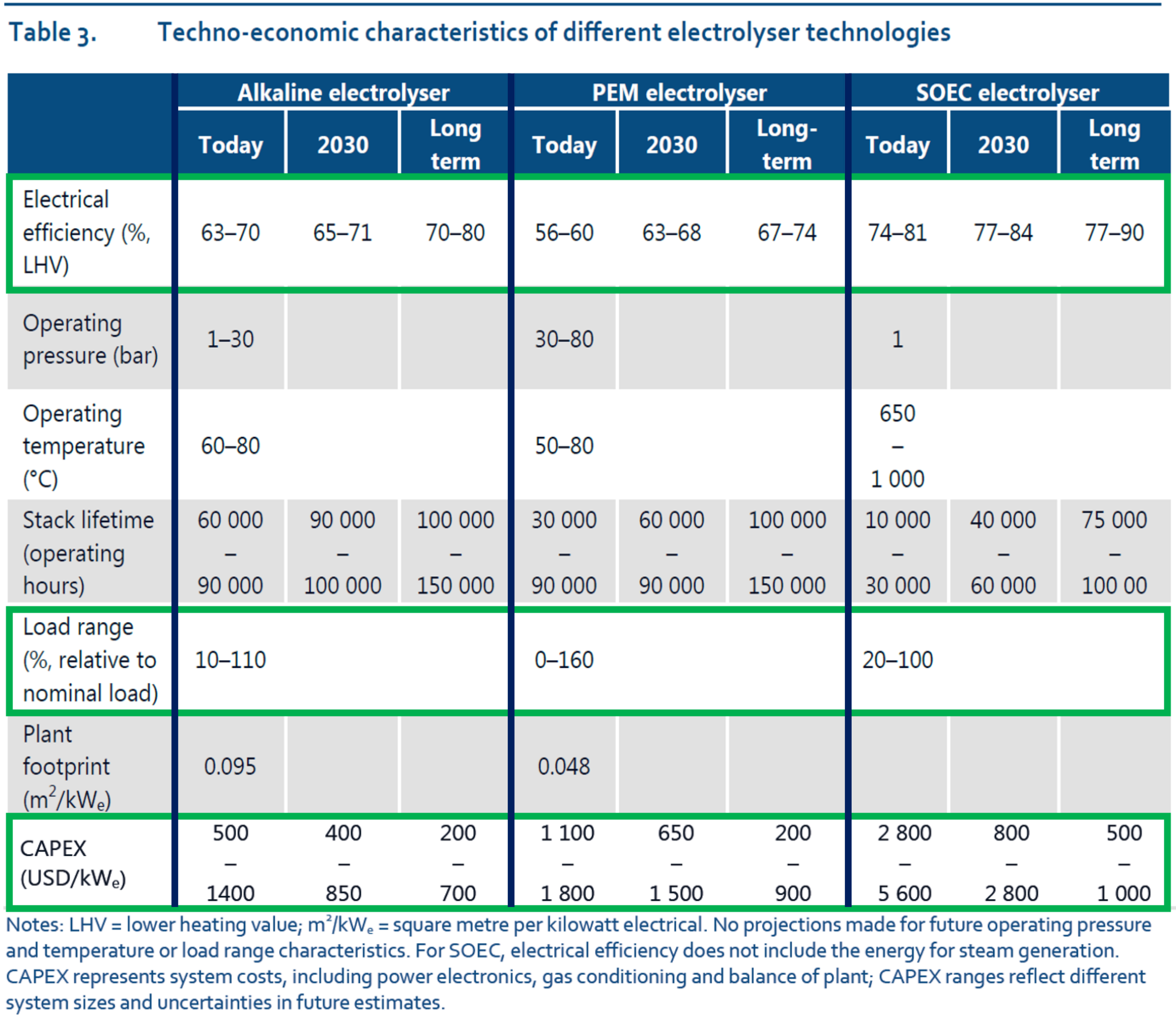


Table 3. **Techno-economic characteristics of different electrolyser technologies**

