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

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Journal: International Journal of Hydrogen Energy

Abstract

Low-carbon hydrogen is considered as one of the key measures to decarbonise continental Europe and Japan. Northern Norway has abundant renewable energy and natural gas resources which can be converted to low-carbon hydrogen. However, Norway is located relatively far away from these markets and finding efficient ways to transport this hydrogen to the end-user is critical. In this study, liquefied hydrogen (LH_2) and ammonia (NH_3), as H_2-based energy carriers, are analysed and compared with respect to energy efficiency, CO_2 footprint and cost. It is shown that the LH_2 chain is more energy efficient and has a smaller CO_2 footprint (20 and 23 kg-CO_2/MWh_{th} for Europe and Japan, respectively) than the NH_3 chain (76 and 122 kg-CO_2/MWh_{th}). Furthermore, the study finds the levelized cost of hydrogen delivered to Rotterdam to be lower for LH_2 (5.0 EUR/kg-H_2) compared to NH_3 (5.9 EUR/kg-H_2), while the hydrogen costs of the two chains for transport to Japan are in a similar range (about 7 EUR/kg-H_2). It is also shown that under optimistic assumptions, the costs associated with the LH_2 chain (3.2 EUR/kg-H_2) are close to meeting the 2030 hydrogen cost target of Japan (2.5 EUR/kg-H_2).

Keywords: techno-economic analysis, liquid hydrogen, ammonia, long distance transport

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1. Introduction

Since signing the Paris agreement in 2015, the ratifying countries have submitted their Nationally Determined Contributions to tackle climate change. For almost all countries, this means that huge efforts must be made within a rather short time period. For example, Japan plans to cut emissions by 26% by 2030 compared to 2013 levels [1], and the EU has recently set an ambitious target to reach climate neutrality by the year 2050 through the 'European Green Deal'. Utilisation of hydrogen is expected to be one of the key deep decarbonisation options for the transportation, residential and commercial, power and industry sectors [2], in addition to energy efficiency, renewable energy and nuclear technologies.

Norway is a major natural gas producer and has large hydropower resources and potential for development of wind energy, a part of which could be pocketed in the northern area unless proportional capacity is added to the transmission grid. Central transmission grid extensions have substantially longer lead time than wind power generation capacity and therefore risks lagging behind. The country also puts strategic efforts towards RD&D (Research, Development and Deployment) in carbon capture and storage (CCS) technology. By combining these abundant natural resources and CCS technologies, the country has great potential to be a significant producer of renewable and low carbon hydrogen. However, Norway is located relatively far away from the global and continental European market, making the transport aspect critical.

A variety of research and development projects targeting different aspects of hydrogen value chains are being carried out, not only under EUs Fuel Cells and Hydrogen Joint Undertaking, but also in national programs. In an EU scenario with 50% of the primary energy demand supplied as hydrogen, 3,100-6,000 TWh/y of hydrogen is

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http://dx.doi.org/10.1016/j.ijhydene.2020.09.017

estimated to be required in 2050 [3, 4]. A fraction of this is expected to be transported by ship as liquid hydrogen or other hydrogen carriers. Japan is, similarly to the EU, putting significant efforts into hydrogen related projects. Japan has set a target to initiate large scale hydrogen import from the 2030s. In their national hydrogen strategy, hydrogen import can contribute to Japan's energy strategy, the 3Es: energy security, environment and economic efficiency [5]. For an energy importing country such as Japan, energy security mainly means diversification of energy resources and supply countries in addition to maximum utilization of domestic energy resources. As hydrogen can be produced from a variety of resources, hydrogen contributes to diversification of energy resources and supply countries. It is believed that hydrogen can also be an economically efficient option. However, it is necessary to fully understand the costs and implications of the full value chain for several hydrogen transport options in order to select the most suitable and cost-efficient options, and to understand where in the value chains technology improvement and cost reduction efforts should be focused. These aspects are analysed in the current study, which is a high-level analysis of large-scale hydrogen value chains from Norway to Japan and Europe, with production capacity 500 tpd.

Several studies of similar concepts can be found in the literature, where energy is transported to a region of high energy demand and insufficient domestic production. The Euro-Quebec Hydro-Hydrogen Pilot Project (EQHHPP) [6] studied a renewable hydrogen supply chain using liquefied hydrogen (LH_2) and methylcyclohexane (MCH) from Quebec to Germany and presented transparent and detailed assumptions. However, the considered annual chain capacity is one order of magnitude smaller than in the current study, and the results can due to scale merit effects for capital expenditures not be considered as valid for 500 tpd scale. Andreassen et al. [7] analysed hydrogen production with 100 MW hydropower input and transport from Norway to Germany using small LH_2 ships and ISO containers. Again, the capacity is considerably lower than 500 tpd. The WE-NET project published in 1995 [8,10] studied renewable hydrogen production using hydropower in Canada and transport to Japan using LH_2, ammonia and methanol as energy carriers. The assumptions are transparent and detailed. However, technical and economic development since the publication of this study and others from up until the early 2000s should be considered. The study by Specht et al. [9] is similar to the EQHHPP study except that methanol is considered as an energy carrier in an advanced concept where direct air capture technology is used for CO_2 supply. Wietschel [11] studied hydrogen transport of various combinations between hydrogen production countries and technologies, energy carriers, and demand countries. The scope of the study is comprehensive, however, detailed technical aspects of each technology are not described. The transport distances considered are limited to within Europe and adjacent regions. Ingason [12] studied hydrogen production in Iceland and transport to continental Europe. Although the transport aspect is mentioned in the study, it has emphasis on optimization of the hydrogen production location in Iceland. Stiller et al. [13] also analysed hydrogen production and transport from Norway to Germany using pipeline, LH_2 and High Voltage Direct Current (HVDC). Various transport options are considered, but a global market and ammonia as hydrogen carrier are not included. In a feasibility study by Kawasaki [14-16], hydrogen is produced from brown coal with CCS technology in Australia and transported using large LH_2 ships. The assumptions are detailed and transparent. This study focuses on technical feasibility and economic analysis. Lang and Tao [17] studied gaseous hydrogen, ammonia and LH_2 as fuels for fuel cells and analysed high level energy balances of the value chains. Babarit [18] studied LH_2 and gaseous hydrogen (GH_2) supply chains consisting of an offshore windfarm and an offshore terminal, the distance of which is located 1000 km from an offshore terminal, LH_2 and GH_2 carrier ships, and a delivery system to the demand side. The transport concept of this study is similar to the case with transport to the European market in the current study. The scale of transport capacity using the supply chain is however about half of the current study. International transport using large-scale LH_2 carrier ships is not considered in the study. DNV GL [19], Wijayanta [20] and IEA [21] compared long distance transport of LH_2, ammonia and MCH based on the basic properties of the energy carriers. The detailed technical specifications of each facility and assumptions necessary for additional considerations are not provided in sufficient detail. Hauser [22] studied hydrogen transport using LH_2 from Argentine to Japan. The study gives a detailed analysis of hydrogen production in the Patagonia region focusing on geographical aspects. Al-Breiki et al. [23] studied energy and exergy aspects of long-distance supply chains of liquefied natural gas, ammonia and methanol. A series of facilities considered in the supply chain is similar to this study. However, the indicator considered is energy and exergy aspects and environmental and economic aspects are not included. Xue et al [24] performed

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life cycle assessment on ammonia as energy carrier to Japan from Australia, Chile and Saudi Arabia, focusing on the carbon and nitrogen footprint. Economic aspects are not included. Ozawa et al. [25] assessed the lifecycle CO_2 emissions from the supply chains of LH_2, NH_3 and MCH. The scope of this study and scale of transported amount of hydrogen to the demand side are similar to the current study. However, because this study is a sophisticated LCA, the indicator considered is limited to lifecycle CO_2 emissions attributed to the supply chain.

In summary, studies in the literature have investigated a variety of energy carriers with focus on energy efficiency, CO_2 emissions and costs. However, the following limitations are identified. Firstly, one or more energy carriers are studied or compared typically without specific supply and/or demand side countries [19, 20]. The characteristics of specific countries significantly affect economics and available resources used in the value chains. Secondly, the delivered hydrogen capacity of the studied value chains are relatively small for the quantitative contribution to the energy demand and supply of the country as well as contributions to CO_2 reduction targets to the demand side countries. The economic merit by the scale of merit could not be expected due to the small capacity of the different facilities. Thirdly, few studies evaluate both CO_2 footprint, energy efficiency and cost. Finally, average utilization factor without detailed consideration of the supply chain operation is often used [19, 20, 21]. To determine the capacity of equipment in the value chain, descriptions of detailed operational conditions are required.

In the current study these gaps that these earlier studies have are closed by presenting a high-level value chain analysis of bulk hydrogen transport solutions carried out in the knowledge building project Hyper [26] to identify efficient ways to deliver hydrogen produced in northern Norway to markets in Europe (regional market) and Japan (global market). Liquefied hydrogen (LH_2) and ammonia (NH_3) value chains are analysed and compared with respect to energy efficiency, CO_2 footprint and cost, with detailed and transparent technical and economic assumptions and supply chain operating conditions.

In Section 2, system assumptions which include value chain facilities, energy consumption etc. are presented. In Section 3 the cost estimation methodology is described. In Section 4 the results from the environmental and techno-economic analysis are presented and discussed, and finally, conclusions are given in Section 5.

2. Concept and system description

In the present study, production of hydrogen followed by subsequent transport to a targeted market hub is considered. Hydrogen is here partly produced based on reforming of natural gas combined with CCS (86- 90%) and partly based on electrolysis with renewable power (10-14%). The hydrogen production facilities are set to be in the Hammerfest area (Norway) for the base case, while the hydrogen produced is to be delivered to either the European market (at a central hub in Rotterdam) or Japan (Tokyo through the Suez Canal in the base case or via the Northern Sea route in an alternative case discussed in Section 5). Although not considered here, it is worth noting that other H_2 production locations such as Australia or Canada could also be considered and that the optimal supply strategy would depend local hydrogen production and transport costs.

The considered routs are illustrated in Figure 1. Due to the long distances considered (2,539 and 23,407 or 10,885 km for respectively Rotterdam and Tokyo), ship transport of H_2 energy as liquid hydrogen (LH_2) or ammonia (NH_3) was deemed to be the most relevant options. Both these options are analysed with a capacity corresponding to around 500 t/d of hydrogen (164,250 t/y) produced from the production site. The delivered amount of hydrogen at the receiving terminal will vary between the carriers and the transportation distances studied due to the difference in losses and concepts considered.

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Figure 1 Shipping routes from Hammerfest to Rotterdam and Tokyo. For Tokyo, one route is conventional (via the Suez Canal) and another route is the Northern Sea Route discussed in Section 5.

Figure 2 shows a schematic diagram of the long-distance transportation solutions considered in this paper. The evaluation boundaries are from the primary energy resources to hydrogen delivery before end use. The value chain consists of hydrogen production and carrier conversion, loading terminal on the supply side, seaborne transport and storage at the receiving terminal on the demand side. In the present study, the H_2 delivered is foreseen to be used by a hydrogen-fired power plant adjacent to the terminal, although this facility is not included. The delivered hydrogen amount differs between the two chains because of different consumption of hydrogen for ship propulsion during long distance transport of LH_2 and NH_3 cracking.

