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More than storage: system flexibility - Presentation

Hydrogen-based energy conversion

A.T. Kearney Energy Transition Institute
February 2014

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Compiled by the A.T. Kearney Energy Transition Institute

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About the FactBook – Hydrogen-Based Energy Conversion

The FactBook provides an extensive technoeconomic analysis of the entire value chain, from power conversion to end-uses of hydrogen. The objective was to view the hydrogen industry through a technological prism, revealing barriers to progress and providing stakeholders – be they policy-makers, energy professionals, investors or students – with the tools needed to understand a complex and often misunderstood sector. In addition, the Energy Transition Institute summarizes and assesses nine business cases for hydrogen, based on academic literature and research.

About the A.T. Kearney Energy Transition Institute

The A.T. Kearney Energy Transition Institute is a nonprofit organization. It provides leading insights on global trends in energy transition, technologies, and strategic implications for private sector businesses and public sector institutions. The Institute is dedicated to combining objective technological insights with economical perspectives to define the consequences and opportunities for decision makers in a rapidly changing energy landscape. The independence of the Institute fosters unbiased primary insights and the ability to co-create new ideas with interested sponsors and relevant stakeholders.

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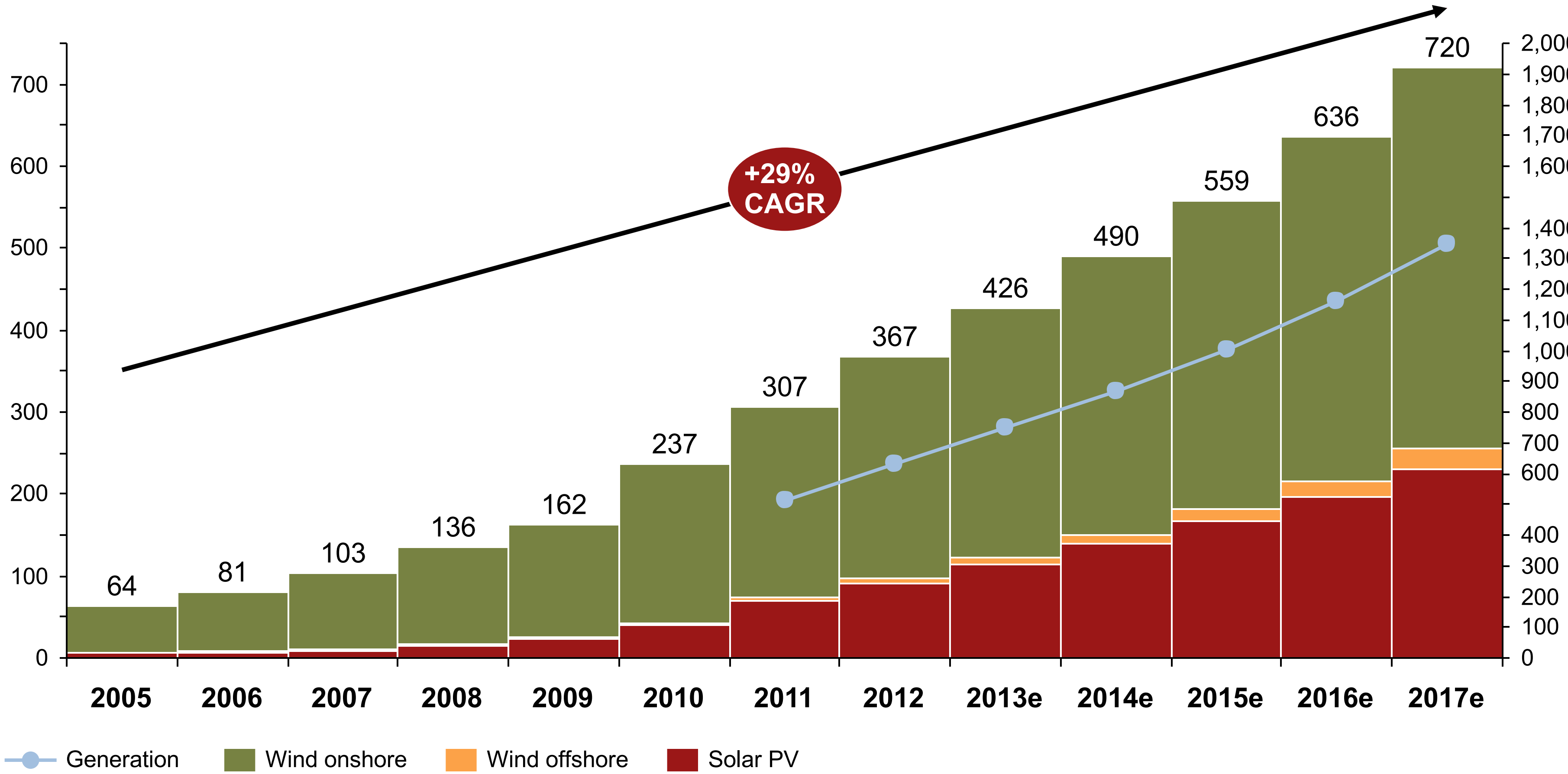
1. Making the case for hydrogen conversion

Wind and solar photovoltaic are at the forefront of power-sector decarbonization and set to expand rapidly

Wind & solar Photovoltaic [PV] technologies lifting off

(estimates for 2013-2017) Capacities in GW (left axis) and generation in TWh (right axis)



1. CAGR: compound annual growth rate.
Source: IEA (2012a); IEA (2012b).

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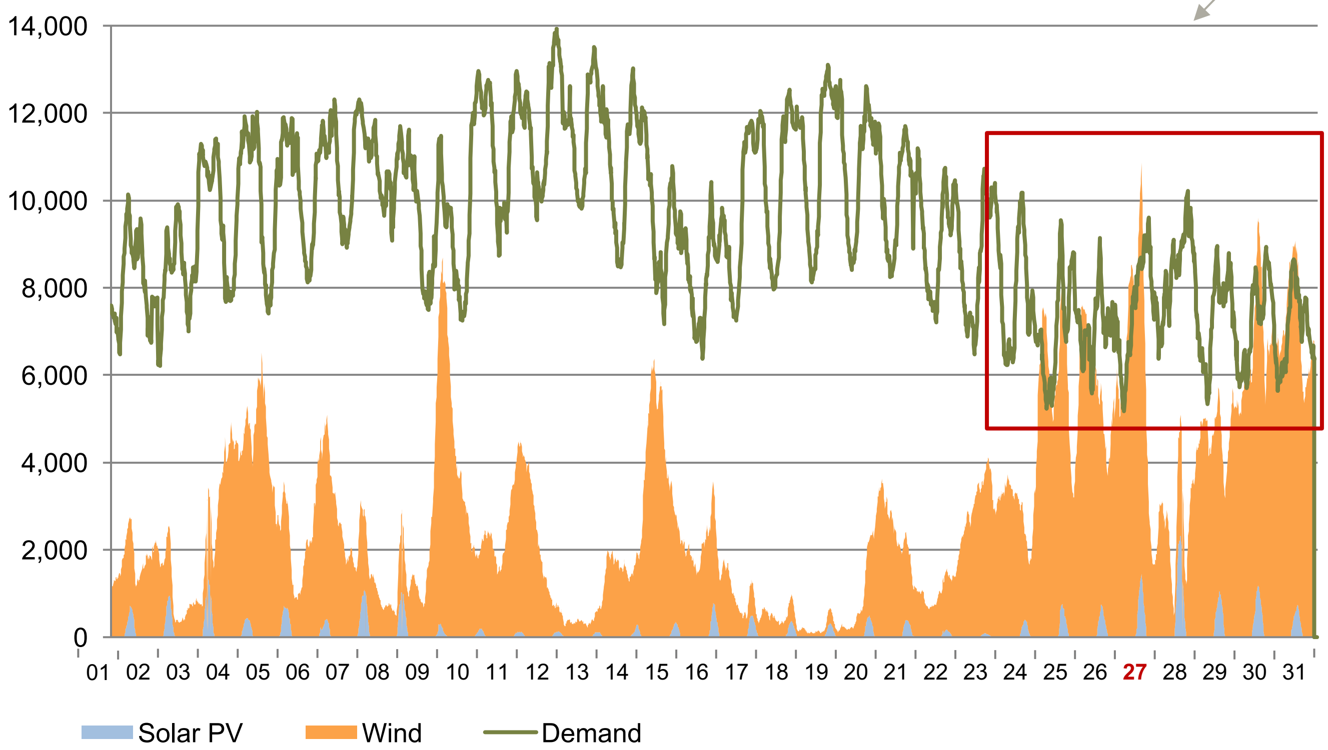
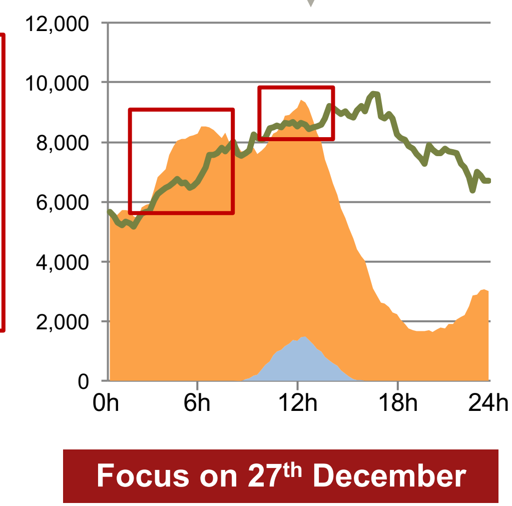
The variable output of wind and solar PV makes demand-supply matching more difficult and increases the need for flexibility within the system

Wind & solar generation vs. demand in northern germany

MW, December 2012 on the 50Hertz Operated Grid

Intermittency[1] generates surplus & deficit





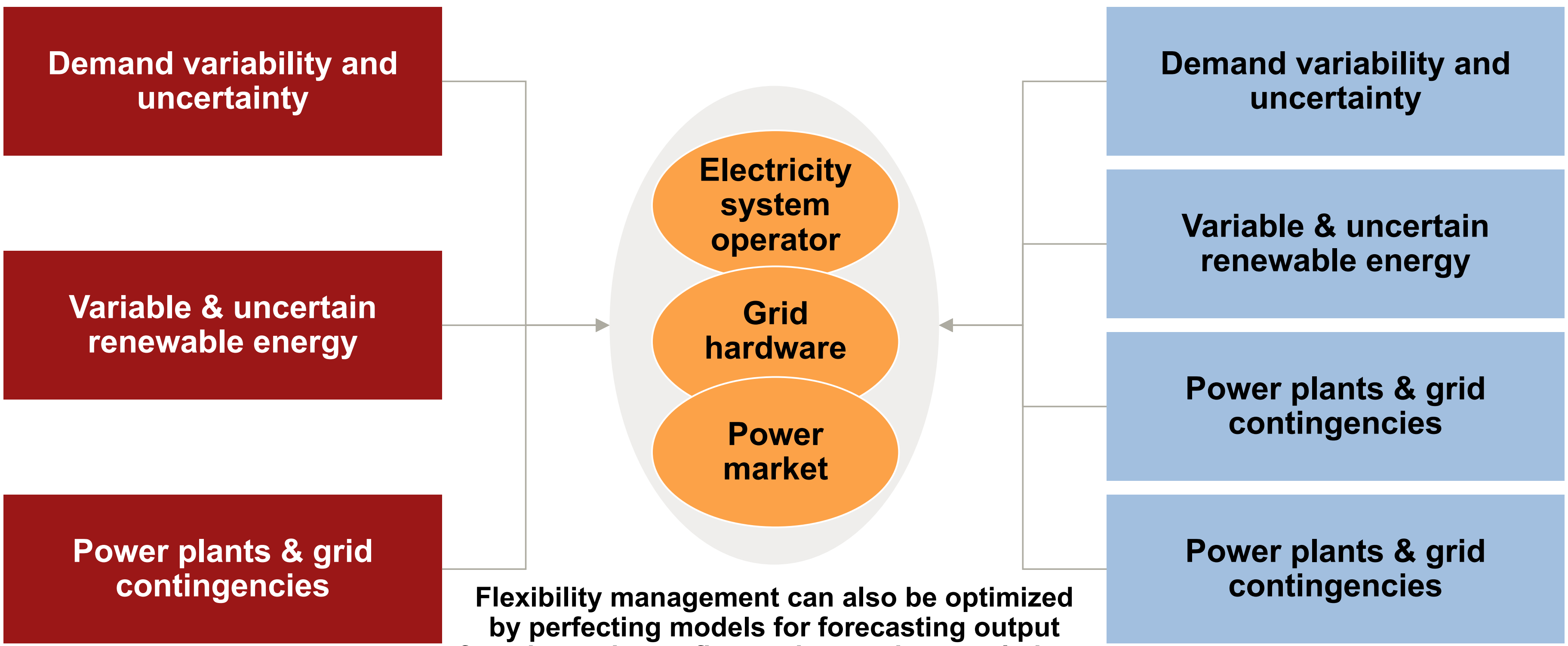
1. Output is variable on multiple timescales, depending on daily or seasonal patterns and on weather conditions; 2. This variability makes long-term forecasting difficult and certainly less predictable than output from conventional technologies; 3. Wind and solar output are subject to ramp events

Source: A.T. Kearney Energy Transition Institute Analysis based on 50Hertz data archive (Wind and Solar Actual In Feed 2012, Control Load 2012).

New flexibility resources must be developed in addition to dispatchable power plants

Power system flexibility management[1]

Flexibility needs | **Flexibility resources**



Flexibility management can also be optimized by perfecting models for forecasting output from intermittent, fine-tuning market regulations and refining the design of power systems

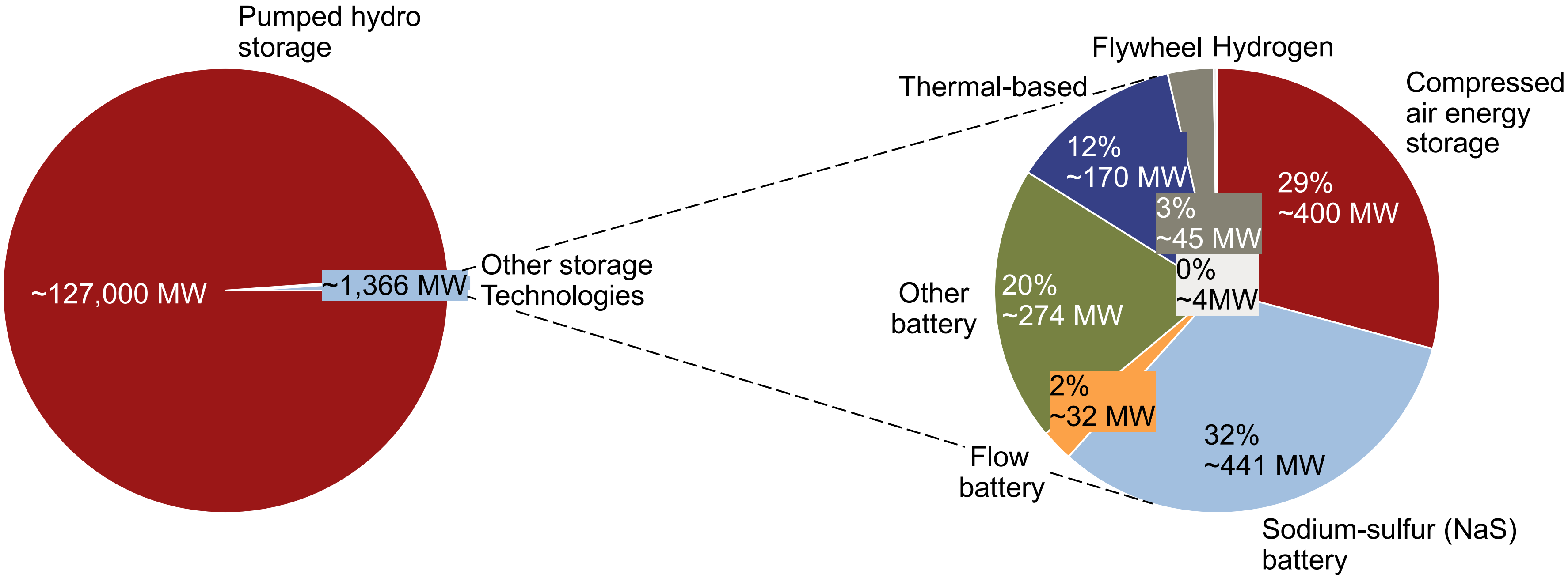
1. Up to a certain penetration rate, the integration of wind and solar into the power mix can usually be managed using existing flexibility sources, mainly dispatchable power plants. The threshold depends on the system's location and characteristics, and ranges roughly between 15% and 25%.

Source: A.T. Kearney Energy Transition Institute analysis based on IEA (2011a), "Harnessing Variable Renewables - A guide to balancing challenge".

With the exception of pumped hydro storage, the deployment of electricity storage is at an embryonic stage

Total electricity storage power capacity MW, 2012

Electricity storage capacity excluding PHS[1] MW, 2012



Electricity storage is not a new concept. However, its development has been restricted to one technology: pumped hydro storage, which accounts for 99% of global installed power capacity.

1. PHS: pumped hydro storage.

Source: A.T. Kearney Energy Transition Institute analysis based on Electric Power Research Institute – EPRI (2010), "Electricity Energy Storage Technology Options - A White Paper Primer on Applications, Costs, and Benefits".

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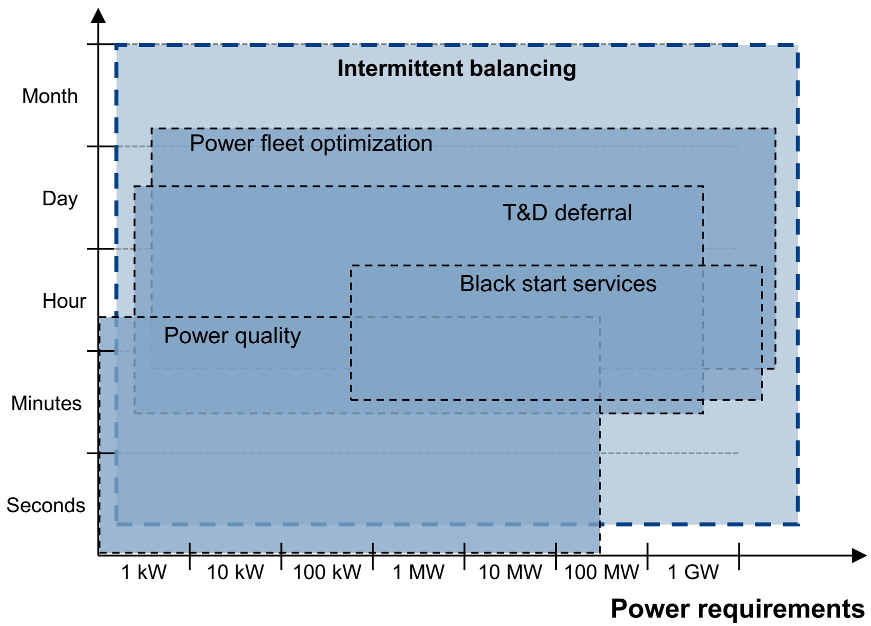
The features of storage technologies must be matched to the requirements of various applications

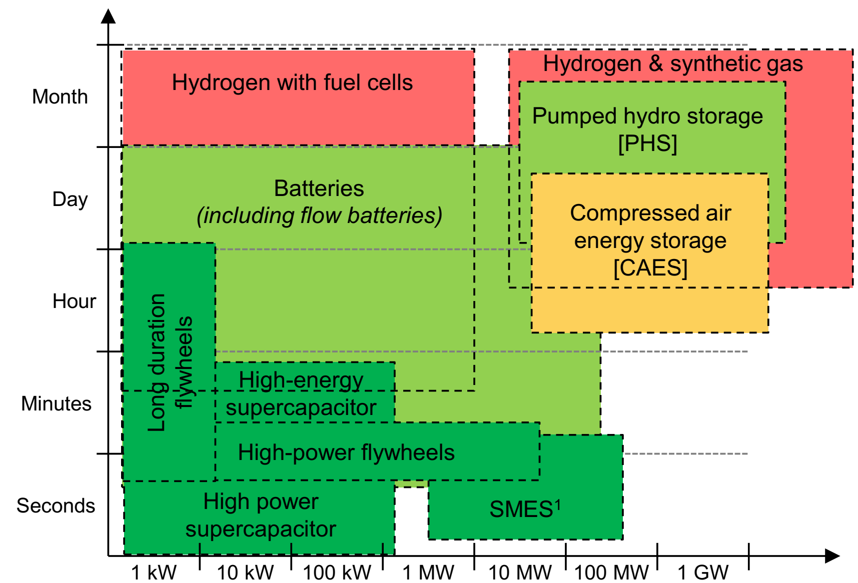
Storage Applications Requirements[2]

Discharge time vs. power requirements (MW)



Electricity storage technollogies' features

Discharge time *vs.* power requirements (MW)



Efficiency of storage cycle	85-100%	70-85%	45-70%	30-45%

1. SMES: superconducting magnetic energy storage; 2. For more information on storage applications, please refer to the Hydrogen FactBook; 3. T&D for transmission & distribution
Source: A.T. Kearney Energy Transition Institute based on US DoE (2011), "Energy Storage Program Planning Document".