	Alkaline electrolyser			**PEM electrolyser**			**SOEC electrolyser**		
	Today	**2030**	**Long term**	**Today**	**2030**	**Long-term**	**Today**	**2030**	**Long term**
Electrical efficiency (%, LHV)	63–70	65–71	70–80	56–60	63–68	67–74	74–81	77–84	77–90
Operating pressure (bar)	1–30			30–80			1		
Operating temperature (°C)	60–80			50–80			650 – 1 000		
Stack lifetime (operating hours)	60 000 – 90 000	90 000 – 100 000	100 000 – 150 000	30 000 – 90 000	60 000 – 90 000	100 000 – 150 000	10 000 – 30 000	40 000 – 60 000	75 000 – 100 00
Load range (%, relative to nominal load)	10–110			0–160			20–100		
Plant footprint (m^2/kW_e)	0.095			0.048					
CAPEX (USD/kW_e)	500 – 1400	400 – 850	200 – 700	1 100 – 1 800	650 – 1 500	200 – 900	2 800 – 5 600	800 – 2 800	500 – 1 000

Notes: LHV = lower heating value; m^2/kW_e = square metre per kilowatt electrical. No projections made for future operating pressure and temperature or load range characteristics. For SOEC, electrical efficiency does not include the energy for steam generation. CAPEX represents system costs, including power electronics, gas conditioning and balance of plant; CAPEX ranges reflect different system sizes and uncertainties in future estimates.

Investment costs include BOP/BOS

PEMEL:
Proton Exchange Membrane Electrolyzer

SOEC:
Solid Oxide Electrolyzer Cell

Hydrogen Production Costs – electrolyzers characteristics

The Future of Hydrogen

Seizing today's opportunities

Report prepared by the IEA for the G20, Japan

June 2019

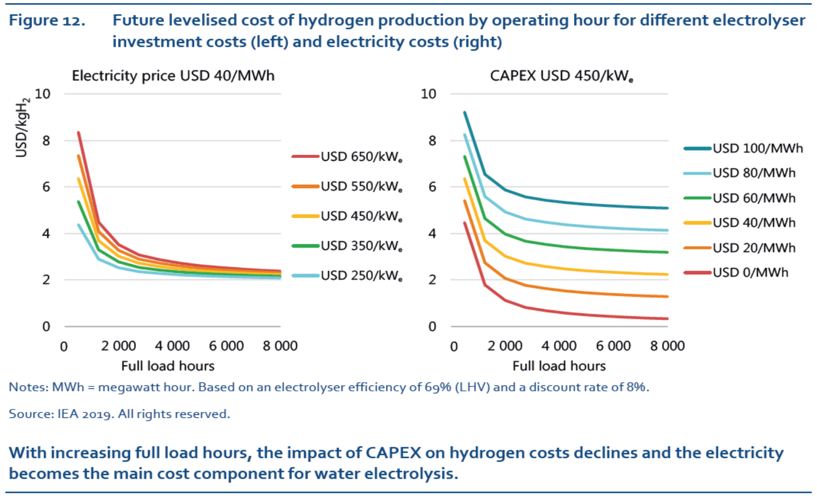


Figure 12. Future levelised cost of hydrogen production by operating hour for different electrolyser investment costs (left) and electricity costs (right)

Notes: MWh = megawatt hour. Based on an electrolyser efficiency of 69% (LHV) and a discount rate of 8%.

Source: IEA 2019. All rights reserved.

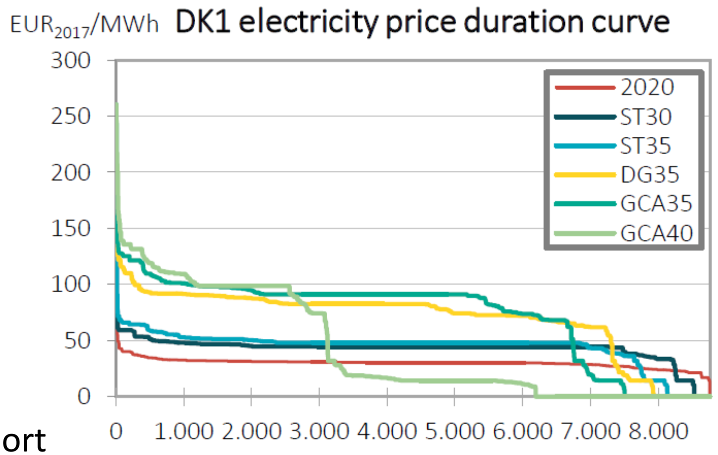
With increasing full load hours, the impact of CAPEX on hydrogen costs declines and the electricity becomes the main cost component for water electrolysis.

