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IEA G20 Hydrogen report: Assumptions

This annex collects the various assumptions that underpin the analyses throughout *The Future of Hydrogen*. For technologies, global averages are presented. However, several analyses in the report present regional examples, for which costs will vary with material and labour inputs and differ from the global average.

These input parameters reflect choices made by the IEA in light of the limited space to present multiple sensitivity analyses. However, there is no doubt that many of the quantitative aspects of hydrogen-related technologies face uncertainties that are compounded when only one case is shown per chart or one illustrative example described. For that reason, the IEA website is home to a growing number of interactive graphics that allow the user to explore variations on the assumptions listed below.

General inputs

General

- All costs in USD (2017)
- Discount rate: 8%.
- CO_2 transport and storage cost for CCUS: USD 20/tCO_2 (all regions)
- Water costs are not considered.

Commodity prices

	Gas price (USD/MBtu)			Lignite price (USD/tonne)		
Region	Today	2030	Long term	Today	2030	Long term
China	8.5	9.3	9.2	30.1	20.6	20.3
European Union	7.3	8.0	7.9	30.1	20.6	20.3
Japan	10.9	10.6	10.2	-	-	-
Australia	5.4	6.1	6.0			
United States	3.3	3.8	4.0	36.6	24.7	24.3
Minimum	2.9	3.5	3.4	30.1	10.6	10.4
Maximum	11	10.7	10.3	40.1	30.6	20.3

Notes: Notes: MBtu = million British thermal units. Natural gas prices are weighted averages expressed on a gross calorific-value basis. The US natural gas price reflects the wholesale price prevailing on the domestic market. The European Union and China gas prices reflect a balance of pipeline and liquefied natural gas (LNG) imports, while the Japan gas price is solely LNG imports; the LNG prices used are those at the customs border, prior to regasification. Lignite prices are weighted averages adjusted to 6 000 kilocalories per kilogramme.

CO_2 prices

	CO_2 price (USD/tCO_2)		
Region	Today	2030	Long term
Advanced economies	5-16	100	160
Emerging economies	0-5	75	145

Production pathways

Hydrogen

Technology	Parameter	Units	Today	2030	Long term
Water electrolysis	CAPEX	**USD/kW_e**	900	700	450
	Efficiency (LHV)	**%**	64	69	74
	Annual OPEX	**% of CAPEX**	1.5	1.5	1.5
	Stack lifetime (operating hours)	**hours**	95 000	95 000	100 000
Natural gas reforming	CAPEX	**USD/kW_{H2}**	910	910	910
	Efficiency (LHV)	**%**	76	76	76
	Annual OPEX	**% of CAPEX**	4.7	4.7	4.7
	Emission factor	**$kgCO_2/kgH_2$**	8.9	8.9	8.9
Natural gas reforming with carbon capture	CAPEX	**USD/kW_{H2}**	1 680	1 360	1 280
	Efficiency (LHV)	**%**	69	69	69
	Annual OPEX	**% of CAPEX**	3	3	3
	CO_2 capture rate	**%**	90	90	90
	Emission factor	**$kgCO_2/kgH_2$**	1.0	1.0	1.0
Coal gasification	CAPEX	**USD/kW_{h2}**	2 670	2 670	2 670
	Efficiency (LHV)	**%**	60	60	60
	Annual OPEX	**% of CAPEX**	5	5	5
	Emission factor	**$kgCO_2/kgH_2$**	20.2	20.2	20.2
Coal gasification with carbon capture	CAPEX	**USD/kW_{H2}**	2 780	2 780	2 780
	Efficiency (LHV)	**%**	58	58	58
	Annual OPEX	**% of CAPEX**	5	5	5
	CO_2 capture rate	**%**	90	90	90
	Emission factor	**$kgCO_2/kgH_2$**	2.1	2.1	2.1

Notes: 25-year lifetime and a 95% availability factor assumed for hydrogen production from natural gas and coal. Availability factors for electrolysis are based on the full load hours of electricity shown in following table. For water electrolysis, possible revenues from oxygen sales have not been considered in the cost analysis.

