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Economic and environmental evaluation of hydrogen carriers traveling from overseas production to final demand in Japan

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Summary

Various hydrogen carriers, including liquified hydrogen, methylcyclohexane (MCH), ammonia, and synthetic methane will be an option for importing hydrogen. The economic and environmental performance of these hydrogen carriers varies depending on the domestic supply chain, including end-use (electricity or heat), in addition to the international supply chain. In this study, we evaluated the economic performance and the carbon footprint of hydrogen carriers traveling from overseas production sites to final demand sites in Japan assuming a long-term perspective beyond 2030. We obtained the following conclusions:

- In terms of cost for power generation application, synthetic methane (innovative technology)-firing is the lowest among carriers derived from renewable electricity, followed by ammonia cracked hydrogen-firing. Among carriers derived from natural gas (abated by carbon capture and storage: CCS), synthetic methane (existing technology)-firing and ammonia cracked hydrogen-firing are the least expensive. In terms of the cost of industrial heating application, which is significantly affected by domestic transportation, synthetic methane is the least expensive option due to the fact that synthetic methane can use existing gas pipelines and other infrastructure.
- With regard to the carbon footprint of the entire supply chain for the power generation application, synthetic methane is the smallest among carriers derived from renewable electricity, while ammonia is the smallest among carriers derived from natural gas (with CCS). For the industrial heating application, synthetic methane using existing gas pipelines has the smallest carbon footprint because truck transportation can be avoided through the utilization of existing city gas infrastructure. On the other hand, the carbon footprint of MCH is the largest due to the high fuel consumption involved in international transportation and dehydrogenation. Synthetic methane and ammonia can maintain their economic advantage due to the smaller carbon footprint of their entire supply chains, even after counting in a certain level of carbon price. It should be noted although the carbon footprint of synthetic methane will vary

depending on how international rules are formed regarding the attribution of CO_2 emissions from synthetic fuel and gas combustion, the CO_2 emissions from synthetic methane combustion are assumed to belong to the original CO_2 emitters in this analysis.

This analysis is based primarily on the assumptions made in the 2019 International Energy Agency (IEA) report "The Future of Hydrogen," and does not take into account the effects of recent soaring resource prices, high commodity prices, and the depreciation of the Japanese yen.

A certain amount of clean fuels such as hydrogen and its derivatives is required for decarbonization. The cost structure of hydrogen carriers employed for importing clean fuels from overseas is roughly divided into hydrogen carrier synthesis and transportation. The cost of hydrogen carrier synthesis is higher for carriers derived from renewable electricity than for those derived from natural gas (with CCS). However, it is necessary to reduce the capital cost of hydrogen carrier synthesis in both cases, and procuring inexpensive renewable electricity is critical for carriers derived from renewable electricity.

With regard to transportation costs, MCH, ammonia, and synthetic methane, which can utilize existing infrastructure and commercial transportation technologies, are considerably less expensive than liquefied hydrogen, which requires new transportation technologies. However, dehydrogenation of MCH and cracking of ammonia into hydrogen are factors that increase cost, and the advantageous options are direct use of ammonia and synthetic methane, which do not require conversion into hydrogen. If domestic transportation is included, the cost of synthetic methane is the lowest because the use of existing city gas infrastructure avoids the use of trucks and the construction of hydrogen pipelines, which would be cost-increasing factors.

In other words, in order to achieve a cost-effective supply of clean fuel from overseas to Japan, it is necessary to secure inexpensive feedstocks, reduce the cost of hydrogen carrier synthesis through technological innovation, and squeeze the transportation cost by utilizing existing infrastructure and transportation technologies that are already in commercial use.

Introduction

Various hydrogen carriers, including liquified hydrogen, methylcyclohexane (MCH), ammonia, and synthetic methane will be an option for importing hydrogen. The Institute of Energy Economics, Japan (IEEJ) has conducted evaluations and studies on international hydrogen supply chains connecting hydrogen producing countries and Japan, represented by the "Study on the Economics of the Green Hydrogen International Supply Chain" [1]. However, when considering the actual application of hydrogen, it is necessary to carry out an evaluation that includes domestic customers in Japan. As indicated by the establishment of a price difference support scheme (contract for difference) to promote the introduction of hydrogen and the establishment of a CO_2 emissions intensity standard for the hydrogen production mentioned in the Basic Hydrogen Strategy revised in June 2023, the economic efficiency and carbon footprint are important axes for evaluation.

In this report, we evaluated the economics and carbon footprint of hydrogen in a manner that includes not only international supply chains but also domestic supply chains assuming domestic consumers in Japan.

1. Economic evaluation of international supply chains

This study first estimates the costs involved in international transportation and import (including reconversion costs) of hydrogen produced at suitable overseas locations. As shown in Section 1.1, multiple supply chains are assumed, and the cost per unit of supply is calculated by dividing the annual cost of each supply chain by the annual supply volume (Equation 1-1). In calculating the annual cost, capital costs are converted to an annual cost using a capital recovery factor.

$$\text{JPY/Nm}^3\text{-H}_2 = \frac{\text{Annual cost (JPY/year)}}{\text{Annual supply (Nm}^3\text{-H}_2\text{/year)}}$$
$$= \frac{\text{Hydrogen or carrier production cost + Port storage cost + Transportation cost + Reconversion cost}}{\text{Total supply}} \tag{1-1}$$

1.1. Supply chain options

Figure 1-1 summarizes the supply chain options. A total of 14 cases were assumed, depending on the hydrogen production process and domestic and international transportation carriers. Two types of hydrogen production processes are considered: water electrolysis using renewable electricity (cases 1 to 9) and natural gas reforming abated by CCS (cases 10 to 14). Synthetic methane, liquefied hydrogen, MCH, and ammonia are assumed as carriers for international transportation, while synthetic methane, hydrogen, and ammonia are assumed as carriers for domestic distribution after unloading in Japan. The boundary for cost estimation is set to the gate before the distribution by these domestic carriers (Figure 1-2 and Figure 1-3). The cost of infrastructure for distribution to consumers and the cost of energy-consuming equipment of the customers are not included. Furthermore, Cases 8 and 9, as references, estimate the cost of producing synthetic methane from hydrogen derived from domestic renewable electricity.

Case	Production site and feedstock	International H_2 carrier	Domestic delivery H_2 carrier
1 Overseas SCH_4 (innov)	Overseas renewable electricity	$LSCH_4$	SCH_4
2 Overseas SCH_4 (conv)			
3 Overseas LH_2		LH_2	H_2
4 Overseas MCH		MCH	
5 Overseas NH_3 (split into H_2)		LNH_3	
6 Overseas NH_3 (direct use)			LNH_3
7 Overseas MCH + Domestic methanation		MCH	SCH_4
8 Domestic SCH_4 (innov)	Domestic renewable electricity	none	
9 Domestic SCH_4 (conv)			
10 Overseas SCH_4 (conv)	Overseas natural gas abated by CCS	$LSCH_4$	SCH_4
11 Overseas LH_2		LH_2	H_2
12 Overseas MCH		MCH	
13 Overseas NH_3 (split into H_2)		LNH_3	
14 Overseas NH_3 (direct use)			LNH_3

Figure 1-1 Cases for International Supply Chain

Note: SCH_4 = Synthetic methane; $LSCH_4$ = Liquified Synthetic methane; LH_2 = Liquified Hydrogen; MCH = methylcyclohexane; LNH_3 = Liquified ammonia; innov = innovative, conv = conventional.