Dependency on price of input electricity

Even for zero-marginal cost REES, input electricity has a cost

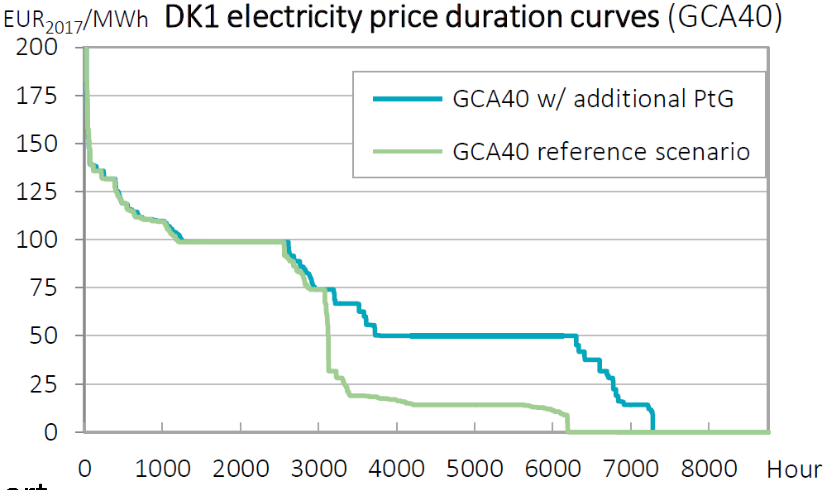
- Investors want a reasonable ROI of their REES investment
- When electrolyzer on the grid, then electrolyzer increases demand for electric power sector→ higher elec wholesale prices. (General conseqence of 'sector coupling')
- In regulated mkts, or large stand-alone REES projects, the LCOE or with LT-PPA will set the price.

Hydrogen Production Costs – exemple Study Energinet DK

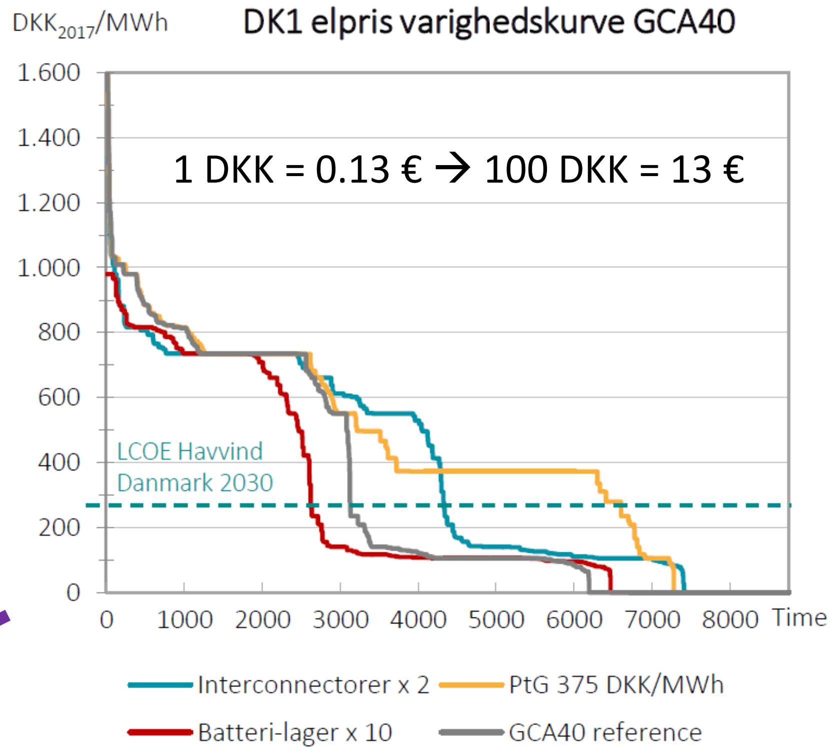


Main report

Note: The duration curves do not fall below zero, as negative prices are not used in the model. Duration curves for scenarios many years into the future should be interpreted with caution. The modelling assumes optimum delivery patterns and regulation and, consequently, the number of hours with very high prices and zero prices is probably underestimated.