Sources: References in Table 1 of Chapter 2 for electrolysis IEAGHG (2014), "CO_2 capture at coal based power and hydrogen plants", IEAGHG (2017), "Techno-economic evaluation of SMR based standalone (merchant) hydrogen plant with CCS".

Electricity prices and full load hours

	Grid				Variable renewable electricity	
	Electricity price (USD/MWh)			Full load hours	Electricity price (USD_{2017}/MWh)	Optimised full load hours
Region	Today	2030	Long term		Long term	Long term
Australia	86	156	163	5 000	31	2 321
Chile	-	-	-	5 000	23	2 758
China	113	140	137	5 000	18	2 822
European Union	98	114	123	5 000	47	2 054
India	-	-	-	5 000	19	2 598
Japan	156	177	158	5 000	63	1 675
Middle East	-	-	-	5 000	25	2 563
North Africa	-	-	-	5 000	23	2 547
United States	70	100	108	5 000	31	2425
Minimum	19	52	55	5 000	18	2 822
Maximum	171	177	178	5 000	63	1 675

Methanation

Parameter	Units	Today	2030	Long term
CAPEX	**USD/kW_{prod}**	845	735	565
Efficiency (LHV)	**%**	77	77	77
Annual OPEX	**% of CAPEX**	4	4	4
Lifetime	**years**	30	30	30
Electricity consumption	**GJ_e/GJ_{prod}**	0.013	0.013	0.013

Fischer-Tropsch

Parameter	Units	Today	2030	Long term
CAPEX	**USD/kW_{liquid}**	890	760	565
Efficiency (LHV)	**%**	73	73	73
Annual OPEX	**% of CAPEX**	4	4	4
Lifetime	**years**	30	30	30
Electricity consumption	**GJ_e/GJ_{liquid}**	0.018	0.018	0.018

Ammonia (NH_3)

Feedstock	Parameter	Units	Today	2030	Long term
Natural gas	CAPEX	**USD/tNH_3**	905	905	905
	Annual OPEX	**% of CAPEX**	2.5	2.5	2.5
	Gas consumption	**GJ/t_{NH_3}**	42.0	38.3	32.2
	Electricity consumption	**GJ/t_{NH_3}**	0.3	0.3	0.3
	Emission factor	**$kgCO_2/kgNH_3$**	2.35	2.14	1.8
Natural gas w/CCUS	CAPEX	**USD/tNH_3**	1 315	1 260	1 165
	Annual OPEX	**% of CAPEX**	2.5	2.5	2.5
	Gas consumption	**GJ/t_{NH_3}**	42.0	38.3	32.2

	Electricity consumption	GJ/t_{NH_3}	1.3	1.3	1.3
	Emission factor	$kgCO_2/kgNH_3$	0.12	0.11	0.09
Coal	CAPEX	USD/tNH_3	2 175	2 175	2 175
	Annual OPEX	% of CAPEX	5	5	5
	Coal consumption	GJ/t_{NH_3}	38.4	38.4	38.3
	Electricity consumption	GJ/t_{NH_3}	3.7	3.7	3.7
	Emission factor	$kgCO_2/kgNH_3$	3.9	3.9	3.9
Coal w/CCUS	CAPEX	USD/tNH_3	2 810	2 810	2 810
	Annual OPEX	% of CAPEX	5	5	5
	Coal consumption	GJ/t_{NH_3}	38.4	38.4	38.3
	Electricity consumption	GJ/t_{NH_3}	5.3	5.3	5.3
	Emission factor	$kgCO_2/kgNH_3$	0.2	0.2	0.2
Biomass	CAPEX	USD/tNH_3	6 320	6 320	6 320
	Annual OPEX	% of CAPEX	5	5	5
	Biomass consumption	GJ/t_{NH_3}	45.0	45.0	45.0
	Electricity consumption	GJ/t_{NH_3}	5.0	5.0	5.0
	Emission factor	$kgCO_2/kgNH_3$	0.0	0.0	0.0
Electrolysis	CAPEX	USD/tNH_3	1160	885	575
	Annual OPEX	% of CAPEX	1.5 %	1.5%	1.5%
	Electricity consumption	GJ/t_{NH_3}	37.8	35.3	33.2
	Emission factor	$kgCO_2/kgNH_3$	0.0	0.0	0.0

Notes: 25-year lifetime and 95% availability assumed for all equipment. CCUS options correspond to those capturing all emissions streams, and consider a 95% capture rate. The electrolysis route parameters include the electrolyser costs (see Hydrogen table). For major routes deployed, average energy performance is assumed today, tending towards best practice technology by 2050. Declining CAPEX/OPEX for CCUS options reflects the size of capture capacity required as the energy intensity improves. Emission factors correspond to net direct CO_2 emissions in the industrial sector.

