Deliverables

HyDelta

WP 7B – D7B.1
Technical analysis of H2 supply chains

Factsheets

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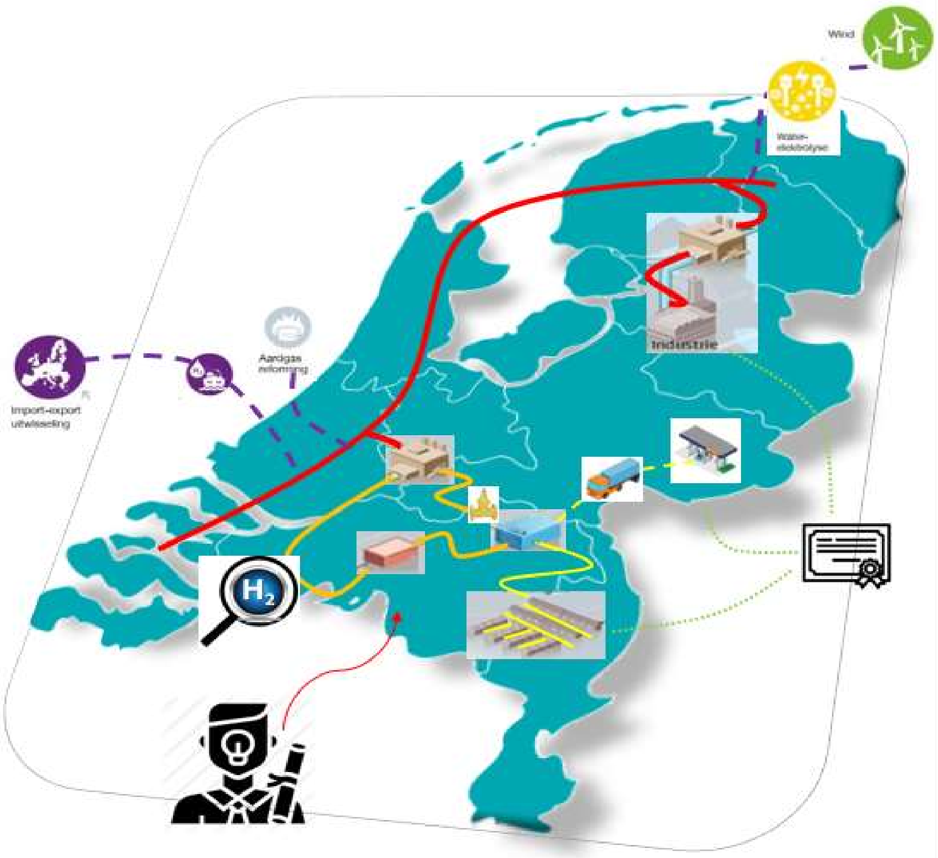

Dit project is medegefinancierd door TKI Nieuw Gas | Topsector Energie uit de PPS-toeslag onder referentienummer TKI2020-HyDelta.

Tag	Production	Tag	Conversion	Tag	Terminals (export/import)	Tag	Shipping (long haul)	Tag	Storage	Tag	Reconversion
P1	Electrolysis - Alkaline	C1	H2 compression	T1	Terminal - LH2	SH1	Shipping LH2	ST1	CH2 storage - HP vessels	~~R1~~	~~LH2 regasification~~
P2	Electrolysis - PEM	C2	H2 liquefaction	T2	Terminal - NH3	~~SH2~~	~~Shipping NH3~~	ST2	CH2 storage - salt caverns	R2	NH3 dissociation
P3	SMR + CCS	C3	NH3 synthesis	~~T3~~	~~Terminal - MeOH~~	~~SH3~~	~~Shipping MeOH~~	ST3	Liquid storage (LH2)	R3	MeOH reforming
P4	ATR + CCS	C4	MeOH synthesis	~~T4~~	~~Terminal - LOHC~~	~~SH4~~	~~Shipping LOHC~~	ST4	Liquid storage (NH3)	~~R4~~	~~LOHC dehydrogenation~~
		C5	LOHC hydrogenation	~~T5~~	~~Terminal - FA~~	~~SH5~~	~~Shipping FA~~	ST5	Liquid storage (MeOH)	~~R5~~	~~FA decomposition~~
		C6	HCOOH synthesis	~~T6~~	~~Terminal - KBH4~~	~~SH6~~	~~Shipping KBH4~~	ST6	Liquid storage (LOHC)	~~R6~~	~~KBH4 decomposition (?)~~
		C7	KBH4/NaBH4 synthesis					~~ST7~~	~~Liquid storage (FA)~~		
								~~ST8~~	~~Solid storage (KBH4)~~		

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P1: Electrolysis - Alkaline

Parameter name	Description	Unit	Source ID	2020	2030	2040	Remarks
Anchor_AEL	Scale of the electrolyzer plant	[MW]		100	100	100	AC input power to the system (i.e. larger than the total DC capacity of the stacks). Anchor point for CAPEX scaling
	System energy efficiency	[%]	(1-3)	64	70	72	Power2H2 system efficiency, LHV basis. These values correspond to running at nominal capacity.
PtH2_eff_kg	Specific power consumption	[kWh/kg H2]	(1-3)	52.1	47.6	46.3	Total power input for the system
	Heat released	[%]		26	20	18	Low temp / rough estimate. This is inversely correlated with system efficiency and roughly estimated as 90% - system efficiency (assuming that 10% of the energy input can't be recovered as heat)
	H2 output, hourly	[t/h]		1.9	2.1	2.1	At nominal capacity / correlated with system efficiency
	Annual utilization	[%]		45	50	65	Assumed to run on green power. Utilization increases as more RES are integrated to the grid & power storage capacity expands
	Operating hours	[h/y]		3942	4380	5694	
	H2 output, annual	[kt/y]		7.6	9.2	12.0	Depends on the annual utilization of the plant. Values correspond to a 100MW (power input) plant capacity
	O2 output, annual	[kt/y]		60.5	73.6	95.7	Based on the mass balance (8 kg of O2 per kg of H2)
CAPEX_AEL	Total direct cost, specific	[€/kW]	(1-4)	780	407	332	Specific TDC, excluding indirect & EPC costs. The 2030 cost estimate is based on the expectation that costs would drop to 450 €/kW by 2025
	System cost decline (annual)	[%]			2	2	(Guesstimate for) CAPEX reduction beyond 2025
	Total direct cost	[M€]	(1-4)	78.0	40.7	33.2	(1-4) / TNO estimates for future TDC, per annual capacity Overall investment cost (not annualized)
ScalingFactor_AEL	Scaling factor	N/A		0.9	0.9	0.9	Rough estimate of cost reduction potential when scaling up above 100MW. Electrolyzers don't scale well, because stacks and most of their auxiliary systems are multiplied.
	Fixed OPEX	[M€/y]		2.0	1.0	0.8	Assumed to be 2.5% of TDC, annual cost
	System footprint	[m2]					

Source ID	References
1	IRENA, 2018, Hydrogen from Renewable Power Technology Outlook for the Energy Transition
2	Element Energy, 2018, Hydrogen supply chain evidence base
3	ISPT, 2020, Gigawatt green hydrogen plant
4	Data provided by various alkaline electrolyser technology suppliers (Nel, ThyssenKrupp, McPhy, HydrogenPro, PERIC):
5	Nel Hydrogen: https://nelhydrogen.com/resources/electrolysers-brochure/
6	ThyssenKrupp: https://www.thyssenkrupp-uhde-chlorine-engineers.com/en/products/water-electrolysis-hydrogen-production
7	McPhy: https://mcphy.com/en/equipment-services/electrolyzers/large/
8	HydrogenPro / THE: https://hydrogen-pro.com/solutions/ and http://www.cnthe.com/en/product_detail-35-43-30.html
9	PERIC: http://www.peric718.com/Alkaline-Type-Hydrogen-G/r-85.html
10	John Cokerill: https://h2.johncockerill.com/en/products/electrolysers/
11	Asahi Kasei: https://www.nedo.go.jp/content/100925658.pdf; Asahi Kasei 2018 brochure - Electrolysis System for 100% Green H2
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P1: Electrolysis - PEM