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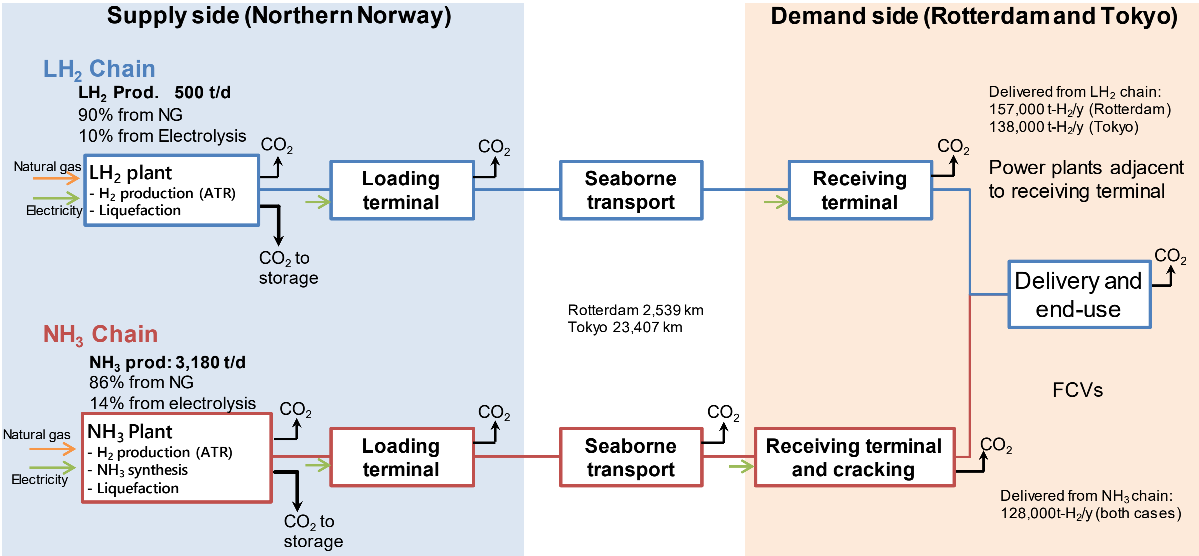

Figure 2 Schematic diagram of the LH_2 and NH_3 chains.

3. Methodology

The following section describe in details the LH_2 and NH_3 value chains considered in this study and their energy inputs and flows, design and details for the techno-economic modelling.

3.1. Value chain model

3.1.1. Liquid hydrogen

Figure 3 shows a block diagram of the LH_2 chain. The LH_2 plant mainly consists of natural gas reforming by autothermal reforming (ATR) with deep CO_2 capture (aMDEA and PSA), electrolysis and liquefaction processes to produce liquefied hydrogen. Power produced from excess heat in the reforming process covers the power demand of the liquefaction process. The amount of liquefied hydrogen supplied to the storage tanks in the loading terminal is 500 t/d, with 90% from natural gas reforming and 10% from electrolysis using renewable power [26]. The specification of liquefied hydrogen supplied from the LH_2 plant is 21.44 K and 1.85 bar. The CO_2 capture rate of the LH_2 plant is 93%. The LH_2 plant is described in detail by Gardarsdottir et al. [27] and plant inputs are summarised in Table 1.

Table 1 Natural gas and electricity input to the LH_2 plant.

Natural gas input	873.7 MW
Net power input	229.0 MW
Electrolysers	106.5 MW
Hydrogen compression (El.-derived hydrogen)	2.5 MW
Hydrogen liquefaction	134.6 MW
ATR plant, net power	-14.6 MW

After the H_2 production and liquefaction, temporary LH_2 storage in a loading terminal is considered. During the storage period, boil-off gas (BOG) is continuously returned to the liquefiers for re-liquefaction. LH_2 is loaded to the LH_2 tanker. The loading process is assumed to take 15 h. The electricity consumption resulting from BOG re-liquefaction is included in the electricity consumption of the LH_2 plant. The specifications of the loading

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terminal are shown in Table 2. The terminal consists of storage tanks, loading arms and pumps to transfer LH_2 to the ship tanks, BOG compressor to send BOG back to liquefiers, as well as supporting equipment.

After accumulation and temporary storage at the loading terminal, LH_2 is loaded and transported by ship. This step includes the following operations: receiving LH_2 from the loading terminal, ship transport, and unloading of the LH_2 to storage tanks in the receiving terminal within 15 h. Equipment and specification of the seaborne transport is given in Table 2. The feature of LH_2 ships, assumed to be fuelled by BOG during voyage, are principally similar to LNG tankers with insulated cargo tanks. Due to the comparatively low boiling temperature of LH_2 at atmospheric pressure as well as lower volumetric energy density, a high-performance insulation technology is assumed to keep the BOG rate low and around the quantity required as fuel for propulsion.

At the LH_2 storage in the receiving terminal, the following operations take place: receiving of the LH_2 from the LH_2 tankers, storage of LH_2 until delivery to market, storage of BOG until delivery to market. The equipment and specifications of the receiving terminal are also given in Table 2. The facility of the receiving terminal is similar to the loading terminal except for vaporisers to supply gaseous hydrogen to the demand side.

The duration considered in the modelling is 1 y and the time resolution is 1 h.

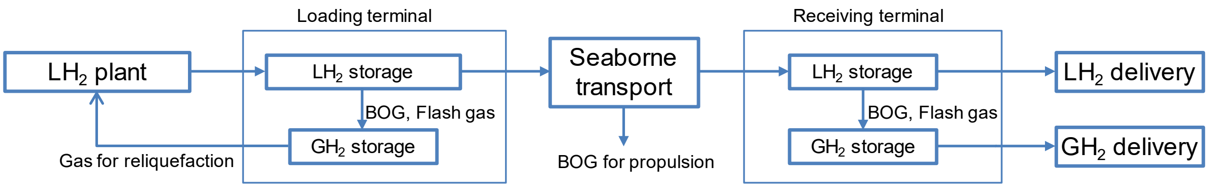

Figure 3 Block diagram of the LH_2 chain.

Table 2. Specification of the loading terminal, seaborne transport, and receiving terminal.

Facility	Equipment	Specification
Loading terminal	Storage tanks	3 Spherical tanks, 50,000 m^3/tank (Rotterdam case), 4 Spherical tanks, 55,000 m^3/tank (Tokyo case)
	Vaporisation rate	0.1% /d
	Electricity consumption	198 kWh/t-H_2 (Estimated from the electric capacities of the terminals in the literature [15])
	Loading arm	One set for loading of the LH_2 carrier
	LH_2 submerged pumps	15 h for transfer 730 t/h (Rotterdam case), 830 t/h (Tokyo case)
	BOG compressor	40 t/h (Rotterdam case), 46 t/h (Tokyo case)
	Supporting equipment	Berth, piping, utility, instrumentation, building, etc.
Seaborne transport	Dimensions	Length 315 m, draught 11 m, beam 58 m (within Suez max, Rotterdam)
	Capacity	86,000 m^3 (6,359 t, Rotterdam case) 172,000 m^3 (12,718 t, Tokyo case)
	Number of LH_2 carriers	1 (Rotterdam), 3 (Tokyo)
	Maximum storage rate to the capacity:	98%
	Vessel speed	16 knots
	Evaporation rate (BOG)	0.2%/d
	BOG and return gas during loading	5.6% of transferred liquefied hydrogen (estimated from [15] including BOG from tanks)
	BOG and displacement gas during unloading	6.1% of transferred liquefied hydrogen (estimated from [15], including BOG from tanks)

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	Working days	330 d/y
	Loading/Unloading	4 d/voyage
	LH_2 pump for unloading	15 h for transfer 700 t/h
Receiving terminal	Storage tanks	7 Spherical tanks, 50,000 m^3/tank (Rotterdam case) 7 Spherical tanks, 50,300 m^3/tank (Tokyo case)
	Vaporisation rate	0.1%/d
	Electricity consumption	182 kWh/t-H_2 (Estimated from the electric capacities of the terminals in the literature [15])
	Loading arms	One set for each LH_2 carrier
	LH_2 submerged pumps	17 t/h
	BOG compressor	42 t/h
	Vaporiser	17 t/h
	Supporting equipment	Berth, piping, utility, instrumentation, building, etc.

3.1.2. Ammonia

Figure 4 shows a block diagram of the NH_3 chain. The NH_3 long-distance transport chain consists of a loading terminal, seaborne transport, and a receiving terminal with NH_3 cracking and purification. The product delivered to the market is gaseous H_2.

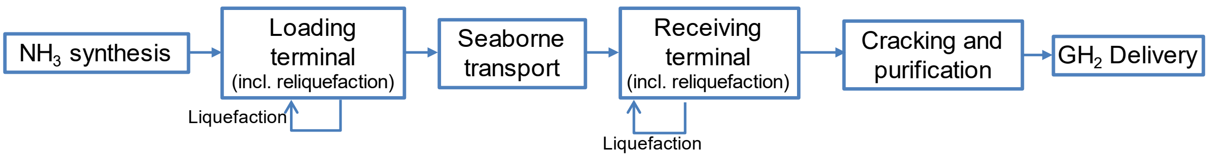

Figure 4 Block diagram of NH_3 chain for NH_3 balance.

In a similar way as in the LH_2 chain, there are two origins of H_2: natural gas (NG) with CCS and electrolysis based on renewable power. In the production of hydrogen from NG and in the NH_3 synthesis, the BAT (Best Available Technology) of ATR and NH_3 synthesis is assumed [29]. In the NH_3 synthesis based on H_2 from renewable power, electrolysers, ASU (Air Separation Unit), and compressors are considered. NG and renewable power input in a similar range as for the LH_2 reference plant is assumed in the NH_3 chain, and the two chains are comparable in terms of energy output at the production plant outlets (LH_2 19,682 TJ/y, NH_3 19,485 TJ/y). In the ammonia production system analysed here, there are two N_2/H_2 mixture streams as input to the ammonia synthesis due to the two origins of the hydrogen. This is different from conventional NG-based NH_3 synthesis plants. Excess heat from the ammonia synthesis is converted to power in a steam turbine and supply the additional required compressor power for NH_3 separation and recycle compressors. There is no energy (steam or heat) export to outside of the synthesis plant.

The NH_3 synthesis model is a static model, with an assumed time resolution of long-distance transportation and delivery to end use of 1 h. The intermittency of renewable hydrogen production is not considered. The parameters of NH_3 synthesis are tabulated in Table 3. As a result, 84% of NH_3 is produced from natural gas. Hydrogen for the rest of NH3 is supplied from electrolyzers using renewable electricity.

Table 3 Parameters of NH_3 synthesis.