Methanol (MeOH)

Feedstock	Parameter	Units	Today	2030	Long term
Natural gas	CAPEX	USD/t_{MeOH}	310	310	310
	Annual OPEX	% of CAPEX	2.5	2.5	2.5
	Gas consumption	GJ/t_{MeOH}	33.9	33.0	31.5
	Electricity consumption	GJ/t_{MeOH}	0.3	0.3	0.3
	Emission factor	$kgCO_2/kgMeOH$	0.8	0.7	0.6
Natural gas w/CCUS	CAPEX	USD/t_{MeOH}	525	510	490
	Annual OPEX	% of CAPEX	2.5	2.5	2.5
	Gas consumption	GJ/t_{MeOH}	33.9	33.0	31.5
	Electricity consumption	GJ/t_{MeOH}	0.7	0.7	0.6
	Emission factor	$kgCO_2/kgMeOH$	0.04	0.04	0.03
Coal	CAPEX	USD/ t_{MeOH}	750	750	750
	Annual OPEX	% of CAPEX	5	5	5
	Coal consumption	GJ/t_{MeOH}	46.3	44.2	40.7
	Electricity consumption	GJ/t_{MeOH}	3.7	3.7	3.7
	Emission factor	$kgCO_2/kg\ MeOH$	3.3	3.1	2.7
Coal w/CCUS	CAPEX	USD/t_{MeOH}	1 505	1 450	1 350
	Annual OPEX	% of CAPEX	5	5	5
	Coal consumption	GJ/t_{NH_3}	55.3	52.5	47.8
	Electricity consumption	GJ/t_{NH_3}	3.9	3.9	3.9
	Lifetime	years	25	25	25
	CO_2 capture rate	%	95	95	95

	Emission factor	**$kgCO_2/kg$ MeOH**	0.17	0.15	0.14
Biomass	CAPEX	**USD/t_{MeOH}**	5 165	5 165	5 165
	Annual OPEX	**% of CAPEX**	5	5	5
	Biomass consumption	**GJ/t_{NH_3}**	47.9	47.9	47.9
	Electricity consumption	**GJ/t_{NH_3}**	5.0	5.0	5.0
	Emission factor	**$kgCO_2/kgNH_3$**	0.0	0.0	0.0
Electrolysis	CAPEX	**USD/t_{MeOH}**	790	595	380
	Annual OPEX	**% of CAPEX**	1.5	1.5	1.5
	Electricity consumption	**GJ/t_{MeOH}**	25.4	23.7	22.2
	Emission factor	**$kgCO_2/kgNH_3$**	0.0	0.0	0.0

Notes: 25-year lifetime and 95% availability assumed for all equipment. CCUS options correspond to those capturing all emissions streams, and consider a 95% capture rate. The electrolysis route parameters include the electrolyser costs (see Hydrogen table). For major routes deployed, average energy performance is assumed today, tending towards best practice technology by 2050. Declining CAPEX/OPEX for CCUS options reflects the size of capture capacity required as the energy intensity improves. Emission factors correspond to net direct CO_2 emissions in the industrial sector. CO_2 feedstock for the electrolysis route is assumed to be available at zero cost.