Hydrogen energy storage solutions are based on the conversion of electricity into a new energy carrier, hydrogen, by means of water electrolysis

Hydrogen-based storage system – schematic representation

Charge

1 Hydrogen production

Extraction of green energy from variable renewables and **conversion** to a new carrier by means of water electrolysis[1]

Electron-to-hydrogen

Store

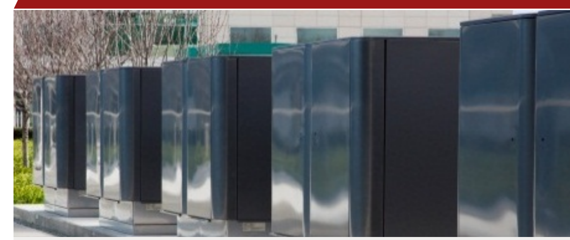
2 Hydrogen storage & transport

Time and spatial **decoupling** of production and consumption

Hydrogen state

Discharge

3 Hydrogen use



Valorization of the energy where and when it is needed **with or without conversion** to a new carrier

Hydrogen-to-electron

Hydrogen-to-gas

Hydrogen-to-motion

Hydrogen-to-chemical

Hydrogen-to-liquid fuels[2]

1. Water electrolysis is the process of using electrical energy to split water into its chemical constituents (hydrogen [H2] and oxygen [O2]), thereby converting electrical energy into chemical energy; 2. Fuel cell electric vehicles involve on-board re-electrification, but are considered as a 'direct' application of hydrogen in this report; Heating is considered an end-use in the study, and hydrogen-to-heat is therefore not displayed on the graph.

Source: A.T. Kearney Energy Transition Institute analysis.

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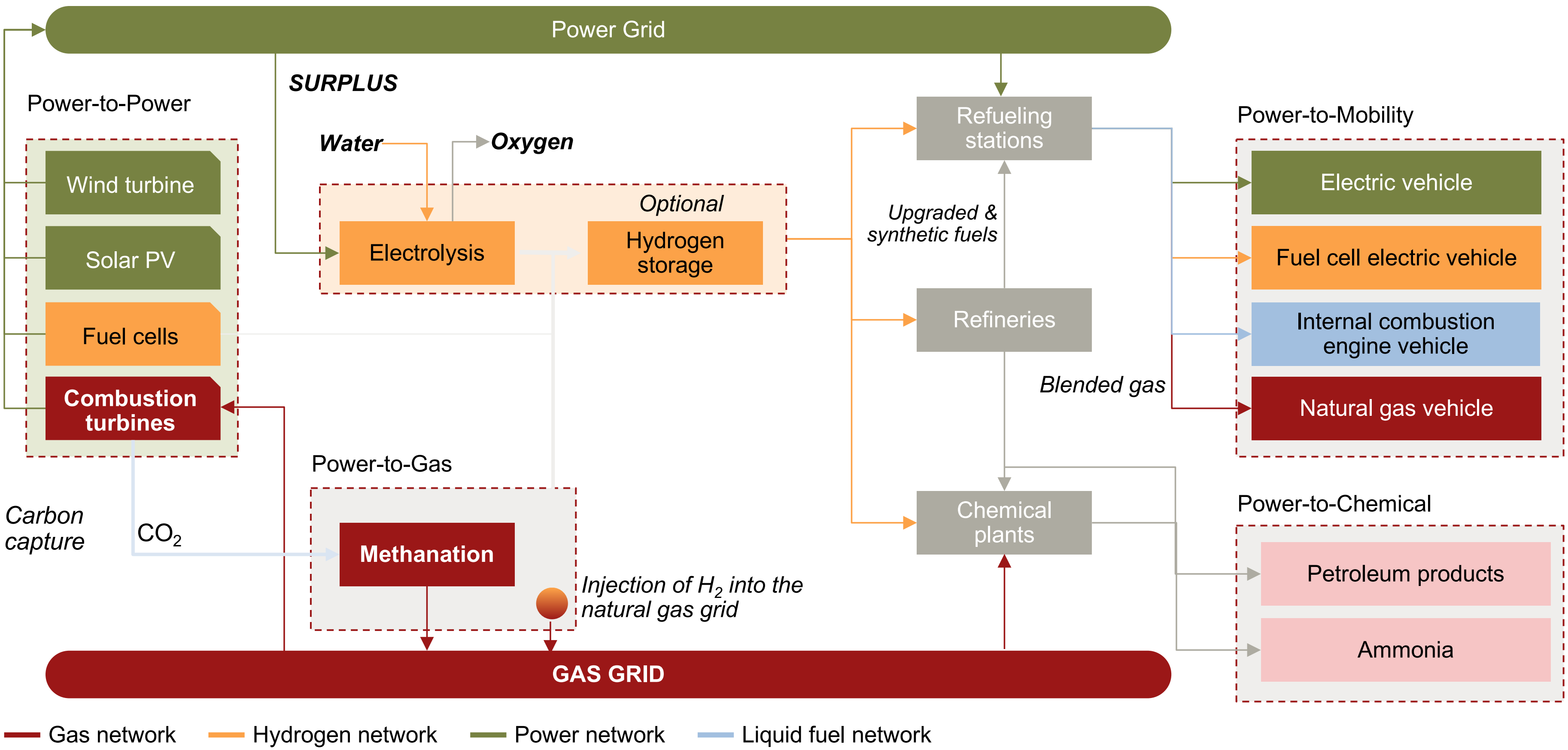
Exploiting hydrogen's versatility, chemical energy storage opens up alternatives to the usual approach to electricity storage

Simplified value chain of hydrogen-based energy conversion solutions[1]



1. Simplified value chain. End uses are non-exhaustive. For more information on the technologies mentioned in this diagram, please refer to next chapter or to the Hydrogen FactBook.
Source: A.T. Kearney Energy Transition Institute analysis.

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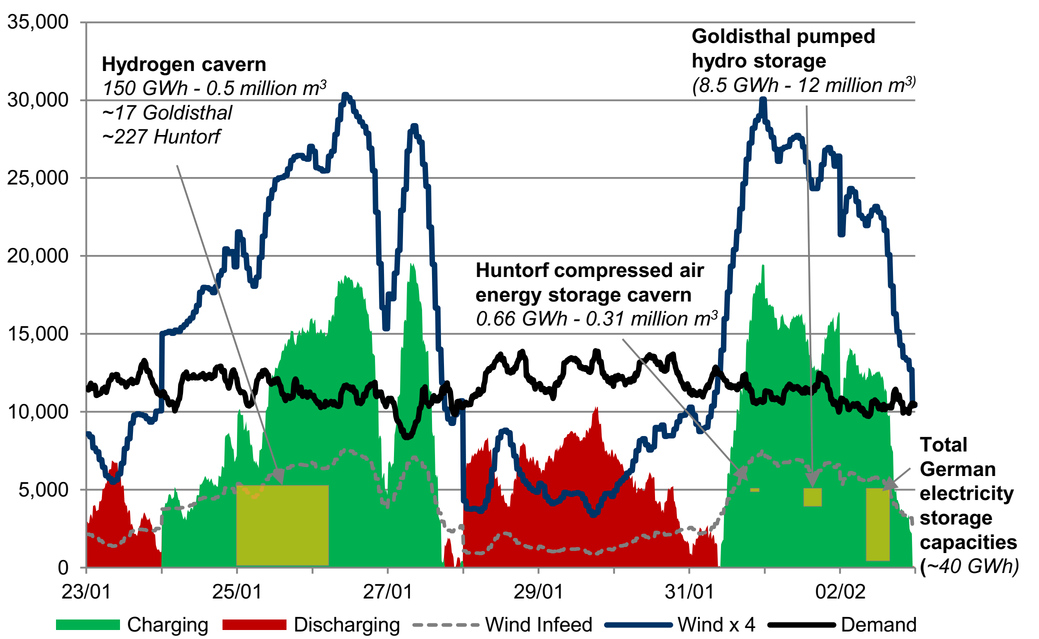
Time: the physical properties of hydrogen make it particularly suited to large-scale, long-term re-electrification applications

Comparison between hydrogen and conventional STORAGE – Illustrative simulation MW, 50 Hertz Data from 23rd January to 2nd February 2008



How to read this graph?

- To simulate the storage potential that would result from a fourfold increase in wind capacity in northern Germany, the wind power that was actually generated and fed into the 50Hertz grid during the week of the 23/01-02/02/2008 (the dashed grey line) has been multiplied by four: this is the Wind x 4 blue line.
- The difference between this simulated wind power production and power demand1 (black line) in that week is depicted by the green and read areas:
  - Green when simulated wind generation > demand, enabling storage charging
  - Red when simulated wind generation < demand, requiring storage discharge
- Finally, the yellow rectangles depict, on the same scale the energy-storage capacity of a typical hydrogen cavern and of existing storage plants in Germany: a CAES cavern (Huntorf), a PHS2 plant (Goldisthal), as well as the country's total electricity-storage capacity. The location of the yellow rectangles is unimportant.

1. Demand is assumed to be the same as it was in the same week in 2008; 2For existing pumped hydro plants, the volumetric energy density is estimated by Chen et al. (2009) to range between 0.5 and 1.5 kWh/m^3.

Source: A.T. Kearney Energy Transition Institute analysis, based on HyUnder Proceedings and 50 Hertz Data.

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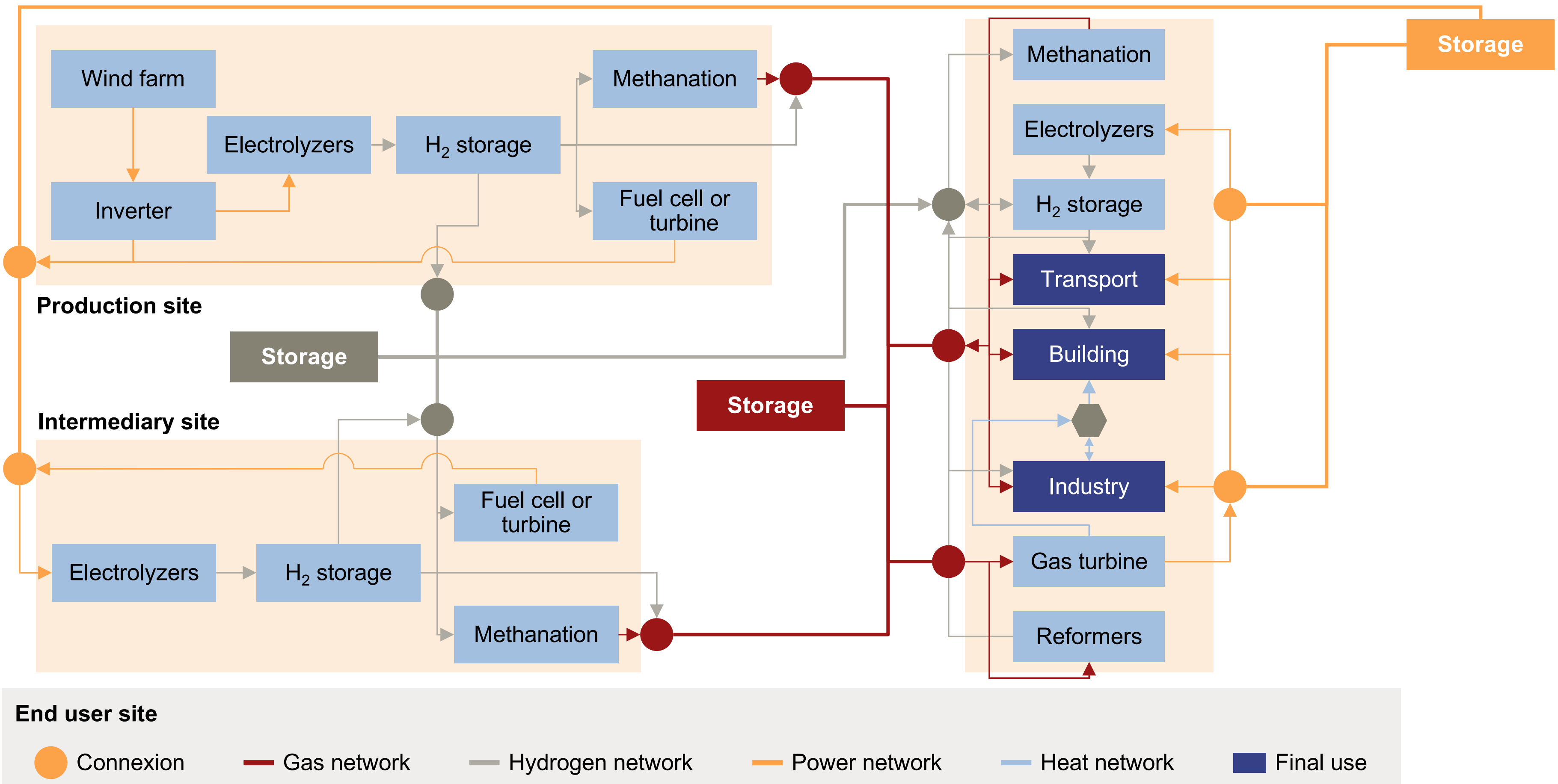
Location: converting electricity to a new energy carrier enables extracted energy to be transported through alternative infrastructure

Hydrogen-based energy transport routes[1]



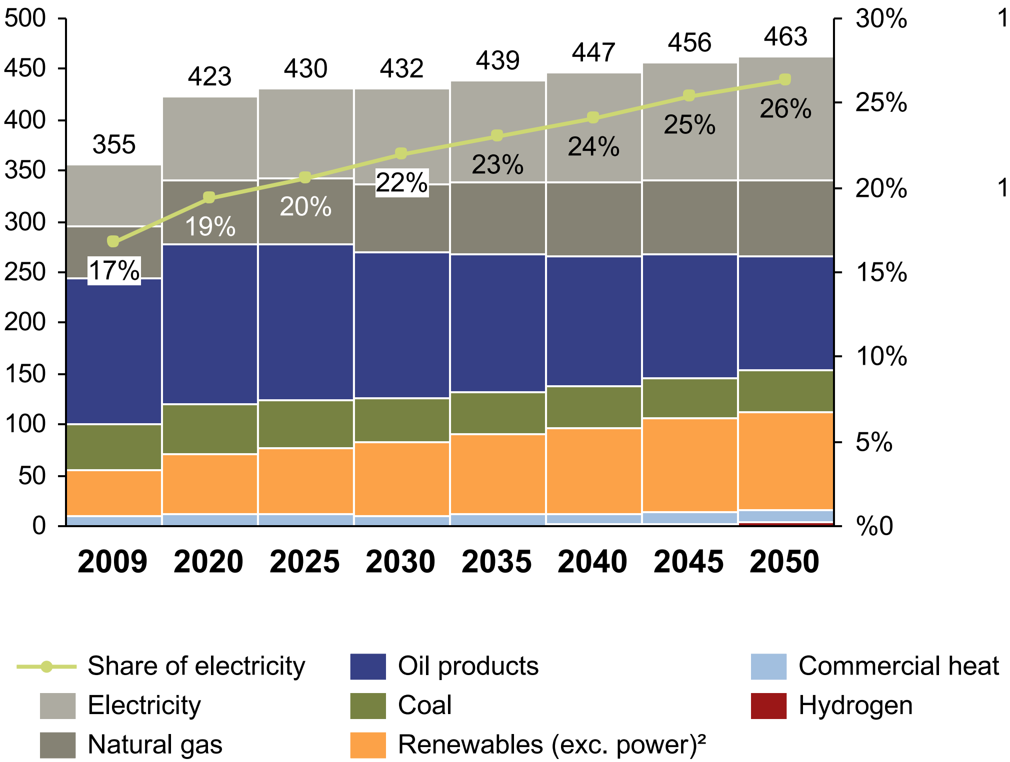
1. For more information on the technologies mentioned in this diagram, please refer to next chapter or to the Hydrogen FactBook.
Source: A.T. Kearney Energy Transition Institute analysis.

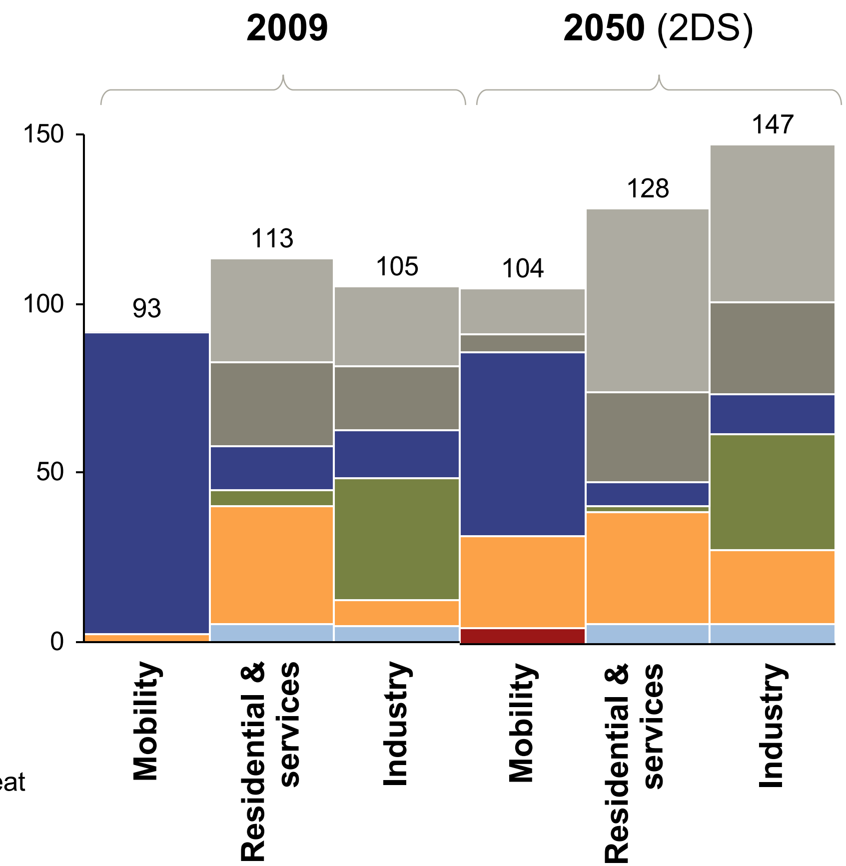
Application: hydrogen-based energy storage solutions are not restricted to providing electricity back to the grid

Energy carrier distribution by end-use, 2009 and 2050

(IEA's 2DS scenario[1]) ExaJoules

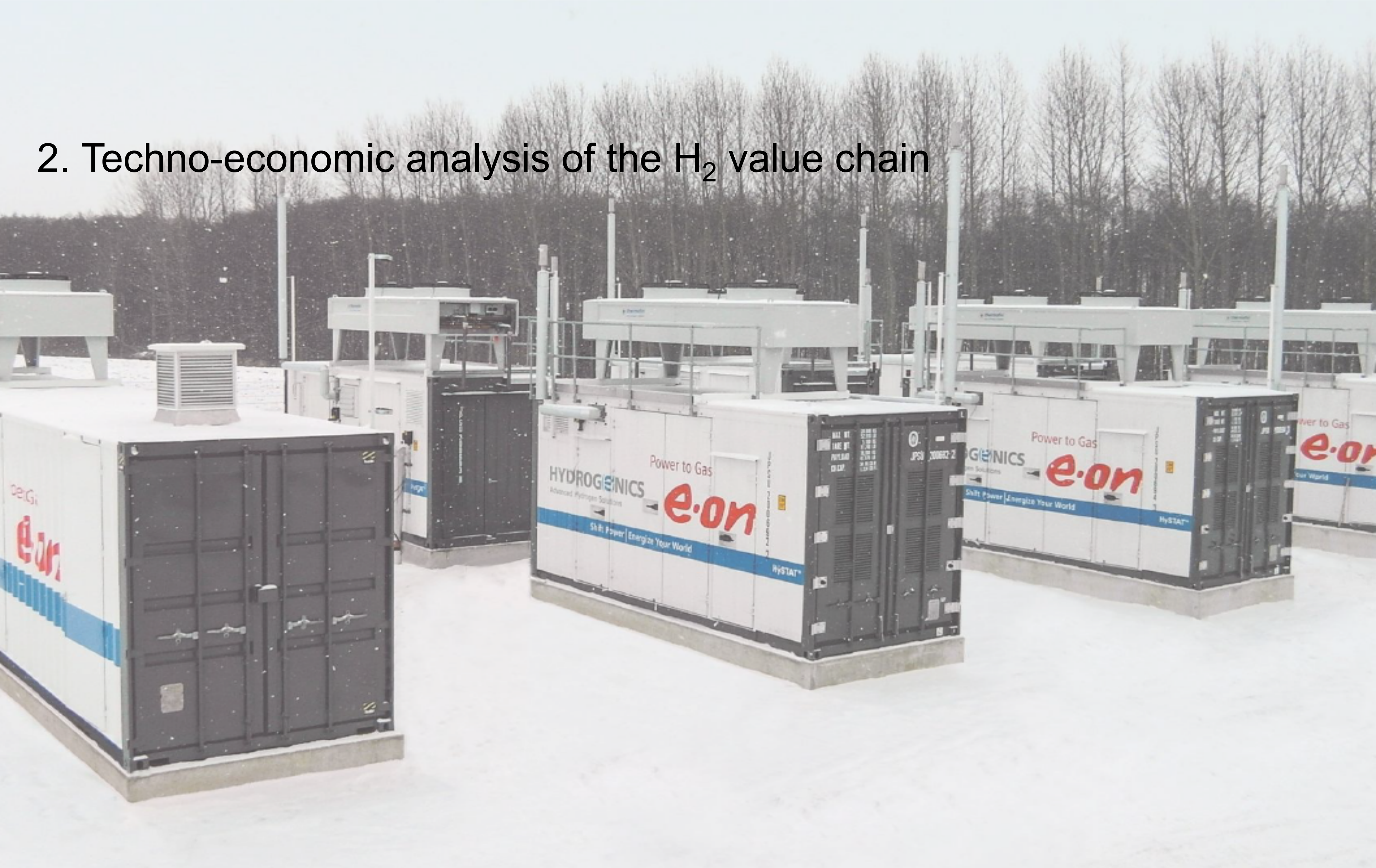
Electricity is only a limited part of the game