NG based NH_3 synthesis	
Feedstock	24.8 GJ/t-NH_3 [29]
Fuel	5.4 GJ/t-NH_3 (3.6–7.2 GJ/t-NH_3) [29]
Synthesis pressure	175 bar (Typically 100–250 bar) [29]
Synthesis temperature	450 °C (Typically 350–550 °C) [29]

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CO_2 capture rate in the N_2/H_2 mixture stream	94% (Similar to the LH_2 plant)
CO_2 compressor specific power.	77.5 kWh/t-CO_2 (to 110 bar)
Renewable based NH_3 synthesis	
Electrolyser	4.512 kWh/N·m^3 (including rectifier loss, without purification power penalty) [26]
Specific power consumption of N_2 generator	0.20 kWh/N·m^3-N_2 @ 8 bar (0.15–0.25 kWh/N·m^3 [30])
Specific power consumption of hydrogen compressor	182 kWh$_{el}$/ t-NH_3
Specific power consumption of N_2/H_2 mixture compressor	416 kWh$_{el}$/ t-NH_3
Heating up of N_2/H_2 mixture	403 kWh$_{th}$/t-NH_3 supplied by NG combustion.
Total conversion ratio from the mixture to NH_3	99%

A detailed block diagram of the NH_3 synthesis with required fuel and power for each block is shown in Figure 5. The total plant capacity is estimated to be 3,190 t-NH_3/d (1,048,000 t-NH_3/y) which is equivalent to 390 t-H_2/d at the demand side. Detailed reaction processes of WGS, methanation, and the syngas compressor in the NG stream are not explicitly considered because the specific NG consumption for 1 t-NH_3 production is used, and this includes energy requirement of WGS, methanation, syngas compressor and liquefaction.

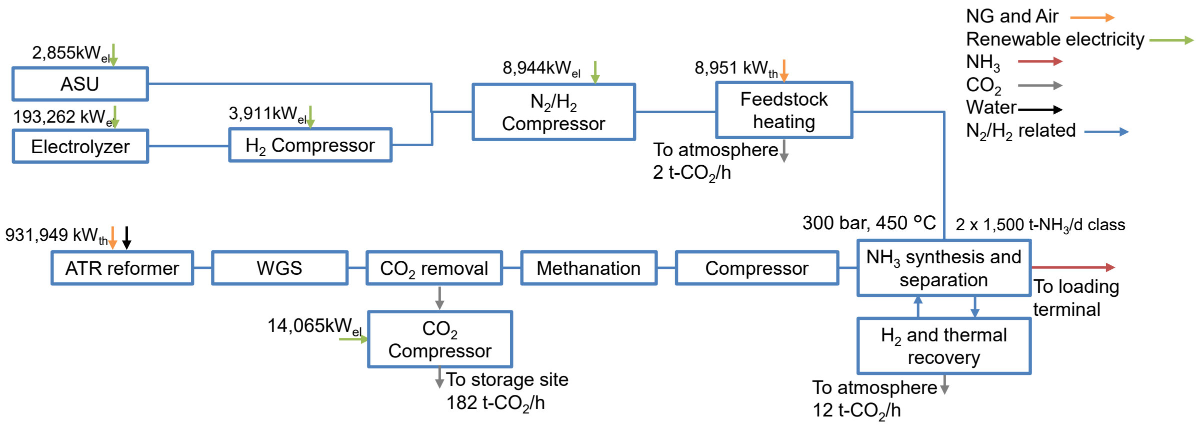

Figure 5 Block diagram of NH_3 synthesis.

After the NH_3 production and liquefaction, a temporary NH_3 storage in the loading terminal is considered. During this step, the NH_3 from the production is stored, boil-off gas (BOG) is re-liquefied by a refrigeration plant in the terminal. A specific figure for boil off rate (BOR) for NH_3 tanks in NH_3 terminals is not available in the literature, so the BOR of NH_3 storage is assumed to be the same as that of LH_2 storage. This assumption is most likely in the high end. The BOG of NH_3 is not explicitly treated in the mass balance in long-distance transportation because the specific power consumption considered in the calculations already includes all electricity demands in the terminals. NH_3 is loaded to the NH_3 tanker, and this process takes 15 h. Equipment and specification of the loading terminal are shown in Table 4. The loading terminal consists of storage tanks, loading arms and pumps to transfer NH_3 to the NH_3 ship.

After accumulation and temporary storage in the loading terminal the ammonia is loaded on to ship for seaborne transport. This step includes the following operations: receiving NH_3 from the loading terminal, ship transport, and unloading of the NH_3 to storage tanks at the receiving terminal. Equipment and specification of the seaborne transport is shown in Table 4. Some existing LPG carriers are designed to transport both LPG and NH_3. The capacity of the NH_3 carrier is set considering the maximum capacity of these existing carriers. The NH_3 ships are assumed to consume fuel oil for ship propulsion. Fuel consumption is obtained from the CO_2 emission of a

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typical LPG carrier [32]. It is also assumed that the energy consumption of re-liquefaction of BOG onboard the NH_3 carriers is included in the fuel consumption, because LPG/NH_3 carriers are in general equipped with refrigeration plants for re-liquefaction.

At the NH_3 storage in the receiving terminal, the following operations take place: receiving of the NH_3 from the NH_3 tankers, storage of NH_3, re-liquefaction of BOG from storage tanks and NH_3 cracking to extract hydrogen for delivery to the market. The equipment and specification of the receiving terminal are shown in Table 4. The facility of the receiving terminal is almost the same as for the loading terminal, except for the number of storage tanks. However, there is the additional NH_3 cracking facility adjacent to the receiving terminal.

Table 4 Specification of the loading terminal.

Facility	Equipment	Specification
Loading terminal	Storage tanks	2 cylindrical tanks, 50,000 t/tank
	Vaporisation rate	0.1%/d (assumed to be same as LH_2 storage)
	Loading arms	One set for a NH_3 carrier ship
	NH_3 transfer pump	15 h for transfer 3,800 t/h
	Supporting equipment	Berth, piping, utility, instrumentation, building, etc.
	Electricity consumption	80 kWh/t-NH_3 [31] (power for reliquefaction is included in the electricity consumption)
Seaborne transport	Dimensions	Length 230 m, draught 11 m, beam 37 m (an LPG carrier with similar capacity)
	Capacity (at maximum)	85,000 m^3
	Number of carriers	4 (Tokyo case), 1 (Rotterdam case)
	Maximum storage rate to the capacity	98% [33]
	Vessel speed	16.6 knots
	Fuel consumption	0.12 MJ/t-km
	Loading/Unloading	4 d/voyage
	NH_3 pump for unloading	15 h for transfer 3,800 t/h
Receiving terminal	Storage tanks	3 cylindrical tanks, 50,000 t/tank
	Vaporisation rate	0.1%/d (assumed to be same as LH_2 storage)
	Loading arms	One set for a NH_3 carrier ship
	NH_3 transfer pump	3,800 t/h
	Supporting equipment	Berth, piping, utility, instrumentation, building, etc.
	Electricity consumption	80 kWh/t-NH_3 [31] (power for re-liquefaction of BOG is included in the electricity consumption)

NH_3 cracking is the reverse reaction of the NH_3 synthesis and it is an endothermic reaction. Small-scale NH_3 crackers are available to supply a reduction atmosphere in, e.g., the metallurgic industry, while large scale crackers are not in common use. However, the design of the large-scale NH_3 decomposition is available from a subtask report of the WE-NET project [34]. The mass balance assumed of the NH_3 cracker is shown in Figure 6. The parameters shown in Table 5 are obtained from the mass balance. It is assumed that a part of the product hydrogen is used as fuel to crack NH_3. The total hydrogen recovery rate from the input NH_3 is 69.5%.

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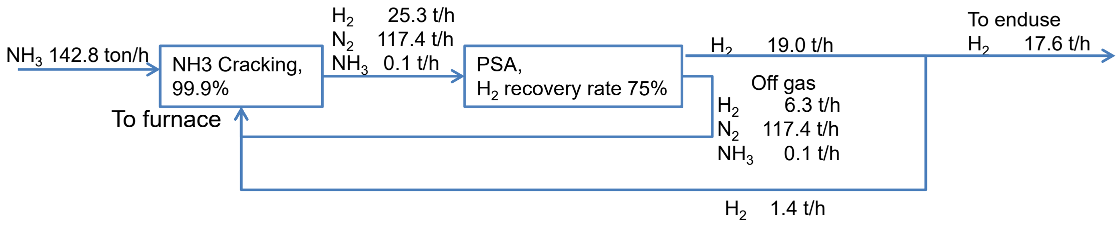

Figure 6 Mass balance of an NH_3 cracker [34].

Table 5 Specifications of NH_3 cracking and purification.

Capacity	120 t-NH_3/h
NH_3 cracking ratio	99.9%
PSA recovery rate	75%
Total H_2 recovery rate	69.5%
Power consumption	400 kWh/t-NH_3

3.2. Cost estimation

The hydrogen cost consists of capital and operational expenditures (i.e. CAPEX and OPEX) as illustrated in Figure 7. The CAPEX includes the investment cost and decommissioning of the facility. The investment cost is estimated using literature values and the scaling law as explained below. The decommissioning cost is accounted in the year after the end year of the plant (year 25). The OPEX includes labour costs, maintenance costs, chemical and other consumables costs, fuel, electricity, insurance, administration and CO_2 transport and storage costs. Labour costs, maintenance costs, chemical and other consumables costs, and insurance costs are estimated based on the total plant cost and a cost rate for each item (Table 7). The cost of CO_2 transport and storage is included as a separate unit for the OPEX, while for the CAPEX it is included as a part of the overall investment and decommissioning cost.

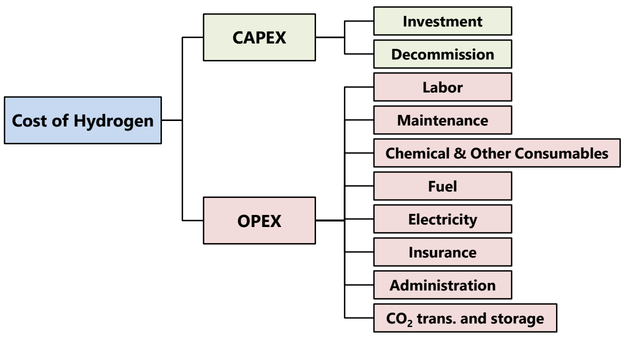

Figure 7 Cost structure of delivered hydrogen.

The investment cost is estimated based on cost data available in the literature for the various segments of the value chain. In this study, the plant construction cost is taken to be the total plant costs (TPC) which is made up of the cost elements shown in Figure 8. The Total Equipment Cost (TEC) is the sum of all equipment costs in the plant. The installation costs are additional expenses to integrate the individual equipment into the plant, such as costs for piping/valves, civil works, instrumentations, electrical installations, insulation, painting, steel structures, erection, and outside battery limits cost (OSBL). This cost can vary from 20% to 370% of TEC depending on the cost scope of the literature used [47]. The Total Direct Cost (TDC) is the sum of the Equipment Costs and the Installation Costs and shall also include the appropriate process contingency factor in order to

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reflect the differences in the technology's maturity. Process contingencies are 0.05 for commercial technologies [46]. Indirect Costs include the costs for yard improvements, service facilities and engineering costs as well as the building and sundries. The owner's costs for planning, designing, and commissioning the plant and for working capital together with project contingencies are set to 19 % of the total EPC cost in the case of commercial technologies. Further, the cost is adjusted to the relevant cost year (2015) using a plant cost index (PCI), adapted to the relevant location using a location factor, and converted to euros. The location factors used are 1.3, 1.19 and 1.23 for Northern Norway, Continental Europe and Japan respectively. The ships are assumed to be built in Japan. Then an adjusted literature value (C_0) is obtained.