Parameter name	Description	Unit	Source ID	Values/estimates									Remarks
				2020	2020	2020	2030	2030	2030	2040	2040	2040	
				Low	Mid	High	Low	Mid	High	Low	Mid	High	
	Scale of the electrolyzer plant	[MW]			20			20			20		AC input power to the system (i.e. larger than the total DC capacity of the stacks). Anchor point for CAPEX scaling
	System energy efficiency	[%]	(1-3)		60			66			70		Power2H2 system efficiency, LHV basis. These values correspond to running at nominal capacity.
	Specific power consumption	[kWh/kg H2]	(1-3)		55.6			50.5			47.6		Total power input for the system
	Heat released	[%]			30			24			20		Low temp / rough estimate. This is inversely correlated with system efficiency and roughly estimated as 90% - system efficiency (assuming that 10% of the energy input can't be recovered as heat)
	H2 output, hourly	[t/h]			0.4			0.4			0.4		At nominal capacity / correlated with system efficiency
	Annual utilization	[%]			45			50			65		Assumed to run on green power. Utilization increases as more RES are integrated to the grid & power storage capacity expands
	Operating hours	[h/y]			3942			4380			5694		
	H2 output, annual	[kt/y]			1.4			1.7			2.3		Depends on the annual utilization of the plant. Values correspond to a 20MW (power input) plant capacity
	O2 output, annual	[kt/y]			11.4			13.9			18.0		Based on the mass balance (8 kg of O2 per kg of H2)
	Total direct cost, specific	[€/kW]	(1-4)		1000			652			481		Specific TDC, excluding indirect & EPC costs. The 2030 cost estimate is based on the expectation that costs would drop to 800 €/kW by 2025
	System cost decline (annual)	[%]						4			3		(Guesstimate for) CAPEX reduction beyond 2025
	Total direct cost	[M€]	(1-4)		20.0			13.0			9.6		(1-4) / TNO estimates for future TDC, per annual capacity Overall investment cost (not annualized)
	Scaling factor	N/A			0.9			0.9			0.9		Rough estimate of cost reduction potential when scaling up above 20MW. Electrolyzers don't scale well, because stacks and most of their auxiliary systems are multiplied.
	Fixed OPEX	[M€/y]			0.5			0.3			0.2		Assumed to be 2.5% of TDC, annual cost
	System footprint	[m2]											

Source ID	References
1	IRENA, 2018, Hydrogen from Renewable Power Technology Outlook for the Energy Transition
2	Element Energy, 2018, Hydrogen supply chain evidence base
3	ISPT, 2020, Gigawatt green hydrogen plant
4	Data provided by various alkaline electrolyser technology suppliers (Nel, Hydrogenics, ITM Power, Siemens, Giner ELX):
5	Nel Hydrogen: https://nelhydrogen.com/resources/electrolysers-brochure/
6	Hydrogenics (now part of Cummins) 2019 presentation: Large scale PEM electrolysis - technology status and upscaling strategies
7	ITM Power - 10MW and larger PEM units https://www.itm-power.com/hgas10mw
8	Siemens hydrogen solutions - https://www.siemens-energy.com/global/en/offerings/renewable-energy/hydrogen-solutions.html
9	Giner ELX - https://www.ginerelx.com/electrolyzer-systems
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P3: SMR + CCS

Parameter name	Description	Unit	Source ID	Values/estimates									Remarks
				2020 Low	2020 Mid	2020 High	2030 Low	2030 Mid	2030 High	2040 Low	2040 Mid	2040 High	
	Scale of the SMR +CCS plant	[MW]	1,2	300	300	300	300	300	300	300	300	300	Hydrogen output
	System energy efficiency	[%]		70	68	68	70	68	68	70	68	68	Hydrogen out/Natural gas in (excl. electricity out)
	Specific power production	[kWh/MJ H2]		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	Net power output for the system through use of excess steam
	Specific NG consumption	[MJ NG/MJ H2	1,2	1.42	1	1.48	1.42	1.48	1.48	1.42	1.48	1.48	
	H2 output, hourly	[t/h]		9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	At nominal capacity (100000 m3/h at 10.8 MJ/m3 with H2 (LHV) = 120 MJ/kg)
	Annual utilization	[%]	2	95	95	95	95	95	95	95	95	95	
	H2 output, annual	[kt/y]		75	75	75	75	75	75	75	75	75	Depends on the annual utilization of the plant. Values correspond to a 300MW (hydrogen output) plant capacity
	CO2 emissions, annual	[kt/y]	1	330	344	80	330	344	80	330	344	80	Based on the mass balance (3.6 kg CH4 or 9.6 kg of CO2 per kg of H2) and capture rate (as a percentage)
	Total direct cost, specific	[€/kW]	1,2	1046	984	1328	951	984	1328	778	984	1328	Total plant costs
	System cost decline (annual)	[%]					1	0	0	2	0	0	For one route some CAPEX reduction expected beyond 2020
	Total direct cost	[M€]		314	295	398	285	295	398	233	295	398	
	Scaling factor	N/A		0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	We assume a scaling factor of 0.8 applies
	Fixed OPEX	[M€/y]		9.8	9.4	9.4	9.0	9.4	9.4	7.2	9.4	9.4	
	System footprint	[m2]											

Source ID	References
1	IEAGHG, 2017, Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS. Accessed through https://ieaghg.org/exco_docs/2017-02.pdf
2	TNO, 2018. Factsheets about SMR, Accessed through https://energy.nl (July 2021)
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P4: ATR + CCS

Parameter name	Description	Unit	Source ID	Values/estimates									Remarks
				2020	2020	2020	2030	2030	2030	2040	2040	2040	
				Low	Mid	High	Low	Mid	High	Low	Mid	High	
	Scale of the ATR+CCS plant	[MW]	1	1350	1350	1350	1350	1350	1350	1350	1350	1350	Hydrogen output (HHV)
	System energy efficiency	[%]		82	80	80	82	80	80	82	80	80	Hydrogen out/(Natural gas and electricity in)
	Specific power consumption	[kWh/MJ H2]	1,2,3	0.011	0.014	0.014	0.011	0.014	0.014	0.011	0.014	0.014	Net power input for the system
	Specific NG consumption	[MJ NG/MJ H2]	1,2	1.18	1.20	1.20	1.18	1.20	1.20	1.18	1.20	1.20	
	H2 output, hourly	[t/h]		34	34	34	34	34	34	34	34	34	At nominal capacity (11.8 TWh/yr with H2 (HHV) = 142 MJ/kg)
	Annual utilization	[%]	2	92	92	92	92	92	92	92	92	92	
	H2 output, annual	[kt/y]		276	276	276	276	276	276	276	276	276	Depends on the annual utilization of the plant. Values correspond to a 1350MW (hydrogen output) plant capacity
	CO2 emissions, annual	[kt/y]	1	86	88	175	86	88	175	86	88	175	Based on the mass balance (3.6 kg CH4 or 9.6 kg of CO2 per kg of H2) and capture rate (92-96%)
	Total direct cost, specific	[€/kW]	1,2	1201	1300	1400	1201	1300	1400	1201	1300	1400	Total plant costs
	System cost decline (annual)	[%]		0	0	0	0	0	0	0	0	0	No CAPEX reduction expected beyond 2020
	Total direct cost	[M€]		1621	1755	1890	1621	1755	1890	1621	1755	1890	
	Scaling factor	N/A											
	Fixed OPEX	[M€/y]		49	53	95	49	53	95	49	53	95	3-5% of CAPEX
	System footprint	[m2]											

Source ID	References
1	NOE, 2018, H21 North of England Report v1.0 - Northern Gas Networks
2	TNO, 2019. Factsheets about ATR, Accessed through https://energy.nl (July 2021)
3	Jakobsen, Daniel; Åtland, Vegar, 2016, NTNU, Concepts for Large Scale Hydrogen Production
4	Noelker & Johanning, 2010, Autothermal reforming: a flexible syngas route with future potential
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C1: H2 Compression