An overview of each case is described below. Firstly, in Cases 1, 2, and 10, synthetic methane is produced and liquefied in the overseas production country and transported internationally. Conventional technology (Sabatier reaction) and innovative technology were considered for the methane synthesis technology. Specifically, the conventional methane synthesis technology is combined with water electrolysis located upstream, while the innovative technology is a more efficient direct methane synthesis technology that integrates water electrolysis and methane synthesis. After the liquefied methane gas is unloaded in Japan, it is distributed to consumers as synthetic methane. In Cases 3 and 11, liquefied hydrogen is transported from the producing country to Japan. After being unloaded in Japan, it is vaporized into hydrogen for domestic distribution. Cases 4, 7, and 12 involve international transportation of MCH and dehydrogenation to extract hydrogen after unloading in Japan. Cases 4 and 12 are based on the assumption that domestic distribution is made in the form of hydrogen, while Case 7 is based on the assumption that methane synthesis is performed at the unloading site. As shown in Section 1.3, Case 4 was the least expensive among Cases 3 to 5, in which hydrogen derived from overseas renewable energy is transported in the form of carriers and converted back to hydrogen after unloading in Japan. Based on these results, we decided in this study to set Case 7, in which synthetic methane, the main component of city gas, is produced from hydrogen transported by MCH. Cases 5, 6, 13 and 14 are cases in which liquefied ammonia is used as a carrier for international transport. Cases 5 and 13 involve cracking ammonia into hydrogen after unloading in Japan, while Cases 6 and 14 involve the direct use of imported ammonia (excluding the cost of ammonia cracking).

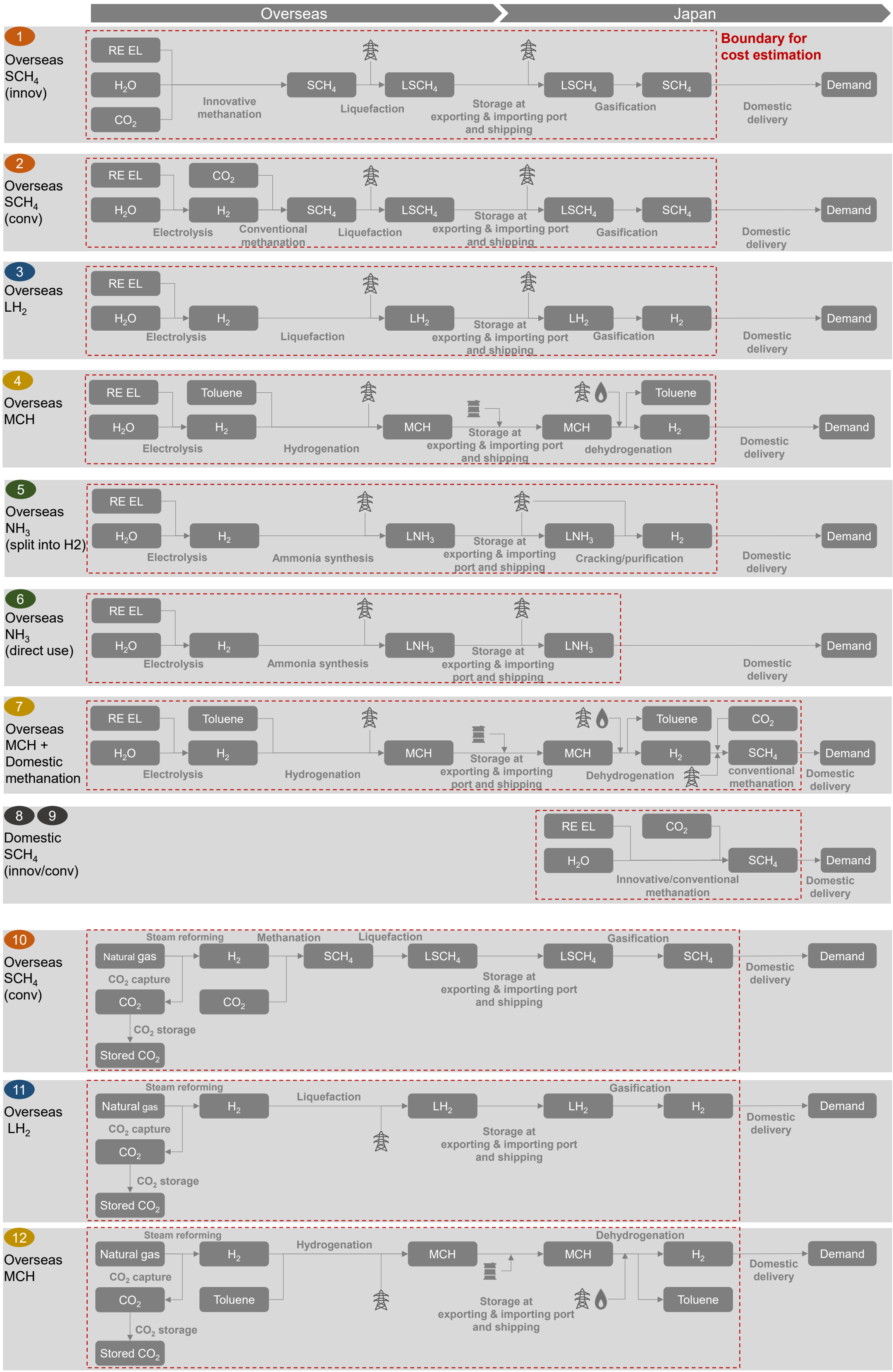

Figure 1-2 Description of International Supply Chains

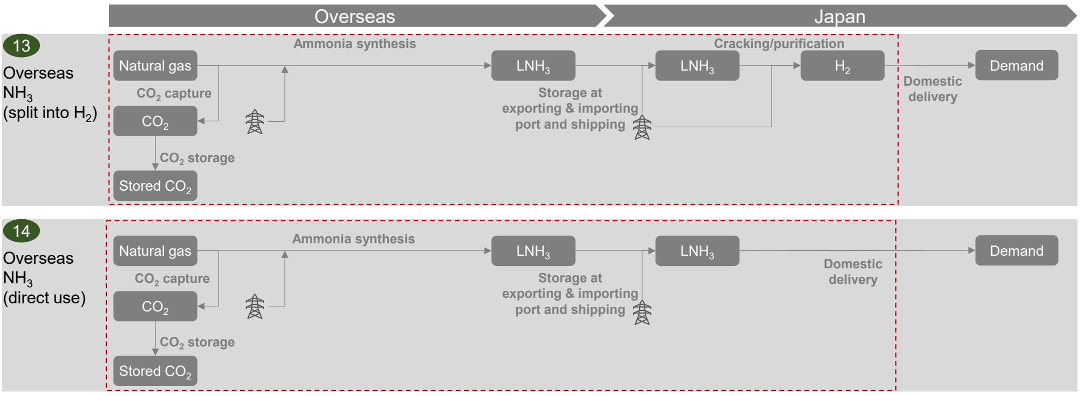

Figure 1-3 Description of International Supply Chains (cont.)

Note that Case 10, in which synthetic methane is produced from natural gas-derived hydrogen abated by CCS, needs to be considered from the viewpoint of overall system efficiency. In Case 10, the procedure is that natural gas is separated into hydrogen and CO_2 in the overseas production country, and then the CO_2 captured from other CO_2 sources and hydrogen are synthesized into methane. Compared to this case, it would be more efficient in the overall system to transport natural gas directly to Japan, capture CO_2 from the CO_2 sources, and store CO_2 directly (Figure 1-4, "Separated gas chain and CCS system"). In other words, the "Separated gas chain and CCS system" (Figure 1-4) keeps the overall system CO_2 emissions and energy amount transport to Japan at the same level as Case 10, but is able to eliminate the natural gas reforming, CO_2 capture (required for methane synthesis), and methane synthesis processes. Needless to say, in the "separation system," as the natural gas chain and CCS are separated, there is no environmental benefit to the natural gas chain. However, from the perspective of overall optimization, it is important to note that there may be a way to maintain the natural gas chain and to achieve net decarbonization through measures like credit transfers.