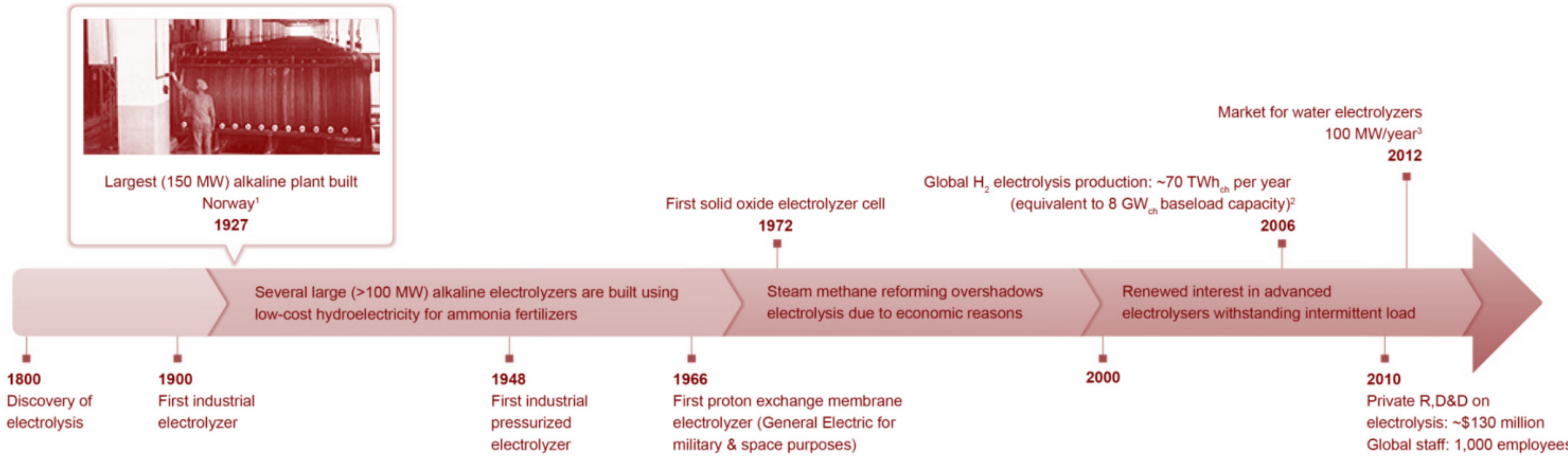
Note: 1The 2DS scenario is the IEA most ambitious decarbonization scenario and corresponds to a scenario that would limit global warming to 2°C by 2050; 2Renewables excluding power correspond mainly to biomass & waste, biofuels and solar thermal.
Source: A.T. Kearney Energy Transition Institute analysis; IEA (2012a).

2. Techno-economic analysis of the H_2 value chain



Electrolyzers capable of tolerating variable loads are pre-requisites for hydrogen-based storage solutions

History of water electrolysis



Although continuous-load water electrolysis is a mature technology, the need for electrolysis systems to withstand variable loads requires significant flexibility and this has changed the game.

Note: 1The plant built in 1927 by Norskhydro consisted of 150 alkaline stacks of 1 MW each. It was used to produce hydrogen from nearby hydroelectric plant to produce ammonia for fertilizers.
Source: A.T. Kearney Energy Transition Institute analysis; image courtesy of NEL Hydrogen.

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The momentum is with proton exchange membrane technology because of its ability to withstand variable electric loads and to supply pressurized H_2

Comparative performance of the three types of electrolyzers

Alkaline, proton exchange membrane [PEM] and solid oxide electrolyzer cells [SOEC]`

	Alkaline	PEM	SOEC
Comparative advantages Summary	• Cheapest option at the moment • Large stack size • Ultra-pure hydrogen output	• Ability to withstand variable load • Ability to operate self-pressurized • Design simplicity (modular & compact) • Compact system	• Energy efficiency • Possibility of co-electrolysis (CO_2 or H_2O) • Reversible use as a fuel cell (heat recycling) • No noble metals
Electrolyte	KOH liquid	Polymer membrane	Ceramic membrane
Charge carrier	OH^-	H^+	O^{2-}
Temperature	70-90°C	60-80°C	700-900°C
Current density	0.3 – 0.5 A/cm²	1 - 2 A/cm²	0.5 – 1 A/m²
Technical maturity	Commercial	Early commercial	R&D
Max stack capacity (kW_{ch})	3,000	~1,000	10 today,
System capital costs ($\$/kW_{ch}$)	850 today, 550-650 expected[2]	1,000-2,000 today, 760 expected[2]	200 expected at 500 MW/yr production[3]
System efficiency at beginning of life (% HHV)	68-77% today, potentially up to 82% at 300 mA/cm²	62-77% today, potentially up to 84% at 1,000 mA/cm²	89% (laboratory), potentially above 90%
Annual degradation[1]	2-4%	2-4%	17% (1,000h test only)
System lifetime (years)	10-20 proven	5 proven, 10 expected	1 proven

1. Power consumption increase per year in baseload utilization; 2. Expected by 2025 according to assumption from US DoE H2A model; 3. Expected if industrial production is reached.
Source: A.T. Kearney Energy Transition Institute analysis, based on EIFER (2011), Hydrogenics (2012), DTU (2012), Giner (2012), US DoE (2012) and FuelCellToday (2013).

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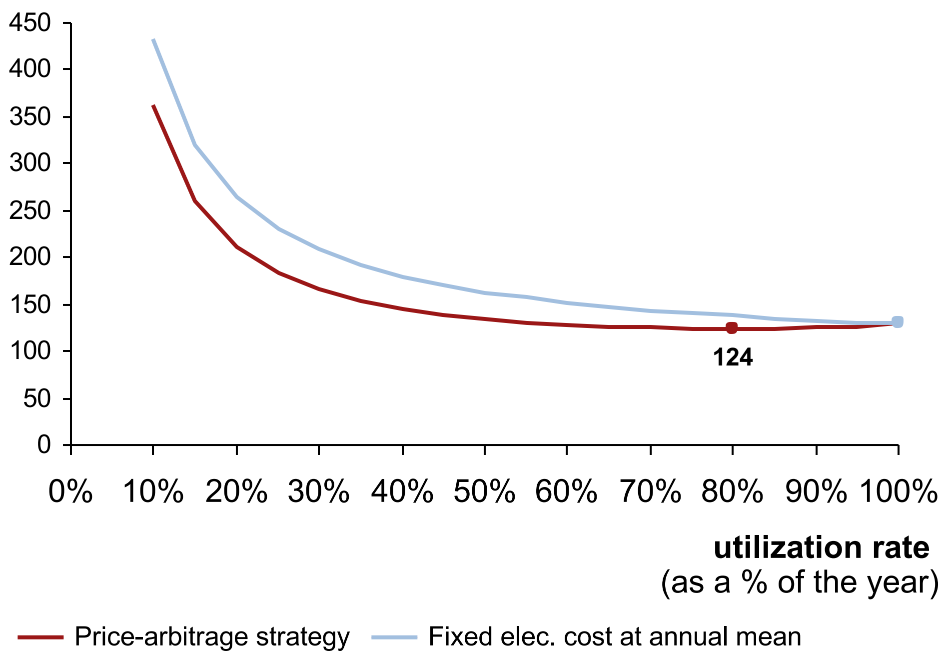
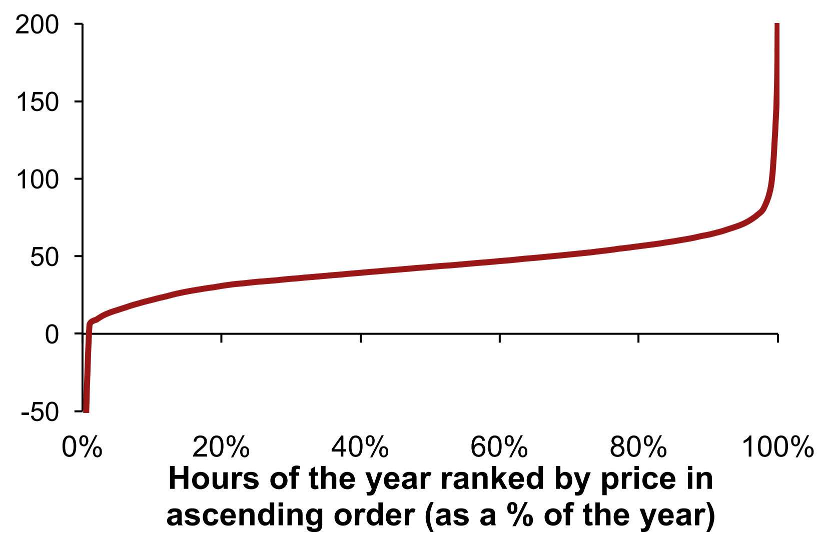
At present, electricity price spreads on the spot markets are still too narrow to enable significant hydrogen-production cost reductions through price arbitrage

Levelized Costs Of Hydrogen [LCOH] of a grid-connected electrolysis plant

€/MWh_{ch}, based on EPEX Spot price 2012 for Germany



2012 electricity spot price duration curve in Germany (€/MWh)



Spot price arbitrage leads to an optimal plant utilization rate of 80%. As a result, LCOH would be reduced by only 4% compared with baseload mode. It is essential for electrolysis economics to be viable to complement revenues by provide grid services.

Note: EPEX SPOT intraday trading “index price for each hour of 2012. Intraday SPOT and day-ahead SPOT auctions have been found to give very similar price duration curves. Electrolysis assumptions is based on the US for a 10MW alkaline plant with total installed system CAPEX: $848/MWh; Efficiency: 78%. Project lifetime: 30 years. Real discount rate after tax:10%.
Source: A.T. Kearney Energy Transition Institute Simulation based on EPEX Market Data, US DoE H2A Model.

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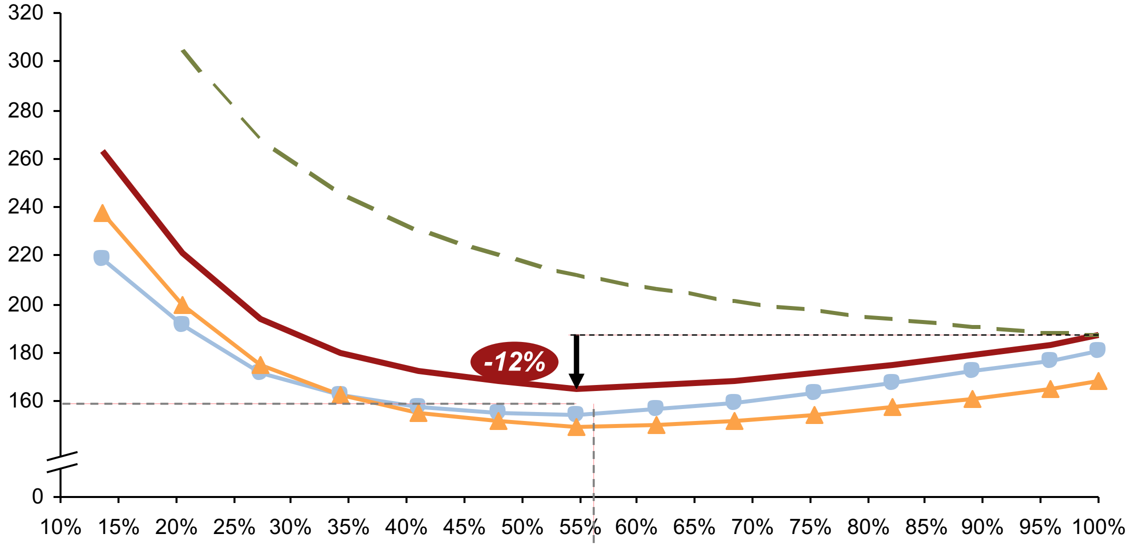
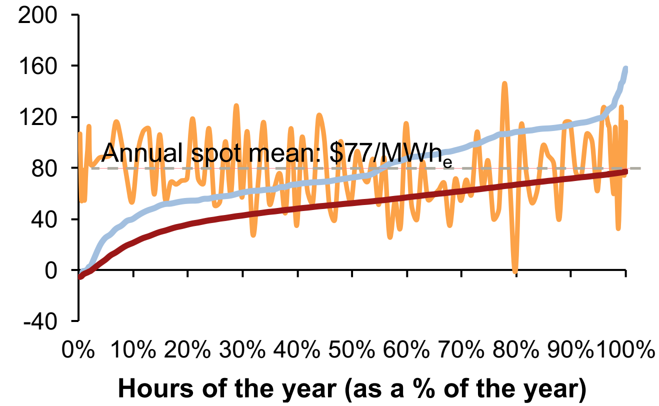
The priority is to lower manufacturing costs, which have a greater impact than efficiency on the LCOH, if the electrolyzer is operated highly discontinuously

Levelized Costs Of Hydrogen [LCOH] of a grid-connected electrolysis plant
$/MWh



Production excess monetization ← ***Plant load factor / utilization rate*** (operational hours as a % the year) → *Baseload*

Electricity price distribution used to assess the LCOH *($/MWh$_e$)*



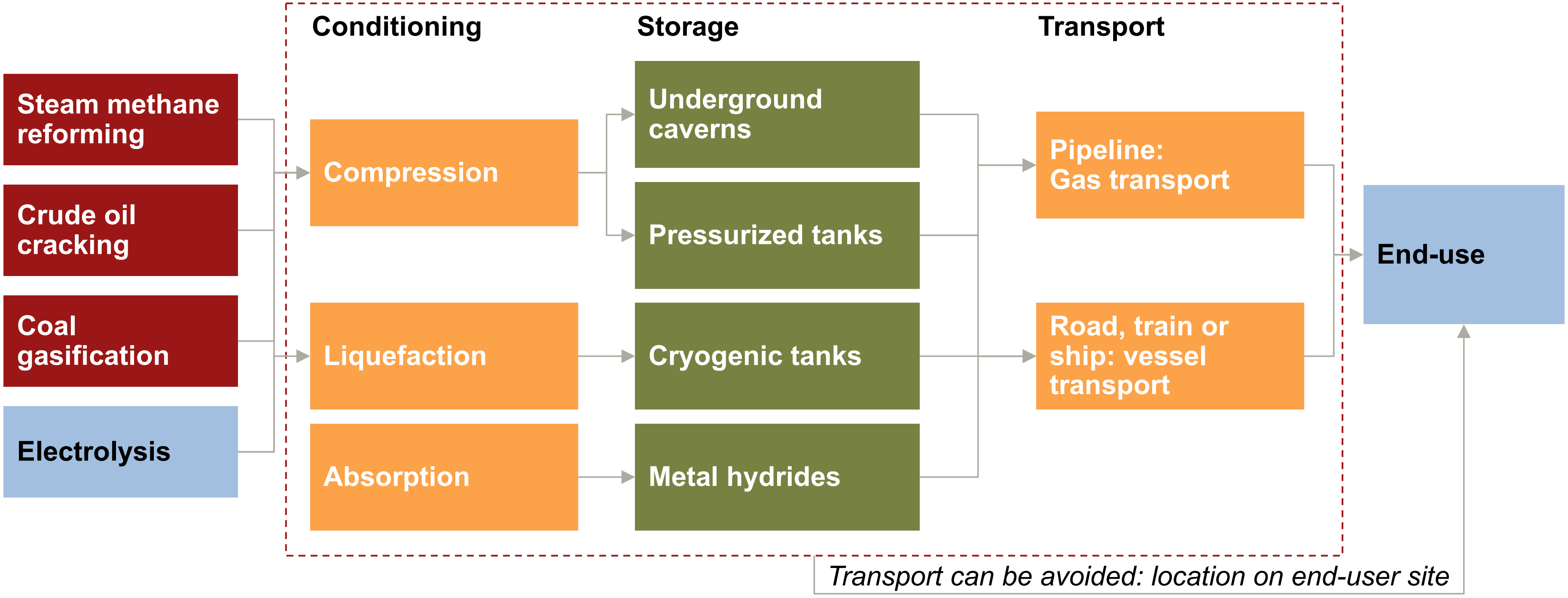
- Hourly prices ranked in chronologic order
- Hourly prices ranked in ascending order
- Cumulated average of hourly prices ranked in ascending order

- Reference plant with price-arbitrage strategy
- CAPEX -20% with price-arbitrage strategy
- Efficiency +10% with price-arbitrage strategy
- Reference plant buying electricity at annual spot mean

Note: Illustrative example based on 8.5MWch electrolysis (5 alkaline stacks of 7MWch each), with total installed system CAPEX: $765/MWh, Efficiency: 79%HHV, Project lifetime: 30 years and real discount rate after tax:10%.
Source: A.T. Kearney Energy Transition Institute Simulation based on US DoE H2A Model.

Due to hydrogen very low volumetric energy density at ambient conditions, it needs to be conditioned before it can be practically stored and transported

Hydrogen conditioning options before storage and transport options

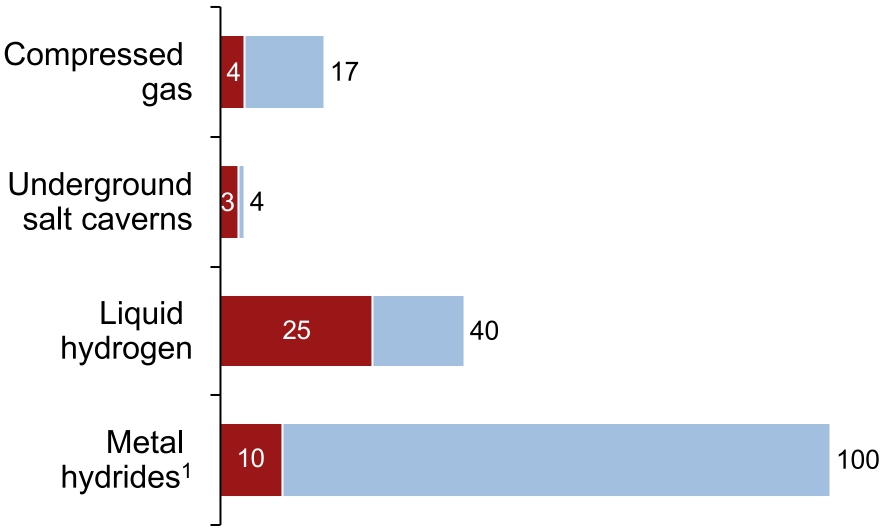


Hydrogen storage and transport form the most mature segment of the chain, benefiting from the chemicals and petrochemicals industries' experience of hydrogen utilization. The challenge is, first and foremost, economic. Due to hydrogen's very low volumetric energy density at ambient conditions, the volume of hydrogen gas produced by water electrolysis must be reduced in some way

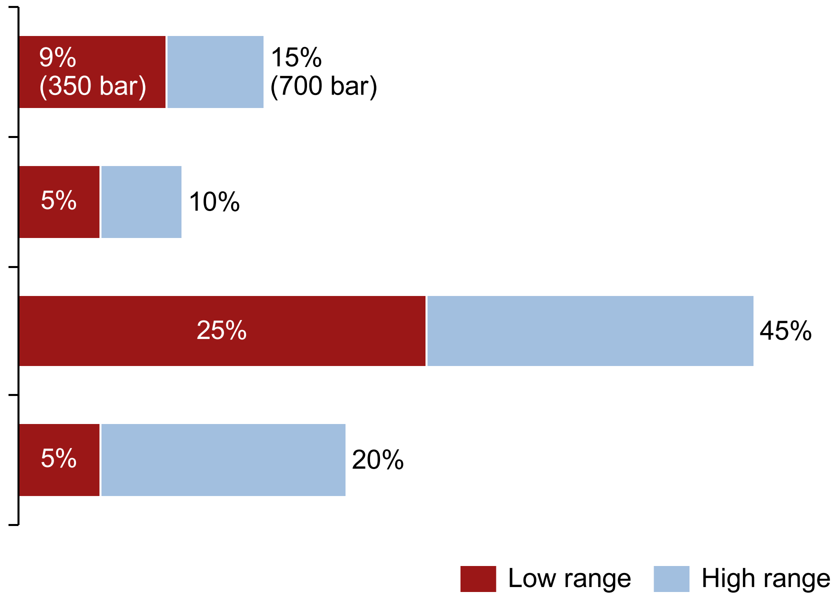
Source: A.T. Kearney Energy Transition Institute analysis.