Parameter name	Description	Unit	Source ID	Values/estimates 2020	2025	2030	2040	Remarks
	Scale of compressor	[MW]	[1-3]	0.945				For 100 MW electrolyzer, the equivalent H2 flow rate at 52.1kWh/kg H2 is 1900 kg/h. Duty assumed: 30 bar inlet pressure, 60-80 bar discharge pressure. Size of compressor expressed in Power
	efficiency	[%]	1,4, 5	90				The data sheet is based on reciprocating piston type compressors, non-lubricated type to avoid oil contamination.
	Specific power consumption	[kWh/kg H2]	5,6	0.52				range : 0.2-1.3. Total power input for the system
	H2 output, hourly	[t/h]		1.9				At nominal capacity / correlated with system efficiency
	Annual utilization	[%]	1	85.0				Average Availability
	H2 output, annual	[kt/y]		14.1				Depends on the annual utilization of the plant. Values correspond to a 100MW (power input) plant capacity
	~~O2 output, annual~~	~~[kt/y]~~						~~Based on the mass balance (8 kg of O2 per kg of H2)~~
	Total direct cost, specific	[€/kW]	1,2,4	2.67E+03				Compressor CAPEX is assumed to be linearly related to the compressor power (P in kW). CAPEX compression [€] =2677 *P. In 2014 [1] used 2545 euros as constant and according to ECB consumer price index, inflation
	System cost decline (annual)	[%]		?				(Guesstimate for) CAPEX reduction beyond 2025
	Total direct cost	[M€]		2.52				(1-4) / TNO estimates for future TDC, per annual capacity Overall investment cost (not annualized)
	Lifetime	[years]	1,5,6	15				
	Scaling factor	N/A		?				
	Fixed OPEX	[M€/y]	1,5,6	0.10				Assumed to be 3-8%% of TDC, annual cost. Does not include electrcity cost
	System footprint	[m2]	7	110				small scale

Source ID	References
1	André, J., Auray, S., De Wolf, D., Memmah, M. M., & Simonnet, A. (2014). Time development of new hydrogen transmission pipeline networks for France. International Journal of hydrogen energt, 3992(
2	NSE3 Technical assessment of Hydrogen transport, compression, processing offshore: https://north-sea-energy.eu/static/7ffd23ec69b9d82a7a982b828be04c50/FINAL-NSE3-D3.1-Final-report-technical-a
3	Castello, P, E Tzimas, P Moretto, and S D Peteves. "Techno-Economic Assessment of Hydrogen Transmission & Distribution Systems in Europe in the Medium and Long Term." Petten, The Netherlands: Tl
4	Rodica Loisel, Laurent Baranger, Nezha Chemouri, Stefania Spinu, Sophie Pardo (2015). Economic evaluation of hybrid off-shore wind power and hydrogen storage system.40, 6727-6739
5	DNV GL (2020). Study on the Import of Liquid Renewable Energy: Technology Cost Assessment
6	HyChain II (2019). Cost implications of importing renewable electricity, hydrogen and hydrogen carriers into the Netherlands from a 2050 perspective
7	NSE3 - D3.8. Offshore Energy Islands
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C2: H2 Liquefaction

Parameter name	Description	Unit	Source ID	Values/estimates 2020	2025	2030	2040	Remarks	
	Scale of the liquefaction plant	[TPD]	[1-4]	50	150	150	300	Commonly plants are rated based on their ton per day output	
	System energy efficiency	[%]	4	0.73	0.77	0.81	0.87	system eff=$LHV_{LH2}/(LHV_{LH2}+SEC)$ @ LHVLH2=120Mj/kg	
	Specific energy consumption (SEC)	[kWh/kg H2]	[1-3]	12.5	10.0	8.0	5.0	[1] Using helium refrigerant cycles will introduce additional savings in the future; check fig 24 for conceptual plants;	
	H2 output, hourly	[t/h]		2.1	6.3	6.3	12.5	Derived from TPD values	
	Annual utilization	[%]	3	95	95	95	95		
	H2 output, annual	[kt/y]		17.3	52.0	52.0	104.0	Calculated	
	Total direct cost, specific	[€/kg LH_2]		2.307	1.346	1.346	0.961	Refering to the specific costs per kg LH_2 out	
	System cost decline (annual)	[%]							
	Installed CAPEX	[M€]		40.0	70.0	70.0	100.0	extrapolated from DOE's. Capital costs required for the engineering, procurement and construction as well as the commissioning and start-up of	
	Scaling factor	N/A		0.7	0.7	0.7	0.7	From IDEALHY plant	
	Fixed OPEX	[M€/y]		0.08	0.14	0.14	0.20	4% CAPEX	4%
	System footprint	[m2]							

Source ID	References
1	Aasadnia, M., & Mehrpooya, M. (2018). Large-scale liquid hydrogen production methods and approaches: A review. In Applied Energy (Vol. 212, pp. 57–83). Elsevier Ltd. https://doi.org/10.1016/j.apener
2	d'Amore-Domenech, R., Leo, T. J., & Pollet, B. G. (2021). Bulk power transmission at sea: Life cycle cost comparison of electricity and hydrogen as energy vectors. Applied Energy, 288, 116625. https://doi.
3	2017 - Cardella et al - Economically viable large-scale hydrogen liquefaction
4	2011 - Advanced hydrogen liquefaction process - Praxair and DOE
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C3: Ammonia synthesis

Parameter name	Description	Unit	Source ID	Values/estimates 2020 Low	2020 Mid	2020 High	2030 Low	2030 Mid	2030 High	2040 Low	2040 Mid	2040 High	Remarks
	Scale of the NH3 synthesis plant	[ktpa]	(3, 15)	100		500							Modern NH3 plants can have very large capacities (in excess of 1 Mtpa) but there is a lot of flexibility and companies offer turnkey designs at intermediate scale.
20-30 bar syngas	Specific power consumption	[MWh/t NH3]	(1-3)	0.75									For a green NH3 plant, the power consumption of the H-B loop and ASU is reported to be relatively small compared to the electrolyzers (roughly 8% of the total). For a plant with an overall power consumption of 9.4 MWh/t NH3 this corresponds to ~0.75 MWh/t NH3, or 2.7 GJ/t NH3.
	Specific H2 consumption	[t H2/t NH3]		0.177									Stoichiometric ratio (H2 conversion is nearly 100%)
	Operating hours	[h/y]		8000									The operating hours of the ammonia plant are assumed to be equal to 8000h per year, a typical value (~90%) for this type of plant.
	NH3 output, daily	[t/d NH3]		300.0		1500.0							At nominal capacity
installed cost	Total direct cost, specific	[M€/tpd NH3] (capacity)	(1-4)	0.267									Rough cost estimate derived based on comparing values from (1)-(8). See slide 5 in the documentation
	installation factor			?									
with small scale plants, perhaps learning curves possible? >20ktpa = okay	System cost decline (annual)	[%]		?									(Guesstimate for) CAPEX reduction beyond 2025
mature tech.	Scaling factor	N/A		0.65									Rough cost estimate derived based on comparing values from (1)-(8). See slide 5 in the documentation
	Total direct cost	[M€]	(1-8)	80.0									Rough cost estimate derived based on comparing values from (1)-(8). See slide 5 in the documentation
	Fixed OPEX	[M€/y]		2.0									Assumed to be 2.5% of TDC, annual cost
	System footprint	[m2]											