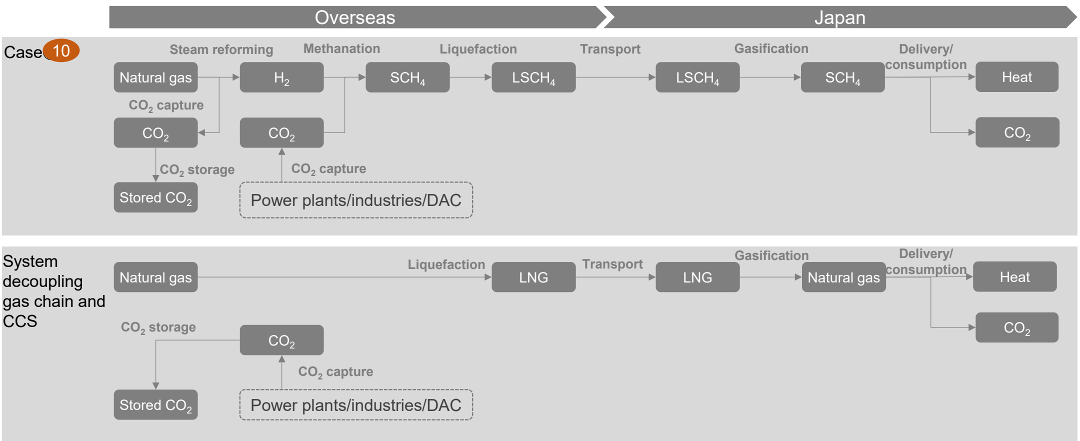

Figure 1-4 Comparison of Case⑩ and "System decoupling gas chain and CCS"

1.2. Major assumptions

The analysis methodologies are based on [2]. The scale of transportation volume for each supply chain is assumed to be about 260 ktH_2/year (about 2.9 billion Nm^3-H_2/year, or 100,000 Nm^3-CH_4/h in synthetic methane equivalent) based on the "The Future of Hydrogen" by the IEA [3]. When supplied as synthetic methane, this scale corresponds to about 2% of Japan's annual city gas consumption. The year of analysis is not specifically identified, but the parameters are set assuming a long-term perspective beyond 2030.

Overseas producing countries are assumed to be in the Middle East, which has relatively excellent renewable energy conditions and abundant natural gas resources. The unit price of renewable electricity is set at 2.5 cents/kWh and the capacity factor at 29%, based on the IEA's report [3]. This renewable energy is assumed to be a hybrid of solar photovoltaic and wind power. The capacity factor for the water electrolysis and the innovative methane synthesis (Case 1) are assumed to be identical to that of renewable energy electricity. The natural gas price is assumed to be 3.4 USD/MMBtu (the world's lowest long-term price level in the IEA's report [3]). The domestic renewable energy assumptions for Cases 8 and 9 are also based on the same IEA report (the unit price of renewable electricity is 6.3 cents/kWh, and the capacity factor is 19%). The hydrogen production (water electrolysis and natural gas reforming with CCS), liquefied hydrogen production and transportation, MCH production and transportation, and ammonia production and transportation are also based on the IEA's report [3], while methane synthesis, methane gas liquefaction, and liquefied methane gas transportation and receiving facilities are based on interviews with companies working on these technologies. For the factors related to hydrogen production, the capital cost for water electrolysis is set at 450 USD/kW and the efficiency (based on lower heating value) at 74%. The capital cost for natural gas reforming with CO_2 capture is set at 1,280 USD/kW_{H2} and efficiency at 69%, with an additional 20 USD/tCO_2 for CO_2 transportation to the storage site and storage. See Table 1-1 for the description and parameters for the conversion of hydrogen to each carrier and its transport and receiving at the port. The discount rate for this analysis is assumed to be 8%, following the IEA [3]. In addition, since the assumptions in the IEA's report [3] are presented in 2017 USD prices, this analysis is also based on 2017 prices, and the exchange rate is assumed to be 113 yen/USD. Note that some of the factors related to methane synthesis and liquefied methane gas transportation are changed from [2], so the results are slightly different from those in [2]. Also, note that only supply chain costs are evaluated in this estimation, and the environmental aspects (such as CO_2 emissions) were not included in this estimation. The CO_2 emission intensity of each supply chain is discussed in Chapter 3.

Table 1-1 Process and Parameters for International Supply Chains

(a) Overseas synthetic methane chain (Case①, ②, ⑩)

Process/technology	Description	Utilities	Major parameters
Innovative methanation	Technology that integrates electrolysis and methanation, which does not need independent electrolysis and gains high conversion efficiency. The capacity factor of the innovative methanation is identical with that of renewable electricity.	Electricity (renewables)	CAPEX and life OPEX Capacity factor Water unit consumption CO_2 unit consumption Electricity unit consumption
Conventional methanation	Sabatier reaction. When electrolytic hydrogen is used, the capacity factor of electrolysis and conventional methanation is identical with that of renewable electricity. When natural gas steam reforming hydrogen is used, the capacity factor of Sabatier reaction is assumed to be 95%.	Electricity (Renewable electricity is used if the hydrogen is produced from renewable electricity. If hydrogen is produced from natural gas, grid electricity is used.)	CAPEX and life OPEX BOP electricity consumption
Liquefaction	Existing liquefaction is used (efficiency is 50%).	Electricity (grid)	Electricity unit consumption Maintenance cost
Storage at exporting & importing port and shipping	Existing infrastructure is used (storage tank, loading, LNG tanker). The fuels required for shipping are supplied from cargo $LSCH_4$, reducing the arriving amount of $LSCH_4$.	Electricity (grid)	Electricity unit consumption Boil-off rate Port entry interval Maintenance cost Loading/unloading days Boil-off rate at loading/unloading Nautical speed of tanker

(b) Overseas liquified hydrogen chain (Case③, ⑪)

Process/technology	Description	Utilities	Major parameters
Liquefaction	The capacity factor of H_2 liquefier is assumed to be 90%.	Electricity (grid)	Facility scale CAPEX Life OPEX Capacity factor Electricity unit consumption
Storage at exporting port	Liquefied H_2 storage tank.	Electricity (grid)	Facility scale CAPEX Life OPEX Boil-off rate Capacity factor Electricity unit consumption
Shipping	Liquified H_2 tanker. The fuels required for shipping are supplied from boil-off H_2 and cargo LH_2 if boil-off is not sufficient, reducing the arriving amount of LH_2.	none	Facility scale CAPEX Life Nautical speed of tanker OPEX Fuel consumption Boil-off rate Flush-rate Loading/unloading days
Storage at importing port and gasification	Liquefied H_2 storage tank.	Electricity (grid)	Storage days Others are same as exporting port

(c) Overseas MCH chain (Case④, ⑦, ⑫)

Process/technology	Description	Utilities	Major parameters
Hydrogenation	Hydrogenation of toluene. Initial and refill costs are included. Heat is supplied from hydrogen. The capacity factor is assumed to be 90%.	Electricity (grid) Natural gas	Toluene price Toluene initial requirement and refill Facility scale CAPEX Life OPEX Capacity factor Electricity unit consumption Heat unit consumption
Storage at exporting port	Existing petroleum storage tanks are used.	Electricity (grid)	OPEX Electricity unit consumption
Shipping	Existing oil tankers are used. The fuels required for shipping are supplied by fuel oil.	none	Nautical speed of tanker OPEX Fuel consumption Fuel price Loading/unloading days
Storage at importing port	Existing petroleum storage tanks are used.	Electricity (grid)	Same as exporting port
Dehydrogenation	Dehydrogenation of MCH. The heat required is supplied from natural gas. PSA is used for purifying hydrogen.	Electricity (grid) Natural gas	Facility scale CAPEX Electricity unit consumption Heat unit consumption OPEX H_2 recovery rate (dehydrogenation and PSA)

Table 1-2 Process and Parameters for International Supply Chains (cont.)