The starting point for estimation depends on the cost scope from the literature source. For example, if the cost scope is EPC (Engineering, procurement, and construction) cost, the owner's cost and the project contingency are considered in addition.

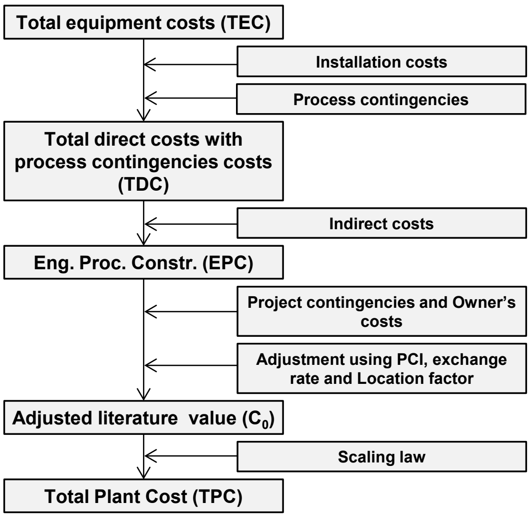

Figure 8 The estimation of total plant cost

The costs C for a facility or a section of a plant at capacity S_1 is estimated based on the adjusted literature value C_0 with capacity S_0 with the following equation:

$$C(S_1) = C_0\left(\frac{S_1}{S_0}\right)^n \tag{4}$$

where n is a scaling exponent. Table 6 shows cost estimation of value chain segments based on literature sources.

For the cost estimation, the hydrogen production plant is divided into several sections such as natural gas reforming, CO_2 capture, transport, storage, electrolyser, liquefier, and so on. In long distance transportation, each facility is not divided into equipment level. e.g. For the LH_2 loading terminal, the aggregated literature investment cost is used. The sum of these costs makes up the TPC. Interest during the construction period is considered based on the TPC.

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Table 6. Reference cost estimates of LH_2 and NH_3 value chain segments based on literature sources (updated to reflect € 2015 estimates).

Value chain	Assumptions	Production	Loading terminal	Seaborne transport	Receiving terminal	Cracking
LH_2	C_0 (adjusted, M €)	1,844*	1,295	484	1,013	-
	S0	500 t/d	200,000 m^3	200,000 m3	200,000 m^3	-
	N	-	0.67	0.67	0.67	-
	Reference	[27, 36]	[15]	[8, 15, 49]	[15]	-
	Location	Northern Norway**	Northern Norway **	-	Rotterdam or Tokyo***	-
NH_3	C_0 (adjusted M€)	1,308	286	102	294	51
	S_0	1,591 t/d	150,000 m^3	78,000 m^3	150,000 m^3	20,000 m^3/h
	N	0.67	0.67	0.67	0.67	0.67
	Reference	[42]	[48]	[34]	[48]	[34]
	Comment	Northern Norway **	Northern Norway **	-	Rotterdam or Tokyo***	Rotterdam or Tokyo***

* Estimated in this study based on literature [27,36].

** Location factor of 1.3 included to represent Northern Norway TPC level.

*** Location factor of 1.21 and 1.19 to represent to represent Japan and Continental Europe TPC levels, respectively.

Table 7 shows financial and OPEX assumptions. Large-scale LH_2 and NH_3 supply chains in utility scale has not been realized yet for energy transport, though NH_3 as a chemical is internationally traded on an industrial scale. These assumptions are taken from the literature and for similar business conditions. Each annual fixed OPEX other than administration cost is estimated by multiplying TPC by corresponding fixed OPEX rate (e.g. labour, maintenance etc.). Administration cost is estimated by multiplying the total of labour, maintenance, and insurance cost by the administration cost rate. Variable costs come from natural gas and electricity consumption through the value chain.

Table 7 Financial, OPEX and carbon intensity assumptions.

Item	Value	Unit	Note
Discount rate	7.5	%	Green business in Europe
TPC to Investment Factor	1.17	-	Assuming a 7.5% discount rate and a 3-year construction period (40%, 30%, 30%)
Base year	2015	-	Assumption
Project duration	25	y	Assumption
Utilization rate	7,884	h	Assumption (90%)
Decommission cost rate	5.0	%	Percentage of total plant cost at the end of the project [43]
Labour cost rate	0.17	%	Percentage of total plant cost. Typical rate in Japan's power industry
Maintenance cost rate	1.1	%	Percentage of total plant cost. Estimated from [15]
Insurance rate	0.6	%	Percentage of total plant cost. [34]
Admin. cost rate	12.0	%	12% of labour, maintenance, and insurance cost. Typical rate in Japan's power industry
Chemical & other consumables cost rate	2.2 0.6 3.0	%	Percentage of total plant cost, for production [44] Percentage of total plant cost, for long distance transport [15] NH_3 cracking [34]
Natural gas price	4.5	EUR/GJ	The natural gas price from 2006 to 2016 [45]. The cost is estimated by deducting transport cost from the market price.
Fuel oil price	12	EUR/GJ	Fuel oil for ship, 2014, Japan
Electricity price	38 131	EUR/MWh	For Norway, based on projections for 2030 For demand side, price for industries in Japan, 2014
Carbon intensity of electricity from grid	16 367	kg-CO_2/MWh_{el}	For Norway, 98% is from renewable For Japan, natural gas fired combined cycle (efficiency:55%) is assumed.

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Finally, the costs of CO_2 transport and storage were evaluated assuming a stand-alone infrastructure dedicated to the hydrogen production facility. An offshore saline aquifer formation injectivity of 0.8 $MtCO_2$/well/y is considered. As the saline aquifer is assumed to be located 140 km away from the hydrogen production facility, an offshore pipeline is required. The investment cost and operating cost associated with offshore pipeline transport and the CO_2 storage were assessed using the iCCS tool developed by SINTEF Energy Research for CCS value chain assessment [37-39]. The cost model of the transport section in the iCCS tool is based on Knoope et al. [40] while the storage is based on the Zero Emission Platform (ZEP) [41].

3.3. Performance indicators

In this analysis the LH_2 and NH_3 hydrogen transport value chains are evaluated with respect to energy efficiency, CO_2 intensity and cost. The energy efficiency η is defined as:

$$\eta = \frac{\text{Delivered } H_2}{\text{Energy input}} \tag{1}$$

where the energy content of material streams is measured on LHV basis.

The CO_2 intensity (kg-CO_2/MWh_{th}) is defined as:

$$CO_2 \text{ intensity} = \frac{CO_2 \text{ emissions from the chain}}{\text{Delivered } H_2} \tag{2}$$

The levelized cost method which is widely used for evaluation of cost in the energy sector (e.g. the electricity cost report published by the IEA [43]) is implemented. The levelized cost of hydrogen is given by the following equation:

$$C_{H_2} = \frac{\sum_{t=0}^{n-1}(CAPEX_t + OPEX_t)(1+r)^{-t}}{\sum_{t=0}^{n-1} P_{H_2}(1+r)^{-t}} \tag{3}$$

where C_{H_2} is the levelized cost of hydrogen (EUR/kg-H_2 delivered), P_{H_2} is the annual amount of hydrogen delivered, r is the discount rate, t is the year where t=0 is the current year and n-1 is the end year, CAPEX_t is the capital expenditures at time t, and OPEX_t is the operational expenditures at time t.

4. Results

4.1. Value chain characteristics

Table 8 shows the assessed characteristics of the considered liquid hydrogen and ammonia chains. The capacities and number of units are based on energy and mass balance analyses of the value chains. The chains have the same production capacities in the Rotterdam case as in the Tokyo case. For the Tokyo case, the ship capacities for LH_2 are based on the plans of Kawasaki [15] and the ship capacities for NH_3 are set to the current maximum size for NH_3 ship. For the Rotterdam case only one ship with capacity lower than these maximum capacities is required in each chain. Storage capacities in the loading terminal are higher in the Tokyo case than in the Rotterdam case because of the larger ship capacity in the Tokyo case. The capacity of the receiving terminal depends on business conditions. In this study, the minimum storage capacity for 36.5 days is considered for the receiving terminal since the average utilization factor of the production is 90%. Depending on the number of production units, the actual storage capacities on the demand side are from 40 to 58 days, and are the summation of plant maintenance periods (36.5 d) and the time required between each delivery to produce enough LH_2 or NH_3 for transferring to the ships. In the Rotterdam case only one ship is required for the transportation, while

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three or four ships are required in the Tokyo case due to substantially longer transportation distance. The NH_3 cracking capacity is set to match the averaged production capacity of the NH_3 plant.

Table 8 Characteristics of LH_2 and NH_3 chains. Cost figures in brackets are costs for the optimistic case for the LH_2 chain discussed in Section 5.2.

			Production	Loading terminal	Seaborne transport	Receiving terminal	Cracking
Rotterdam	LH_2	Unit capacity	500 t-H_2/d	50,000 m^3	86,000 m^3	50,000 m^3	
		Number of units	1	3	1	7	
		BOR	-	0.1%/d	0.2%/d	0.1%/d	
		Energy consumption		198 kWh/t-H_2		182 kWh/t-H_2	
		Other	-	Reliquefaction included	Vessel speed 16 knots	BOG delivered as gaseous hydrogen	
		TPC (M€)	1,844	1,068 (489)	275 (178)	1,473 (464)	
	NH_3	Unit capacity	1,591 t-NH_3/d	75,000 m^3	52,200 m^3	75,000 m^3	120 t-NH_3/h
		Number of units	2	1	1	3	-
		BOR	-	0.1%/d	0%/d *	0.1%/d	-
		Energy consumption		80 kWh/t-NH_3	0.12 MJ/t-km	80 kWh/t-NH_3	400 kWh/t-NH_3
		Other	-	Reliquefaction included	Vessel speed 16.6 knots	Reliquefaction included	-
		TPC (M€)	2,616	286	102	294	430
Tokyo	LH_2	Unit capacity	500 t-H_2/d	50,000 m^3	172,000m3	50,300m^3	
		Number of units	1	4	3	7	
		BOR	-	0.1%/d	0.2%/d	0.1%/d	
		Energy consumption		198 kWh/t-H_2		182 kWh/t-H_2	
		Other	-	Reliquefaction included	Vessel speed 16 knots	BOG delivered as gaseous hydrogen	
		TPC (M€)	1,844	1,380 (632)	1318 (851)	1,479 (464)	
	NH_3	Unit capacity	1,591 t-NH_3/d	75,000 m^3	85,000 m^3	75,000 m^3	120 t-NH_3/h
		Number of units	2	2	4	3	-
		BOR	-	0.1%/d	0%/d *	0.1%/d	-
		Energy consumption		80 kWh/t-NH_3	0.12 MJ/t-km	80 kWh/t-NH_3	400 kWh/t-NH_3
		Other	-	Reliquefaction included	Vessel speed 16.6 knots	Reliquefaction included	-
		TPC (M€)	2,616	286	409	294	430

4.2. Energy efficiency

Figure 9 (a) and (b) show the energy balances of the LH_2 chains in the Rotterdam and Tokyo cases, respectively. The largest parasitic energy loss (i.e. energy that is lost from the chain to the surroundings) is related to hydrogen production and CO_2 compression in the LH_2 plant for both cases. The second largest energy loss is the BOG which is used for ship propulsion during the ship transport. This also makes up the largest difference between the two cases since there is a large difference in transportation distance from Northern Norway to Tokyo and to Rotterdam. In the Rotterdam case, the amount of delivered LH_2 and GH_2 is therefore 14% higher than that in the Tokyo case. At the loading terminal it is assumed that the BOG is sent back to the liquefier and re-liquefied, while the BOG generated at the receiving terminal is assumed to be delivered as a gaseous hydrogen product. There is therefore no energy loss due to wasted BOG at the supply and demand sides.