Source ID	References
1	E. Morgan, 2013 (PhD), Techno-Economic Feasibility Study of NH3 Plants Powered by Offshore Wind, Ch. 6.5
2	ECN (ISPT), 2017, Power to Ammonia
3	E. Morgan et al, 2017, Sustainable ammonia production from US offshore wind farms, a techno-economic review
4	Northern Gas Networks & Equinor, 2018, H21 North of England report
5	https://www.basf.com/global/en/media/news-releases/2018/04/P-US-18-044.html
6	R. Nayak-Luke et al, 2018, Green Ammonia - Impact of RES Intermittency on Plant Sizing and Levelized Cost of Ammonia
7	IEA, 2020, Future of Hydrogen
8	C. Fúnez Guerra et al, 2020, Techno-economic analysis for a green NH3 production plant in Chile and its subsequent transport to Japan
9	Linde, 2019, Modular air separation plants
10	S. Tesch et al, 2019, Comparative Evaluation of Cryogenic Air Separation Units from the Exergetic and Economic Points of View
11	HydroHub (ISPT), 2019, HyChain3 - Analysis of the current state and outlook of technologies for production
12	C. Fúnez Guerra et al, 2020, Techno-economic analysis for a green NH3 production plant in Chile and its subsequent transport to Japan
13	Thyssenkrupp Industrial Solutions – Ammonia technology brochure
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C4: Methanol synthesis

Parameter name	Description	Unit	Source ID	Values/estimates 2020	2020	2020	2030	2030	2030	2040	2040	2040	Remarks
				Low	Mid	High	Low	Mid	High	Low	Mid	High	
	Scale of the Methanol plant	[MW]		317	317	317	317	317	317	317	317	317	10 PJ/yr methanol output (LHV of 20 MJ/kg), between CRI plant (0.1 PJ/yr) and Lurgi Megamethanol (37 PJ/yr)
	System energy efficiency	[%]		83	79	76	83	81	76	83	82	76	MeOH out/(H2 and electricity in), excluding excessive heat generation
	Specific power consumption	[kWh/MJ MeOH]	3,4,6,7	0.008	0.014	0.017	0.008	0.011	0.017	0.008	0.010	0.017	Net power input for the system reduces slightly over time
	Specific H2 consumption	[MJ H2/MJ MeOH]	1,3,4,8	1.17	1.22	1.25	1.17	1.20	1.25	1.17	1.19	1.25	Average efficiency improves slightly over time
	Specific CO2 consumption	[kg CO2/MJ MeOH]	6	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	CO2 input as feedstock
	MeOH output, hourly	[t/h]		57	57	57	57	57	57	57	57	57	At nominal capacity (10 PJ/yr with MeOH (LHV) = 20 MJ/kg)
	Heat output	[MJ Heat/MJ MeOH]	6	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	
	Annual utilization	[%]		95	95	95	95	95	95	95	95	95	
	MeOH output, annual	[kt/y]		475	475	475	475	475	475	475	475	475	Depends on the annual utilization of the plant.
	CO2 emissions, annual	[kt/y]		57	57	57	48	48	48	38	38	38	Based on the incinerated flue gas from purge streams
	Total direct cost, specific	[€/kW]	1,3,4,5	95	347	726	221	252	347	158	237	347	Total plant costs per kW methanol output
	System cost decline (annual)	%					-9	3	7	3	1	0	According to CAPEX estimates, which are based on literature
	Total direct cost	[M€]		30	110	230	70	80	110	50	75	110	
	Scaling factor	N/A											
	Fixed OPEX	[M€/y]	1,2,3,4,7	1	4	9	2	2	3	1	2	3	decline from 4% in 2020, to 3% in 2030, and 2.5% in 2040 of CAPEX
		[m2]											

Source ID	References
1	TNO ETS factsheet about MeOH from CO2 (2019)
2	IEA 2019. The Future of Hydrogen (Assumptions Annex)
3	Detz et al. 2018. The future of solar fuels: when could they become competitive?
4	Tremel et al. 2015. Techno-economic analysis for the synthesis of liquid and gaseous fuels based on hydrogen production via electrolysis
5	Anicic et al. 2014. Comparison between two methods of methanol production from carbon dioxide
6	Van Dal and Bouallou 2013. Design and simulation of a methanol production plant from CO2 hydrogenation
7	Terwel et al. 2018. Carbon neutral aviation with current engine technology: the take-off of synthetic kerosene production in the Netherlands
8	Bellotti et al. 2017. Feasibility study of methanol production plant from hydrogen and captured carbon dioxide
9	Marlin, D.S., Sarron, E., Sigurbjörnsson, O., Process Advantages of Direct CO2 to Methanol Synthesis. Front. Chem., 2018, 6:446
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HyDelta

C5: LOHC hydrogenation

Parameter name	Description	Unit	Source ID	Values/estimates 2020	2025	2030	2040	Remarks
	Scale of the hydrogenation plant	[MW]	2	1037				Based on 4200 ktpa of TOL assuming 6,1 wt% of H2 content and 99% conversion efficiency
	System energy efficiency	[%]						
	MCH output	TPD	3	11507				
	Specific power consumption	[kWh/kg H2]	3	0.4				
	Heat released	[kWh/kg H2]	[3,4]	8.8				At around 150-200 degC according to [4]
	H2 output, hourly	[t/h]	2	31				
	Annual utilization	[%]	1	95.0				
	H2 output, annual	[kt/y]	2	259				
	Total direct cost, specific	[€/kW]		186				
	System cost decline (annual)	[%]						
	Total direct cost	[M€]	3	193				for Toluene input of 300 TPD
	Scaling factor	N/A	3	0.7				
	Fixed OPEX	[M€/y]	3	0.4				
	System footprint	[m2]						

Source ID	References
1	2020 - TNO - International Supply Chains of Renewable Energy Using Hydrogen: Argentina - The Netherlands
2	2019 - IEA - The Future of Hydrogen - Assumptions Annex
3	2019 - Reuß, M., Grube, T., Robinius, M., & Stolten, D. - A hydrogen supply chain with spatial resolution: Comparative analysis of infrastructure technologies in Germany. Applied Energy, 247, 438–4
4	2018 - Wulf, C., & Zapp, P. - Assessment of system variations for hydrogen transport by liquid organic hydrogen carriers. International Journal of Hydrogen Energy, 43(26), 11884–11895. https://doi.
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HyDelta

C6A: Formic acid synthesis

Parameter name	Description	Unit	Source ID	Values/estimates									Remarks
				2020	2020	2020	2030	2030	2030	2040	2040	2040	
				Low	Mid	High	Low	Mid	High	2-compartment	Direct	High	
	Scale of the fromic acid synthesis plan	[ktpa]	1			12							This route is thermochemical route
	Specific power consumption	[MWh/t Formic acid]	2			0.30							
	Specific heat consumption (steam)	[MWh/t formic acid]	2			2.78							
	CO2 consumption	[t/t formic acid]	2			0.83							
	Specific H2 consumption	[t H2/t formic acid]	2			0.06							
	Operating hours	[h/y]				8000							
	Fomic acid output, daily	[t/d formic acid]				36.0							
	Total direct cost, specific	[M€/tpd formic acid] (capacity)				0.254							
	System cost decline (annual)	[%]											
	Scaling factor	N/A				0.6							
	Total direct cost	[M€]	2			9.15							
	Fixed OPEX	[M€/y]				0.27							3% of CAPEX assumed
	Variable OPEX	[M€/year]	2			8.40							It was assumed that catalyst is exchanged every year.
	System footprint	[m2]											

Source ID	References
1	Bulushev, D. A., & Ross, J. R. H. (2018). Towards Sustainable Production of Formic Acid. ChemSusChem, 11(5), 821–836. doi:10.1002/cssc.201702075
2	Pérez-Fortes, M.; Schöneberger, J.C.; Boulamanti, A.; Harrison, G.; Tzimas, E. Formic acid synthesis using CO2 as raw material: Techno-economic and environmental evaluation and market potential. Int. J. Hydrog. Energy 2016, 41, 16444–16462.
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HyDelta