(d) Overseas ammonia chain (Case⑤, ⑥, ⑬, ⑭)

Process/technology	Description	Utilities	Major parameters
Synthesis	If using renewable electricity, electrolysis and ammonia synthesis is regarded to be not-integrated; the capacity factor of electrolysis is identical with that of renewable electricity, while the capacity factor of ammonia synthesis is assumed to be 95%. If using natural gas, the process is integrated, the capacity factor is assumed to be 95%. The hydrogen is abated by CCS.	Electricity (grid)	CAPEX Life Capacity factor OPEX Unit consumption of electricity and natural gas CO_2 coefficient
Storage at exporting port	Liquified ammonia storage tank.	Electricity (grid)	Facility scale CAPEX Life Capacity factor OPEX Electricity consumption
Shipping	Liquified ammonia tanker. The fuels required for shipping are supplied from cargo LNH_3, reducing the arriving amount of LNH_3.	none	Facility scale CAPEX Life Nautical speed of tanker OPEX Loading/unloading days Fuel consumption
Storage at importing port	Liquified ammonia storage tank.	Electricity (grid)	Storage days Others are same as exporting port
Cracking	Ammonia is split into hydrogen, with required heat supplied from natural gas. PSA is used to purify hydrogen.	Electricity (grid) Natural gas	Facility scale CAPEX Electricity unit consumption Heat unit consumption OPEX H_2 recovery rate (cracking and PSA)

1.3. Analysis results

Figure 1-5 shows the cost analysis results for international supply chains. As an overall trend, it can be inferred that hydrogen carriers derived from natural gas with CCS (Cases 10 to 14) are less expensive than those derived from renewable electricity (Cases 1 to 9). The least expensive of the cases is Case 14 (direct use of ammonia derived from natural gas with CCS), which is at the level of JPY 21/Nm^3-H_2. The Japanese government has set targets for "hydrogen supply cost" (CIF cost) of JPY 30/Nm^3-H_2 in 2030 and JPY 20/Nm^3-H_2 in 2050, and for ammonia at the upper JPY 10 level/Nm^3-H_2 in 2030 in the Basic Hydrogen Strategy [4]. In Case 14, the cost equivalent to CIF (excluding "import port and reconversion" in Figure 1-4) was estimated to be 20 yen/Nm^3-H_2, which is close to the Japanese government target. The technologies for ammonia production from natural gas and ammonia transportation are matured and commercialized. On the other hand, Case 13, which involves cracking ammonia into hydrogen after unloading, resulted in worse economic performance throughout the supply chain compared to direct combustion. This is due to the cost of supplying heat to the ammonia cracking process and to losses in hydrogen purification.

Next to overseas ammonia derived from natural gas with CCS (direct use), overseas synthetic methane (Case 10) derived from natural gas with CCS was evaluated as a favorable option (JPY 25/Nm^3-H_2). Like ammonia, synthetic methane has a significant advantage in that the technologies related to transportation (liquefaction, transportation, receiving base, storage tanks, etc.) are commercially established. Furthermore, in the case of synthetic methane, existing infrastructure can be utilized, which is also regarded to contribute to cost reduction. As pointed out in Figure 1-4, Case

10 needs to be considered from the perspective of overall system efficiency. However, the utilization of hydrogen derived from natural gas may be useful in the short to medium term as a foothold for the future expansion of synthetic methane derived from renewable electricity. For example, one of the technological challenges for methane synthesis is scaling up, and if natural gas-derived hydrogen can be used for demonstration purposes to achieve a larger scale at an early stage, it could contribute to the expansion of the synthetic methane supply chain derived from renewable electricity in the long term.

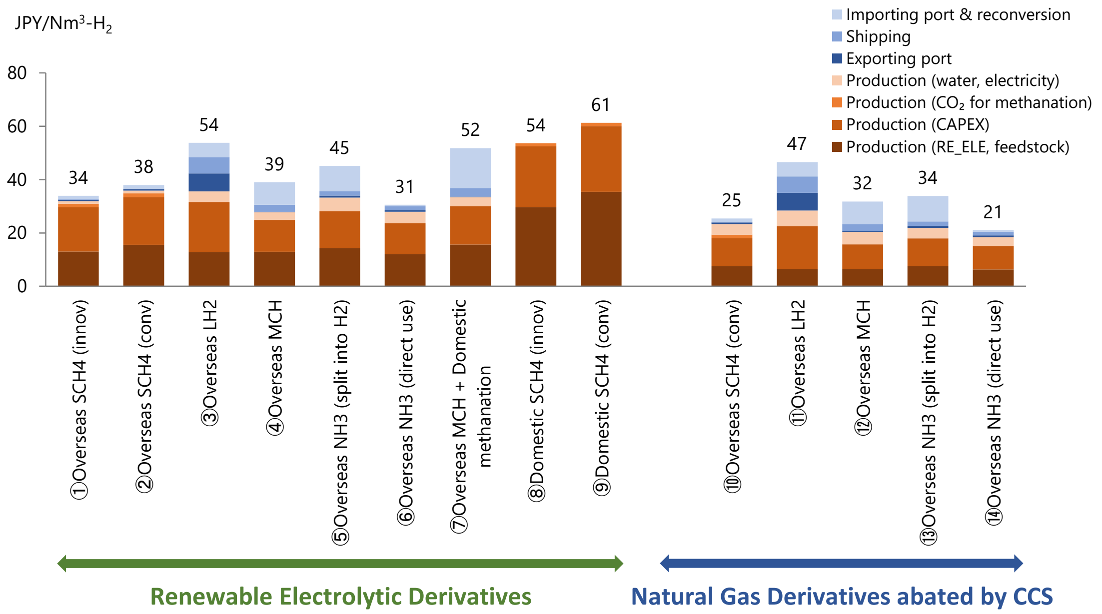

Figure 1-5 Cost Comparison among International Supply Chains

Note: "Production" includes costs associated with the production of hydrogen carriers (water electrolysis, methane synthesis, hydrogen liquefaction, hydrogenation reaction, and ammonia synthesis).
Note: The estimates in the IEEJ's report [1], which aim to compare the economics of multiple hydrogen supply chains connecting Japan and other countries (but do not include synthetic methane), and the estimates of this study show almost the same results. The slight difference stems from differences in assumptions for water electrolysis capital costs, energy prices, and other such aspects.

For hydrogen derived from renewable electricity in Cases 1 through 9, overseas ammonia (direct use) in Case 6 is the least expensive option, followed by overseas synthetic methane in Cases 1 and 2. It can be said that overseas ammonia (direct use) and overseas synthetic methane are important options for hydrogen carriers.