Main report

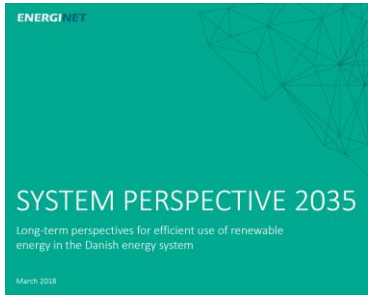


1 DKK = 0.13 € → 100 DKK = 13 €

Figure 1.8: Duration curves for the electricity price shown for DK1 (Western Denmark) in Global Climate Action (GCA) scenario. The reference in 2030 and 2040 shows that electricity prices can be relatively low for many hours in 2040 if measures are not implemented. The effect of measures in the form of battery storage, enhanced infrastructure (ICL) and power-to-gas has been analyzed overall. There is a great deal of uncertainty associated with the analysis, but the trend shows that power-to-gas can be a very effective means of increasing the price formation of electricity.

Batteri-lager = Battery storage

LCOE Havvind = LCOE Offshore Wind



ENERGINET

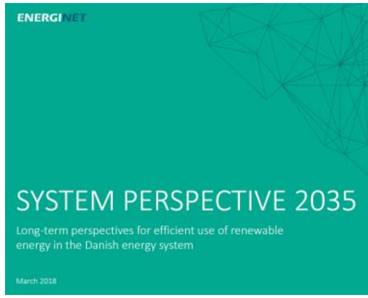
SYSTEM PERSPECTIVE 2035

Long-term perspectives for efficient use of renewable energy in the Danish energy system

March 2018

Background report, Danish

Hydrogen Production Costs – exemple Study Energinet DK



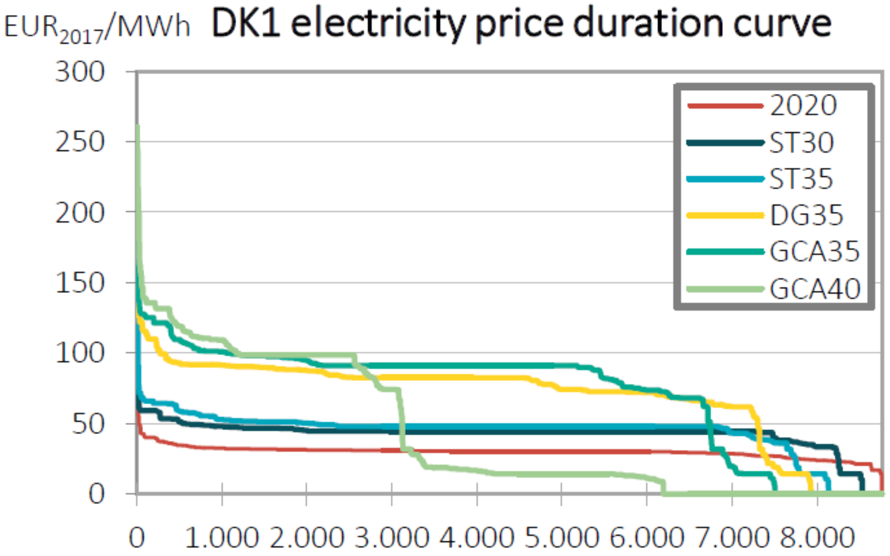
ENERGINET

SYSTEM PERSPECTIVE 2035

Long-term perspectives for efficient use of renewable energy in the Danish energy system