C6B: Formic acid synthesis

Parameter name	Description	Unit	Source ID	Values/estimates 2020 Low	2020 Mid	2020 High	2030 Low	2030 Mid	2030 High	2040 Low	2040 Mid	2040 High	Remarks
	Scale of the fromic acid synthesis plan	[ktpa]	1		10.00								This route is electrochemical, TRL is low so the highest capacity difficult to estimate
	Specific power consumption	[MWh/t Formic acid]	3		4.20								
	Specific heat consumption (steam)	[MWh/t formic acid]	3		6.27								
	CO2 consumption	[t/t formic acid]	3		1.08								
	Specific H2 production	[t H2/t formic acid]	3		0.04								
	Specific O2 production	[t O2/t formic acid]	3		0.44								
	Operating hours	[h/y]			8000								
	Fomic acid output, daily	[t/d formic acid]			30.00								
	Total direct cost, specific	[M€/tpd formic acid] (capacity)			0.72								
	System cost decline (annual)	[%]											
	Scaling factor	N/A			0.90								Capex is determined by electrolyser costs. So maybe we can apply scale factor for electrolyser?
	Total direct cost	[M€]	3		21.60								
	Fixed OPEX	[M€/y]			0.65								3% of CAPEX assumed
	Variable OPEX	[M€/year]			4.10								
	System footprint	[m2]											

Source ID	References
1	Bulushev, D. A., & Ross, J. R. H. (2018). Towards Sustainable Production of Formic Acid. ChemSusChem, 11(5), 821–836. doi:10.1002/cssc.201702075
2	Hychain datasheet
3	(September 2020) D 2.2.1.1 First full business case analysis for Power-to-X in the 2 Seas region. Direct Route
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HyDelta

C4: KBH4 and NaBH4

Parameter name	Description	Unit	Source ID	Values/estimates									Remarks
				2020	2020	2020	2030	2030	2030	2040	2040	2040	
				Low	Mid	High	Low	Mid	High	Low	Mid	High	
	CAPEX	M€/Mt capacity			2,276.8								Calculated for 46.6 kt/year production capacity from Hychain database
	Fixed OPEX	M€/Mt capacity/year			257.50								Fixed charges, general and overhead costs from Hychain: 12 M€/y
	Variable O&M	M€/Mt production/year			7,800.4								Raw materials, utilities, maintenance, labor, co-product credits from Hychain: 363.5 M€/y
	Material input- CO2	t CO2/t NaBH4			0.83								Based on flow scheme and calculations from Hychain
	Material input – H2	t H2/t NaBH4			2.45								Based on flow scheme and calculations from Hychain
	Energy input – Electricity	MWh / t NaBH4			0.02								Based on flow scheme and calculations from Hychain
	Energy input – Heat	MWh / t NaBH4			10								Heat required up to temperatures of 370 °C
	Technical lifetime	Years			25.00								Typical lifetime for such a chemical plant (90% utilization, 3 year construction time)
	Typical capacity	kt NaBH4/year			<70								Based on Hychain.

Source ID	References
1	Li, Zhou Peng, et al. "Preparation of potassium borohydride by a mechano-chemical reaction of saline hydrides with dehydrated borate through ball milling." Journal of alloys and compounds 354.1-2 (2003): 243-247.
2	Saka, Cafer, and Asım Balbay. "Fast and effective hydrogen production from ethanolysis and hydrolysis reactions of potassium borohydride using phosphoric acid." International Journal of Hydrogen Energy 43.43 (2018): 19976-19983.
3	Hagemann, Hans, and Radovan Černý. "Synthetic approaches to inorganic borohydrides." Dalton Transactions 39.26 (2010): 6006-6012.
4	Bilen, Murat, Metin Gürü, and Çetin Çakanyildirim. "Conversion of KCl into KBH4 by mechano-chemical reaction and its catalytic decomposition." Journal of Electronic Materials 46.7 (2017): 4126-4132.
5	Şahin, Ömer, Hacer Dolaş, and Mustafa Özdemir. "The effect of various factors on the hydrogen generation by hydrolysis reaction of potassium borohydride." International journal of hydrogen energy 32.13 (2007): 2330-2336.
6	Minkina, Valentina G., et al. "Long-term stability of sodium borohydrides for hydrogen generation." international journal of hydrogen energy 33.20 (2008): 5629-5635.
7	Liu, B. H., and Z. P. Li. "A review: hydrogen generation from borohydride hydrolysis reaction." Journal of Power Sources 187.2 (2009): 527-534.
8	Laversenne, Laetitia, et al. "Hydrogen storage in borohydrides comparison of hydrolysis conditions of LiBH4, NaBH4 and KBH4." Journal of thermal analysis and calorimetry 94.3 (2008): 785-790.
9	Çakanyıldırım, Çetin, and Metin Gürü. "Hydrogen cycle with sodium borohydride." International Journal of Hydrogen Energy 33.17 (2008): 4634-4639.
10	DEMİRCİ, Ümit Bilge. "Sodium borohydride for the near-future energy: a ''rough diamond'' for Turkey." Turkish Journal of Chemistry 42.2 (2018): 193-220.
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HyDelta

SH1:	Liquid shipping (LH2)							
Parameter name	Description	Unit	Source ID	Values/estimates				Remarks
				2020	2025	2030	2040	
	Storage tank size	[m^3]						
	Storage tank capacity	[ton LH2]				11 000		
	Specific power consumption	[GJ/km]	1			3,6		
	Boil-off rate	[%/day]	2			0.2%		
	Annual utilization							
	Total installed cost, specific	[€/ ton LH2]	2,3			365		IEA Future of hydrogen (technical parameters annex): 412M$/ship with 11kt LH2 capacity HyChain 175M€ for a 10.3 kt H2 carrier
	Scaling factor	[N/A]				0,7		
	Total direct cost	[M€]						
	Fixed OPEX	[M€/year]				2%		
	Life time	[Years]						
	System cost decline (annual)	[%]						
	System footprint	[m2]						

Source ID	References
1	IEA-The-Future-of-Hydrogen-Assumptions-Annex_CORR
2	IEA Future of hydrogen (technical parameters annex)
3	HyChain
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HyDelta

ST1: CH2 Storage -HP Vessels

Parameter name	Description	Unit	Source ID	alues/estimates 2020	2025	2030	2040	Remarks
	Storage capacity (mass)	[kg]	[1]	1000	1.00E+03			Compressed gaseous hydrogen in large bundles or tube trailers at pressure of 500 bar is considered. 500 bar is high pressure category and requires composite overwrapped pressure vessels (commonly referred to Type -4 vessel) are preferred. A single trailer have capacity of up to 1000 kg of hydrogen
	storage capacity (volume)	[m^3]		11 123.5	11 123.5			
	storage capacity (energy)	[kWh]		33 240.0	3.32E+04			Based on H2 Lower Heating Value of 120 MJ/kg or 0.033 MWh/kg.
	Total direct cost, specific	[€/kg]	[1]	853	650			
	System cost decline (annual)	[%]	[1,5]	4.0	4.0			bulk of cost reductions must come from reducing the amount and costs of carbon fiber composite materials and Balance-of-Plant (BOP). Since the technology is not fully mature, future cost reduction is expected as more trailers are produced. The data from [1] shows a 4% yearly reduction upto the 2025 and this trend could continue upto 2030
	Total direct cost	[M€]		0.85				Assumed to be total installed costs (including site preparation, engineering, project management etc.)
	Scaling factor	N/A						Rough estimate of cost reduction potential
	Fixed OPEX	[M€/y]	[1,4]	0.03				in [4] OPEX pf 3-5% of annual CAPEX costs is suggested. In [1] 4% uses
	Life time	[Years]	4	25				Mobile storage has a lifetime of 20-30 years, but requires maintenance and inspection every 10 to 15 years
	System footprint	[m2]						minimum tank required is 2. On