A breakdown of the cost structure shows that the production costs of hydrogen carriers account for the greater part of all supply chains. In particular, hydrogen carrier production costs dominate in case of ammonia (direct use) and synthetic methane, which have relatively low transportation and post-unloading costs. More specifically, the capital costs of water electrolysis and hydrogen carrier production (for example methane synthesis) and the procurement costs of feedstock energy (renewable electricity and natural gas) are the major cost factors. In order to improve the economics of each supply chain, in addition to technological development, securing "concessions" of inexpensive renewable energy with high capacity factors (such as securing land) as well as stable and inexpensive natural gas procurement in the producing country is extremely important for realizing each supply chain.

MCH was the most competitive option in the supply chains with conversion back to hydrogen after unloading (Cases 3 to 5 and 11 to 13), but was evaluated as more expensive than ammonia (direct use) and synthetic methane. The cost structure of MCH includes a relatively high heat supply cost for the dehydrogenation reaction (endothermic reaction) after unloading. To improve the economics of MCH, it is important to reduce the heat supply cost in addition to the points figured out in the previous paragraph (capital cost of carrier production and procurement cost of feedstock energy). If effective utilization of waste heat from the hydrogen consumer side can be achieved, there is a possibility to improve the economics. With this background, Case 7 (domestic methane synthesis from MCH hydrogen) is more expensive than the overseas synthetic methane in Cases 1 and 2. For liquefied hydrogen, it was suggested that the costs for the export port, transportation, and import port would be challenges. It will be key to have future technological development in the hydrogen liquefaction process and in liquefied hydrogen storage tanks and ships.

2. Economic evaluation of whole supply chains from overseas to domestic consumers

In Chapter 1, we evaluated the economics of hydrogen carriers imported from overseas, but only to the reconversion to hydrogen after unloading (excluding synthetic methane), and downstream consumers are not in the scope. However, in reality, it is important to evaluate the economics of hydrogen carriers including the consumers. Therefore, this chapter specifically assumes hydrogen carrier consumers and evaluates the economic performance including cost up to the end-use consumers. Electricity generation and heat use are considered as the end-use forms of hydrogen carriers.

2.1. Power generation use

In the case of power generation, we assume that a power plant is located adjacent to the hydrogen carrier unloading (receiving) port, and delivery costs from the unloading base to the power plant are not taken into account.

2.1.1. Power generation technology

We assume three power generation technologies: Gas Turbine Combined Cycle (GTCC) for synthetic methane as for LNG, hydrogen GTCC for liquefied hydrogen and MCH, and ammonia cracked hydrogen GTCC for ammonia. All technologies are assumed to be single-fuel-firing (not cofiring with natural gas). Ammonia cracked hydrogen GTCC is a technology in which a portion of recovered waste heat from gas turbine is used in ammonia cracking and the hydrogen extracted is fed into the hydrogen gas turbine [5].

2.1.2. Major assumptions

The annual fuel demand at the power plant is assumed to be the amount of fuel arriving at the unloading port in Chapter 1. The factors for the power generation cost assessment follow the METI [6] for GTCC and hydrogen GTCC. The LHV-based power generation efficiency is 60% and 64.3%, and the construction cost is JPY 161,000/kW for both. For the ammonia cracked hydrogen GTCC, the power generation efficiency is assumed to be 60% on LHV basis, which is equivalent to GTCC based on [5], and the total capital cost is assumed to be JPY 238,000/kW based on [7]. For other details, see the Appendix.

2.1.3. Analysis results

Figure 2-1 shows the results of the power generation cost estimation. As shown in Chapter 1, the import cost of ammonia is the least expensive among fuels derived from renewable electricity, but the capital cost of ammonia cracked hydrogen GTCC is expensive, so the innovative synthetic methane with GTCC is the least expensive in terms of power generation cost. On the other hand, in the case of natural gas derived synthetic methane (with CCS), the costs of synthetic methane (conventional technology) × GTCC and ammonia cracked hydrogen GTCC are almost equivalent.

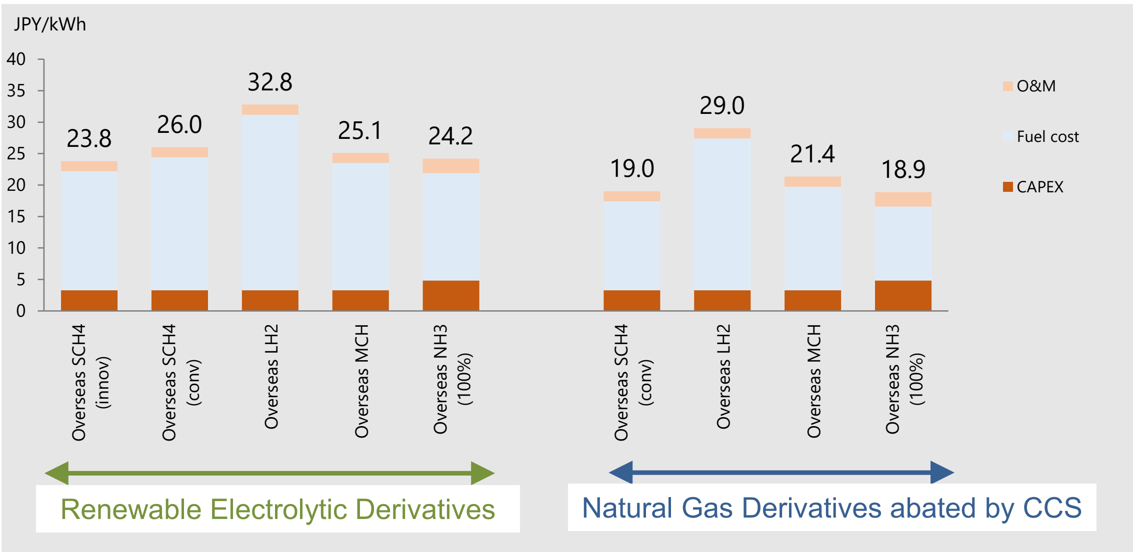

Figure 2-1 Results of power generation cost estimation

2.2. Heat use

In the case of heat use, delivery to the end-user is assumed to be by truck and existing infrastructure (existing city gas pipelines). In addition, a boiler is assumed as the heat use application.

2.2.1. Transportation routes

Two cases were assumed with synthetic methane delivery to end-users: LNG trucks and existing city gas pipelines. For others (liquefied hydrogen, MCH, and ammonia), two cases were assumed: trucks and hydrogen pipelines (in the case of direct use of ammonia, only truck delivery was assumed). Furthermore, in the case of truck delivery, dehydrogenation of MCH or cracking of ammonia is performed at a satellite base located near the end user. In the case of hydrogen pipelines, dehydrogenation and cracking are performed at the receiving port. Three cases of end-use equipment are assumed: gas boilers, hydrogen boilers, and ammonia boilers (Table 2-1).

In all cases, the delivery distance is assumed to be 50 kilometers.

Table 2-1 Hydrogen carrier delivery methods and hydrogen carrier usage forms for heat use

Hydrogen carrier	Delivery method	Satellite base	End-use equipment
Synthetic methane	Existing gas pipelines	-	Gas boilers
	LNG trucks	LNG satellite bases	
Liquefied hydrogen	Liquified hydrogen trucks	Liquified hydrogen satellite bases	Hydrogen boilers
	Hydrogen pipelines	-	
MCH	MCH trucks	MCH satellite bases (including dehydrogenation)	Hydrogen boilers
	Hydrogen pipelines	-	
Ammonia	Ammonia trucks	Hydrogen use Ammonia satellite bases (including ammonia cracking)	Hydrogen boilers
		Direct ammonia use Ammonia satellite bases	Ammonia boilers
	Hydrogen pipelines	-	Hydrogen boilers

2.2.2. Major assumptions

The amount of annual fuel demand (= annual amount of fuels delivered by trucks) for the consumer is defined as the amount of fuel arriving at the unloading port in Chapter 1. The scale of the satellite base is set based on a report [8]. See the Appendix for detailed assumptions for satellite bases, LNG trucks, liquefied hydrogen trucks, MCH trucks, ammonia trucks, truck travel patterns, and labor costs. The assumptions for dehydrogenation or ammonia cracking equipment in the case of MCH and ammonia (hydrogen use) are the same as those assumed for the international supply chains in Chapter 1. The electricity price (USD 158/MWh) and city gas price (USD 35/MWh) are also the same as those assumed for the international supply chains.