Figure 9 (c) and (d) show the energy balances of the NH_3 chain in the Rotterdam and Tokyo cases, respectively. The NH_3 synthesis which also includes hydrogen production and CO_2 compression causes the largest parasitic energy loss in both cases and is higher than in the LH_2 chain. The second largest loss is from the NH_3 cracking process that requires heat and electricity for the reaction and purification. Off gas from the purification process and a part of the product hydrogen is used to supply high-temperature heat for cracking. The largest difference between the two cases is the energy input required for ship fuel, due to the difference in transportation distance. The amount of NH_3 delivered at the demand side is the same in these two cases because BOG during seaborne transport is assumed to be re-liquefied.

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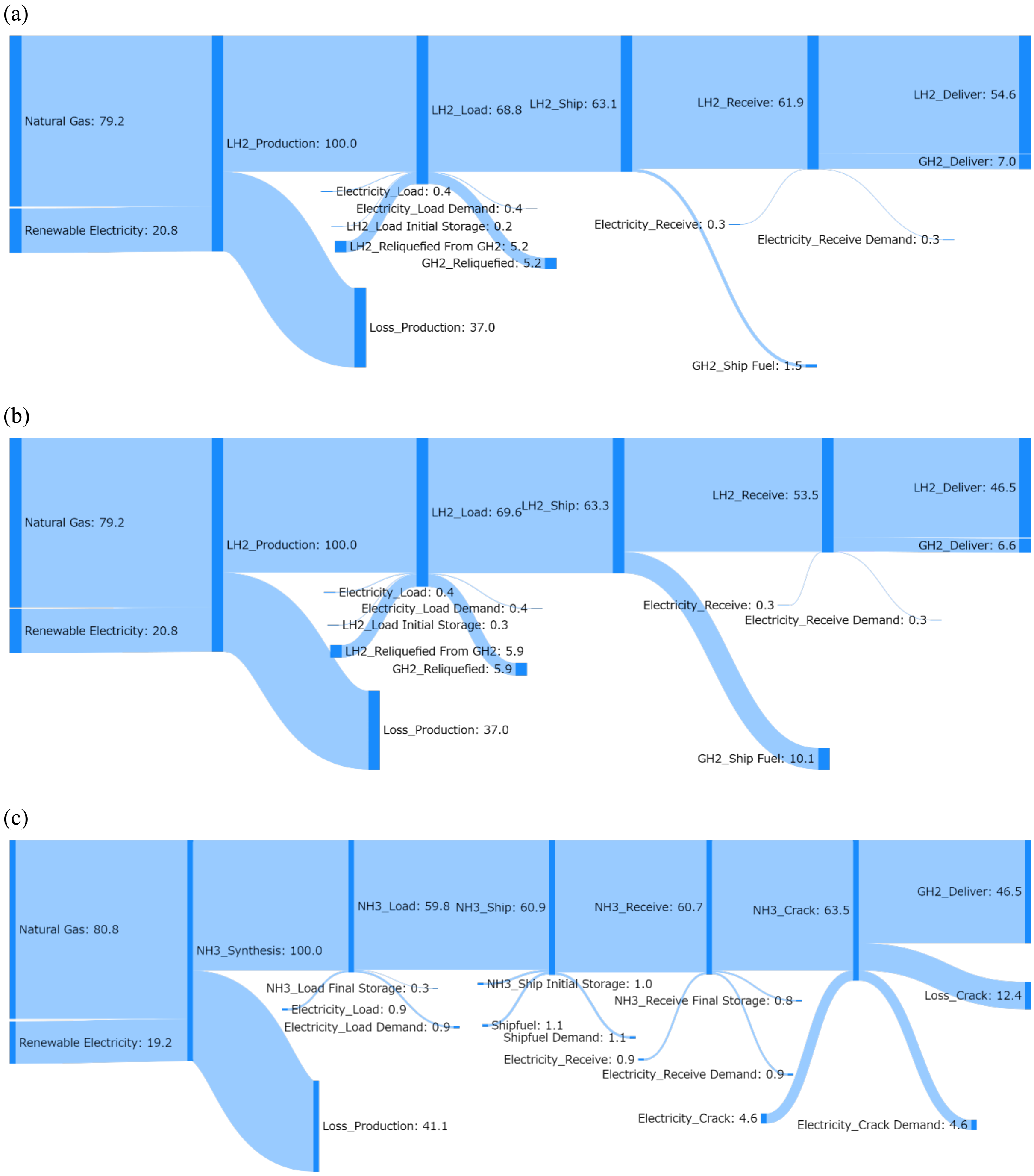

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(d)

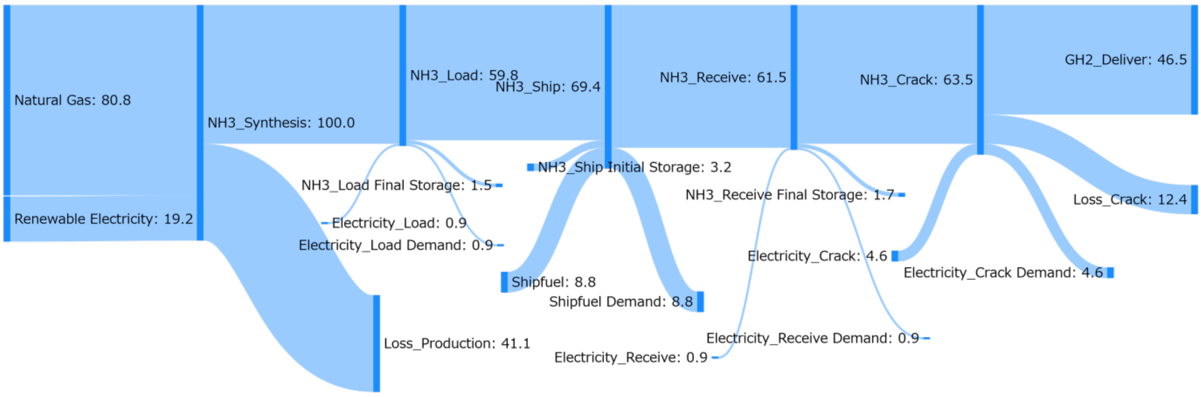

Figure 9 Energy balance of the LH_2 chain in (a) the Rotterdam and (b) Tokyo case. 29,975 TJ is set as 100. Energy balance of the NH_3 chain in the in (c) the Rotterdam and (d) Tokyo case. 33,026 TJ is set as 100. The values show the total flow to/from each node.

Figure 10 shows the energy efficiencies and breakdown of parasitic losses of the LH_2 and NH_3 chains. The blue columns illustrate the value chain energy efficiency while the other colours represent different causes of losses. The energy efficiency of the LH_2 chain is higher than NH_3 chain for both the Rotterdam case and the Tokyo case. Energy lost in hydrogen production makes up the largest portion in both LH_2 and NH_3 chains as also shown in the energy balances. NH_3 cracking is responsible for the second largest loss in NH_3 chains. In the Tokyo case, ship fuel is also a considerable loss for both the LH_2 and NH_3 chains. If cracking is not necessary (e.g. direct utilization technologies such as NH_3 fired gas turbines and direct NH_3 fuel cell is available), the efficiency of both chains could be on a similar level for both the Rotterdam and Tokyo case. Losses for the loading and receiving terminal and ship fuel in the Rotterdam case are marginal compared with the other major losses as energy consumption in these facilities are small.

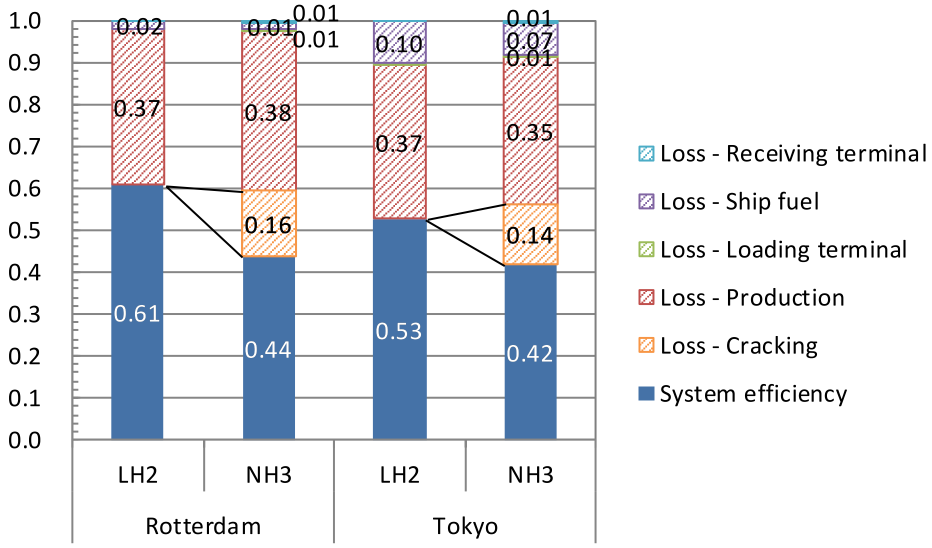

Figure 10 Energy efficiency (blue) and losses of LH_2 and NH_3 chains

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4.3. CO_2 intensity

Figure 11 shows the CO_2 intensity of the LH_2 and NH_3 chains for the Rotterdam and Tokyo cases. The CO_2 emissions to the atmosphere related to the chains are made up by the residual fraction of the CO_2 that is not captured from the reforming processes (capture rates are approximately 93-94%), CO_2 related to the consumption of electric power, and CO_2 related to consumption of fossil fuel for propulsion. Upstream emissions related to the consumption of natural gas are not accounted for but will be similar for both the LH_2 and NH_3 chains. It is shown that the CO_2 intensities of the LH_2 chains, that are less than 25 kg-CO_2/MWh_{th}, are much lower than those of the NH_3 chains. The low carbon characteristics of hydrogen from the LH_2 chain can drastically reduce CO_2 emission from the end-use sector such as power, transport and industry sectors. The difference in specific CO_2 emissions between the LH_2 chains is due to the difference in the delivered amount of hydrogen.