Source ID	References
1	FCH JU (2017) - Study on early business cases for H2 in energy storage and more broadly power to H2 applications. Final report www.fch.europa.eu/sites/default/files/P2H_Full_Study_FCHJU.pdf.
2	Gaby Janssen, 2020. Technology Factsheet: Compressed Hydrogen Storage, available at https://energy.nl/wp-content/uploads/2021/04/Compressed_Hydrogen_Storage-1.pdf
3	M. Reuss et al. (2017): Seasonal storage and alternative carriers: a flexible hydrogen supply chain model. Applied Energy 200, 290-302
4	HyChain 3. Hydrogen Supply Chain- Technology Assessment
5	NREL (2014) - Hydrogen Station Compression, Storage, and Dispensing. Technical Status and Costs. Technical Report NREL/BK-6A10-58564.
6	DOE (2013). Onboard Type IV Compressed Hydrogen Storage Systems – Current Performance and Cost
7	FCH JU (2017) - Study on early business cases for H2 in energy storage and more broadly power to H2 applications. Final report www.fch.europa.eu/sites/default/files/P2H_Full_Study_FCHJU.pdf.
8	Linde (2013). https://www.greencarcongress.com/2013/09/20130925-linde.html
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HyDelta

ST2: CH2 Storage -Salt Caverns

Parameter name	Description	Unit	Source ID	Values/estimates				Remarks
				2020	2025	2030	2040	
	Scale /size	[m^3]	1,2,3,8	1.00E+06	1.00E+06	1.00E+06	1.00E+06	This value is geometric volume. Typical salt cavern sizes range from 500,000 m3 -1000,000 m3 geometrical volume.
	diameter	[m]	8	27				
	depth	[m]	8	450				
	depth of the roof	[m]	8	1000				Typical depth range: 1000-1300 meters. Initial formation pressure and temperature depends on the depth of the cavern roof.
	Maximum pressure	[bar]	4	245				The maximum pressure should not be more than 80% the smaller one of the overlying pressure or the fracture breakdown pressure at the casing shoe.
	minimum pressure	[bar]	4	73				typically the minimum pressure is around 30% of the maximum pressure
	Temperature (average)	[K]	9	286.75				temperature varies with depth. Typical temperature changes: 3 °C between the top and bottom of a small cavern and 7.5 °C for a large salt cavern.
	storage capacity/working gas(volume)	[Nm^3]	2	160 000 000.00				This depends on the final choice of cavern size and the detailed thermodynamic calculations to estimate the effect of temperature changes on the cavern inventory in more detail
	storage capacity/working gas (energy)	[GWh]		480				
	Cushion gas (volume)	[Nm^3]		6.72E+07				Assuming nitrogen as cushion gas. Typical cushion gas volume for salt caverns require typically around 25-30% of the total volume. Here 30 % is considered. Total volume includes volume of cushion gas plus working gas.
	Injection rate	[Nm^3/day]		0.67				for simplicity withdrawal rate is assumed to be equal to injection rate. This is mostly the case for structural stability reason. Depends on allowable pressure gradient and well tubing diameter. The value here is asuming 10 bar/day. alternatively, as a rule of tumb, the maximum withdrawal rates are in the order of 10 % of the storage capacity per day
	Injection rate	[GW]		0.67				
	Annual Utilization	[%]		99				Caverns are available all season with rare maintance periods
	Total direct cost, specific	[€/m^3]	5	25				includes geological exploration and infrastructure of the well, and then relatively minor costs for the creation of the actual cavity. Cost varies 30–50 € m–3 (geometrical volume).
	Total direct cost, specific	[€/kWh]	8	0.14				Investment cost of UHS in caverns = 4.800 €/kg. 1 kg=33.33 KWh
	System cost decline (annual)	[%]	3	10				The technology is largely mature. No signficant cost decline is expected. 10% is assumed for fast cycle operation cost decline facility.
	Total direct cost	[M€]	2,8	2.50E+07				Value is for a single cavern. Includes the installation cost assumed to be 2 times the equipment cost
	Scaling factor	N/A	5	0.83				derived from the data from the specific cost vs size graph in [5]
	Fixed OPEX	[M€/y]	2,8	1.00E+06				OPEX =3-5% of annual Investment cost costs . 4% isssumed for this study
	Life time	[Years]	2	45				45-50 years
	System footprint	[m2]						known for the small footprint required above ground.
	TRL			6		8		Fast cycle operation is at TRL 5-6 but constant operation is around TRL 8

Source ID	References
1	TNO, 2020. Large-Scale Energy Storage in Salt Caverns and Depleted Fields (LSES) – Project Findings
2	ISPT, 2019. Hydrohub Hychain3- Analysis of the current state and outlook of technologies for production Hydrogen Supply Chain – Technology Assessment
3	M. Reuss et al. (2017): Seasonal storage and alternative carriers: a flexible hydrogen supply chain model. Applied Energy 200, 290-302
4	Wang. T et al. 2019. Determination of the maximum allowable gas pressure for an underground gas storage salt cavern – A case study of Jintan, China. Journal of Rock Mechanics and Geotechnical Engineering, Volume 11, Issue 2
5	Fritz Crotogino, 2016. Chapter 19 - Traditional Bulk Energy Storage—Coal and Underground Natural Gas and Oil Storage. Storing Energy, Elsevier.
6	A. Ozarslan, "Large-scale hydrogen energy storage in salt caverns," Int. J. Hydrogen Energy, vol. 37, no. 19, pp. 14265–14277, 2012
7	R. Tarkowski, "Underground hydrogen storage: Characteristics and prospects," Renew. Sustain. Energy Rev., vol. 105, no. February 2017, pp. 86–94, 2019
8	Danish Energy Agency and Energinet (2020). Technology Data – Energy storage
9	Caglayan,D.G. et al. (2020). Technical potential of salt caverns for hydrogen storage in Europe, International Journal of Hydrogen Energy, Volume 45, Issue 11, pp 6793-6805,

ST3: Liquid storage (LH2)

Parameter name	Description	Unit	Source ID	Values/estimates 2020	2025	2030	2040	Remarks
	Storage tank capacity	[m^3/tank]	[1,2]	8000				NASA size storage. Tank capacity size guestimate based on Ref: R.K. Ahluwalia et.al. (2020) System Level Analysis of Hydrogen Storage Options. There are few LH2 storage tanks globally all associated with the space industry (e.g. NASA: 3800 m3 , JAXA: 540 m3, NASA (under construction): 5300 m3).
	Storage tank capacity	[ton]		624				Volume * density of LH2 at 1 bar and -253°C. Tanks that can store 115 ton-900 ton exist.
	Storage tank capacity	[MWh]		20 809				Based on the Lower Heating Value of hydrogen which is 120 MJ/kg or 0.033 MWh/kg
	Specific power consumption	[kWh/kg]	[5]	0.6				To keep the temperature at -253°C. For liquification energy consumption look into the H2 liquification factsheet (C2).
	Annual utilization	[%]		95.0				minimal
	losses	[%/year]	[2]	11.00				Based on 0.03%/day loss due to boil-off
	factor for buffer capacity	[N/A]	[5]	1.3				Assumption of upto 30% of the initial storage capacity.
	Total installed cost, specific	[€/kg LH2]	[2]	25				No-scaling applied. approx. 2000 €/ton for 3800 m^3 tank. See ref [1]
	Total installed cost, specific	[€/kWh]	[3]	0.75				A.T.Kearney estimates the cost of the tanks at 800-10000 USD/MWh H2 (2014 value)
	Scaling factor	[N/A]						
	Total direct cost	[M€]	[1-5]	15.61				Cost of storage dominated by material and welding costs. Cost similar between LNG and LH2. Data shows varying investment cost values depending on size of tank: Ref [5] reported 200 M€ for 50,000 m^3 LH_2 tank, Ref [4] reported 250 M€ for 50, 000 m^3 LH2 tank
	Fixed OPEX	[M€/year]	[2,5]	0.3				2% of CAPEX is assumed
	Variable OPEX	[M€/year]						Depends on scale. In [5] Total Opex is expressed as ratio of total ownership cost
	Life time	[Years]	[5]	30				storage tanks can operate for upto 30 years
	System cost decline (annual)	[%]						
	System footprint	[m2]						