When the transportation method is existing city gas pipelines (synthetic methane), the delivery cost is assumed to be JPY 3.5/Nm^3-CH_4 based on the price of city gas pipeline usage. See the Appendix for more details. The various factors used to evaluate the unit delivery cost of a hydrogen pipeline are based on a report [9]. Specifically, the cost of pipeline construction is JPY 32,000/(inch*m), the pipe diameter is 500 mm, the variable cost is 100 million yen/year, and the hydrogen transportation volume is 100,000 tons/year.

For the boiler on the consumer side, based on the scale of the satellite base, the boiler capacity was set at 1,000 kg/h x 2 boilers. The capital cost is assumed to be 10 million yen/unit, 95% efficiency, and 80% capacity factor.

2.2.3. Analysis results

Figure 2-2 shows the results of heat use cost estimation. The heat use cost of synthetic methane with existing gas pipelines is the lowest cost option because domestic transportation costs can be significantly reduced by using existing gas pipelines. In the case of truck delivery, the heat use costs of synthetic methane and ammonia are at the same level. In the case of hydrogen pipelines, the heat use costs of MCH and ammonia are comparable and less expensive than liquefied hydrogen. The hydrogen use case also shows that the delivery cost of hydrogen pipelines is less expensive than that of trucks. The hydrogen pipeline costs assumed in this estimation are based on the condition that the pipelines are located near the receiving base (unloading port), which is considered to have few restrictions on the construction of hydrogen pipelines. It should be noted that the cost of a hydrogen pipeline passing through a city gas area would be higher than assumed due to the many restrictions on laying pipelines.

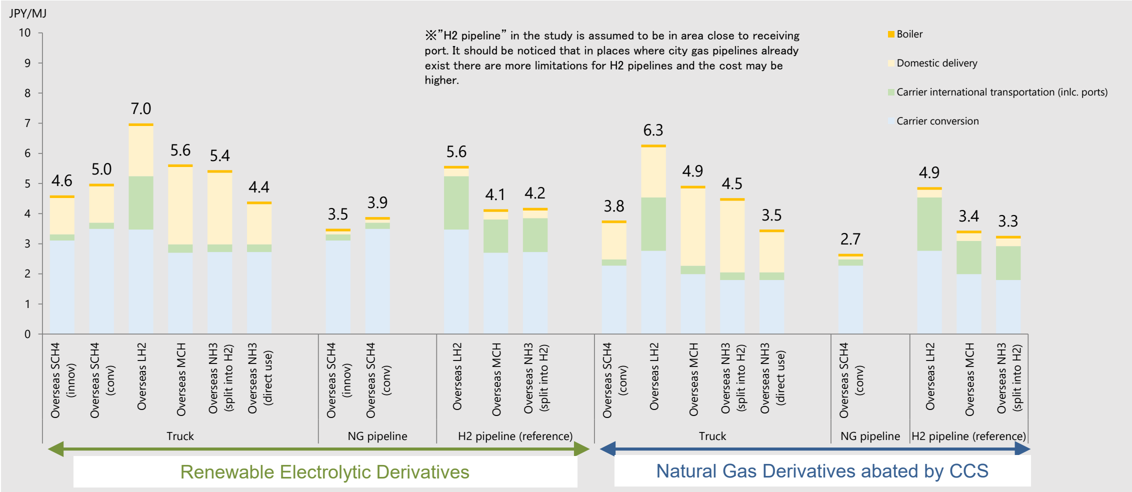

Figure 2-2 Results of heat use cost estimation

3. Economic evaluation based on CO_2 emissions of entire hydrogen supply chains

In this chapter, the economic evaluation is conducted considering the carbon footprint (carbon emission intensity) of entire hydrogen supply chains. In June 2023, the EU Renewable Energy Directive announced its definition of renewable fuels of non-biological origin (RFNBO) in conjunction with its definition of renewable hydrogen, which allows for a conditional deduction of the CO_2 emitted during the combustion of synthetic fuels and gases.[1] In Japan, institutional discussions on CO_2 emissions attribution between original emitters of CO_2 and synthetic methane users are underway.[2] Although the carbon footprint of synthetic methane varies depending on how international rules are formed regarding the attribution of CO_2 emissions from the combustion of synthetic fuels and gases, CO_2 emissions from synthetic methane combustion are assumed to belong to the original CO_2 emitters in this analysis.

3.1. Major assumptions

The carbon footprint of hydrogen supply chains is evaluated by taking into consideration hydrogen production, carrier conversion, export ports, shipping, unloading (receiving) ports, and domestic delivery. CO_2 emissions for each process are calculated by the consumption of fuel and the CO_2 emission factor of the fuel. Note that GHG emissions associated with the upstream development of

[1] Together with biological origin CO_2 and direct air capture (DAC)-derived CO_2, CO_2 emissions from power generation facilities can be deducted until 2035 and CO_2 emissions from the industrial sector until 2040 (https://energy.ec.europa.eu/system/files/ 2023-02/C_2023_1086_1_EN_ACT_part1_v5.pdf).

[2] 6th Methanation Promotion Public-Private Council, "Interim Report on CO_2 Counting during Combustion of Synthetic Methane," March 22, 2022.

fossil fuels for natural gas-derived (with CCS) hydrogen and ammonia production were not considered. The energy input for each process is shown in Table 3-1.

See the Appendix for emission factors of fuels. Emission factors for grid electricity are taken from the "Announced Pledges Scenario" for 2040 in the IEA's "World Energy Outlook 2022". The exporting country is assumed to be in the Middle East, as in the international supply chains in Chapter 1.

Table 3-1 Energy inputs in each process

Process		Hydrogen carrier			
		Synthetic methane	Liquified hydrogen	MCH	Ammonia
Hydrogen production and carrier synthesis	Renewable electricity	Innovative synthesis technology Renewable electricity Conventional technology Renewable electricity	Renewable electricity	・Hydrogen production: Renewable electricity ・Carrier conversion: Grid electricity, natural gas	・Hydrogen production: Renewable electricity ・Ammonia synthesis: Grid electricity
	Natural gas (with CCS)	Conventional technologies ・Hydrogen production: Gas reforming (CO_2 capture rate: 90%) ・Methane synthesis: Grid electricity	・Gas reforming (CO_2 capture rate: 90%)	・Hydrogen production: Gas reforming (CO_2 capture rate: 90%) ・Carrier conversion: Grid electricity, natural gas	・Ammonia production: Natural gas (CO_2 capture rate: 95%) Power input: Grid electricity
Liquefaction, etc.		Liquefaction: Grid electricity (exporting country)	Liquefaction: Grid electricity (exporting country)	-	-
Export port storage		Grid electricity (exporting country)	Grid electricity (exporting country)	Grid electricity (exporting country)	Grid electricity (exporting country)
Fuel for international shipping		LNG (synthetic methane)	Hydrogen	Fuel oil	Ammonia
Receiving port storage		Grid electricity (Japan)	Grid electricity (Japan)	Grid electricity (Japan)	Grid electricity (Japan)
Domestic transportation	For power generation	N/A	N/A	Dehydrogenation: Grid electricity (Japan), heat (city gas)	N/A
	For heat use	・Truck delivery: Diesel ・Satellite base: Grid electricity	・Truck delivery: Diesel Satellite base: Grid electricity	・Truck delivery: Diesel ・Satellite base (including dehydrogenation): Grid electricity (Japan), heat (city gas)	Hydrogen use ・Truck delivery: Diesel ・Satellite base (including ammonia cracking): Grid electricity (Japan), heat (city gas) Direct use of ammonia ・Truck delivery: Diesel Satellite base: Grid electricity
		・Existing gas pipeline: None	・Hydrogen pipeline: None	・Hydrogen pipeline (dehydrogenation at receiving port): Grid electricity (Japan), heat (city gas)	Hydrogen use ・Hydrogen pipeline (dehydrogenation at receiving port): Grid electricity (Japan), heat (city gas)