Hydrogen is likely to be stored predominantly in gaseous form, although metal hydrides may play a growing role

$/MWh – ranges in literature



Energy lost in processing and storage In % of energy input



- Pressurized tanks are likely to remain the main means of storing hydrogen. They are well suited to small- to mid-scale applications, safe thanks to years of experience, efficient and affordable, as long as the cycling rate is high.

- Underground storage in man-made salt caverns allows lower cycling rates and is the most competitive option for large-scale storage. However, bulk hydrogen storage seems unlikely to be needed in the near future and could suffer from limited geological availability.

1. The very large range reflects the level of maturity of the technology and, in particular, the uncertainty concerning large-scale manufacture of the hydrides alloy.

Source: A.T. Kearney Energy Transition Institute analysis, based on Hawkins (2006) and US DoE H2A delivery model.

Underground storage in man-made salt caverns is a mature technology, but storage in aquifers and depleted oil and gas fields raises safety concerns

underground reservoirs suitable for hydrogen storage

Salt formations	The best option for underground hydrogen storage (and the only one that has been tried and used) consists of caverns mined in thick salt formations, at depths of up to 2,000 m. This host rock has a triple advantage over other geological formations: it allows a better cycling rate, needs only a small amount of cushion gas and its components do not react with hydrogen, avoiding gas poisoning. However, the costs are higher than its alternatives, and storage capacity lower.
Depleted oil & gas fields	The pore space of permeable rock formations sealed by a closed surface layer in depleted O&G fields makes them pertinent candidates for high-volume underground storage. Their tightness has been proved over millions of years, lowering geological risk. However, the need for a large amount of cushion gas and the risk of H2 contaminating other substances in the cavern (rocks, fluids and microorganisms) are significant barriers to progress and must be addressed.
Deep aquifers	The storage of hydrogen in aquifers remains an immature concept. These structures require additional exploration, which is usually costly. Aquifers present the highest potential in volume to store hydrogen. However, risks related to pressure losses when hydrogen is injected at a high rate and the potential for the various components of the reservoir (rocks, fluids and microorganism) to react with hydrogen may deter development

- Salt deposits are the only type of geological formation successfully used to store hydrogen underground to date. There are three facilities in operation for refining purposes in Texas (Moss Bluff, Spindletop and Clemens Dome) and in the United Kingdom (Teesside).
- Since these caverns are man-made, their size is largely customizable, albeit constrained by the dimensions of the salt formation.
- The shortage of suitable salt deposits, however, is a major hindrance to widespread use. Salt formations are unevenly distributed throughout the world and not all salt formation are suitable for H_2 storage.
- Research into alternatives to salt storage – *i.e.* natural reservoirs in deep aquifers and depleted oil & gas fields – is under way (*e.g.* Hychico in the Argentinian province of Chubut, is injecting H_2 into depleted gas fields, and testing for leaks and reactivity with the host rock)

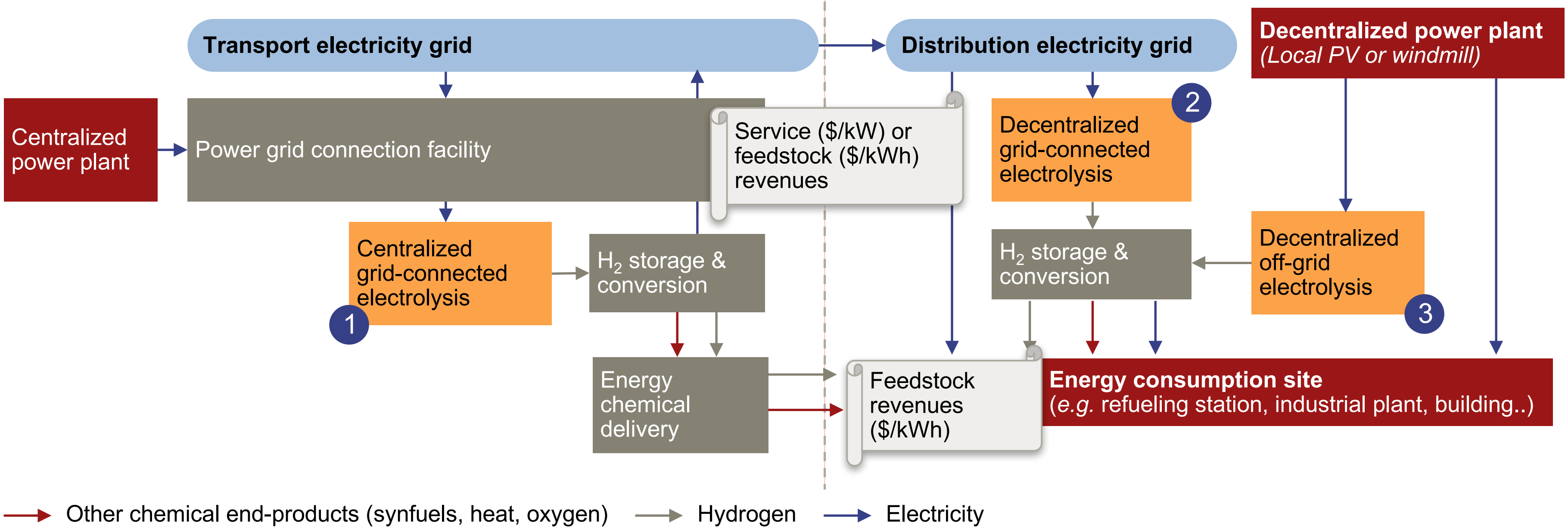
Source: A.T. Kearney Energy Transition Institute analysis; based on HyUnder (2012).

Decentralized hydrogen production is essential in order to minimize hydrogen-transportation costs

Schematic layouts of integrated projects

Centralized
(Grid-connected power plant or regional hub near electricity congestion points)

Decentralized
(Energy consumption site)



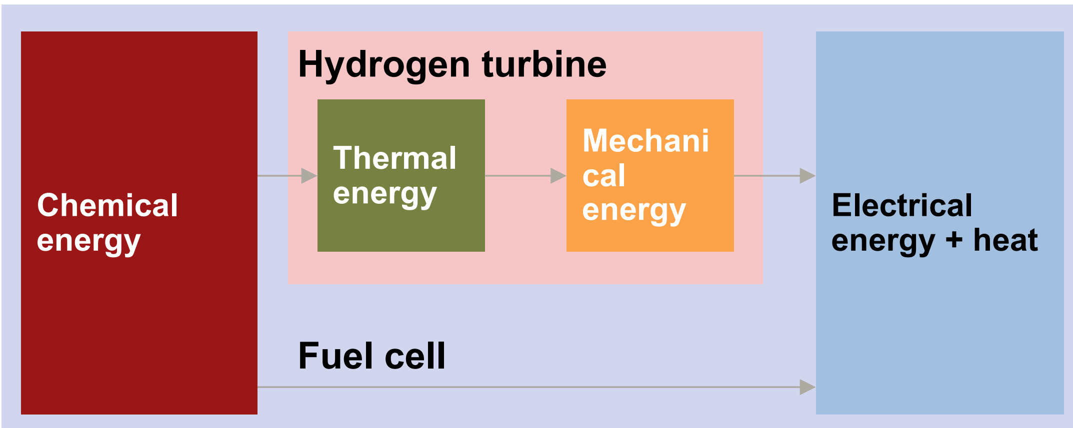
Decentralized production will be preferred to avoid the cost of transport[1]. When H_2 transport is still pertinent, the choice of transport depends on transport distance, on H_2 throughput and on the distribution of end users[2].

1. H_2 transportation, in itself, incurs limited energy losses in addition to those incurred by conditioning, but requires high up-front capital cost for pipeline and significant operation cost for road transport. Road transport enables distributed delivery (short distances & low throughputs in tanks, large quantity delivered over long distance for liquid H_2). Pipelines can provide a low-cost option for point-to-point delivery of large volumes of hydrogen. The final layout could include a mix of solutions, such as decentralized electrolysis located on end-user site, with a centralized production centers as delivered with road transports.

Source: A.T. Kearney Energy Transition Institute analysis.

Hydrogen can be re-electrified in a direct electrochemical process, using fuel cells, but also using conventional thermal combustion turbines

Energy forms in the two re-electrifications pathways



Fuel cells[1] (left) and turbines[2] (right) do not compete for the same applications: fuel cells are much more suited to decentralized designs and prioritize reliability, autonomy and low-maintenance; turbines are more suited to large-scale centralized projects because of economies of scale.

- Hydrogen can be re-electrified using fuel cells, but also using conventional thermal combustion turbines.
- Combustion turbines can be used to burn hydrogen - essentially a fuel gas. Pure-hydrogen turbines remain in the early demonstration phase because of limited demand, but would pose only moderate technical issues. However, most turbine manufacturers focus their attention on the use of mixture of natural gas and hydrogen into existing power plants. The latter raises safety, performance and environmental issues above a ratio of 1-5% of hydrogen by volume.
- Fuel cells have long been under development, driven by the promise of fuel-cell-electric vehicles. They are now in the early commercialization phase, mainly because of the growing popularity of stationary applications. Because the technology in fuel cells and electrolyzers is basically the same, the issues are similar: manufacturing costs and lifetime. Fuel cells are generally slightly less efficient than electrolyzers, but technically more mature.

Source: A.T. Kearney Energy Transition Institute analysis; image courtesy of [1]Bloom Energy and [2]Enel.

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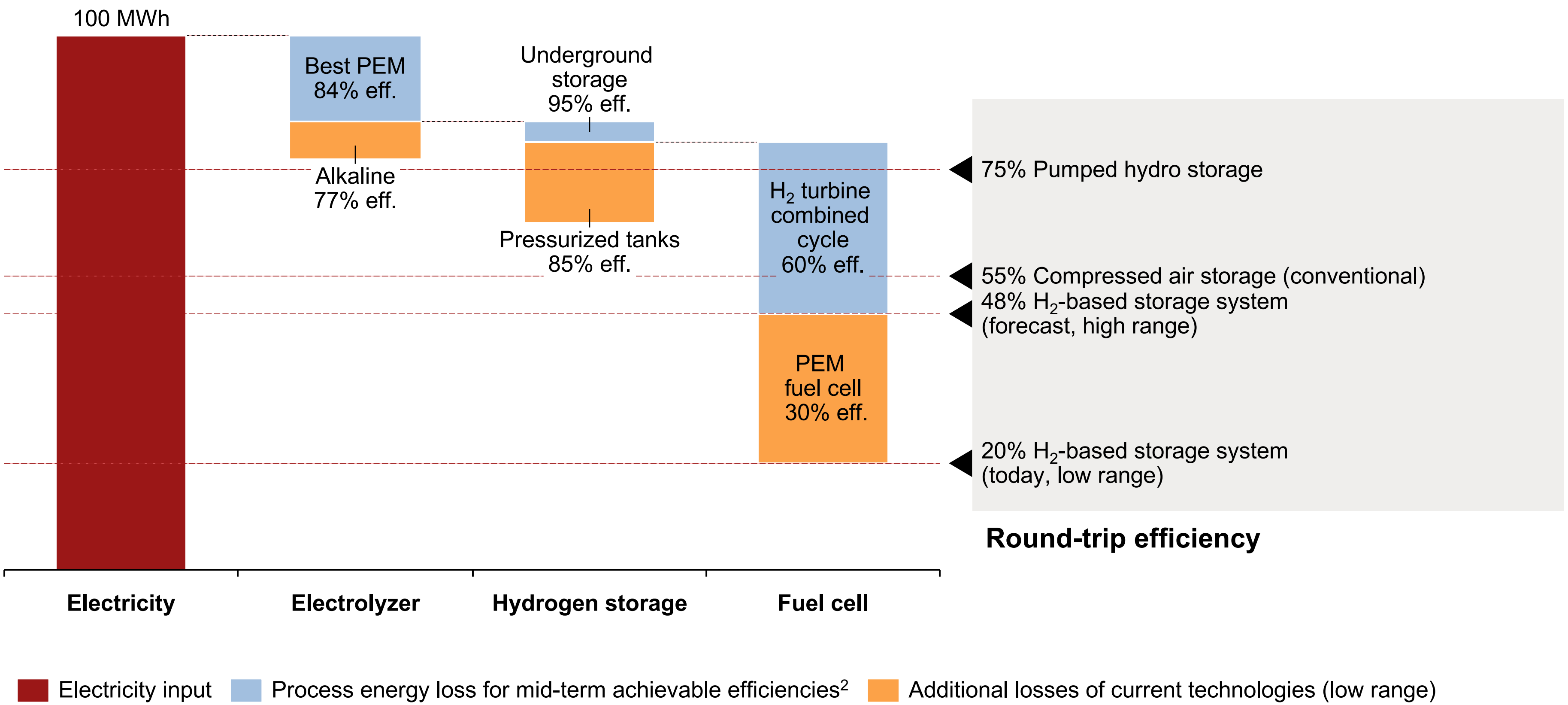
Hydrogen re-electrification results in poor round-trip efficiency, which is likely to impede its development in the short term

Losses along the stored hydrogen re-electrification value chain[1]

MWh, Based on a 100 MWh storage system with no hydrogen transport



Note: 1The waterfall presents the maximum range of best mid-term efficiencies together (84% for electrolyzers, 95% for storage, and 60% for re-electrification) and lowest current efficiencies combined (77% for electrolyzers, 85% for storage and 30% for re-electrification); 2Mid-term (<10 years) realistic target for efficiencies.
Source: A.T. Kearney Energy Transition Institute analysis.

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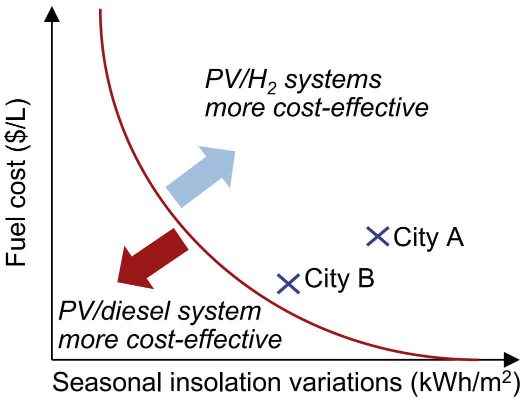
Fuel cells could yet be successful in applications where reliability and a low maintenance requirement are highly valued

Autonomous system for PV-powered telecom tower

A remote location

PV/H_2 *vs.* PV/diesel systems: boundary curve



PV-powered telecoms tower in India

How to read this graph?

- Several case studies have examined the conditions under which autonomous PV/H_2 systems could compete with PV/diesel for very small-scale applications. In both cases, batteries are required to overcome the short-term supply variations of solar electricity generation, but they do not compensate for the seasonal mismatch of PV output in high-latitude regions, which is managed by diesel generators or H_2-based systems.
- The sensitivity criteria are the cost of on-site diesel and seasonal insolation variations. According to these criteria, a boundary curve delineates where the two systems are equally cost-effective.
- Case studies argues that PV/H_2 systems for small-scale applications could be a pertinent in most regions by 2015. India is arguably the largest market for autonomous telecoms towers, where fast-spreading infrastructure is overly reliant on diesel, because of inadequate electricity grids.

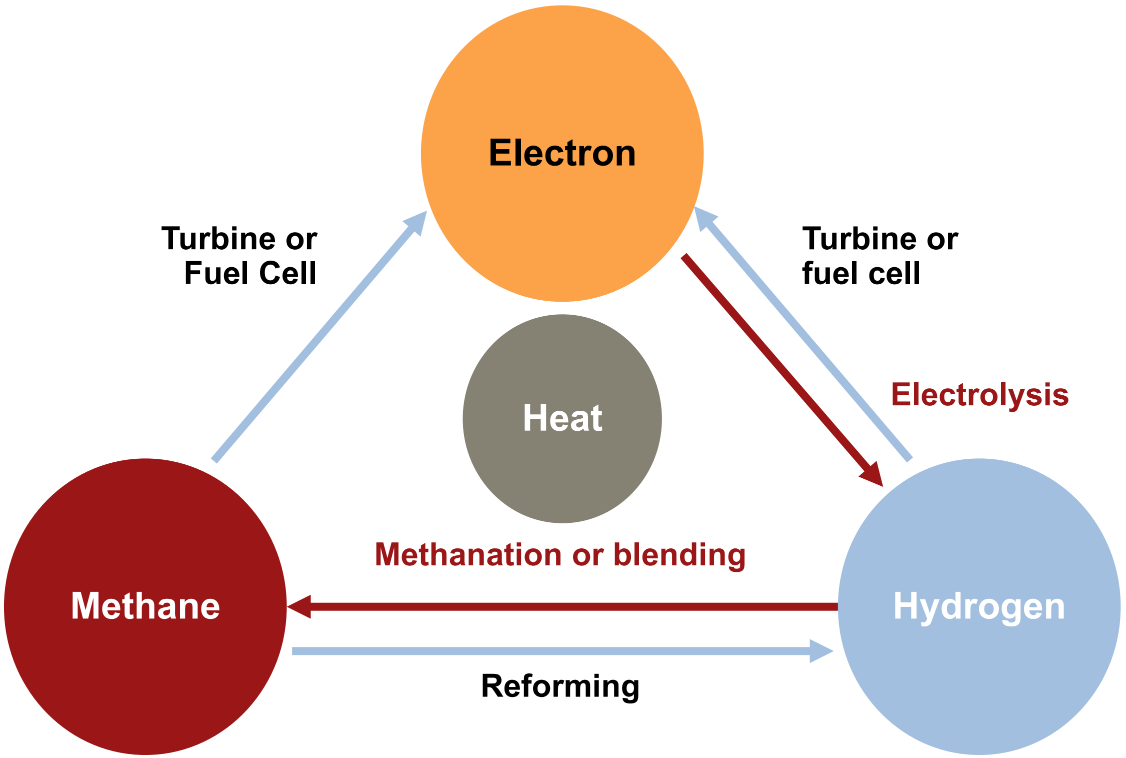
- Fuel-cell technologies are extremely reliable because they lack moving parts. Fuel cells could be particularly successful in applications where reliability and a low maintenance requirement are highly valued, such as back-up and auxiliary power, and uninterruptible power supply.
- One of the most promising markets is expected to be off-grid telecom towers in developing countries. In cases such as these, the main competitor to H_2 solutions would be diesel generators. Solar PV or wind turbine energy systems that incorporate batteries for diurnal storage and hydrogen storage solutions for smoothing seasonal variations are close to competitiveness in some countries. This illustrates the role that emerging countries may play in the development of off-grid energy storage because of the lack of legacy networks.

Source: A.T. Kearney Energy Transition Institute analysis, based on Raj et al. (2012), Utsira IPHE (2011), and IRENA (2012); Image courtesy of Greenpeace India Society.

Power-to-gas may change the rules of the energy game by linking the natural gas grid with the power grid

Pathways between energy carriers

Power-to-gas pathway in red



- P2G was conceived as a way of using the gas grid to store renewable electricity. But, in practice, P2G does more than this. Its benefits include:
  - The "greening" of end-uses of natural gas, such as heat generation;
  - The pooling of gas and power infrastructure to optimize the flexibility of the energy system.
- Power and gas grids can be linked in two ways:
  - Blending, which involves injecting hydrogen into the gas grid;
  - Methanation, i.e. the conversion of hydrogen and CO_2 into methane, also known as synthetic natural gas [SNG].

Source: A.T. Kearney Energy Transition Institute analysis.