Source ID	References
1	R.K.Ahluwalia et al. (2020) System Level Analysis of Hydrogen Storage Options. Available at https://www.hydrogen.energy.gov/pdfs/review20/st001_ahluwalia_2020_o.pdf
2	M. Reuß et al. (2017): Seasonal storage and alternative carriers: a flexible hydrogen supply chain model. Applied Energy 200, 290-302
3	A.T Kearney (2014), Energy transition Institute, Hydrogen based energy conversion, 2014. https://www.kearney.com/web/home/insights/hydrogen.
4	HydroHub (ISPT), 2019, HyChain3 - Analysis of the current state and outlook of technologies for production
5	S.Lanphen (2019). Hydrogen Import Terminal: Master Thesis, Delft University of Technology
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ST4: Liquid NH3 tanks

Parameter name	Description	Unit	Source ID	Values/estimates 2020 Low	2020 Mid	2020 High	2030 Low	2030 Mid	2030 High	2040 Low	2040 Mid	2040 High	Remarks
	Max. NH3 storage tank capacity	[m3]	(2)		80000								Maximum capacity for a single storage unit. Equivalent to 55kt liquid NH3
	Max. NH3 storage tank capacity	[t NH3]			54480								Volume * density of liquid ammonia at 1bar and -33°C
	Specific power consumption	[kWh/t NH3]											Not addressed yet - see slides for more information
	Total installed cost, specific	[€/t NH3]			2000								Cost of refrigerated tank storage per t of NH3, for a 5000 t NH3 storage tank
	Scaling anchor point	[t NH3]			5000								Based on the cost indication provided by Proton Ventures for a 5,000 t refrigerated ammonia tank. Assumed to be total installed costs (including site preparation, engineering, project management etc.)
	Total direct cost (@ max capacity)	[M€]			49.5								Additional costs could be considered for auxiliary equipment (pumps, boil-off gas management system, loading/unloading facilities, etc.)
	Scaling factor	N/A			0.67								Rough estimate of cost reduction potential when scaling up above 20MW. Electrolyzers don't scale well, because stacks and most of their auxiliary systems are multiplied.
	Fixed OPEX	[M€/y]			1.0								Assumed to be 2% of TDC, annual cost
	System footprint	[m2]											

Source ID	References
1	E. Morgan, 2013 (PhD), Techno-Economic Feasibility Study of NH3 Plants Powered by Offshore Wind, Ch. 6.5
2	Northern Gas Networks & Equinor, 2018, H21 North of England report
3	HydroHub (ISPT), 2019, HyChain3 - Analysis of the current state and outlook of technologies for production
4	K. Rouwenhorst et al, 2019, Islanded ammonia power systems - Technology review & conceptual process
5	IEA, 2020, Future of Hydrogen
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HyDelta

ST5: Liquid storage (MEOH)

Parameter name	Description	Unit	Source ID	Values/estimates 2020	2025	2030	2040	Remarks
	Storage tank size	[m^3]	[1]	50 000				Maximum capacity for a single storage tank is 50,000 m^3
	Storage tank capacity	[ton MEOH]	[1,3,4]	31 680				Rounded up and assuming that the operating volume of the tank is approx. 80% of its max capacity. A general rule of thumb is to allow 20% of tank working volume for liquid expansion. Density MeOH =792 kg/m^3
	Specific power consumption	[kWh/ ton MEOH]	[1,2]	-				Methanol storage is happen at ambient temperature and atmospheric pressure (20 oc and 1 bar).
	Annual utilization	[%]		99				minimal outage for repair
	Total installed cost, specific	[€/ ton MEOH]	[2]	472.5				unit cost of 75 €/ MWh MeOH in [2], energy density of 6.4 MWh/ton
	Scaling factor	[N/A]						Only one data available yet at 50,000 m3 cpacaity
	Total direct cost	[M€]	[1]	15				15 M€ data from VoPak (obtained by the HyChain 3 project)
	Fixed OPEX	[M€/year]	[1]	0.1				0.6% of CAPEX is assumed
	Life time	[Years]	[1]	30				
	System cost decline (annual)	[%]						Already used in large scale, no significant opportunities expected due to maturity of technology
	System footprint	[m2]						

Source ID	References
1	HydroHub (ISPT), 2019, HyChain3 - Analysis of the current state and outlook of technologies for production
2	DNV GL (2020). Study on the Import of Liquid Renewable Energy: Technology Cost Assessment
3	J. Andersson, S. Grönkvist (2019). Large-scale storage of hydrogen Int J Hydrogen Energy, 44 (23), pp. 11901-11919
4	Methanol Institute Atmospheric Above Ground Tank Storage of Methanol. http://www.methanol.org -> AtmosphericAboveGroundTankStorageMethanol-1.pdf
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HyDelta

ST5: Liquid storage (LOHC)

Parameter name	Description	Unit	Source ID	Values/estimates 2020	2025	2030	2040	Remarks
	Storage tank capacity	[m^3/tank]	[1]	50 000	50 000	50 000	50 000	38.5 for MCH and 43.4 for TOL
	Storage tank capacity	[ton MCH]		38 500				38.5 for MCH and 43.4 for TOL
	Scaling factor	[N/A]		0.7				Ranges from 0.6 to 0.7. For investment compare of 300 ton/day and investment base of 30 million euros.
	Total direct cost	[M€]		13.1				The data is per tank. Includes equipment (tank) cost and installation cost. Data is 2019 and is converted to 2021 using the average yearly inflation rate of 0.35%. 2019 data (MCH is 11.2 for the tank and 2 for the installation and for TOL 12.1 for tank and 3.0 installation. With out loading and unloading facilities. HyChain12.5 for 50,000 m3 bulk liquid
	Fixed OPEX	[M€/year]		0.1				MCH 0.11 per tank and TOL 0.12 per tank excluding Jetty and unloading facilities
	Life time	[Years]		30				
	System cost decline (annual)	[%]						
	System footprint	[m2]						

Source ID	References
1	HydroHub (ISPT), 2019, HyChain3 - Analysis of the current state and outlook of technologies for production
2	A.T. Wijayanta et al. (2019). Liquid hydrogen, methylcyclohexane, and ammonia as potential hydrogen storage: Comparison review. International Journal of Hydrogen Energy. 44 (29). Pp 15026-15044
3	M. Reuss et al. (2017): Seasonal storage and alternative carriers: a flexible hydrogen supply chain model. Applied Energy 200, 290-302
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HyDelta

ST4: NH3 dissociation

Parameter name	Description	Unit	Source ID	Values/estimates 2020 Low	2020 Mid	2020 High	2030 Low	2030 Mid	2030 High	2040 Low	2040 Mid	2040 High	Remarks
	NH3 feed flow	[t/h NH3]			50								Arbitrarily selected capacity (will depend on the use case and expected market demand), assuming that this technology would be used for large-scale applications, for instance imports using NH3 as a H2 carrier.
	Max H2 fuel output	[MW th]			291								Corresponding energy output (H2-rich fuel with ~10% residual NH3 / no purification losses taken into account)
	Heat of reaction	[MWh/t NH3]	(1-2)		0.88								Enthalpy of reaction at ~733 K (theoretical heat input). This should be checked, as some sources indicate a much higher heat requirement per kg of H2 recovered. The difference can be partially explained through quality requirements (purification losses).
	Process thermal efficiency	[%]			90								Assumption / more energy would be required than the theoretical minimum for the dissociation reaction.
	Heat input required (at rated capacity)	[MW th]			48.9								If a higher purity is needed, the heat required could be (partially) supplied by burning the off-gas stream from the purification section. If this system is coupled with a gas turbine for power generation, turbine exhaust gases can also be used as a heat source.
	Power input required (at rated capacity)	[MW el]			--								Left blank but should be reviewed if a purification unit is added (for example, using a PSA type of system could require additional gas compression)
	Total CAPEX (installed) (@ max capacity)	[M€]	(3)		94.5								Total cost for the NH3 cracking unit (installed), estimated as a scaled-down version of the cost estimate reported in the H21 NoE study.
	Total direct cost (@ max capacity)	[M€]			63.0								Assumed a 1.5 factor for the additional (indirect) costs
largest = 2mw outp	learning curves?												
largest = 2mw outp	Scaling factor	N/A			0.7								Typical cost scaling factor used for chemical plants
	Fixed OPEX	[M€/y]			1.6								Assumed to be 2.5% of TDC, annual cost
	System footprint	[m2]											