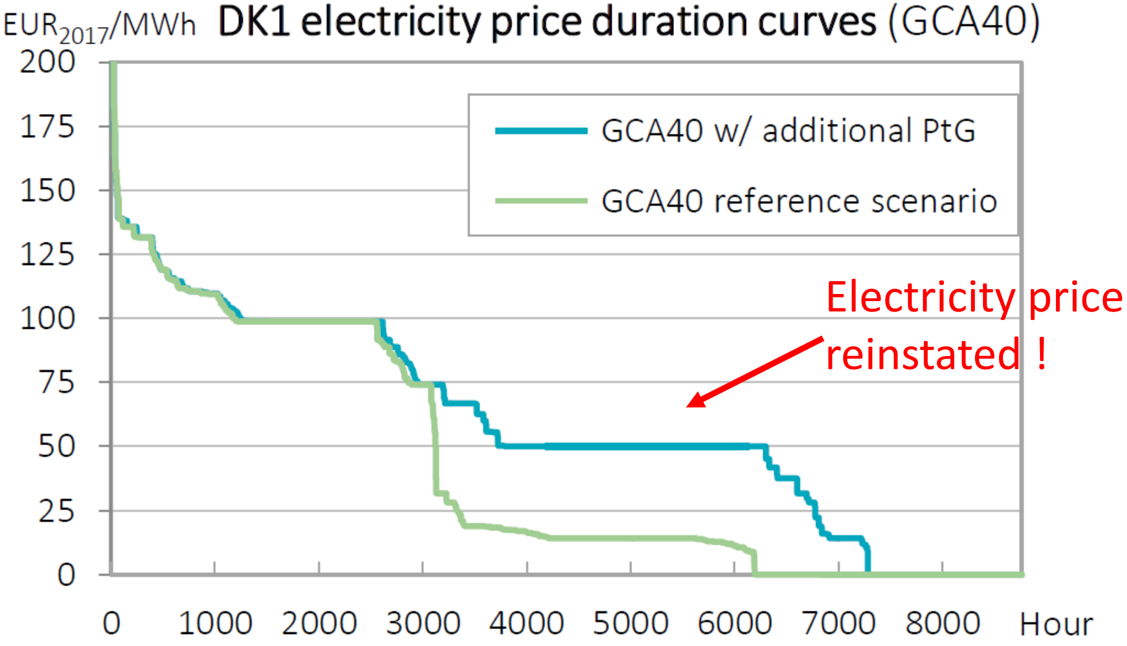
March 2018

Summarizing result P2G



DK1 electricity price duration curve

Note: The duration curves do not fall below zero, as negative prices are not used in the model. Duration curves for scenarios many years into the future should be interpreted with caution. The modelling assumes optimum delivery patterns and regulation and, consequently, the number of hours with very high prices and zero prices is probably underestimated.



DK1 electricity price duration curves (GCA40)

Electricity price reinstated !

Hydrogen Technologies for Grid Support

Hydrogen Technologies for Grid Support

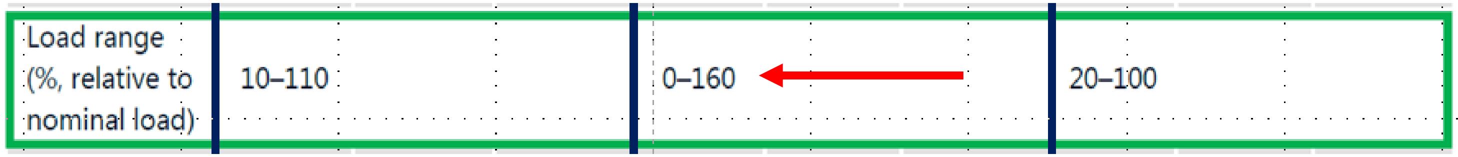
- For electric grid support by electrolyzers there is a need for *installed electrolyzers!*
- Will be very different for different regions (mete conditions RES)
- Competition from Li-ion batteries
- Dependent on type of electrolyzer

- Should consider *four* configurations
  - Input EL connected to el grid / H_2 output EL connected to H_2 gas grid (via H_2 storage buffer)
  - Input EL connected to el grid / H_2 output EL stand alone (via H_2 storage buffer)
  - Input EL <u>not</u> connected to el grid / H_2 output EL connected to H_2 gas grid (via H_2 storage buffer)
  - Input EL <u>not</u> connected to el grid / H_2 output EL stand alone (via H_2 storage buffer)

Hydrogen Technologies for Grid Support

- Electrolyzers:
  - **Alkaline** most mature, in the future probably overtaken by PEM
  - Future looks promising for **PEM**
  - **SOEC** need high temperatures & still in reseach phase

- Load range (recall):



	Alkaline	**PEM**	**SOEC**
Load range (%, relative to nominal load)	10–110	0–160	20–100

PEM can react both ways:
in/decrease nominal demand!