3.1.1. Power generation use

Figure 3-1 shows the results of the carbon footprint evaluation for power generation use. For fuels derived from renewable electricity, the carbon footprint of synthetic methane is the smallest, and for fuels derived from natural gas (with CCS), the carbon footprint of ammonia is the smallest. On the other hand, MCH, with its high fuel consumption in international shipping and CO_2 emissions from dehydrogenation, has the largest carbon footprint in both cases.

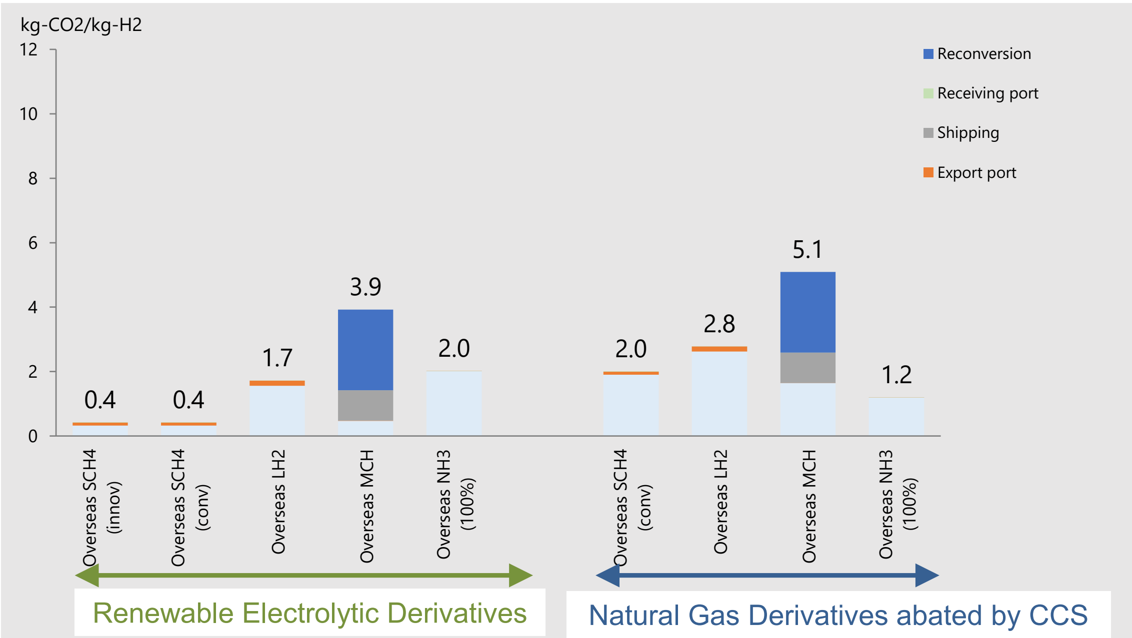

Figure 3-1 Carbon footprint of fuels for power generation

3.1.2. Heat use

Figure 3-2 shows the results of the evaluation of carbon footprint for heat use. CO_2 emissions related to domestic delivery have a significant impact on the carbon footprint of the entire supply chain. Therefore, the carbon footprint of synthetic methane with existing gas pipelines, where existing city gas infrastructure can be used, is the smallest. In the case of truck delivery, as in the case of power generation use, the fuel with the smallest carbon footprint is synthetic methane when derived from renewable electricity and ammonia when derived from natural gas (with CCS).

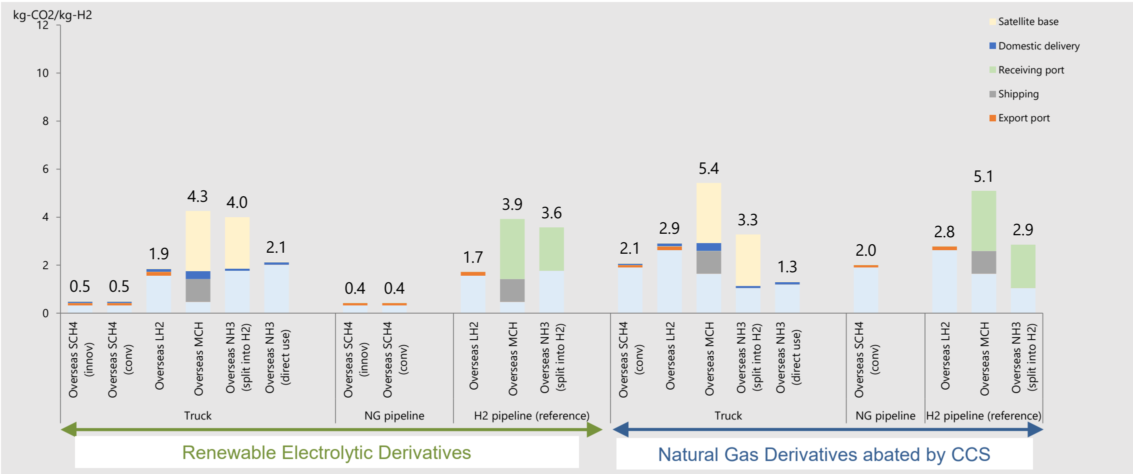

Figure 3-2 Carbon footprint in the case of heat use

3.2. Analysis results: Economics

Figure 3-3 (power generation use) and Figure 3-4 (heat use) show the results of cost estimation assuming a carbon price of JPY10,000/t-CO_2. Synthetic methane and ammonia have a small carbon footprint in the fuel supply chain, so maintain a cost advantage even when carbon costs are added.