Source ID	References
1	V. Hacker and K. Kordesch, 2003, Ammonia Crackers, Volume 3, Part 2, pp 121–127, Handbook of Fuel Cells – Fundamentals, Technology and Applications
2	Max Appl, 2012, Ammonia 2. Production Processes, Ullmann's Encyclopedia of Industrial Chemistry
3	Northern Gas Networks & Equinor, 2018, H21 North of England report
4	MVS Engineering brochure https://www.mvsengg.com/wp-content/uploads/2018/08/130_MVS_Ammonia-Cracker-Brochure.pdf
5	Thermal Dynamix website - https://www.thermaldynamix.com/ammonia-dissociators
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R3: MeOH reforming

Parameter name	Description	Unit	Source ID	Values/estimates 2020 Low	2020 Mid	2020 High	2030 Low	2030 Mid	2030 High	2040 Low	2040 Mid	2040 High	Remarks
	MeOH feed flow	[kg/h MeOH]	[2,3]		630								Typical capacity (generally depend on the use case and expected market demand), assuming that this technology would be used for large-scale applications, for instance import using methanol as a H2 carrier.
	water feed flow	[kg/h]	[2,3]		360								Demineralized water for the reforming reaction
	Max H2 fuel output	[Nm^3/h]	[3]		1000								Depends on the required output. From 200 to 5000 Nm^3/h. For the utilitiy values listed in this data sheet 1000 Nm3/h is the typical output
	electrcity consumption	[kW el]	[3]		55								
	Heat input required	[kW th]			?								
	Process thermal efficiency	[%]			?								
	Operating pressure	[bar]	[1,2,3]		15								Operating pressure e between 10 bar to 30 bar is produced
	Heat released	[kWh/kg H_2]			-								
	Total CAPEX (installed) (@ max capacity)	[M€]			?								
	Total direct cost (@ max capacity)	[M€]			?								
largest = 2mw outpu	learning curves?				?								
largest = 2mw outpu	Scaling factor	N/A			?								
	Fixed OPEX	[M€/y]			?								
	System footprint	[m^2]			?								

Source ID	References
1	*A.Lulianelli et al (2014). Methanol steam reforming for hydrogen generation via conventional and membrane reactors: A review. Renewable and Sustainable Energy reviews, 29, pp.355-368*
2	*Mahler AGS (2021). Available at* Hydrogen Generation by Methanol Reforming| Mahler AGS (mahler-ags.com)
3	*Caloric Anlagenbau GmbH (2021). Available at* Hydrogen by Methanol Reforming - Caloric Anlagenbau GmbH
4	*P.Ribeirinha et. Al. (2014). Study of different designs of methanol steam reformers: Experiment and modeling. International Journal of Hydrogen energy, vol 39. pp. 19970-19981.*
5	*UltrCell (2021). Reformed methanol fuel cell. Available at* UltraCell | Applications (ultracell-llc.com)
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T1: Liquid Hydrogen (LH2)

Parameter name	Description	Unit	Source ID	Values/estimates 2020	2025	2030	2040	Remarks
Export Terminal								
storage	Export terminal storage tank capacity	[m^3/tank]	[1,2]	50 000	50 000	50 000	50 000	Assumed-scale storage. Typical storage tank size considered for LH2 storage at terminals. There only few LH2 storage tank globally all associated with the space industry (e.g. NASA: 3800 m3 , JAXA: 540 m3, NASA (under construction): 5300 m3).
	Export terminal storage tank capacity	[ton]		3 540	3 540	3 540	3 540	Volume * density of LH2 at 1 bar and -253°C
	losses from storage	[% per year]		11				0.03%/day loss due to boil-off
	Cycles per year		[1]	26.0				
	Investment (CAPEX)	[M€/tank]	[1]	200				
	OPEX rate	[%]		0.0				2% of CAPEX
	OPEX	[M€/year]		4.0				
	Lifetime	[years]		30.0				
Jetty	Capacity	[ton/year]	[1]	4 000 000				
	Investment cost, specific	[M€/jetty]						
	# of Jetty							
	Total Investment cost	[M€]						
	Fixed Opex	[M€/year]						
	Lifetime							
Total	Total export terminal investment cost							
	Total export terminal OPEX							
Import Terminal								
storage	Export terminal storage tank capacity	[m^3/tank]	[1,2]	50 000	50 000	50 000	50 000	Assumed-scale storage. Typical storage tank size considered for LH2 storage at terminals. There only few LH2 storage tank globally all associated with the space industry (e.g. NASA:
	Export terminal storage tank capacity	[ton]		3 540	3 540	3 540	3 540	Volume * density of LH2 at 1 bar and -253°C
	losses from storage	[% per year]						
	Cycles per year							
	Investment (CAPEX)							
	OPEX rate							
	OPEX							
	Lifetime							
Jetty	Capacity							
	Investment cost, specific							
	# of Jetty							
	Total Investment cost							
	Fixed Opex							
	Lifetime							
Pipeline	Capacity							
	Total Investment cost							
	Fixed Opex							
	lifetime							
Total								
	Total import terminal investment cost	[M€]		0.0	0.0	0.0	0.0	
	Total import terminal OPEX	[M€/year]		0.0	0.0	0.0	0.0	

Source ID	
1	S.Lanphen (2019). Hydrogen Import Terminal: Master Thesis, Delft University of Technology
2	Y.Ishimoto et.al. (2020). Large-scale production and transport of hydrogen from Norway to Europe and Japan: value chain analysis and comparison of liquid hydrogen and ammonia as energy carriers. International Journal of Hydrogen En
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T2:	Ammonia (NH_3)							
Parameter name	Description	Unit	Source ID	Values/estimates 2020	2025	2030	2040	Remarks
Export Terminal								
storage	Export terminal storage tank capacity	[m^3/tank]	[1,2]	50 000	50 000	50 000	50 000	Assumed-scale storage. Typical storage tank size considered for NH3 storage at terminals.
	Export terminal storage tank capacity	[ton]		34 050	34 050	34 050	34 050	Volume * density of NH3 at 1 bar and -33°C
	losses from storage	[% per year]		11				0.03%/day loss due to boil-off
	Cycles per year		[1]	26.0				
	Investment (CAPEX)	[M€/tank]	[1]	200				
	OPEX rate	[%]		0.0				2% of CAPEX
	OPEX	[M€/year]		4.0				
	Lifetime	[years]		30.0				
Jetty	Capacity	[ton/year]	[1]	4 000 000				
	Investment cost, specific	[M€/jetty]						
	# of Jetty							
	Total Investment cost	[M€]						
	Fixed Opex	[M€/year]						
	Lifetime							
Import Terminal								
storage	Export terminal storage tank capacity	[m^3/tank]	[1,2]	50 000	50 000	50 000	50 000	Assumed-scale storage. Typical storage tank size considered for NH3 storage at terminals.
	Export terminal storage tank capacity	[ton]		34 050	34 050	34 050	34 050	Volume * density of NH3 at 1 bar and -33°C
	losses from storage	[% per year]		11				0.03%/day loss due to boil-off
	Cycles per year							
	Investment (CAPEX)							
	OPEX rate							
	OPEX							
	Lifetime							
Jetty	Capacity							
	Investment cost, specific							
	# of Jetty							
	Total Investment cost							
	Fixed Opex							
	Lifetime							
Pipeline	Capacity							
	Total Investment cost							
	Fixed Opex							
	lifetime							

Source ID	
1	S.Lanphen (2019). Hydrogen Import Terminal: Master Thesis, Delft University of Technology
2	Y.Ishimoto et.al. (2020). Large-scale production and transport of hydrogen from Norway to Europe and Japan: value chain analysis and comparison of liquid hydrogen and ammonia as energy carriers. International Journal of Hydrogen En
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