Fuel for seaborne transport and grid electricity in the cracking and purification process are the major sources of CO_2 emissions in the NH_3 chain. Other technical options for the NH_3 chain could be considered, such as ships driven by ammonia as fuel and direct use of ammonia at the demand side. Gas engines and fuel cells for ammonia as fuel are being developed in some projects (MAN [50] and ShipFC [1]). If ammonia is used for ship propulsion, CO_2 emission from fuel oil combustion can be eliminated, but the amount of delivered hydrogen will decrease with the transport distance. A rough estimate of the CO_2 intensity in the case of propulsion with NH_3 as fuel is also shown in Figure 11. The ship fuel is simply replaced with the NH_3 of the same heat value in this case. Any additional equipment and costs are not considered. Hydrogen is the final product in this study, but research on direct use of ammonia as fuel in e.g. power plants is ongoing. If the final product from the chain could be ammonia, the ammonia cracking would not be necessary, and emissions and losses related to this would be eliminated. It is however uncertain whether it will be possible to use pure NH_3 as a fuel directly. At least be required anyhow in order to enable efficient combustion of NH_3. It can however be seen from Figure 11 that the LH_2 chain will have lower CO_2 intensity than the NH_3 chains even if emissions related to seaborne transport and cracking are eliminated.

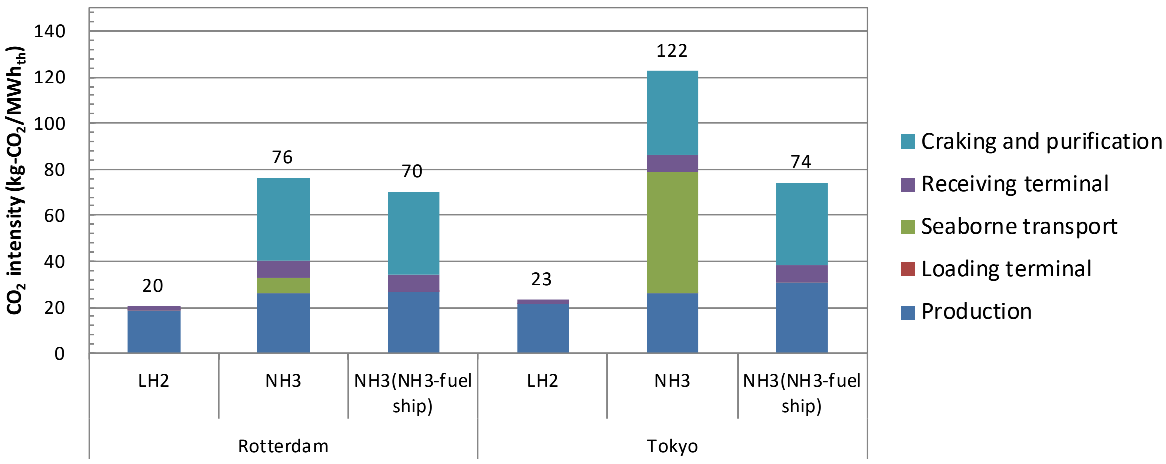

Figure 11 CO_2 intensity of the LH_2 and NH_3 chains.

4.4. Levelized cost of hydrogen

Figure 12 shows levelized cost of hydrogen for all cases. It can be observed that the costs are lower for the LH_2 chain than the NH_3 chain for transport to Rotterdam, while costs are similar for the two chains for transport to Tokyo. The cost difference between the Rotterdam and Tokyo cases comes mainly from the difference in the transportation distance. For the LH_2 chains, the transportation distance affects the amount of delivered hydrogen

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due to the use of BOG for propulsion, as well as the number of ships required. A decrease in the amount of delivered hydrogen results in an increase in the levelized hydrogen cost as shown in Equation 1. CAPEX and CAPEX-related expenditures are proportional to the number of ships. If the NH_3 can be used directly in the demand side, the cracking portion in the figure can be omitted as a rough estimation. NH_3 direct combustion technologies for micro gas turbine are being developed [52] In the current study, it is however reason to believe that at least partial cracking will be required in order to obtain efficient combustion for large scale gas turbines considering the similarity of combustion characteristics (the reactivity, the flame speed and its blow-off resilience) of the cracked gas mixture and backup fuel (i.e. Natural gas)[53].In cases with partial or no cracking, the costs of NH_3 at Rotterdam would be close to that of LH_2 and in the Tokyo case it would be closer or lower than LH_2 .

Figure 13 shows a breakdown of the cost elements of the LH_2 and NH_3 chains for the Tokyo case. The costs of the LH_2 chain has a high CAPEX share, which means that a higher utilization rate would reduce the CAPEX contribution. The technologies essential for the LH_2 chain such as insulation technology for the storage tanks of ships and the terminals and the liquefaction technology are today available as technologies for relatively small-scale supply chains. Large-scale liquefied hydrogen supply chains as assumed in this study does not exist at the moment. Therefore, the investment costs of facilities and ships have high uncertainties. Cost figures in the literature, especially for LH_2 storage tanks, are few and seems somewhat inconsistent. For instance, onshore storage tanks are reported to be more costly than ship-based tanks. The NH_3 chain has a relatively high variable OPEX contribution that is sensitive to natural gas and electricity prices. NH_3 production and transport technologies are commercially mature technologies. This should indicate that the uncertainty of investment of these facilities is smaller than for a LH_2 chain.

The results of the current study can be discussed in comparison with the findings of IEA [21]. Detailed assumptions and results are necessary for direct comparison. As discussed below, however, the limited data is a main obstacle for this purpose. The hydrogen production technology considered in the current study is a combination of natural gas reforming with CO_2 capture and electrolysis while the IEA report's energy carriers section only considers electrolysis. The hydrogen production part of the value chain is therefore deducted in this discussion. Both terminals and seaborne transport parts account for higher costs in the current study than those in IEA report. The apparent comparison is difficult since the terminal operation and the storage capacities in the terminal that largely affect the storage costs are not transparent in the IEA report. The conversion cost from hydrogen to ammonia is about 0.4 EUR/kg-H_2 in the report. Best available technology of NH_3 synthesis from natural gas is assumed in the current study The conversion cost from which the hydrogen production cost is deducted is 2.3 EUR/ kg-H_2. Taking into account a 30% higher construction cost in northern Norway than a generic euro region (i.e. Netherlands), the difference in NH3 production between two studies is considered to be large. NH_3 synthesis from hydrogen gas also requires air separation units for nitrogen production, compressors for hydrogen and nitrogen gas in addition to synthesis loop, though it does not require a steam reforming plant if the hydrogen comes from electrolysis. These additional equipments also requires electricity. The cost scope of NH_3 synthesis in the report might be different from the current study that is comprehensive though a part of major assumption is described in the report [21]. Therefor the two studies are not directly comparable due to

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limited information about the scope of supply chain, assumptions, and results.

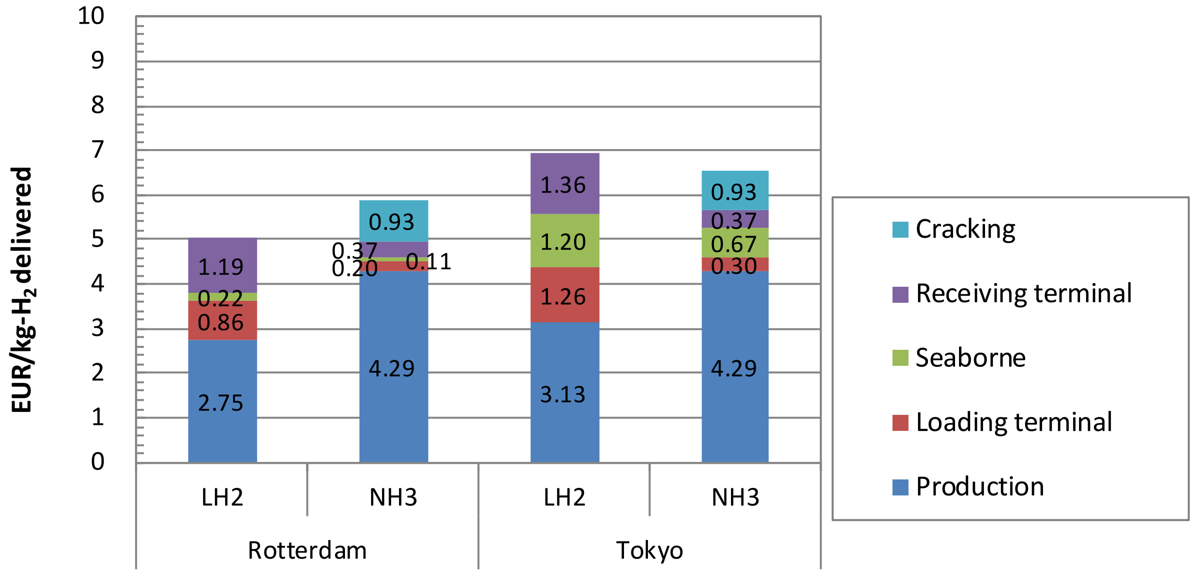

Figure 12 Levelized cost of hydrogen for all cases

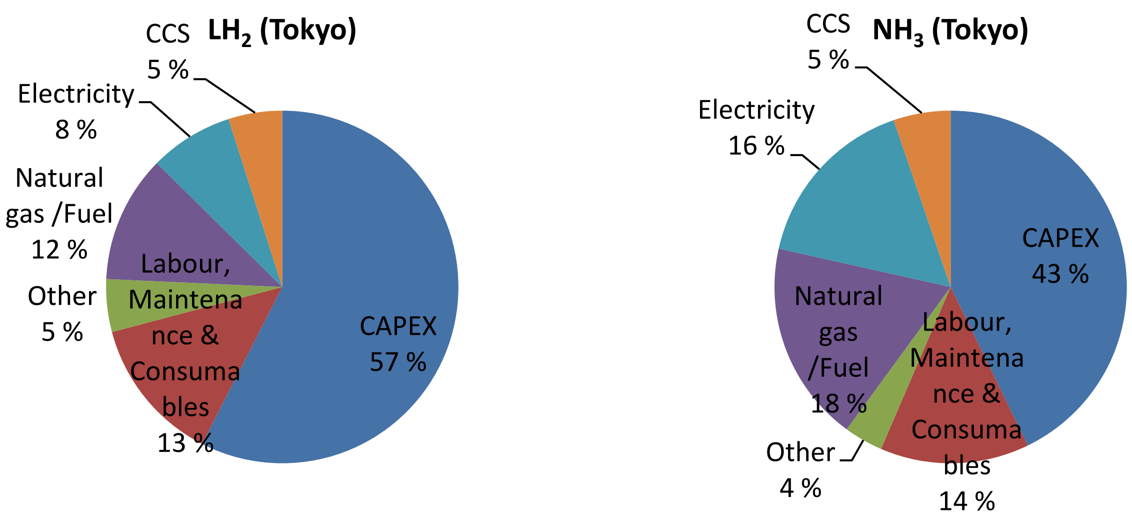

Figure 13 Break down of cost element of LH_2 (left) and NH_3 (right) chains in Tokyo case

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5. Discussion

5.1. Sensitivity analysis

There are uncertainties in the assumptions used in this analysis since there is no utility scale value chains existing today. Table 9 shows the sensitivity analysis parameters considered and their lower and upper limits. In the sensitivity analysis the CAPEX, the natural gas price, the electricity price, the discount rate and the project duration were varied. Figure 14 - Figure 17 show results of the sensitivity analysis performed to consider influences of uncertainties in the assumptions. Out of all the parameters, the CAPEX and discount rate shows the largest influence on the delivered hydrogen cost.