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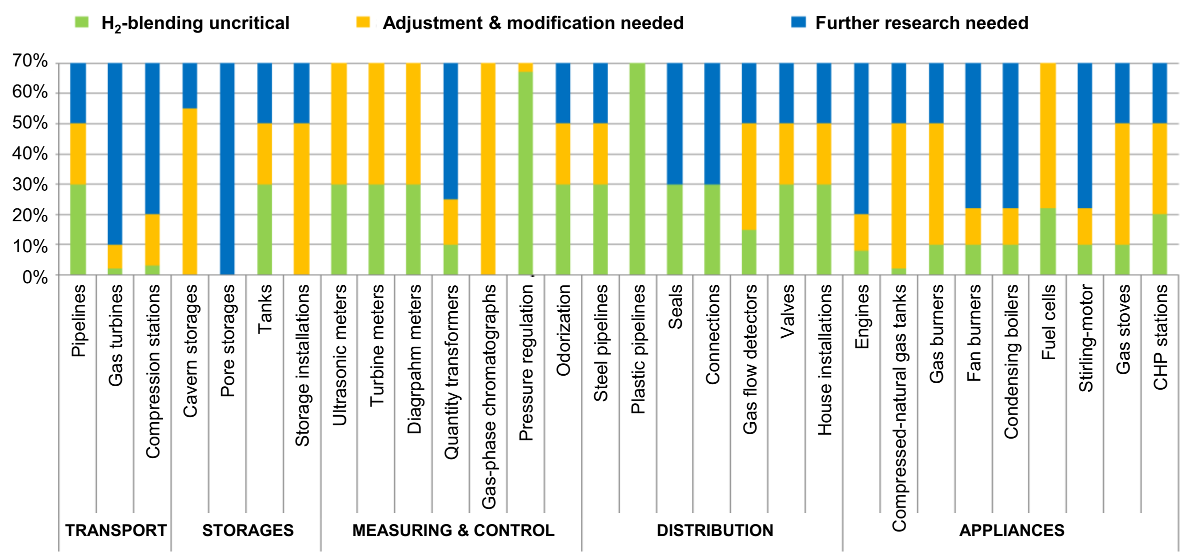
Although parts of the gas grid that do not feed critical appliances can tolerate up to 20% H_2 by volume, setting national limits above 5vol.% will be difficult

Limit of hydrogen blending along the natural gas infrastructure[1]

H_2 concentration (vol.%)

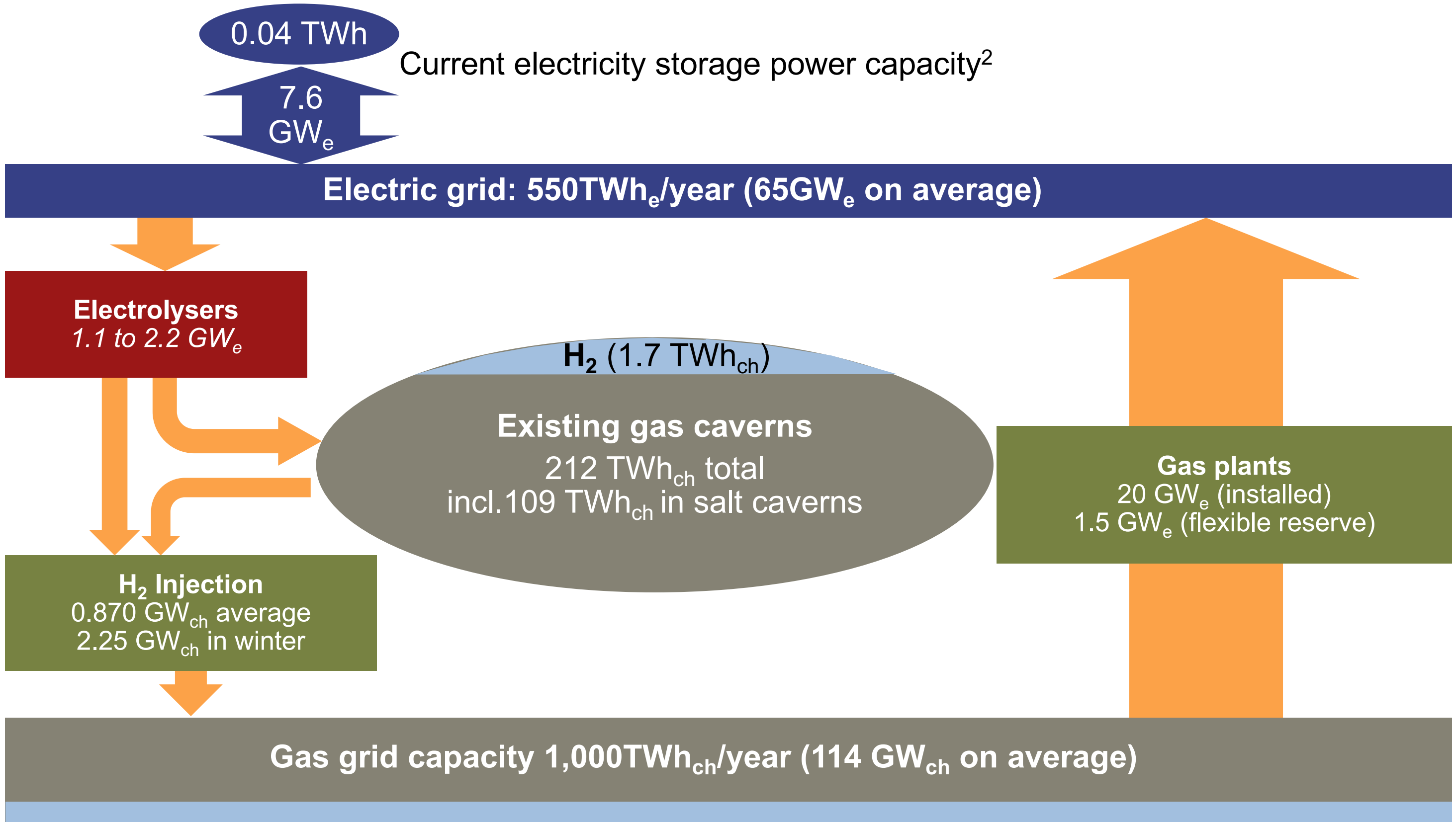


- Three main constraints must be addressed:
  - the integrity and safe use of pipeline and grid appliances;
  - the energy capacity of the grid;
  - the performance sensitivity of end-use appliances to hydrogen/methane blends.
- The latter is likely to impose the greatest limitation. In general, the gas grid should tolerate 1-5% volume blending at any point of the network, and up to 20% in distribution pipelines with no critical downstream appliances (and not made of exotic materials).

Note: 2. Aquifer or depleted oil and gas reservoirs.
Source: 1. DVGW (2013).

Hydrogen blending is an elegant early stage solution for monetizing electricity surpluses in countries with highly developed natural gas infrastructure

Order of magnitude of German hydrogen blending potential at 5vol.% blending[1]



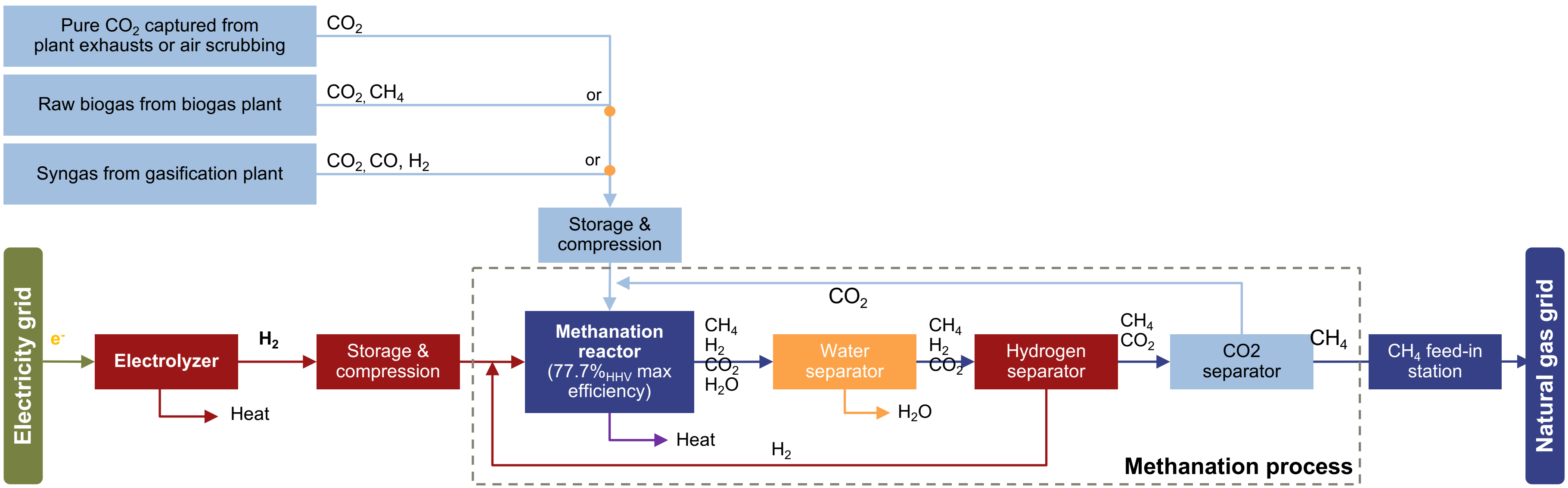
1. Order of magnitude for 5% blending in volume (i.e. ~5% in energy) where it does not affect the grid nor the end-use applications. It takes into account the dynamic of the seasonality of the grid (lowest demand in summer of 58 GW) for the injection rate (58 GW * 5% = 0.870 GW). Electrolyzer could act as negative control reserve (9GW in Germany currently, including 7.6 GW of pumped hydro); 2. Current Electric Storage capacity corresponds mainly to Pumped Hydro Storage capacity, on top of the Huntorf Compressed Air Energy Storage Facility.

Source: A.T. Kearney Energy Transition Institute analysis, based on IER (2011) and ZFES (2012).

A.T. Kearney | Energy Transition Institute

Methanation produces synthetic natural gas from H_2 and CO_2, which is not subject to blending-ratio limits

Power-to-methane process: illustration with the thermochemical route



How to read this diagram?

- The power-to-methane process reacts electrolytic H_2 with carbon dioxide to produce methane that can be injected into the natural gas grid. The siting of such plants is limited, economically, to locations near a large-scale, fatal CO_2 source and an existing gas pipeline. The methanation reaction has been well known since 1897, but integrated power-to-methane projects remain at an early demonstration phase. Two competing approaches are being tested – thermochemical (diagram above) and biological.
- Despite incurring additional capital costs and energy losses – of 40% when heat is not recovered – methanation is considered a promising way of getting round blending-ratio limitations. However, due to the process's huge CO_2 requirements, it is constrained by the availability of affordable CO_2 sources. CO_2 capture from air is extremely energy intensive, resulting in an efficiency drop from 60% to 39%.

Source: A.T. Kearney Energy Transition Institute analysis.`

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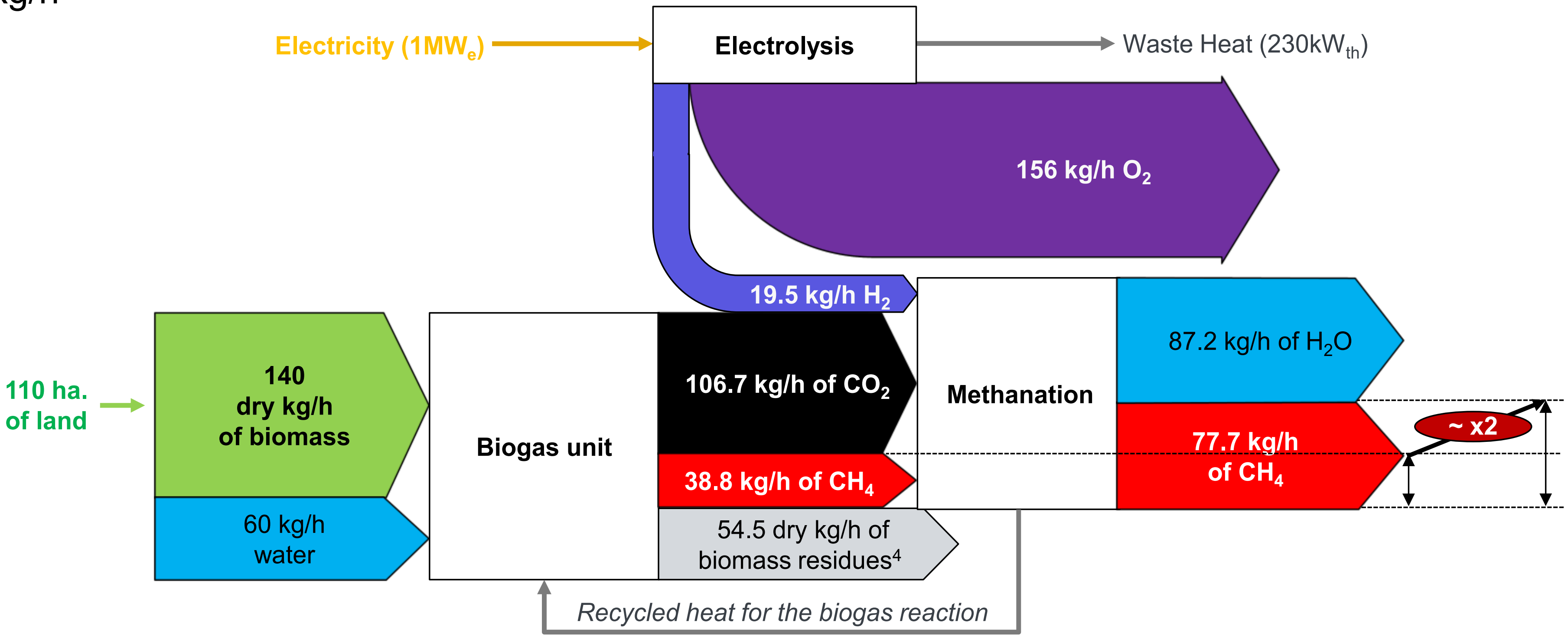
Biomethane feed-in plants are the best CO_2 source for methanation, which is uneconomic without large sources of fatal CO_2

Simplified MASS flow chart of Hydrogen-enriched biomethane plant

kg/h



Biomethane reactors produce raw biogas, with an excess of CO_2, that can be upgraded with electrolytic hydrogen. In addition, the heat from methanation can be recycled to power the biogas unit, boosting the efficiency of biomethane production from 68.7% to 85.3%. This increases the ratio of methane output to biomass input by a factor of up to 2.5 and optimizes land use.

1. feedstock is a maize silage of 5kWhch/kg of dry matter, cultivated with a land yield of 0.63MWch per km².; 2The anaerobic digestion of maize silage requires heat and has an total efficiency of 68.7%; 3Thermochemical methanation at 300°C and 77.7% hydrogen-to-methane efficiency

Source: A.T. Kearney Energy Transition Institute analysis.

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There are two competing methanation processes: thermochemical catalysis and biological methanation

Methanation methods compared[4]

	Thermochemical catalysis	Biological catalysis
Comparative advantages Summary	• Technically more mature • Possibility of up-scaling: easier to control • Lower maintenance time • Higher temperature waste heat for recycling	• Potentially lower costs (no metal catalyst, lower pressure) • Tolerance to impurities in the feed gas • Flexibility in ramping rate and operational load • More adapted to small scale/decentralized (<10MW)
Technical maturity	• Demonstration phase (6 MW being built by Etogas)	• Early demonstration phase (250 kW being built by Electrochaea)
Input gas	any mix of CO_2, H_2, CO, CH_4, H_2O	
Contamination tolerance	• Low tolerance to H_2S and O_2 • Requires dehydration of H_2 after electrolysis	• High tolerance to impurities, H_2S, and water vapor. • Limited tolerance to oxygen
Temperature	• 250-400°C	• 60-70°C
Pressure	• 1-100 bar	• 1 bar
Methane purity (conversion yield[1])	• 92-96% depending on catalyst and flow rate through the reactor	• ~98-99%
H_2-to-methane energy efficiency[2]	77.7% theoretical limit without heat recovery	
Power-to-methane energy efficiency[2]	• ~60% excl. heat recovery; ~80% incl.	• Today: 54.7% excl. heat recovery; 73.5% incl. • Target: 63.2% excl. heat recovery; 82% incl.
Flexibility (0%-90% ramp up/down)	• 30 minutes to 1 hour in cold start	• Second to minutes

Thermochemical catalysis is likely to remain the preferred option in the short to mid-term. On the longer run, the biological method seems better adapted to small-scale applications, and the thermochemical method to mid- to large-scale ones.

1. Conversion yield refers to the ratio of CO_2 molecules actually converted into CH_4 when enriched with H_2 in stoichiometric quantity; 2Energy efficiency in HHV, assuming free CO_2 supply.
Source: A.T. Kearney Energy Transition Institute analysis; based on interviews with methanation technology developers Etogas and Electrochaea.

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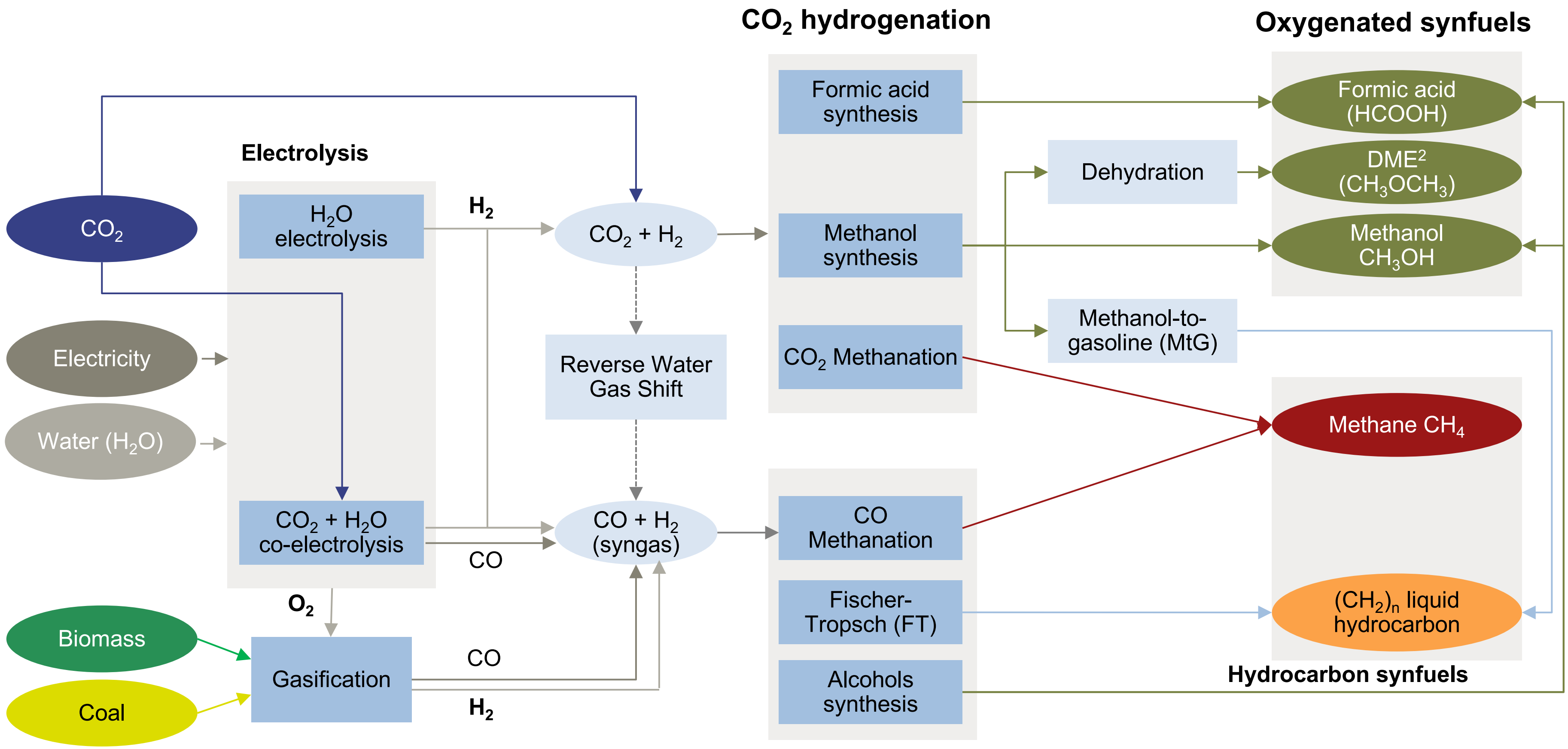
A number of synthetic liquid fuels can also be synthesized from hydrogen and carbon

Power-to-synfuels[1] pathways for H-C-O synfuels production



1. plant are synfuels plants where electricity and electrolyzers are used to produce hydrogen that will help to produce synfuels.
2. DME for Dimethyl ether.

Source: A.T. Kearney Energy Transition Institute analysis.

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Hydrogen is a vital molecule for mobility

The role of hydrogen in mobility

Present → **Future?**

Fossil fuels

Diesel and gasoline
- Increase hydrogen / carbon [H/C] ratio of heavy oil fractions;
- Desulfurization (more stringent regulation).

Natural gas vehicles [NGV]
- Reduce local pollution and increase performance with hydrogen blending (hydrogen compressed natural gas fuel).

Synthetic fuels

Biofuels
- Enrich biofuel plant with hydrogen to maximize biomass yield and thereby land use;

H-C-O synfuels
- Fix hydrogen with CO_2 to synthesize methane, methanol, dimethyl ether, gasoline…;

Ammonia fuels
- Fix hydrogen with nitrogen and use ammonia as a fuel.

Pure Hydrogen fuel[1]

Pure hydrogen carrier
- Use hydrogen to produce electricity in fuel cell electric vehicles [FCEV];
- Use hydrogen fuel cell in battery electric vehicles [BEV] as a range extender.

Mobility will probably be the main driver of hydrogen use in the medium-to-long term, but not necessarily for fuel cell electric vehicles.

1. internal combustion engine [H2ICE] that uses a traditional ICE, modified to burn hydrogen instead of conventional gasoline, has lost momentum compared with FCEV and is not mentioned in this slide.

Source: A.T. Kearney Energy Transition Institute analysis.