- Start-up times:
  - PEM ~ 5-10 mins (from cold) ~ secs (from warm/hot standby)
  - Alkaline ~ 1-2 hrs (from cold) ~ 1-5 mins (from warm/hot standby)
  - SOEC ~ 7-8 hrs (from cold) ~ few mins (from warm/hot standby)
- Ramp rates: Alkaline & PEM full range in secs; SOEC full range in secs to mins

Hydrogen Technologies for Grid Support

Example by Pierluigi Mancarella group

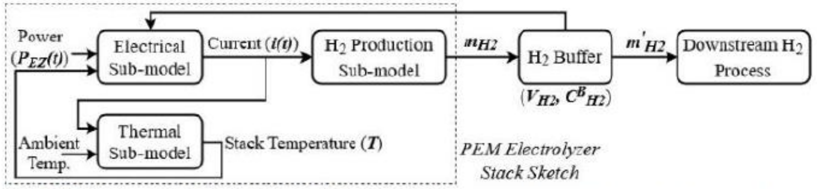


Fig. 1. Proposed sketch of PEM electrolyzer stack model, including its three sub-models, along with downstream H_2 buffer storage/process.

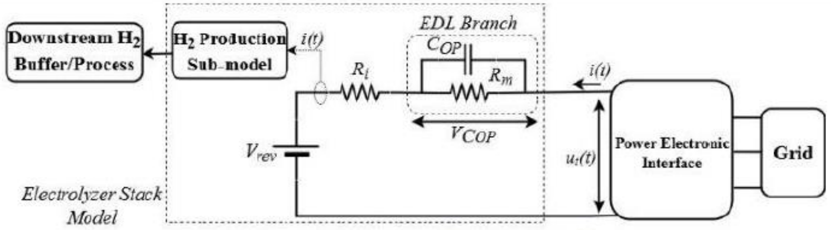


Fig. 2. Proposed electrolyzer stack model and grid interface.

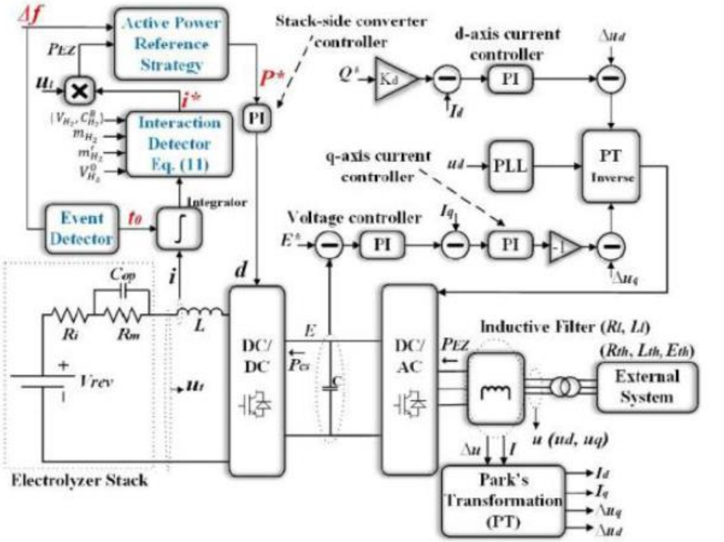


Fig. 3. HE dynamic model with the proposed converter-level control loops including interaction detector scheme.

Figure H_2-j. Illustration of the PEM electrolyzer stack block diagram (LHS top), its electric circuit model and grid interface (RHS top), and the power electronics interface and controls (bottom panel). Taken from [Ghazavi, 2021]

Mehdi Ghazavi Dozein, et al., "Fast Frequency Response from Utility-Scale Hydrogen Electrolyzers", IEEE Trans on Sustainable Energy, 2021