The cost that relates to the CAPEX is approximately half of the levelized cost of hydrogen, as shown in Figure 13. While CAPEX directly affects the levelized cost of hydrogen, the discount rate changes the denominator in Equation 3, that is the discounted value of the hydrogen cost. A high discount rate lowers the denominator. On the other hand, CAPEX is accounted for in the start year of the project and the CAPEX itself is not affected by the discount rate. Therefore, the CAPEX element of the levelized hydrogen cost increase with the discount rate. However, OPEX is generated every year. Changes in the denominator and the numerator are therefore cancelled. The OPEX element of the levelized hydrogen cost is therefore not affected by the discount rate.

Table 9 the ranges of parameters in the sensitivity analysis

Parameter	Default	Lower	Upper	Note
CAPEX	-	-20%	+20%	Arbitrary
Natural gas price	4.5 EUR/GJ	-50%	+50%	Min/max of the internal gas price of Equinor during 2006-2016
Power price	38 EUR/MWh	-50%	+50%	Arbitrary
Discount rate	7.5%	5%	10%	Arbitrary
Project duration	25 y	20 y	30 y	Arbitrary

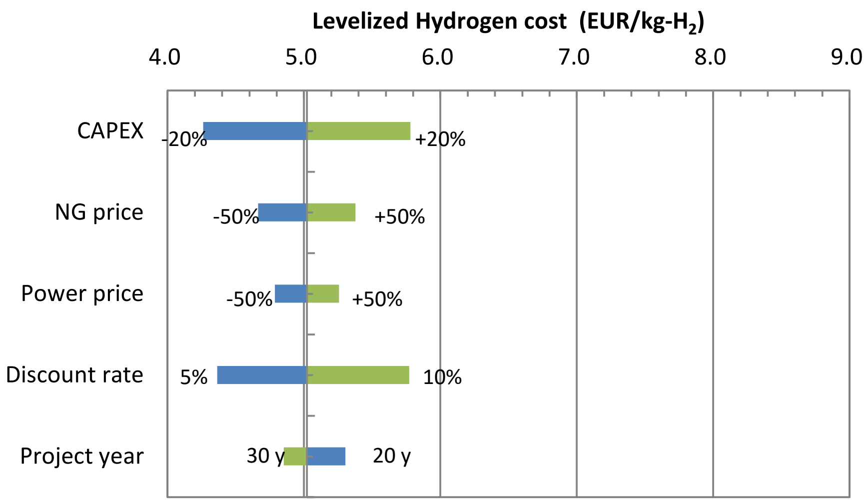

Figure 14 Sensitivity analysis of levelized cost of hydrogen of the LH_2 chain in the Rotterdam case

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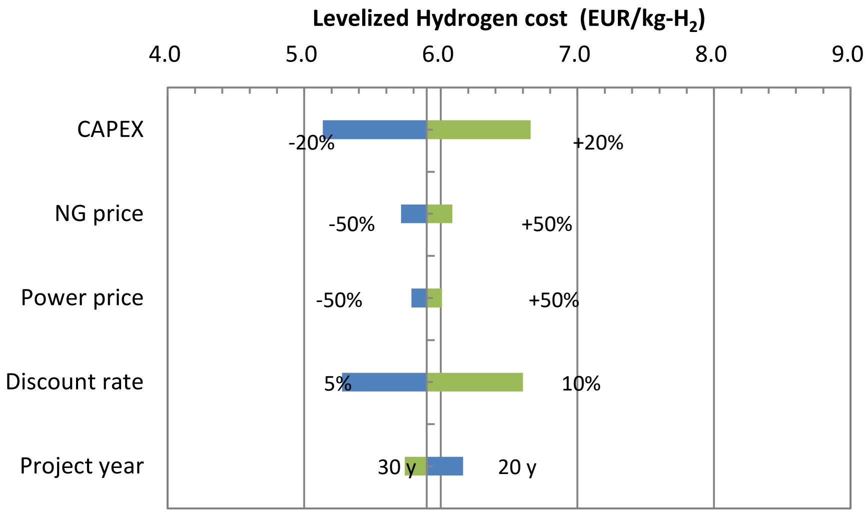

Figure 15 Sensitivity analysis of levelized cost of hydrogen of the NH_3 chain in the Rotterdam case

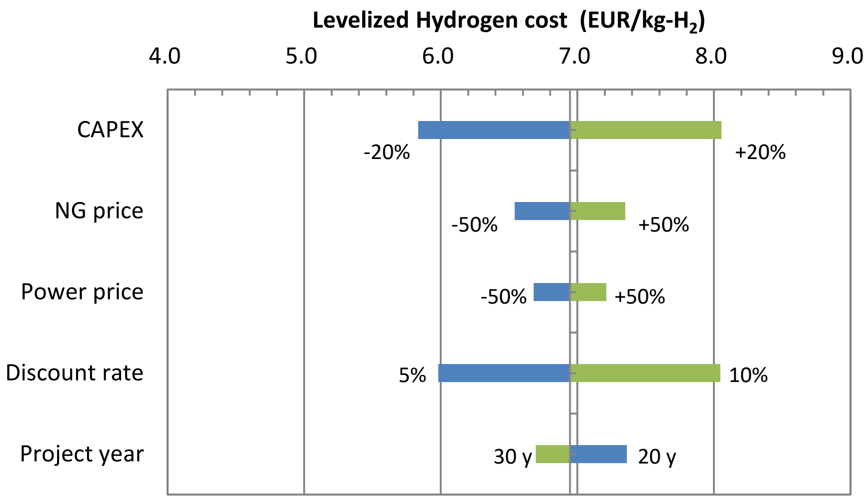

Figure 16 Sensitivity analysis of levelized cost of hydrogen of the LH_2 chain in the Tokyo case.

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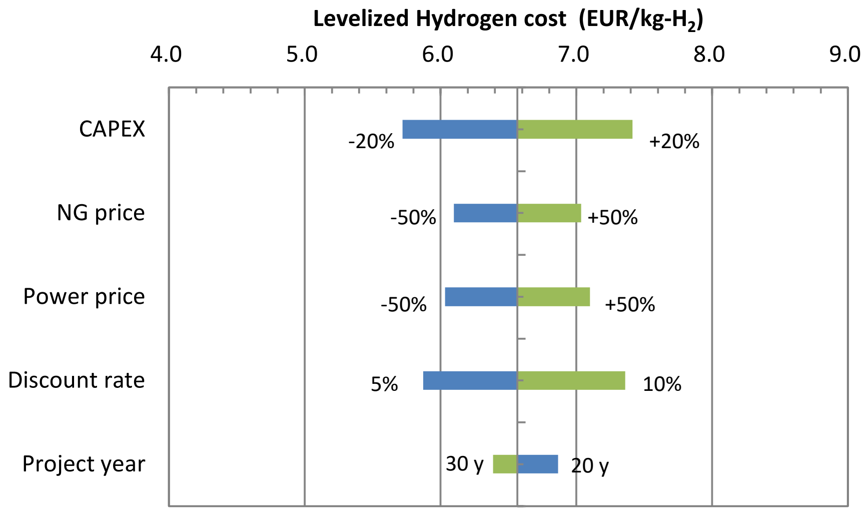

Figure 17 Sensitivity analysis of levelized cost of hydrogen of the NH_3 chain in the Tokyo case

5.2. Case study on cost reduction to meet Japans cost target

In Section 4.4 it was shown that the estimated hydrogen cost is higher than 2.5 EUR/kg-H_2 which is Japan's cost target in 2030. Possible measures to reduce hydrogen cost are:

- Change the production site from Northern Norway to Southern Norway
- Financial support for the introduction phase
- Continuous operations in networked supply chains
- Learning by doing
- Reduce transportation distance

The location factor in Northern Norway is assumed to be high (1.3). If the production site moves to a low-location factor area, for example Southern Norway, CAPEX can decrease by up to 30%. Further, if financial support reduces the discount rate, CAPEX's contribution to the levelized cost of hydrogen would also decrease. These points have a large effect on the results, especially for high CAPEX systems.

Continuous operations imply higher utilization rate, which also reduce the CAPEX contribution. The current model takes shutdowns during maintenance periods into account. Therefore, the receiving terminals are designed to have enough capacity to supply the customers during the shutdown periods. If more than two production sites can supply the energy carrier continuously, some of the storage capacity can be reduced.

The learning effect as a result of constructing similar kinds of plants can reduce CAPEX in general. It is believed that this could benefit LH_2 chains most, not being a common commodity for large scale distribution today.

Considering the losses due to ship fuel, a shorter shipping route for the same destination can improve energy efficiency. As ice in the Arctic Ocean is reported to decrease, utilization of northern sea route (NSR) is often discussed. As shown in Figure 1 NSR is about half of the conventional shipping route that uses the Suez Canal and Straits of Malacca.

As the cost evaluations in the base case are based on conservative assumptions, we consider two cases with more optimistic assumptions in order to see if the 2030 target of Japan can be reached. The assumptions are changed as follows in the "Optimistic" scenario:

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- The production site is changed to the Southern area of Norway to lower the location factor from 1.3 to 1.0.
- Financial support for the introduction phase is assumed. Discount rate is changed from 7.5% to 1.35% corresponding to considering the project to have a lower risk. 1.35% is the recent 25-year AAA-rated bonds in the EU region.
- The capacity of the receiving terminal is reduced to 200,000 m^3 which is the storage required for 25 d of consumption.
- A higher utilization rate of 95% is applied.

For the "Optimistic + Low transport CAPEX" scenario the following assumptions are made for the LH_2 chain in addition to the assumptions for the "Optimistic" scenario:

- Construction cost reduction of the terminals and ships are assumed considering technical similarity between LNG and LH_2 and cost reductions due to learning effects. The assumed reduction is shown in parentheses in Table 8.

Figure 18 shows cost comparison and reduction potential in both chains for the Tokyo case compared to the base case (referred to as "Conservative" in the figure). The delivered hydrogen cost of the two chains are similar for the conservative base case. As shown, the levelized cost of hydrogen improves significantly in the "Optimistic" case. The improvement is highest for the LH_2 chain due to a higher CAPEX share (see Figure 13). The measures considered in this case could be relevant for an introduction phase, corresponding to subsidies for introduction of new technologies in other areas.

The low transportation CAPEX depends mainly on learning by doing and technical progress. To realize this effect, successful introduction of hydrogen as energy carrier and R&D efforts will have to take place first.

As shown, if we can anticipate strong CAPEX reduction efforts (including a site location change) and wide variety of financial support, the levelized hydrogen cost would approach Japan's target for the LH_2 "Optimistic + Low transport CAPEX" case. If the NH_3 can be used directly in the demand side, the cracking portion in the figure can be omitted as a rough estimation. However, in such case, the cost of LH_2 would be Lower than NH_3.

Regarding hydrogen production costs, long-term hydrogen production costs from solar PV and wind will not be less than 3 and 2 USD/kg in respectively Japan and Europe as shown in the literature [21]. One of practical solutions would be combination of hydrogen production from natural gas with carbon capture technology and electrolysis in the regions with abundant solar or wind resources and bulk long distance transport.