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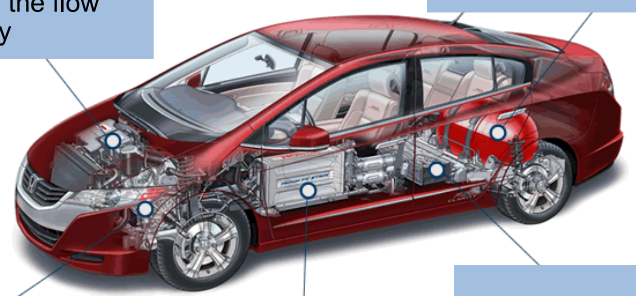
FCEVs are back in the spotlight, but successful deployment depends on the cost of fuel cells and on solving the challenge of the hydrogen infrastructure roll-out

Basic circuits in a fuel-cell electric vehicle [FCEV]

Honda, FCX Clarity

Hydrogen storage tank
Stores hydrogen gas compressed to extremely high pressures, increasing driving range

Power control unit
Governs the flow electricity



Electric motor
Propels the vehicle much more quietly, smoothly, and efficiently than an internal combustion engine and requires less maintenance

Fuel cell stack
Converts hydrogen gas and oxygen into electricity to power the electric motor

High-output battery
Stores hydrogen generated by regenerative braking and provides supplemental power to the electric motor

- Using fuel cells to power electric vehicles [FCEV] has long been considered a promising solution for mobility. FCEV would benefit from the advantages of electric drivetrains (namely high efficiency and no pollution at the point of use), while not incurring its drawbacks (refueling time, mileage range).
- However, FCEVs are still struggling to overcome the deployment “valley of death”. They must resolve three major challenges: onboard hydrogen storage, the durability and high costs of fuel cells, and hydrogen distribution.
- After years of stasis, FCEVs are back in the spotlight
  - Automakers have teamed up to renew the push towards hydrogen mobility. In 2013, Toyota and BMW; Daimler, Nissan and Ford; and General Motors and Honda announced partnerships;
  - Several public-private mobility programs have been announced to foster the deployment of hydrogen infrastructure (*e.g.* UKH_2Mobility, H_2USA) following the lead of existing, ambitious programs in South Korea, Japan and Germany.

FCEV is a type of electric vehicles. But instead of storing electricity, a FCEV stores hydrogen and a fuel cell acts as a micro power plant to generate electricity on board.

1. Fuel cells are also being developed as range extenders for electric vehicles (e.g. SymbioFCell tests hydrogen fuel cell range extender on Renault Kangoo electric vans used by the French postal service).

Source: A.T. Kearney Energy Transition Institute analysis; image courtesy of Honda and U.S. DoE.

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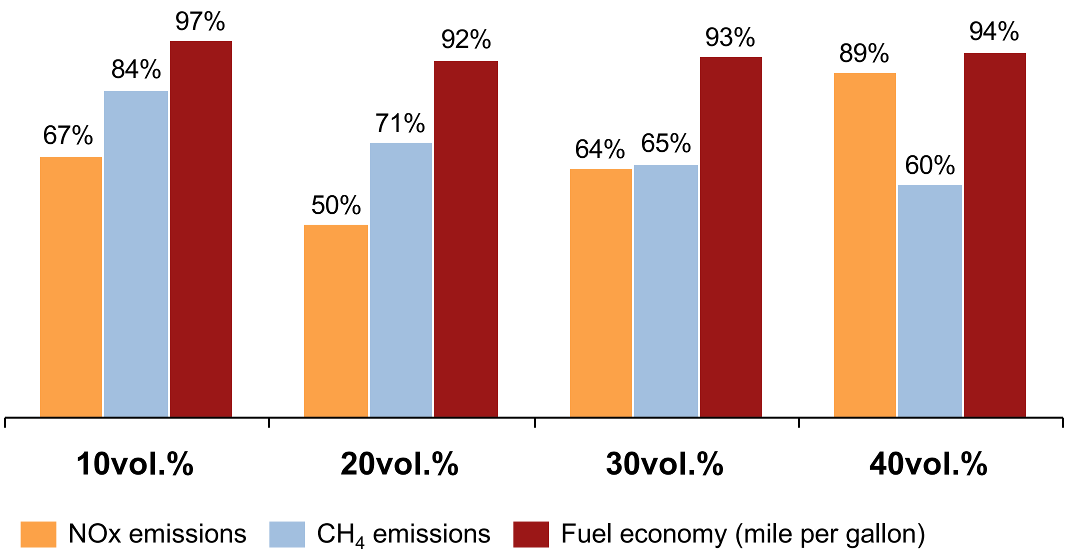
Hydrogen-enriched compressed natural gas vehicles may provide solutions to the hydrogen infrastructure development challenge, and to cleaner mobility

Comparative performances of different blends

% of compressed natural gas vehicles [CNG] fuel performance



How to read this graph?

- 20% blending results in a drop in NOX emissions of up to 50% compared with CNG.
- Fuel economy (km/L) is lower than for CNG when hydrogen is blended.
- Blending hydrogen with CNG significantly reduces the emissions of unburned CH_4.

- Hydrogen can be used to upgrade natural gas for natural gas vehicles [NGVs]. It is believed that blending hydrogen with methane, and calibrating the engines to run on such a mixture, reduces air pollution and incurs a negligible loss of power performance (graph):
  - This is all the more important that NGVs have been introduced in several emerging countries to mitigate the effect of local air pollution on human health;
  - There are currently more than 15 million NGVs on the road, compared with around 100,000 battery electric vehicles [BEVs].
- Methanation is also a valuable option for decarbonizing gas-powered transport[2] and is being considered in several European countries, notably Germany or Sweden.
  - Audi has taken the lead with its e-gas project and a 6 MW demonstration plant in Werlte (Germany);
  - With the same wind power mix, e-gas vehicles would entail roughly similar well-to-wheel greenhouse gas [GHG] emissions than BEVs.

1. When running the motor at constant full load; 2For more information on methanation, please refer to slides 29 to 3
Source: A.T. Kearney Energy Transition Institute analysis, based on 1Ma et al. (2010).

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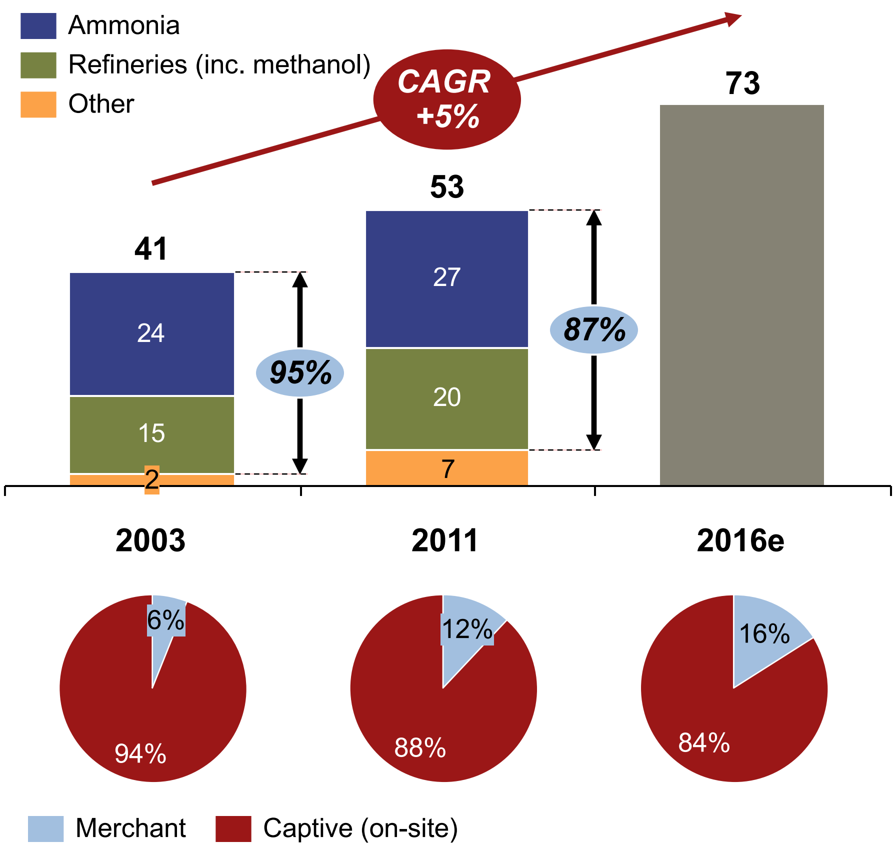
Hydrogen is an important industrial gas, with 87% of demand coming from the chemicals and petrochemicals industries

Annual worldwide hydrogen consumption

2003 – 2016, million tons



- Industry is the largest consumer of hydrogen and will remain so in the near- to mid-term. But industry is also one of the main producers of hydrogen, a by-product of several industrial processes.
- By-product hydrogen accounts for 33% and 36% of hydrogen production in Europe and the United States, respectively. On-purpose large scale captive facilities dominate with 65% and 49% of their production. This is to be compared with 9% and 15% for merchant H_2.
- However, despite being distorted by “over-the-fence” sourcing by refineries, the share of merchant hydrogen has been steadily increasing on a global level – from 6% of consumption in 2003 to 12% in 2011. By 2016, it is expected to reach 16%.
- Small-scale applications, such as food factories and hospitals, may be the most attractive industrial markets in the short term due to the premium charged for very small quantities of high purity hydrogen.

1. A 5.6% CAGR has been applied on 2011 level assuming that 35% of the growth will derived from the merchant analysis.
Source: A.T. Kearney Energy Transition Institute analysis, based on Global Industry Analysis (2012).

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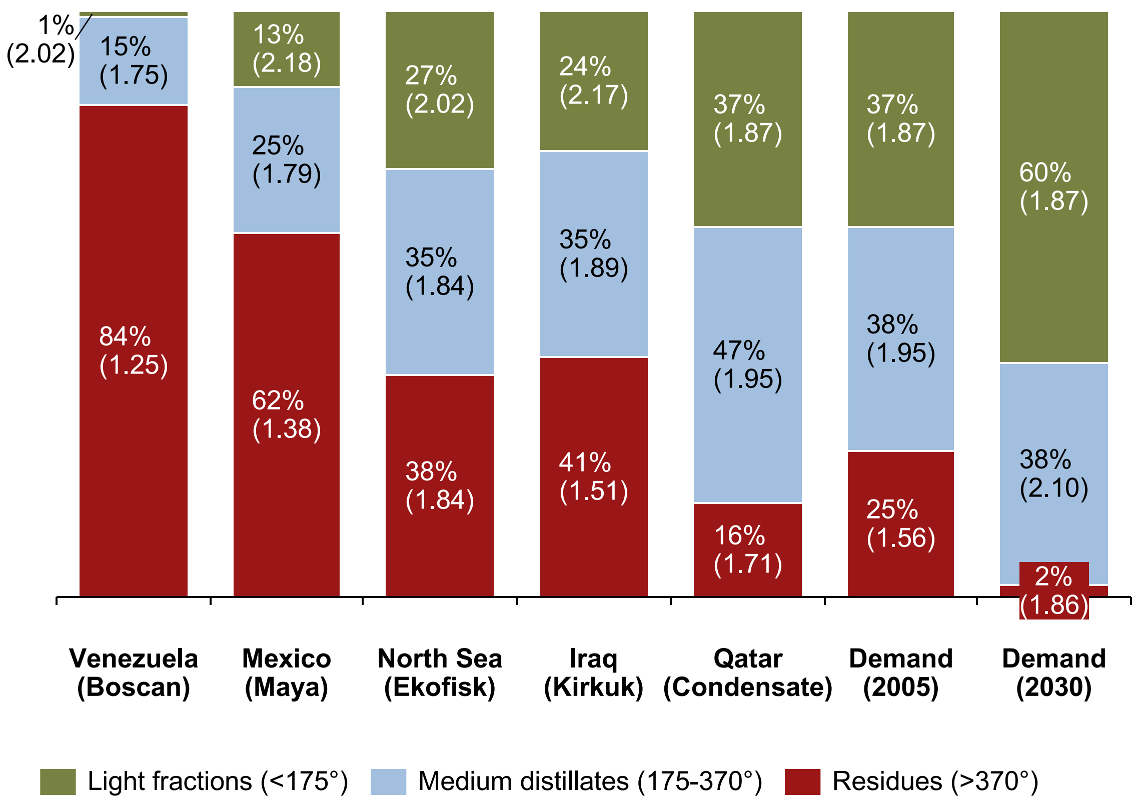
Electrolytic hydrogen is unlikely to compete with steam methane reforming, but may provide refineries close to H_2 equilibrium with additional operational flexibility

Distribution of oil fractions and average H/C ratio[1]

% of weight of crude feed[2]



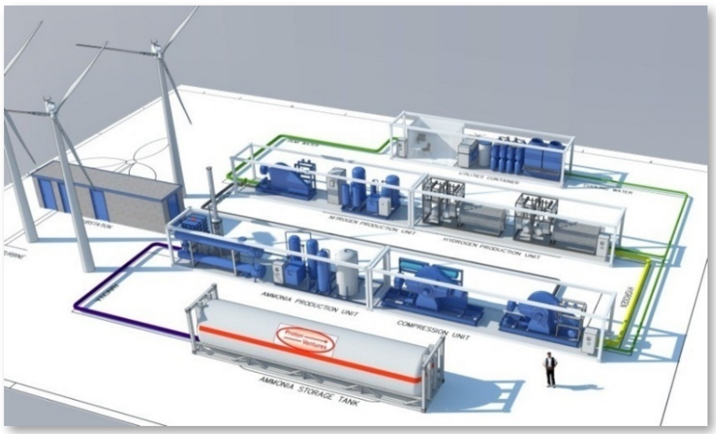
- Refineries produce H_2 as a by-product of catalytic reforming and consume H_2 to reduce the sulfur [SO_X] content of oil fractions and to upgrade low-quality heavy oil.
- On a macro level, the H_2 balance of refineries has turned from positive to negative, a trend that is expected to continue because of: more stringent SO_X regulations; the processing of heavier crudes; and falling demand for heavy end-products and growing demand for light products.
- Most of this deficit will be supplied by the reforming of natural gas. Electrolytic hydrogen is not yet able to compete with steam methane reforming, but it could provide operational flexibility for refineries that are close to hydrogen equilibrium.

1. hydrogen-to-carbon ratio; 2crude feed ranked by API index from extra heavy to condensate. API gravity is the scale developed by the American Petroleum Institute [API] to measure the relative density of petroleum liquids, in degrees.

Source: Institut Français du Pétrole Energies Nouvelles [IFPEN] (2012).

Small-scale ammonia production for fertilizers, coupled with distributed renewable production could make economic sense in remote locations

Proton venture mini wind-to-hydrogen plant[1] COMPARED
with sorfert steam methane reforming fertilizer plant[2]



Proton Venture power-to-ammonia plant

Orascom / Sonatrach Sorfert steam methane reforming fertilizer plant

- More than half of H_2 produced worldwide is used to produce ammonia, obtained from the catalytic reaction of nitrogen and hydrogen. In this process, nitrogen is captured for free from the air, while the hydrogen needs to be produced.
- In practice, ammonia synthesis is usually coupled with H_2 production from steam methane reforming [SMR], in large integrated plants. Consequently, in contrast to refineries that can adjust their H_2 balance with external sourcing, ammonia plants are mainly a captive market.
- However, small-scale ammonia production for fertilizers, coupled with distributed renewable electricity production, could make economic sense in remote locations. In such places, the cost of transporting ammonia might make electrolytic H2 competitive. Several projects have been considered, but none has yet been completed.

1. Sorfert is a greenfield fertilizer plant commissioned by Orascom in 2013 in Algeria. It is supplied in natural gas by Sonatrach (Sorfert is a joint-venture : 49% Sonatrach, 51% Orascom) and has a capacity of 2.200 t/d of ammonia and 3.400t/d of urea.

Source: A.T. Kearney Energy Transition Institute analysis, images courtesy of 1Proton Ventures, 2Orascom Construction Group.

3. Business cases

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The main challenge for hydrogen conversion is economic rather than technical: how to find a sustainable business case in an uncertain environment?

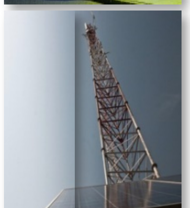
End-markets of electrolytic hydrogen

Power-to-gas

- Injection into the gas network is, so far, limited to feasibility studies and field pilot plants (*e.g.* E.ON's 360 m^3/h hydrogen injection in Falkenhagen). Hydrogen feedstock used for biogas and biofuel plants is also restricted to the up-scaling pilot plants in Germany (*e.g.* Etogas and the Audi 6 MW project in Werlte).

Power-to-mobility

- Mobility applications are constrained by infrastructure in place, which consists, as of 2012, of 221 active refueling stations worldwide supplying around 650 demonstration fuel-cell-electric vehicles and 3,000 forklifts. There are also a small number of compressed natural gas stations equipped with hydrogen-blending facilities.



Power-to-power

- Re-electrification, despite the promising increase in fuel-cell shipments, remains at a nascent stage and is still mainly driven by portable applications. Recent announcements from H_2 manufacturers indicate that the first integrated module may yet provide an outlet for off-grid power or grid support. At this stage, there is no long-term storage project in the pipeline.

Power-to-industry

- The merchant hydrogen market supplying industrial needs (*e.g.* healthcare, space industry, meteorological monitoring) is growing and may generate higher prices in the short term for customers looking for high purity and small volumes of hydrogen. Coupling an electrolyzer with a wind farm or with solar PV cells close to end-demand may provide markets for the first stand-alone business cases.

- Most technologies in the hydrogen value-chain are proved, albeit at different stages of maturity. Cost reduction is the next prerequisite on the road to commercialization.
- Costs are only one side of the commercialization equation. They must be balanced by revenues to achieve profitability and there is a long way to go in this area too.
- Uncertainties over cost reductions and the shape of the market result in a complex business equation for hydrogen-based conversion and storage solutions.

1. Fuel cell shipments reached 100 MW for the first time in 2011; Horizon Fuel Cell Technologies also sent a positive signal by buying ITM's sales and marketing rights for small-scale electrolyzers in some Asian countries.

Source: E.ON (2013); Troncoso (2011).

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The versatility of the hydrogen carriers opens the way to end-uses that valorize the power conversion to H_2 as a service or the H_2 produced as a feedstock

Examples of direct revenue streams from the conversion of intermittent-source

Electricity into hydrogen

Temporary excesses of electricity from renewable energy sources converted into hydrogen by electrolysis

Hydrogen feedstock

Gas network	Inject hydrogen into the gas network to make use of existing infrastructure. It will be in competition with natural gas.
Biogas / biofuel plant	Recycle carbon from biofuel/biogas plants with hydrogen.
Refueling station	Provide hydrogen to refueling. It will compete with alternative fuels (on a \$-per-km basis) and with other H_2 sources.
Power plant	Supply hydrogen to fuel-cell power plants (competing with alternative H_2 sources) or to gas turbines (competing with natural gas).
Merchant hydrogen	Provide hydrogen to an industrial/chemicals customer. It will compete with other hydrogen-production technologies.

Conversion service

Price arbitrage	Take advantage of market signals, competing with alternative storage technologies.
Baseload plants optimization	Avoid shutdown of baseload power, competing with alternative storage technologies.
Curtailment avoidance	Avoid curtailment of wind or solar generators, competing with alternative storage technologies.
Security of supply	Provide long-term supply security (*e.g.* with underground storage) to boost system adequacy and help energy independence.
Quality of supply	Adjust output up or down to provide better power quality and uninterruptible power supply (*e.g.* frequency and voltage control).
Deferred investment	Avoid grid congestion and defer investment in the power network. This also avoids having to invest in back-up power plants.

By-products (oxygen, heat)

Subject to regulation and energy system features, clean hydrogen feedstock may be fostered by:

- Feed-in-tariffs;
- Quotas / obligations;
- Willingness-to-pay; and
- Other mechanisms such as carbon markets.

Source: A.T. Kearney Energy Transition Institute analysis.

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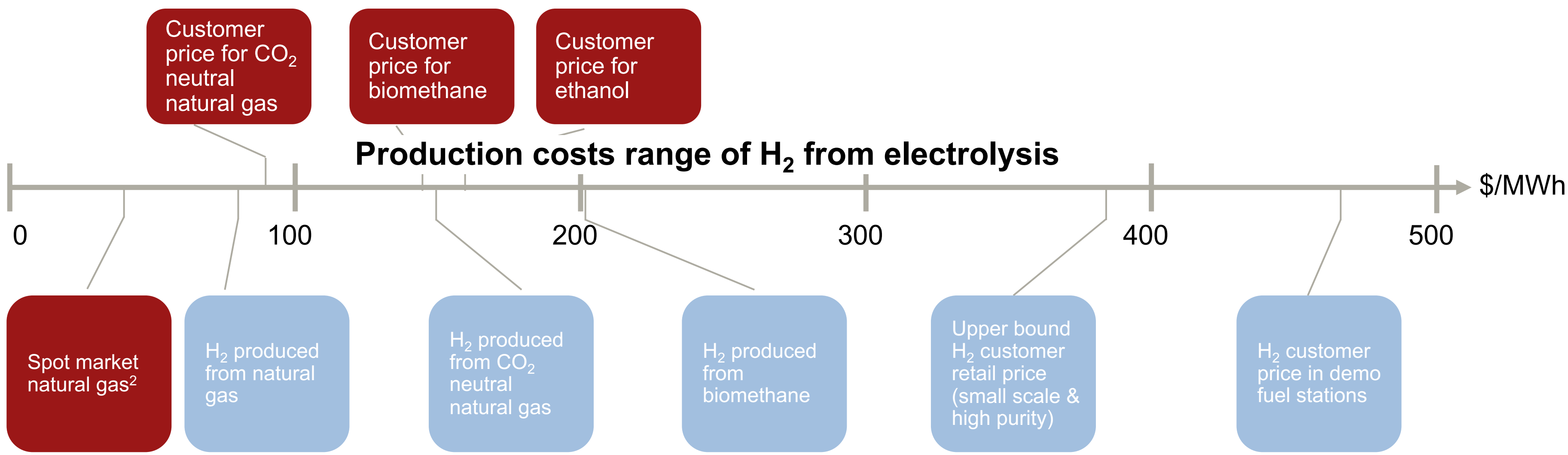
Applications that valorize H_2 as a feedstock and benefit from support mechanisms for low-carbon solutions are likely to drive the first hydrogen energy developments

End-market prices for H_2 feedstock in Germany vs. natural gas adapted from E.ON[1] $/MWh



The use of electrolytic hydrogen as a feedstock fits better in the current market structure and fetches higher end-market prices. However, bundling hydrogen production revenues with grid serviced using electrolyzers is expected to be a promising business model.