Transmission, distribution and storage

Transmission

Technology	Parameter	Units	Hydrogen	LOHC	Ammonia
Pipelines[1]	Lifetime	years	40	-	40
	Distance	km	Function of supply route		
	Design throughput	ktH_2/y	GH_2: 340	800	240
	Gas density	kg/m^3	7.9	-	-
	Gas velocity	m/s	15	-	-
	CAPEX/km	USD million/km	1.21	2.32	0.55
	Utilisation	%	75%	75%	75%
Liquefaction	Installed capacity	ktH_2/y	260	-	-
	Capacity CAPEX	USD million	1 400		-
	Annual OPEX	% of CAPEX	4%	-	-
	Electricity use	kWh/kgH_2	6.1	-	-
Conversion[2]	Installed capacity	kt_{Tol}/y	-	4 200	-
	Plant CAPEX	USD million		230	-
	Annual OPEX	% of CAPEX	-	4%	-
	Electricity use	kWh/kgH_2	-	1.5	-
	Natural gas use	kWh/kgH_2		0.2	
	Start-up toluene	kt	-	260	-
	Toluene cost	USD/t_{Tol}	-	400	-
	Toluene markup	kt_{Tol}/y	-	100	-
Export terminal	Capacity/tank	tH_2 or t_{Tol} or t_{NH_3}	3 190	51 750	34 100
	No. of tanks		Based on days of storage needed for a given ship loading frequency		
	CAPEX/tank	USD million	290	42	68
	Annual OPEX	% of CAPEX	4%	4%	4%
	Electricity use	kWh/kgH_2	0.61	0.01	0.005
	Boil off rate	%/day	0.1%	-	-
	Flash rate	%	0.1%		
Seaborne transport[3]	Capacity/ship	tH_2 or t_{Tol} or t_{NH_3}	11 000	110 000	53 000
	CAPEX/ship	USD million	412	76	85
	Ship speed	km/h	30	30	30
	No. of ships used		Function of distance		
	Annual OPEX	% of CAPEX	4	4	4
	Fuel use	MJ/km	1 487[4]	3 300	2 500
	Boil-off rate	%/day	0.2%	-	-
	Flash rate	%	1.3%	-	-
Import terminal	Capacity/tank	tH_2 or t_{Tol} or t_{NH_3}	3 550	61 600	56 700
	No. of tanks	#	Based on 20 days of storage capacity		
	CAPEX/tank	USD million	320	35	97
	Electricity use	kWh/kgH_2	0.2	0.01	0.02
	Boil-off rate	%/day	0.1	-	-
Reconversion[4]	Capacity	kt_{Tol}/y or kt_{NH_3}/y	-	4 200	1 500

	Capacity CAPEX	**USD million**	-	670	460
	Annual OPEX	**% of CAPEX**	-	4%	4%
	Heat required	**kWh/kgH_2**	-	13.6	9.7
	Plant power	**kWh/kgH_2**	-	0.4	-
	H_2 purification (PSA) power	**kWh/kgH_2**	-	1.1	1.5
	H_2 recovery rate	**%**	-	90%	99%
	PSA H_2 recovery rate	**%**	-	98%	85%

Notes: GH_2 = gaseous hydrogen. PSA = Pressure swing adsorption. System lifetime assumed to be 30 years, unless stated otherwise; discount rate = 8%; utilisation of production, conversion and reconversion capacity = 90%.
[1] Transmission pipeline for hydrogen gas based on Baufumé (2013): Pipeline CAPEX (USD/km) = $4\,000\,000D^2 + 598\,600D + 329\,000$; where D (internal diameter in cm) = $\sqrt{(F/v)/\pi}*2*100$; v = gas velocity (m/s); F (volumetric flow in m^3/s) = Q/ρ; Q = gas throughput (kg/s); ρ = gas density (kg/m3). Based on real gas law (pressure = 100 bar).
[2] Conversion: LOHC = Toluene +H2 → MCH. Toluene mark-up is the quantity of new toluene required reach year. Data for ammonia conversion are included in the table on ammonia above.
[3] Ship carrying liquid hydrogen uses boil-off gas for propulsion; LOHC and ammonia ship uses heavy fuel oil. It is assumed that fuel consumption can be obtained from boil-off losses in the storage tank, so the fuel for the ship would not incur an additional energy penalty.
[4] Reconversion: LOHC = MCH → Toluene + H_2; Ammonia = NH_3 → N_2 +H_2.
Sources: Baufumé et al. (2013), "GIS-based scenario calculations for a nationwide German hydrogen pipeline infrastructure"; IAE (2019), "Institute of Applied Energy (Japan) data based on revisions from Economical Evaluation and Characteristic Analyses for Energy Carrier Systems (FY 2014–FY 2015) Final Report"; ETSAP (2011), *LOHC Ship Cost from: Oil and Natural Gas Logistics*; IMO (2014), *Third IMO Greenhouse Gas Study 2014*.