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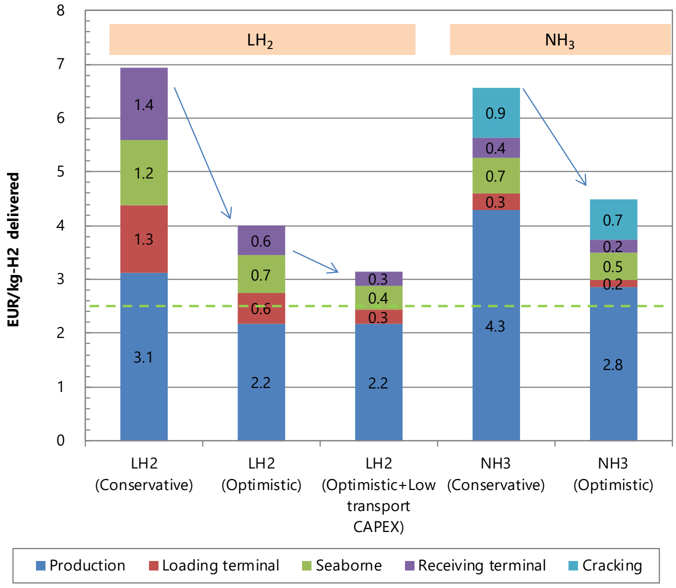

Figure 18 Cost comparison and reduction potential of both chains in the Tokyo case. The "Conservative" case refers to the base case, while the "Optimistic" and "Optimistic + Low transport CAPEX" cases refers to the cases described in Section 5.2.

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http://dx.doi.org/10.1016/j.ijhydene.2020.09.017

A reduction in transportation distance may also reduce the levelized cost of hydrogen. In Figure 19 the distance dependence of hydrogen cost delivered by different solutions is shown. The NH_3 chain has a weaker sensitivity to distance than LH_2 because the NH_3 production cost is more dominant in the total cost. A shorter transport distance will however benefit the LH_2 chain. Hydrogen cost can be reduced due to reduction of the number of ships and an increase in the amount of delivered hydrogen due to reduction of BOG used for propulsion. Utilisation of the Northern Sea Route can thus also help meeting the Japanese cost targets for the LH_2 chain.

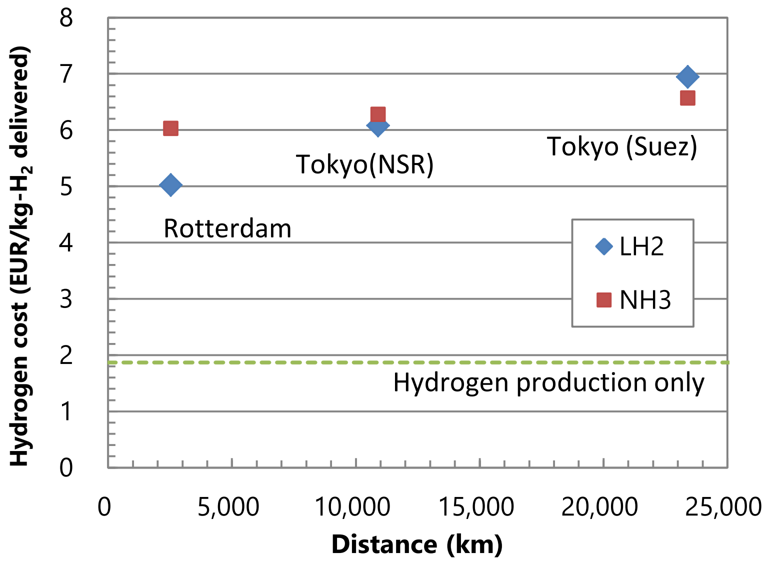

Figure 19 Distance dependence of hydrogen cost.

5.3. Recommendations for further research and development to identify optimal energy carrier for long-distance hydrogen transport

Based on the analysis performed in this study and other learnings obtained while investigating this topic, some recommendations for focus in further research and development on large-scale long-distance hydrogen transport can be made. For comparison of the LH_2 and NH_3 value chains it is important to have certain features of the chains in mind.

For the LH_2 value chain it should be noted that:

- As mentioned in Section 4.4, cost figures in the literature, especially for LH_2 storage tanks, are few and seem somewhat inconsistent. It is important to increase the knowledge on these costs in order to reduce uncertainty.
- As discussed in Section 5.2 the LH_2 value chain is made up of several immature technologies. It is expected that maturing of the technologies and concepts could give considerable cost reduction effects.

For the NH_3 value chain it should be noted that:

- The production, storage and transport related parts of the NH_3 value chains are mature technologies; large quantities of NH_3 are already transported globally today. Certain cost and efficiency figures can therefore be estimated relatively accurately for these parts.
- Parts of the chain that are specific for NH_3 as energy carrier, however, opens several questions that may affect efficiency and costs. As discussed in Section 4.2, the end-use efficiency of NH_3 for energy

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http://dx.doi.org/10.1016/j.ijhydene.2020.09.017

conversion is uncertain. Whether there is need for full, partly or no cracking before or during end use will have a large influence on the value chain efficiency. Research is ongoing in this area.

- Emissions of NO, NO_2, N_2O and possibly unburnt NH_3 from end-use must be kept at very low levels to avoid climatic effects and other environmental effects (the N_2O component has a global warming potential of 300). This may influence costs as well as CO_2 equivalent emissions.

For both the considered energy carriers, uncertainties regarding standards for safe transport and use in large quantities still exist. Factors related to safety may influence costs and possible implementation along the chains.

In general, it must be pointed out that scale is a very important factor. Even though the chains evaluated in this study might be considered to have large capacities, they are small for instance compared to today's LNG value chains. Larger capacity chains and integration of several chains may reduce unit costs considerably.

6. Conclusions

This work evaluates and compares value chains of hydrogen transport using liquid hydrogen (LH_2) and ammonia (NH_3) chains for transport from Norway to markets in Europe and Japan. Energy efficiency, CO_2 emissions and cost of the different value chains are reported. The amount of energy transported corresponds to a hydrogen production of 500 tpd. The base case for hydrogen production considers a combined production from natural gas with CCS (90%) as well as from electrolysis using Norwegian renewable power (10%). CO_2 intensity of hydrogen from the two production processes is very low and comparable when the production country of origin is Norway.

The current analysis shows that the LH_2 chains for transport of hydrogen from Northern Norway to Rotterdam and Japan are more energy efficient than the NH_3 chain if cracking of NH_3 is required to obtain pure H_2 for end-use. If cracking is not required before end-use, the energy efficiencies of the chains are almost equal.

CO_2 emissions from the LH_2 chains are lower than for the NH_3 chains for the given set of assumptions. Important aspects are the emissions of the NH_3 chains due to fuel oil consumption for ship propulsion and the CO_2 intensity of grid electricity required for NH_3 cracking.

It is found that production of hydrogen or ammonia, including liquefaction, represents a major component of the total levelized hydrogen cost for all the investigated cases. The cost difference between the Rotterdam and Tokyo cases is mainly due to the difference in transportation distances. For what is considered as conservative cost assumptions in the base cases, the levelized hydrogen costs from the LH_2 and NH_3 chains are similar for the Tokyo case. For the case with transport to Rotterdam, LH_2 results in lower levelized hydrogen cost than for NH_3.

For the cost estimates of the conservative base case, the chains do not meet the cost target of Japan in 2030. A case with more optimistic assumptions for both technical and economical parameters was also considered. In this case the hydrogen cost of the LH_2 chain almost meets the target, while the cost related to the NH_3 chain did not meet the target.

7. Acknowledgement

This publication is based on results from the research project Hyper, performed under the ENERGIX programme at the Research Council of Norway. The authors acknowledge the following industry partners for financial support: Equinor, Shell, Kawasaki Heavy Industries, Linde Kryotechnik, Mitsubishi Corporation, Nel Hydrogen, Gassco and the Research Council of Norway (255107/E20). The authors wish to thank Rahul Anantharaman and Julian Straus for fruitful discussions.

This is the accepted version of an article published in International Journal of Hydrogen Energy
http://dx.doi.org/10.1016/j.ijhydene.2020.09.017

8. Appendix A: Hydrogen and NH_3 balance in the value chains

8.1. LH_2 chain

Hydrogen flows between blocks are shown below:

LH_2 supply: $f_{1,2}\ (t)$

= 500 t/d (90% utilization)

Gaseous hydrogen (GH_2) for reliquefaction: $f_{2,1}\ (t)$= constant

LH_2 loading: $f_{2,3}\ (t)$

= constant (during loading)

= 0. (during storage)

BOG and flash gas at the loading terminal $f_{2,BOG}\ (t)$

$= r_{2,Trans}\ f_{2,3}(t)$ (during loading)

$= r_{2,BOG}\ S_2$ (during storage)

Gas for ship propulsion: $f_{3,BOG}\ (t)$

$= r_{3,BOG}\ S_3$ (during voyage)

= 0. (connected to the terminals)

LH_2 unloading: $f_{3,4}\ (t)$

= constant (during unloading)

= 0. (during storage)

GH_2 to storage: $f_{4,Gas}\ (t)$

$= r_{4,Trans}\ f_{3,4}(t)$ (during unloading)

$= r_{4,BOG}\ S_4$. (during storage)

Delivery: $f_{4,5}\ (t)$

= $f_{LH2} + f_{GH2}$ (constant)

Where:

$f_{a,b}\ (t)$: the flow from processes a to b at time t.

S_a: LH_2 storage capacity in process a.

$r_{a,BOG}$ and $r_{a,Trans}$: BOG and transfer loss rates in process a, respectively.

1: Production, 2: Loading terminal, 3: Ship, 4: Loading terminal

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http://dx.doi.org/10.1016/j.ijhydene.2020.09.017

8.2. NH_3chain

NH_3 flows between blocks are shown below;

L-NH_3 supply: $f_{1,2}(t)$
$= 3180$ t/d (90% utilization)

Gaseous NH_3 (GNH_3) for reliquefaction: $f_{2,2}\ (t)$
= constant

L-NH_3 loading: $f_{2,3}\ (t)$
= constant (during loading)
= 0. (during storage)

BOG at the loading terminal $f_{2,BOG}\ (t)$
$= r_{2,Trans}\ f_{2,3}(t)$ (during loading)
$= r_{2,BOG}\ S_2$ (during storage)

L-NH_3 unloading: $f_{3,4}\ (t)$
= constant (during unloading)
= 0. (during storage)

GNH_3 to storage: $f_{4,Gas}\ (t)$
$= r_{4,Trans}\ f_{3,4}(t)$ (during unloading)
$= r_{4,BOG}\ S_4(t).$ (during storage)

L-NH_3 to NH3 cracker: $f_{4,5}\ (t)$
=constant

GH_2 to end use: $f_{5,6}\ (t)$
$= r_{crack} f_{4,5}(t)$ (during unloading)

Where:
$f_{a,b}\ (t)$: the flow from processes a to b at time t.
$S_a(t)$: NH_3 storage amount in process a.
$r_{a,BOG}$ and $r_{a,Trans}$: BOG and transfer loss rates in process a, respectively.
r_{crack}: ratio of output hydrogen gas to input NH_3 (kg-H_2/kg-NH_3)
1: Production, 2: Loading terminal, 3: Ship, 4: Loading terminal, 5:Cracking, 6: Demand

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