1. Based on E.ON (2013) analysis presented by Dr. Kopp at the "H_2 in the economy" European Commission workshop. Prices have been converted from €/kWh to $/MWh to improve ease of understanding of the report using a €/$ conversion rate of 31; 2Spot price on NetConnect Germany(NGC) market area.

Source: E.ON (2013); Troncoso (2011).

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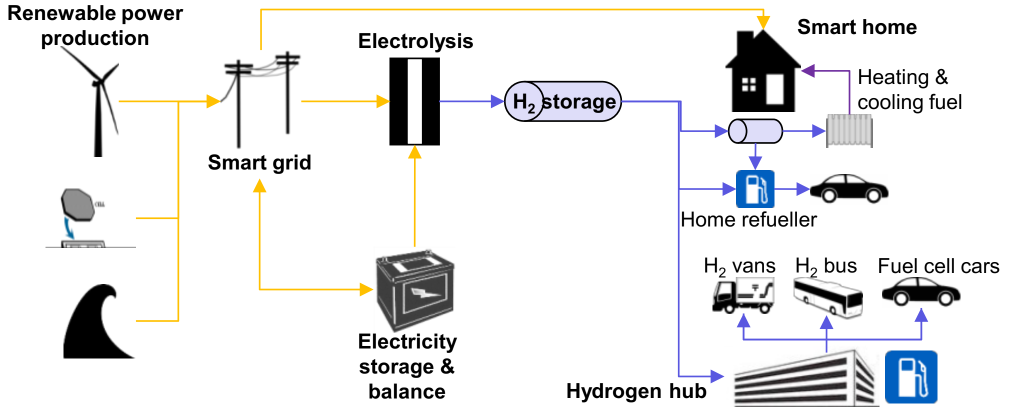
Remote areas and islands could act as testing grounds for the monetization of hydrogen services

The role of the hydrogen energy carrier in the EcoIsland
Project, isle of wight (uk)



How to read this diagram?

- EcoIsland aims to make the Isle of Wight fully renewable by 2020 and a net exporter to the UK mainland. Here, H_2 will be used as an energy storage medium and as a fuel for mobility. The UK Technology Strategy Board has awarded a $7.5 million grant to build the infrastructure. In a second stage, temporary excesses of electricity produced from renewable energy sources could be exported to the UK by injecting it into the gas network.
- Electrolyzers will act as demand-side management, converting temporary excesses of electricity into hydrogen. Two refueling platforms will be installed with 350 bar and 700 bar capability (one of 3,939-4,923 MWh/day, one of 590 MWh/day).
- Project stakeholders include Toshiba for the energy management system and balance, IBM for smart appliances, ITM Power for hydrogen solutions and SSE for grid connections.

- Remote areas – *i.e.* communities not connected to central energy infrastructure - lead the way in using storage in conjunction with renewable energies.
- As highlighted by the IEA: "*Remote areas provide promising locations to evaluate the economics of high-penetration scenarios, potentially shedding insights for larger countries with ambitious renewable energy targets*".
- In this paradigm, hydrogen solutions could be tested to absorb seasonal swing of supply and valorize temporary excesses of power outside the electricity sector for end-uses in mobility, heating and cooling, and even small-scale fertilizer production.

Source: A.T. Kearney Energy Transition Institute analysis, based on IEA-RETD (2012); IRENA (2012); EcoIsland (www.eco-island.org).

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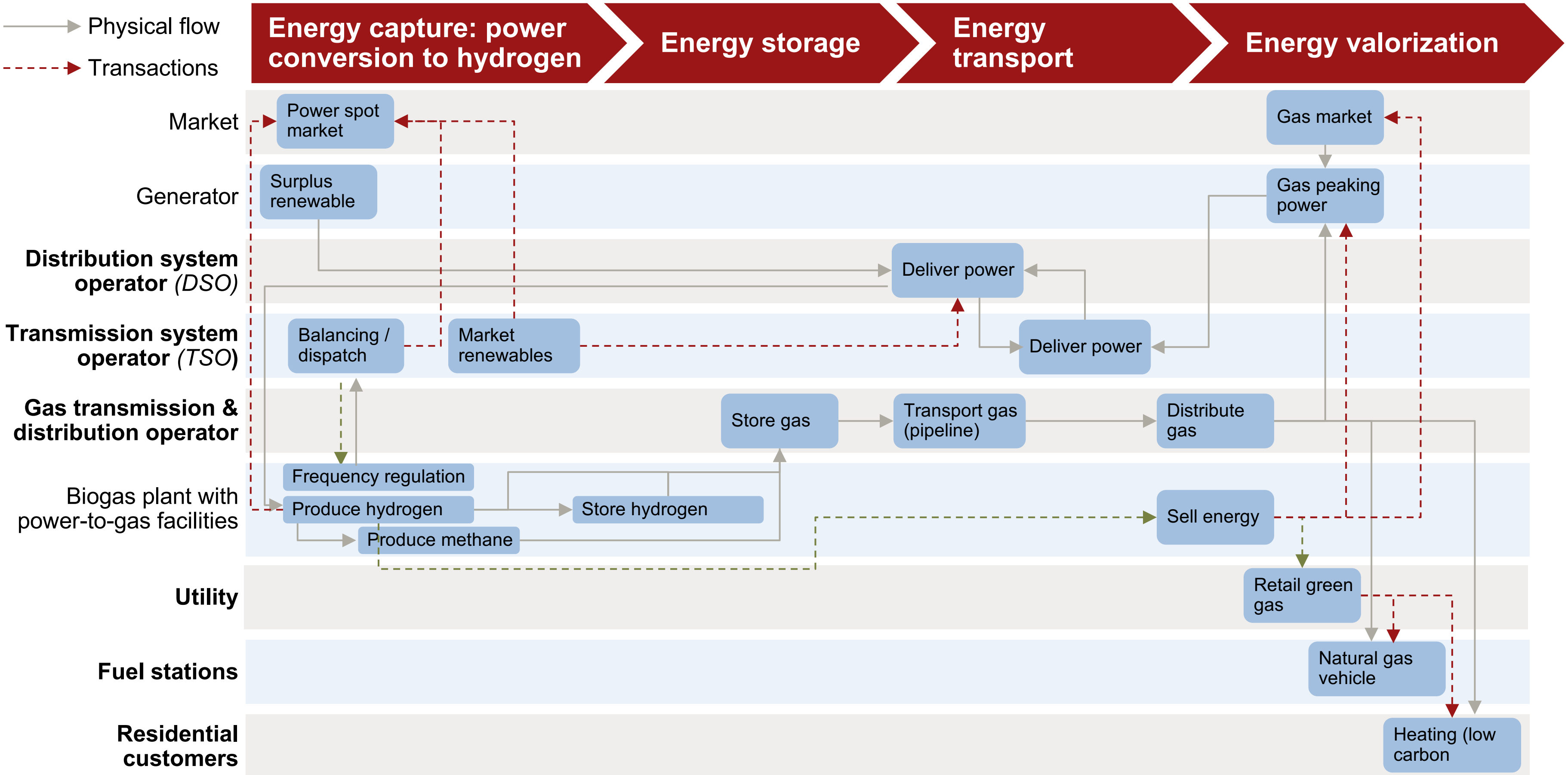
Hydrogen conversion solutions are made more complex because they involve many stakeholders

Simplified stakeholder interactions in power-to-gas pathways in Germany



1. Feed-in-tariff compensation depends on all systems. In Germany, renewable electricity benefiting from priority dispatch is usually feed into the distribution network. It is then transmitted to TSO for sale on the spot market, where utilities purchase the electricity to send to end-consumers.

Source: A.T. Kearney Energy Transition Institute analysis, based on Hydrogenics (2012); Brandstätt et al. (2011).

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Business models for conversion will require further R&D to develop optimization tools

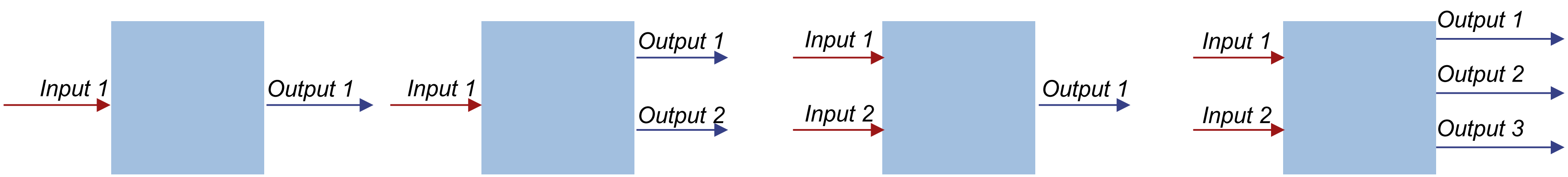
Illustration of energy system layout From single-source single-product to multiple-source multiple-product

1 Single-source single-product

2 Single-source multi-product

3 Multi-source single-product

4 Multi-source multi-product



- Conventional power plant
- Hydrogen production plant

- Combined heat & power plant
- Power plant with an electrolyzer

- Biomass co-firing in coal power plants or hybrid concentrating solar plant with fuel back-up

- Biogas plant with wind turbine and electrolyzer producing synthetic gas, electricity or hydrogen

– → +

Increasing flexibility & complexity

The versatility of the H_2 and its role as a bridge between power, heat, gas and liquid carriers open the way to multi-source multi-product energy systems. However, there is a serious lack of modeling tools for taking advantage of this new flexibility.

Source: A.T. Kearney Energy Transition Institute analysis, based on He et al. (2012); Hemmes et al. (2007).

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The business models of electrolytic hydrogen solutions are inherently system- and application-specific

Power system and application factors influencing hydrogen business cases

Power system-influencing factors

- **Electricity prices** *(including distribution)*
- **Renewable** *(e.g. penetration, mix, pattern)*
- **Regulation** *(e.g. reserve, low-carbon support…)*
- **Grid type** *(island, continental…)*
- **Flexibility sources** (existing, potential)
- **Power demand** *(e.g. profile, distribution…)*

Hydrogen business case

Applications-influencing factors

- **Consumption profile** *(continuous/ discontinuous)*
- **Location & accessibility**
- **End-market prices**
- **Green alternatives**
- **Competitors** *(Hydrogen, natural gas…)*
- **Regulation**

Investors, policy-makers and decision-makers need to assess how appropriate hydrogen-based solutions are compared with the alternatives, in the context of local, application-specific conditions

Source: A.T. Kearney Energy Transition Institute analysis.

4. Environmental impact, safety & social acceptance

A.T. Kearney | Energy Transition Institute

The conversion of variable renewable electricity to hydrogen incurs few environmental challenges

Summary of environmental impacts of hydrogen-based storage of intermittent
Renewable electricity

Air pollution

The conversion of variable renewable electricity to hydrogen incurs few environmental challenges. In general, hydrogen-storage solutions result in lower emissions than other energy-storage technologies, although their full lifecycle pollutants and GHGs emissions depend on the primary energy source and power-production technology.

Land use

Land use is also very unlikely to be a constraint on hydrogen-based conversion solutions, although renewable-based systems could face problems because of their land requirements. Electrolyzing modules require a minimum surface area (typically around 75 m^2/MW of H_2, as low as 16.7 m^2/MW for PEM). When hydrogen is used to enrich biofuel production by recycling excess of CO_2, it is actually maximizing the land use of bioenergy

Water requirements

The water requirement of electrolysis – water is used as a feedstock and for cooling – is an important factor to consider in an environmental-impact assessment of H_2 solutions, but is usually lower than for other low-carbon power generation technologies. Typically, around 250-560 liters of water are required per MWh of hydrogen produced. Cooling requirements are much higher, but can be avoided by using evaporation towers and closed-loop circuits.

Source: A.T. Kearney Energy Transition Institute analysis.

Handling hydrogen raises safety challenges that should not be underestimated

Selective physical properties and risks in air Of hydrogen, methane and gasoline

Properties in air	Hydrogen	Gasoline vapor	Methane
Flammability limits	4 - 75%	1 - 7.8%	5.3 - 15%
Ignition energy (mJ)	0.02	0.24	0.29
Explosion limits	18 - 59%	1.1 - 3.3%	6.3 - 13.5%
Flame temperature (°C)	2’045	2’197	1’875

How to read this table?

- H_2 is flammable over a wide range of concentrations and requires very low energy to ignite. But this energy requirement varies, depending on concentration: under 10%, ignition requires more energy, making it harder to ignite. Inversely, high concentrations, tending towards the stoichiometric[4] mixture, require increasingly low ignition energy.
- Auto-ignition is unusual in vessels containing pure H_2. Hydrogen explosions are yet more severe than those of other fuels (although explosions of hydrocarbon fuels carry more energy).
- A hydrogen flame is as hot as a hydrocarbon flame, but emits less heat radiation, limiting the risk of secondary fires and reducing danger for the public and rescue workers. Hydrogen fires are vertical and localized, and the by-products of combustion are non-toxic.
- Finally, unlike most gases, which generally cool when they expand, H_2 compressed at ambient temperature heats up when it expands to atmospheric pressure. On its own, this is unlikely to lead to spontaneous ignition, but has to be borne in mind due to its possible combination with other effects

- Hydrogen raises safety issues because of its flammable and explosive nature. H_2 molecules are very small and light, allowing them to infiltrate materials and damage their internal structure[1]. This can lead to gas escaping and accumulating in confined spaces, creating risk of fire and explosion.
- The risks are relatively limited in open-air conditions, where hydrogen quickly rises and dilutes into a non-flammable concentration. But, in confined spaces, it may lead to high concentrations at the top of the installation, increasing the risk of explosion and fire.
- Hydrogen risks are particularly problematic because hydrogen leaks are difficult to detect. H_2 is colorless and odorless, and the addition of an odorant is not possible because of the gas’s small molecular size.
- Sensors are therefore crucial in preventing incidents. Although they exist and are used in industry, the technologies are very bulky and expensive, and cannot reliably distinguish between hydrogen and methane molecules.

1. Hydrogen can also react with some geological formations suitable for underground storage of other gases.

Source: A.T. Kearney Energy Transition Institute analysis, based on Health and Safety Laboratory (2008); Bennaceur et al. (2005).

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International collaboration is essential for the development of harmonized regulation, codes and standards and to foster social acceptance

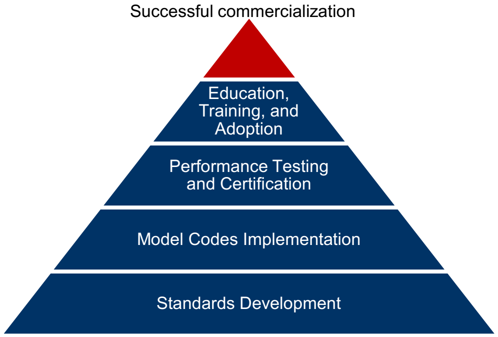
Steps to a socially accepted technology system

Development of regulation, codes & standard [RCS]

International collaboration is essential for the development of harmonized regulation, codes and standards to govern hydrogen-storage solutions:

- Hydrogen has a history of safe use in the chemicals and petrochemicals industries, where it is handled by trained personnel in a similar way to other fuels;
- Small end-users, meanwhile, are subject to very stringent regulatory framework that may be over-protective.

Passing from limited use by trained workforces to public use will require a delicate balancing of existing regulations.



Social acceptance

The use of hydrogen as an energy carrier is relatively new and, as such, may be vulnerable to inaccurate public perception. Social acceptance is vital to the successful deployment of any technology. It can be achieved by heightening awareness of the risks and benefits offered by hydrogen technologies, through: education, providing information on safety and emphasizing the advantages of hydrogen.

Source: A.T. Kearney Energy Transition Institute analysis, based on IFPEN (2012); EERE (2007); European Hydrogen & Fuel Cell Technology Platform (2005); Satyapal (2013).

5. Outlooks

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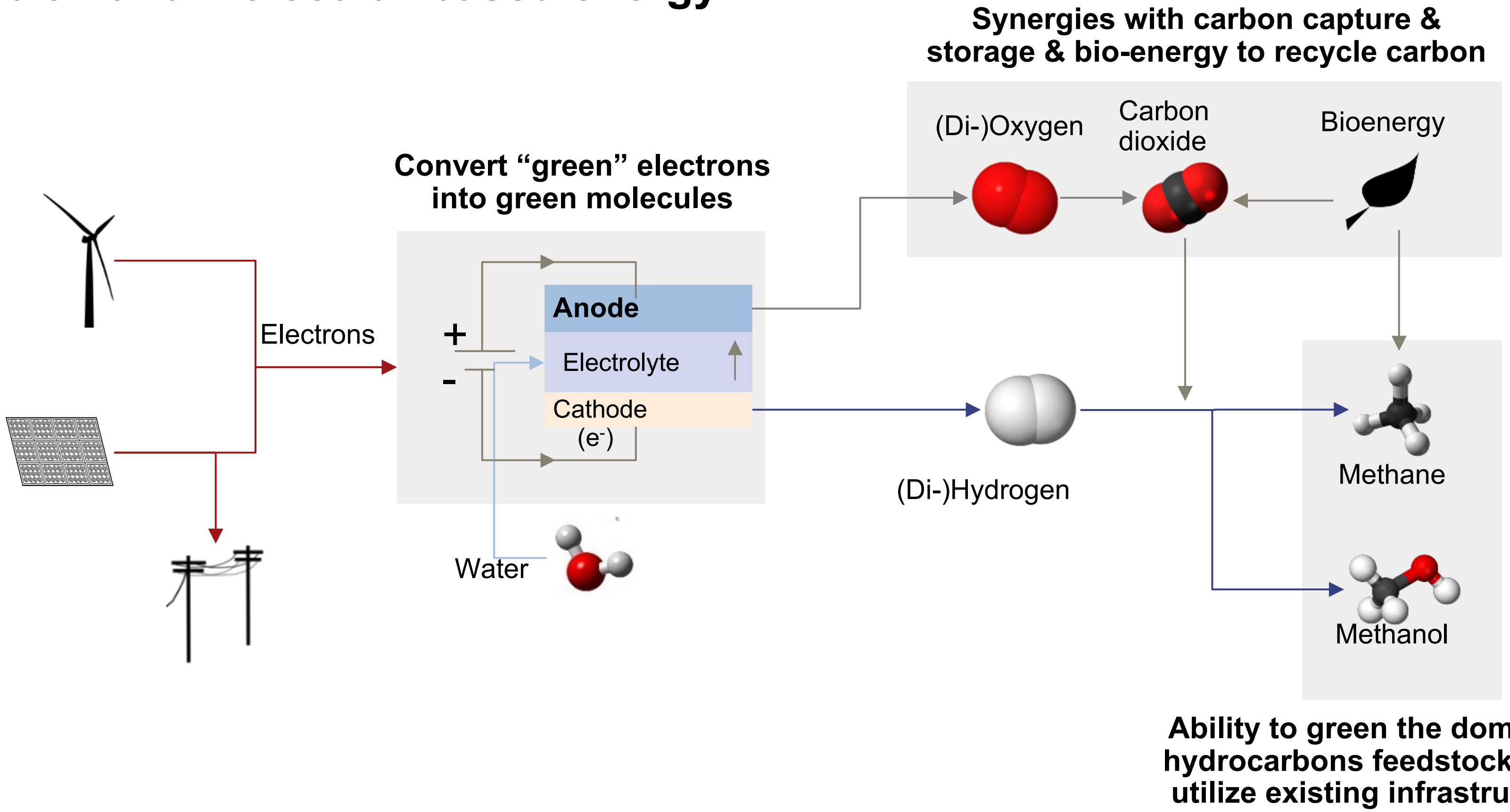
The value of hydrogen-based energy solutions lies predominantly in their ability to convert renewable power into green chemical energy carriers

Illustrative role of electrolytic hydrogen as a bridge between electron and Molecular-based energy



Source: A.T. Kearney Energy Transition Institute analysis.