Hydrogen Technologies for Grid Support

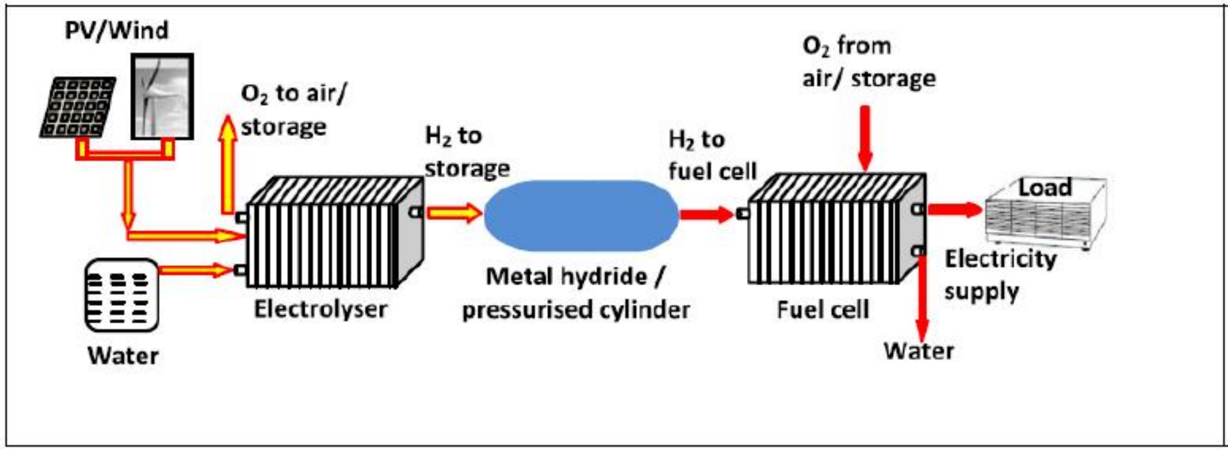
Use of hydrogen gas turbines

In regions with ‘nasty’ meteorological conditions (e.g., cold spells), investments in H_2 gas turbines may be necessary.

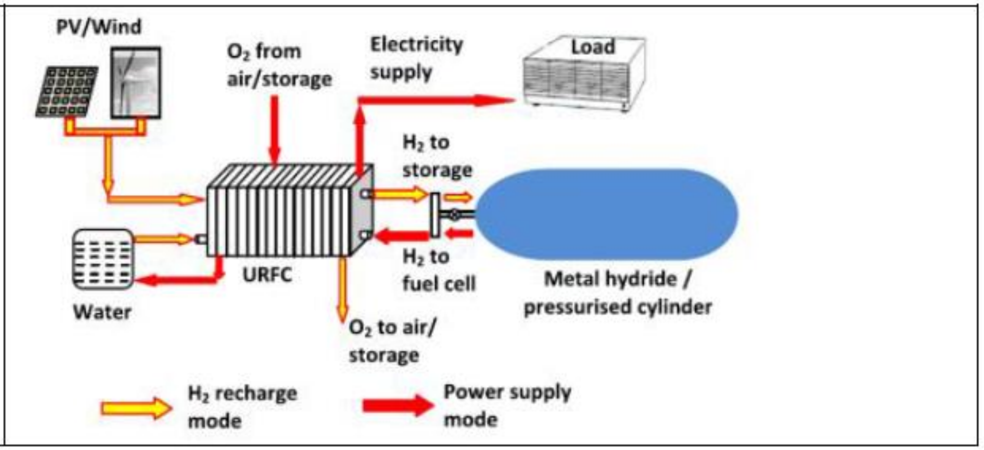
These gas turbines possess the classical flexibility for system balancing.

Bidirectional operation as electrolyzer & fuel cell

Illustration of ‘reversible’ operation of PEM electrolyzers & fuel cells.



Discrete option with a separate PEM electrolyzer and fuel cell.



Unitized regererative fuel cell (URFC) operating as fuel cell and as electrolyzer

Biddyut Paul and John Andrews, “PEM unitized reversible/regenerative hydrogen fuel cell systems: State of the art and technical challenges”, SRER 79 (2017) 585-599

Conclusions & Takeaways

- Hydrogen-economy developmets depends on decarbonization constraints
- Hydrogen-economy development will differ from region to region
- Transition to green hydrogen will often start via blue hydrogen
- Interesting trade opportunities may arise / export – import
- Grid support only if electrolyzers or H_2 gas turbines are present
- No investments in H_2 technologies only for grid support
- Golden rule:
  1. Efficiency
  2. Electrification
  3. Molecules where needed

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