Distribution

Technology	Parameter	Units	Hydrogen	LOHC	Ammonia
Pipelines	Lifetime	**years**	40	40	40
Pipelines (high pressure)[1]	Inlet pressure	**bar**	80	-	-
	Distance	**km**	End use case dependent		
	Design throughput (Q)	**ktH_2/y**	38	-	-
	Gas density (ρ)	**kg/m³**	6.4	-	-
	Gas velocity (v)	**m/s**	15		
	CAPEX	**USD million/km**	0.5	1	0.25
Pipelines (low pressure)[2]	Distance	**km**	3	3	3
	Design throughput (Q)	**t/y**	GH_2: 365	-	-
	Gas density (ρ)	**kg/m³**	0.55	-	-
	Gas velocity (v)	**m/s**	15	-	-
	CAPEX/km	**USD million/km**	0.3		
Trucks[3]	Depreciation period	**years**	12	12	12
	CAPEX	**USD thousand**	185	185	185
	Annual OPEX	**% of CAPEX**	12	12	12
	Speed	**km/h**	50	50	50
	Driver cost	**USD/h**	23	23	23
Trailers	Depreciation period	**years**	12	12	20
	CAPEX	**USD thousand**	LH_2: 1 000 GH_2: 650	170	220
	Annual OPEX	**% of CAPEX**	2%	2%	2%
	Net capacity	**kgH_2**	LH_2: 4300 GH_2: 670	1 800	2 600

	Loading/unloading time	**hrs**	LH_2: 3 GH_2: 1.5	1.5	1.5
H_2 refuelling stations[4]	Station lifetime	**yrs**	10	10	10
	Station size	**kg/day**	1 000	1 000	1 000
	CAPEX	**USD million**	See road transport	3.5	2.2
	OPEX as % of CAPEX	**%**	5%	5%	5%
	Electricity demand	**kWh/kgH$_2$**	LH_2:0.6 GH_2: 1.6	4.4	10.8
	Heat demand	**kWh/kgH$_2$**	0	13.6	0
	Boil off	**% of total weight**	LH_2: 3% GH_2: 0.5%	0.5%	1.5%
	Utilisation	**%**	50%	50%	50%

Note: LH_2 = liquid hydrogen.

[1] Distribution pipeline for hydrogen gas based on Baufumé (2013): Pipeline CAPEX (USD/km) = 3 400 000D2 + 598 600D + 329 000 (Baufumé, 2013); where D (internal diameter in cm) = √(F/v)/π*2*100; v = gas velocity (m/s); F (volumetric flow in m_3/s) = Q/ρ; Q = gas throughput (kg/s); ρ = gas density (kg/m_3) (high-pressure pipeline = 80 bar; low-pressure pipeline = 7 bar).

[2] Pipeline with lower throughput to hydrogen refuelling stations, taking partial flow from high-pressure distribution pipe.

[3] Journey distance doubled to account for journey time and fuel cost calculations, and loading time for LOHC should be doubled for toluene being returned to site of origin.

[4] H2 refuelling station in the case of LOHC and ammonia includes costs for LOHC and ammonia reconversion technology, electricity and natural gas for heat. CAPEX for large fuel cell station (1 000 kg/day) scaled up from small size reference station receiving compressed hydrogen gas according to CAPEX = X*Y*γ(Z/α)β. X = reference station cost (EUR 600 000); Y= installation factor (1.3); γ = station multiplier (LH_2 = 0.9, GH_2 = 0.6, LOHC = 1.4, ammonia = 1.4); α = reference station size (210 kg/day); and β = scaling factor (LH_2 = 0.6, GH_2: 0.7, LOHC = 0.66, ammonia = 0.6).