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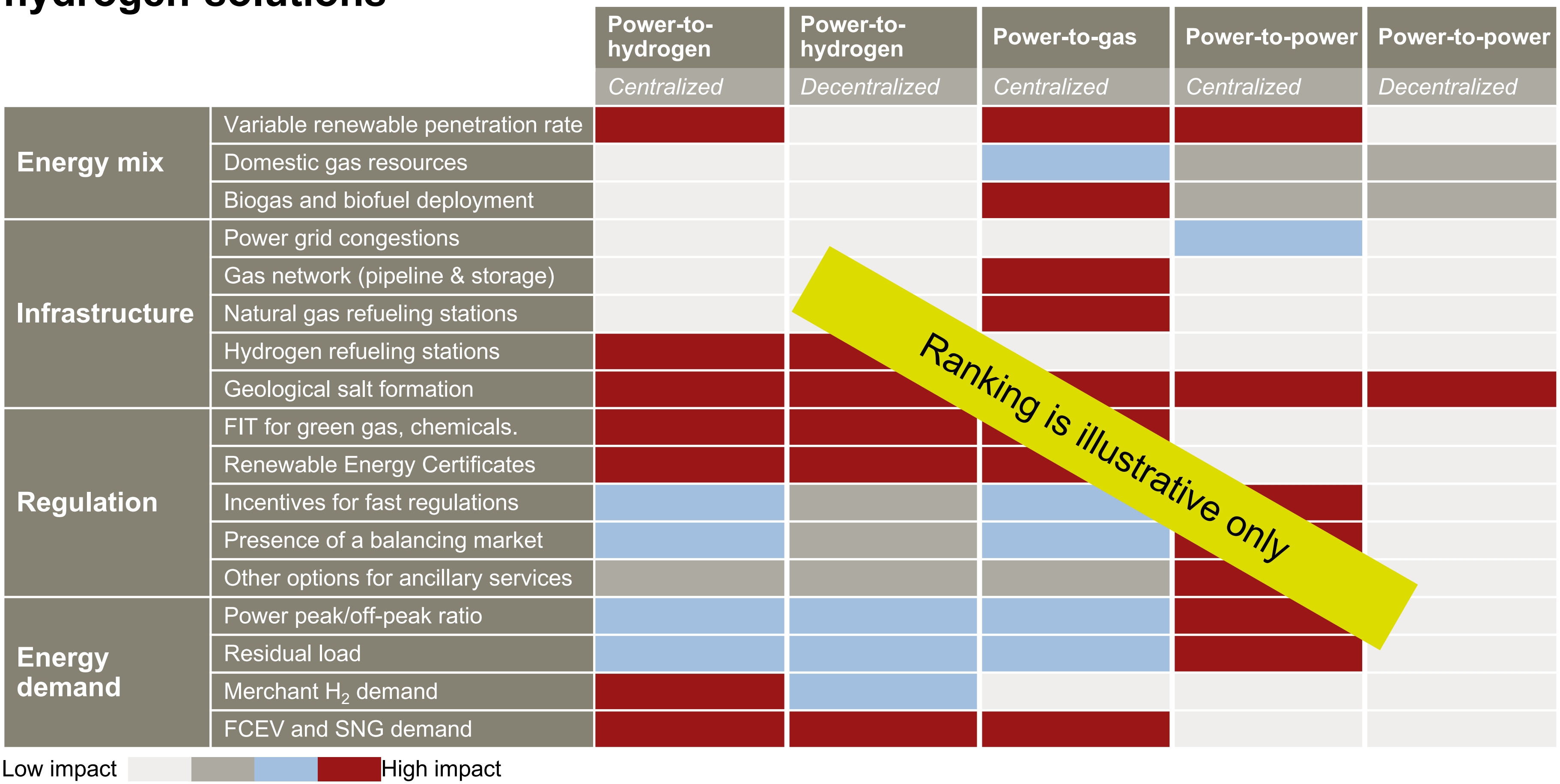
There is no silver bullet for hydrogen-based storage solutions: end-use requirements must be matched with the features of individual energy systems

Illustrative only

Simplified matrix of key energy-system factors, organized by hydrogen-solutions



Source: A.T. Kearney Energy Transition Institute analysis.

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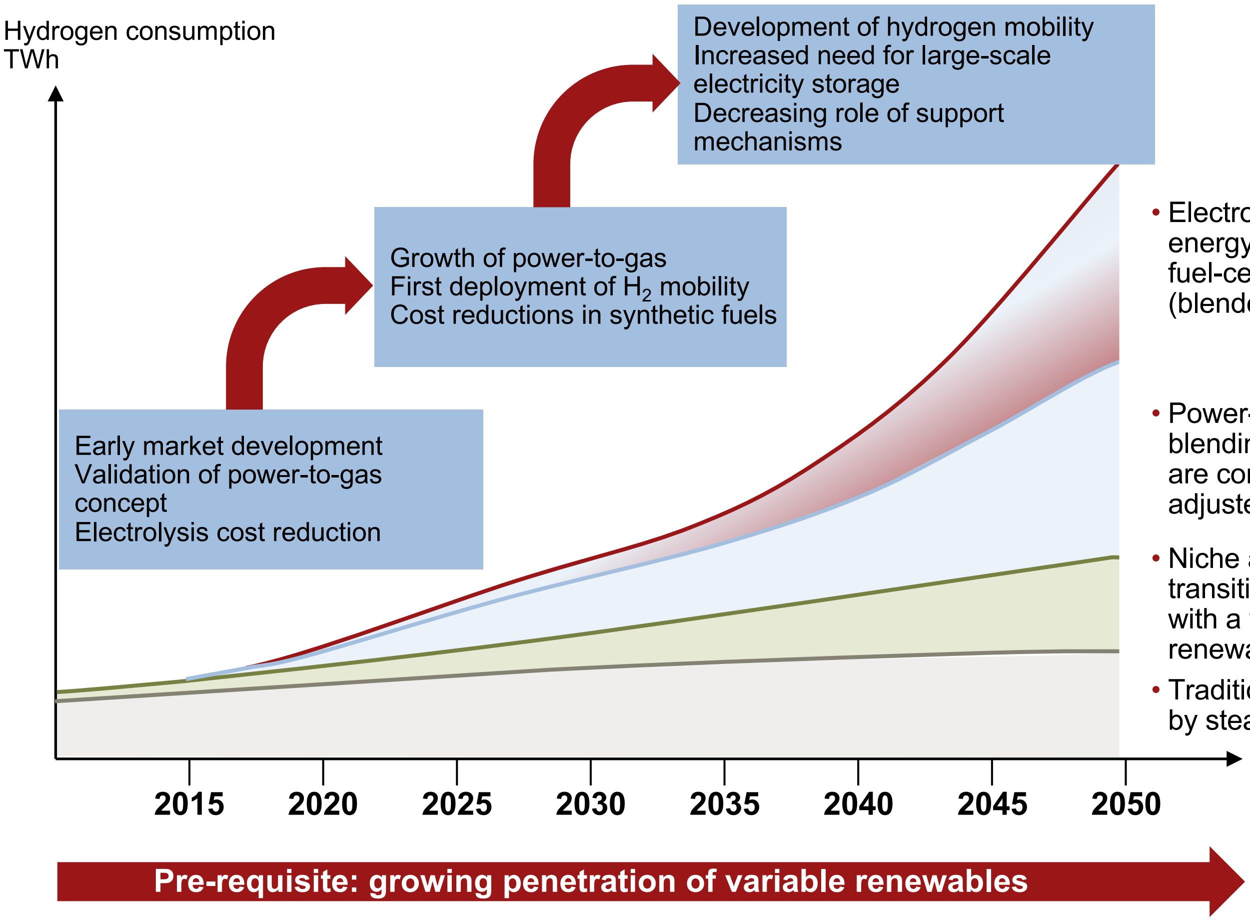
In all cases, the deployment of hydrogen systems requires cost reductions and public support

Illustrative roadmap for hydrogen-based energy storage solutions in Europe



- Electrolytic hydrogen increasingly used as an energy carrier in the transport industry, as use of fuel-cell-electric vehicles and natural gas vehicles (blended gas or synthetic methane) grows.
- Power-to-gas applications will initially be driven by blending (with ratios increasing as more field trials are conducted and as end-use requirements are adjusted) and later supplemented by methanation.
- Niche applications in power-to-power encourage a transition towards larger-scale storage in countries with a very high penetration of variable renewables.
- Traditional uses for hydrogen are mainly supplied by steam-methane reforming.

Source: A.T. Kearney Energy Transition Institute analysis.

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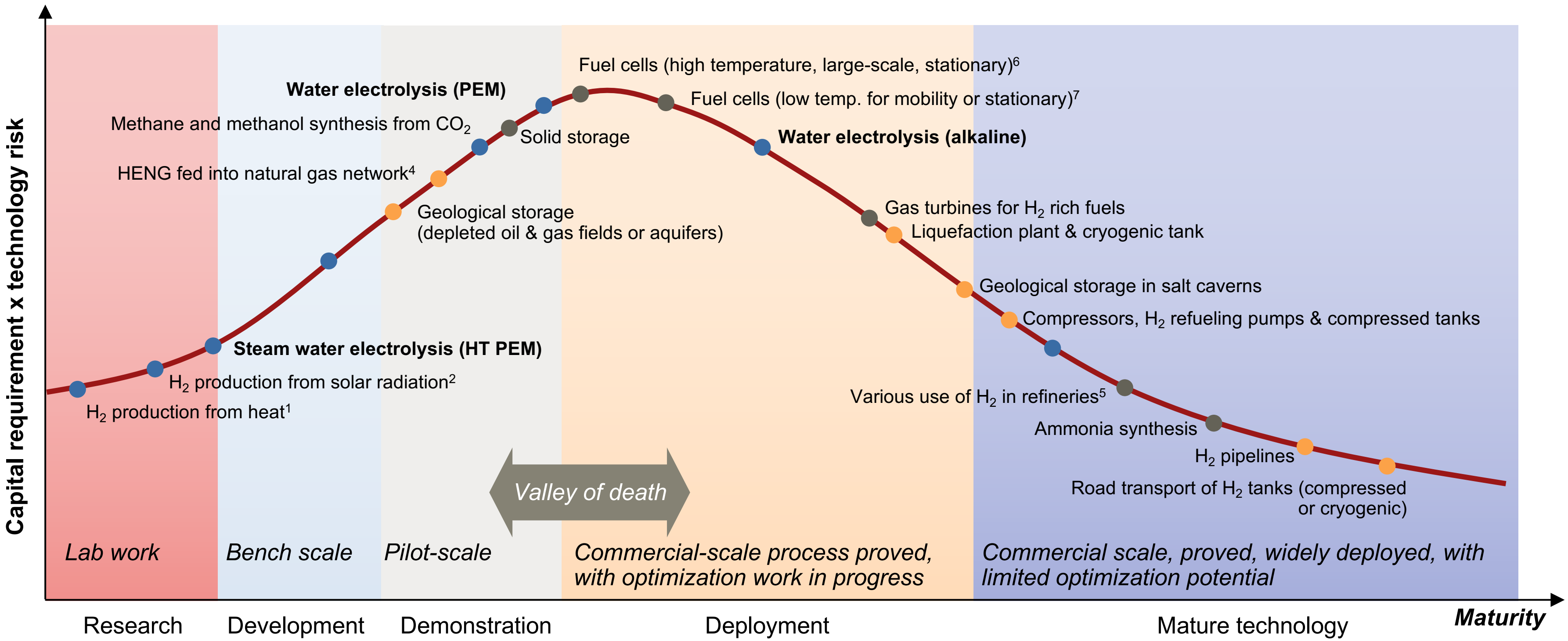
Many individual, hydrogen-related technologies are technologically mature, but electrolysis and power-to-gas are in the "valley of death"

Commercial maturity curve of integrated hydrogen projects



Legend

- Hydrogen conversion
- Hydrogen handling
- Hydrogen production

1. Nuclear or solar thermochemical water splitting; 2Photolysis, photo-electrolysis or photo-biological water-splitting; 3By thermochemical processes, principally: methane reforming, the cracking of petroleum fractions, and coal or biomass gasification; 4HENG: Hydrogen-enriched natural gas; 5Includes the upgrading of heavy/sour oil and the synthesis of synfuels from syngas (methanol, DME, MtG etc); 6Includes SOFC, PAFC and MCFC; 7Includes PEMFC and AFC.

Source: A.T. Kearney Energy Transition Institute analysis.

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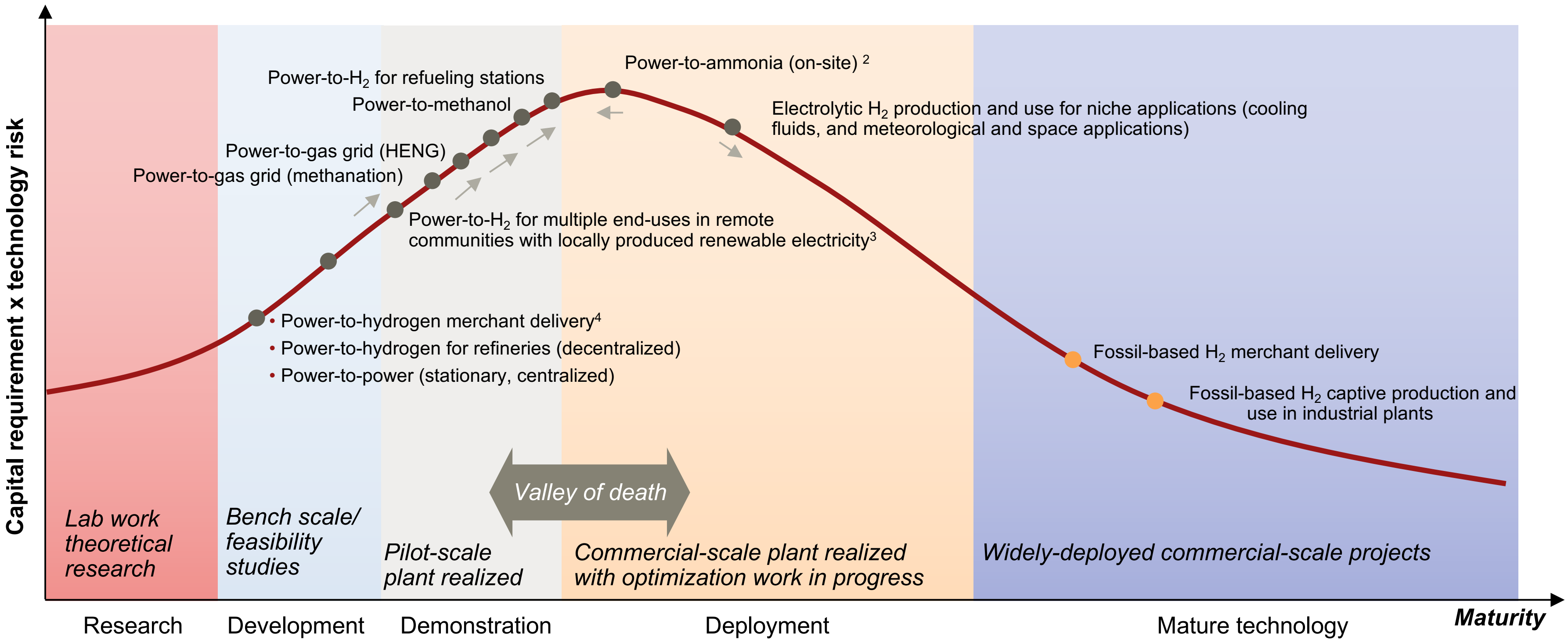
Hydrogen-based energy-storage projects are still a way from commercial deployment

Commercial maturity curve of integrated hydrogen projects



Legend

- Integrated electrolytic hydrogen projects
- Integrated fossil-based hydrogen projects

1. The ranking is an estimate, based on the number of plants installed and their total capacity; in the case of the R,D&D stage, it is based on the size of the largest demonstration project relative to that of a commercial-scale plant. The grey arrows illustrate the dynamics of these projects over time; 2Only three plants are still in operation, and are being replaced by coal or methane-based hydrogen; 3Niche applications require electrolytic hydrogen for its purity.

Source: A.T. Kearney Energy Transition Institute analysis.

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Public authorities have a wide variety of temporary incentives at their disposal to help transform hydrogen-based solutions into self-sustaining commercial activities

Illustration of incentives and Regulation, codes & standard development options

Regulatory framework for natural gas blending

Participation of storage in ancillary services

Safety protocols

Social acceptance & education

- Public support in the form of financing structures and suitable regulation is essential to encourage the deployment of hydrogen solutions in the near term. It is just as important to address public acceptance and perception.

Exemptions: grid & connection fees

Quotas & mandatory targets

Exemptions: tax

Feed-in-tariffs

- In addition to R,D&D funding, public authorities have a wide variety of temporary incentives at their disposal to enable growth in the hydrogen industry. The choice is primarily a political decision and depends on the particular features of each system

For hydrogen-based solutions to be successful, renewable-energy certificates must be integrated across all energy sectors: traceability and proof of origination are crucial.

Source: A.T. Kearney Energy Transition Institute analysis, based on Hydrogenics (2013).

Appendix & bibliography

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Acronyms (1/2)

AC/DC	Alternating/Direct current
AFC	Alkaline fuel cell
API	American Petroleum Institute
BM	Balancing market
BoP	Balance of plant
BTU	British thermal unit
BEV	Battery electric vehicle
CAES	Compressed air energy storage
CAGR	Compound annual growth rate
CAPEX	Capital expenditure
CCS	Carbon capture & storage
CHP	Combined heat and power
CNG	Compressed natural gas
DENA	German Energy Agency
DH	District heating
DME	Dimethyl ether
DS	Degree scenario
DSO	Distribution system operator
EEX	European Energy Exchange
EPEX	European Power Exchange
FC	Fuel cell
FCEV	Fuel cell electric vehicle
FCHJU	Fuel Cell and Hydrogen Joint Undertaking
FIT	Feed-in tariff
GHG	Greenhouse gas
H2ICE	Hydrogen internal-combustion-engine vehicle
H/C	Hydrogen-to-carbon ratio
HCNG	Hydrogen compressed natural gas
HENG	Hydrogen enriched natural gas
H-Gas	High calorific gas
HHV	Higher heating value
HT	High temperature
ICE	Internal combustion engine
IEA	International Energy Agency
IFPEN	Institut Français du Pétrole et Energies Nouvelles
IRENA	International Renewable Energy Agency
IRR	Internal rate of return
K	Kelvin (unit of measurement for temperature)
LCA	Life cycle analysis
LCOE	Levelized cost of electricity
LCOH	Levelized cost of hydrogen
LDV	Light duty vehicle
L-Gas	Low calorific gas
LHV	Lower heating value

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Acronyms (2/2)

LOHC	Liquid organic hydrogen carrier
MCFC	Molten carbonate fuel cell
MtG	Methanol-to-gas
NG	Natural gas
NPV	Net present value
NREL	National Renewable Energy Laboratory
O&G	Oil and gas
O&M	Operation and maintenance
OPEX	Operating expenditure
Pa	Pascal (Unit of measurement for pressure)
P2G	Power-to-gas
P2S	Power-to-synfuel
PAFC	Phosphoric acid fuel cell
PCM	Phase change material
PEM	Proton exchange membrane
PES	Primary energy source
PHS	Pumped-hydro Storage
PV	Solar photovoltaic
R&D	Research and development
RCS	Regulations, codes and standard
RE	Renewables
REC	Renewable energy certificate
RES	Renewable electricity source
RMFC	Reformed-methanol fuel cell
SMES	Super-conducting magnetic energy storage
SMR	Steam methane reforming
SNG	Synthetic natural gas
SOEC	Solid oxide electrolyzer cell
SOFC	Solid oxide fuel cell
T&P	Temperature and pressure
T&D	Transmission and distribution
TCM	Thermo-chemical material
TEPS	Total primary energy supply
TSO	Transmission system operator
URFC	Unitized regenerative fuel cell
US DoE	United States Department of Energy
VRB	Vanadium redox batteries

Picture credits

Slide 4: Wind turbines from the West Wind Project, New Zealand, Siemens

Slide 15: 2 MW electrolysis plant from E.ON's Falkenhagen power-to-gas pilot plant (H2 injection into the local gas grid), Germany, Hydrogenics

Slide 16: Rjukan 150 MW electrolysis plant, Norway, NEL Hydrogen

Slide 24,59: San Jose 500 kW fuel cells eBay installation, US, Bloom Energy

Slide 24: Fusina 16 MW Hydrogen pilot power plant, Italy, Enel

Slide 26,41: Mobile tower powered by solar photovoltaic cells, India, Vihaan Network Limited

Slide 34: Bizkaia Energia 755 MW combined cycle gas turbine, Spain, ESB International

Slide 34: A3 Sportback G-tron e-gas vehicle as part of the methanation project in Werlte, Germany, Audi

Slide 34: Hydrogen storage & refueling facility in Whistler, Canada, Air Liquide

Slide 35: Basic circuits in a fuel cell electric vehicle: FCX Clarity, Unites States, American Honda Motor

Slide 39: Sorfert steam methane reforming fertilizer plant (2,200 t/d ammonia and 3,400 t/d urea), Algeria, Orascom Construction Group

Slide 39: NFuel mini wind-to-hydrogen plant design, The Netherlands, Proton Ventures

Slide 40: Hybrid power plant including 500 kW electrolyzer, Germany, Enertrag

Slide 41: Power-to-gas 250 kW Alpha Plant, Germany, ZSW / Etogas

Slide 41: CUTE hydrogen station to refuel fuel cell buses in Hamburg, Germany, Vattenfall

Slide 41: Hydrogen storage tank, Linde

Slide 58: The Earth as seen from space

Slide 52: MYRTE energy-storage platform including a 560 kWc solar field, and integrated hydrogen module, France, Areva

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