Sources: Baufamé et al. (2013), "GIS-based scenario calculations for a nationwide German hydrogen pipeline infrastructure"; Reuß et al. (2017), "Seasonal storage and alternative carriers: A flexible hydrogen supply chain model"; Reuß et al. (2019), "A hydrogen supply chain with spatial resolution: Comparative analysis of infrastructure technologies in Germany".

Industrial applications

Steel

Route	Parameter	Units	Today	2030	Long term
BF-BOF	CAPEX	USD/t crude steel	600	600	600
	Annual OPEX	% of CAPEX	23	23	23
	Electricity consumption	GJ/t crude steel	0.7	0.7	0.7
	Coal consumption	GJ/t crude steel	18.0	18.0	18.0
	Natural gas consumption	GJ/t crude steel	1.0	1.0	1.0
Natural gas-based DRI-EAF	CAPEX	USD/t crude steel	590	590	590
	Annual OPEX	% of CAPEX	25	25	25
	Electricity consumption	GJ/t crude steel	2.5	2.5	2.5
	Coal consumption	GJ/t crude steel	0.5	0.5	0.5
	Natural gas consumption	GJ/t crude steel	10.1	10.1	10.1
Natural gas-based DRI-EAF w/CCUS	CAPEX	USD/t crude steel	640	640	640
	Annual OPEX	% of CAPEX	23	23	23
	Electricity consumption	GJ/t crude steel	2.7	2.7	2.7
	Coal consumption	GJ/t crude steel	0.5	0.5	0.5
	Natural gas consumption	GJ/t crude steel	10.1	10.1	10.1
Hydrogen-based DRI-EAF	CAPEX	USD/t crude steel	945	855	755
	Annual OPEX	% of CAPEX	16	18	20
	Electricity consumption	GJ/t crude steel	14.7	13.9	13.2
	Biomass consumption	GJ/t crude steel	1.9	1.9	1.9
Oxygen-rich smelt reduction w/CCUS	CAPEX	USD/t crude steel	530	530	530
	Annual OPEX	% of CAPEX	17	17	17
	Electricity consumption	GJ/t crude steel	3.5	3.5	3.5
	Coal consumption	GJ/t crude steel	12.1	12.1	12.1

Notes: 25-year lifetime and 95% availability assumed for all equipment. Capture rate of 95% assumed for CCUS routes. Hydrogen-based DRI-EAF parameters include the electrolyser costs (see Hydrogen table). The hydrogen requirement for this route is estimated to lie in the range of 47-68 kg/t of DRI, with the mid-point of this range used for the cost calculations. For the DRI-EAF routes, a 95% charge of DRI to the EAF is considered. An iron ore (58% Fe content) cost of USD 60/t and a scrap cost of USD 260/t is assumed for all process routes, regions and time periods. Costs of electrodes, alloys and other wearing components are considered as a part of the fixed OPEX.

Transport vehicles

Powertrain	Parameter	Units	Cars	Trucks	Ships
-	Mileage	km/yr	15 000	100 000	100 000
-	Lifetime	years	5	5	15
-	Discount rate	%	10	10	10
-	Glider	USD thousand	23	117.5	35 000
-	Salvage value	%[1]	43	41.8	0
-	Power	kW	95	350	10 989
FCEV	Fuel cell cost	USD/kW	200 / 50[2]	250 / 95	2 000 / 1 000
	Hydrogen tank	USD/kWh	15 / 9	15 / 9	18 / 9

	Battery	**kWh**	2	3.3	-
	Fuel consumption	**MJ/km**	1.36	7.8	1 487 / 1 770
	Electric motor	**USD/kW**	14	39	70
	O&M	**USD/km**	0.0776	0.106	-
	Delivered H_2 price	**USD/kg**	9.2 / 5	7.3 / 5	3.6 / 3.8[3]
Hydrogen refuelling station[4]	Size	**kg/day**	200 / 1 000	500 / 1 300	Based on LNG[5]
	CAPEX	**USD million**	0.9 / 1.8	1.2 / 2.1	
	Utilisation	**%**	10 / 33	10 / 40	-
BEV[6]	Battery cost	**USD/kWh**	200 / 100	200 / 100	
	Battery size[7]	**kWh**	100	850	-
	Fuel consumption	**MJ/km**	0.75	5.1	-
	O&M	**USD/km**	0.065	0.106	-
	Base electricity price[8]	**USD/kWh**	0.12	0.12	-
ICE[9]	Fuel consumption	**MJ/km**	2.7	11.7	1 715
	Motor	**USD/kW**	30	118	216 / 650[10]
	Fuel tank	**USD/kWh**			
	O&M	**USD/km**	0.08	0.16	-
ICE - Hybrid	Fuel consumption	**MJ/km**	1.6	10.9	-
	O&M	**USD/km**	0.078	0.16	-

Note: O&M = operation and maintenance. For ships, engine efficiency is assumed to be 50% for ICEs, 60% for fuel cells, and 95% for electric motors. A 20% margin (between costs and prices) is assumed for all vehicle components on all powertrains, including the glider. Current ammonia price (using SMR with CCS) is USD 460/tonne; the future price (using electrolysis) is USD 355/tonne. The synthetic fuel cost is USD 260/tonne today and USD 140/tonne in the future. Bulk carriers come in a wide range of sizes, from small ships of only a few hundred tonnes deadweight (the total weight that a ship can carry) to over 360 000 tonnes. The bulk carrier considered here is comparable to a Panamax ship with a length of 200–230 metres, a draft of 13–15 metres and a beam close to 30 metres. For all vehicle types, depreciation is set at representative values, and is assumed to be the same for all powertrains.

[1] Percentage of total vehicle cost (CAPEX) equivalent to the glider and powertrain-specific components.

[2] Where there are two values in a single cell they refer to current and long-term values respectively.

[3] The current hydrogen price for ships is USD 3.6/kgH2 (assuming low-cost gas with CCUS) and the long term price is USD 3.8/kgH2 (assuming the it is produced via electrolysis, in the regions with the lowest production costs)

[4] HRS and charging infrastructure (including catenary lines) are assumed to have an economic lifetime of 30 years.

[5] LNG figures from (Danish Maritime Authority, 2012) and (Faber 2017) with the ratio between hydrogen and LNG from (Taljegard et al., 2014)

[6] Slow charger (4 kW) cost is USD 650, fast public charger (47 kW) cost is USD 33 000. Cars assume a 50/50 split between these two. Tesla mega charger (1 600 kW), with a cost of USD 220 000, is used for trucks.

[7] Battery size is proportional to vehicle range. Values shown are for 500 km.

[8] Base electricity price does not include additional costs of installing and operating dedicated charging infrastructure

[9] ICE technologies refer to gasoline for cars, diesel for trucks and very low sulphur fuel oil for ships.

[10] The first value refers to very low sulphur fuel oil, the second value to hydrogen and ammonia.

Sources: US DOE (2019), "Fuel Cell R&D Overview"; IEA (2019a), *Global EV Outlook 2019: Overcoming The Challenges Of Transport Electrification*; IEA (2019b). *Mobility Model*; sources for hydrogen refuelling station as per Figure 4 in Chapter 5.

Large-scale and long-term storage

Parameter	Units	Long-term characterisation of storage technology options				
		PHES	CAES	Li-Ion battery	Compressed hydrogen	Ammonia
CAPEX – power-related	**USD/kW$_e$**	1 130	870	95	1 820	2 840
CAPEX – energy-related	**USD/kWh**	80	39	110	0.25	0.3
OPEX power-related	**USD/kW$_e$**	8	4	10	73	43
OPEX energy-related	**USD/kWh**	1	4	3	0	0
Round-trip efficiency	**%**	78	44	86	37	22
Lifetime	**years**	55	30	13	20	20

Sources: Element Energy (2018), "Hydrogen supply chain evidence base"; ETI (2018), "Salt cavern appraisal for hydrogen and gas storage"; Northern Gas Networks (2018), *H21 North of England*; Kruck et al. (2013), "Overview on all known underground storage technologies for hydrogen"; Roberts, Dolan and Harris (2018), "Role of carbon resources in emerging hydrogen energy systems"; Schmidt et al. (2019), "Projecting the future levelized cost of electricity storage technologies"; Tzimas et al. (2003), "Hydrogen storage: State-of-the-art and future perspective".

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