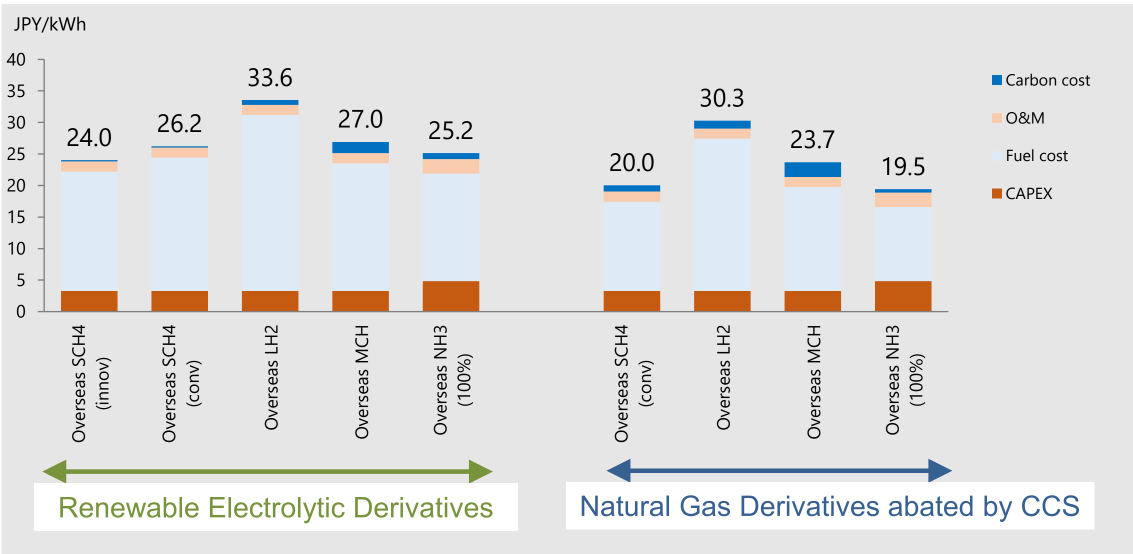

Figure 3-3 Cost of power generation including carbon costs

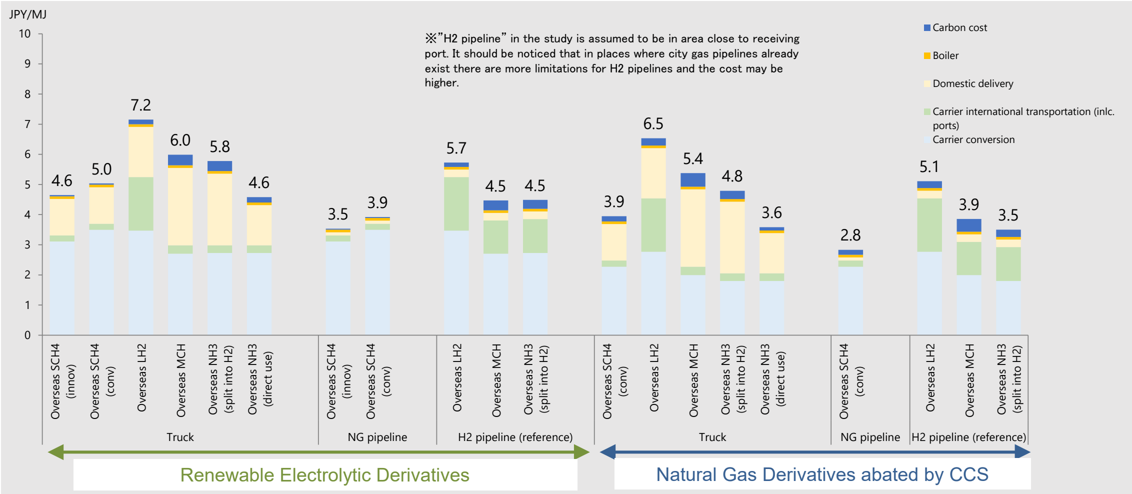

Figure 3-4 Cost of heat use including carbon costs

Conclusion

This study analyzed the economics and CO_2 emissions of the entire supply chains of hydrogen carriers. The results of the analysis are summarized below.

- With regard to international supply chains, ammonia (direct use) is the least expensive for renewable electricity-derived carriers, followed by synthetic methane (innovative technology) and synthetic methane (conventional technology). For natural gas-derived carriers (with CCS), ammonia (direct use) is the least expensive, followed by synthetic methane (existing technology).
- In terms of power generation costs including the domestic supply chain, among the renewable electricity-derived carriers, the most inexpensive is synthetic methane (innovative technology), followed by ammonia cracking hydrogen. Among the natural gas-derived carriers (with CCS), ammonia cracking hydrogen and synthetic methane (conventional technology) are at about the same level.

  In terms of heat use costs including the domestic supply chain, the impact of domestic delivery costs is significant, and synthetic methane is the least expensive through utilization of existing gas pipelines and other infrastructure.
- |For the carbon footprint of entire supply chains, the impact of CO_2 associated with grid electricity for carrier synthesis and domestic delivery is significant.

  In the case of power generation use, the carbon footprint of synthetic methane is the smallest among renewable electricity-derived carriers, and that of ammonia is the smallest among natural gas-derived (with CCS) carriers.

  In the case of heat use, the carbon footprint of synthetic methane with existing gas pipelines is the smallest because truck delivery can be avoided by utilizing existing city gas infrastructure. On the other hand, the carbon footprint of MCH is the largest due to the high fuel consumption in international transportation and dehydrogenation.

Even after counting in the carbon price, synthetic methane and ammonia can maintain their cost advantage due to their small carbon footprints throughout the supply chain.

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[6] Power Generation Cost Verification Working Group, General Resources and Energy Research Committee (8th meeting), August 3, 2021, "List of various power sources."

[7] Basic Policy Subcommittee, General Resources and Energy Research Committee, May 13, 2021; Research Institute of Innovative Technology for the Earth (RITE), "Scenario Analysis of Carbon Neutrality in 2050 (Interim Report)."

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[9] Kobe/Kansai Hydrogen Utilization Council, May 17, 2021, "Kobe/Kansai Hydrogen Utilization Council Report (FY2020): Organizing a Future Vision for a Hydrogen Society and Quantifying Supply and Demand,"
https://www.obayashi.co.jp/news/upload/img/news20210517_1_02.pdf.

Appendix

Assumptions for power generation

	GTCC	Hydrogen GTCC	Ammonia cracked hydrogen GTCC
Power generation plant capacity	1,000 MW		
Thermal efficiency (LHV basis)	60%	64.3%	60%
Equipment utilization rate	50%		
Operating life	30 years		
Equipment construction cost	JPY 161,000 /kW	JPY161,000/kW	JPY 238,000/kW
Equipment disposal cost (% of construction cost)	5%		
Personnel cost	JPY 620 million/year		
Annual repair cost (% of construction cost)	2.4%		
Other annual expenses (% of construction cost)	1.1%		
Annual general and administrative expenses (% of direct costs)	12%		

Note: Thermal efficiencies of gas and hydrogen power generation are converted to lower heating value.
Sources: Power Generation Cost Verification Working Group (8th meeting), August 3, 2021; Basic Policy Subcommittee, General Resources and Energy Research Committee, May 13, 2021; RITE, "Scenario Analysis of Carbon Neutrality in 2050 (Interim Report)."

Assumptions for domestic delivery (Truck)

	LNG trucks	Liquified hydrogen trucks	MCH trucks	Ammonia trucks
Vehicle price (JPY 10,000/unit)	5,000	5,000	3,000	4,000
Life span (years)	13	13	13	13
Transport capacity (kL)	20	20	20	20
Fuel economy (L diesel oil/t*km)	0.027	0.027	0.027	0.027
Vehicle weight (kg)	24,000	24,000	24,000	24,000

Source: The Institute of Applied Energy, "Research Report on Economic Evaluation of Synthetic Methane by Methanation: Domestic Distribution;" various other sources.

Various conditions for truck transportation

Item	Assumed value
Delivery distance	50 km
Truck speed	50 km/h
Fuel (diesel) price	JPY 130/L
Drivers	2 people/truck
Driver payment	JPY 4.5 million/person
Truck maintenance cost	JPY 218,440/truck

Source: Transportation distance is assumed based on the "Research Report on Economic Evaluation of Synthetic Methane by Methanation: Domestic Distribution" by The IAE. Travel speed is assumed based on the legal speed limit for large freight vehicles. Other assumptions are based on various data.

Assumptions on a satellite base

	LNG satellite base	Liquefied hydrogen satellite base	MCH satellite base	Ammonia satellite base
Tank capacity	40 kL	100 kL	MCH tank: 160 kL Toluene tank: 160 kL	70 kL
Vaporizer, etc.	130 Nm^3-CH_4/h	400 Nm^3-H_2/h	-	-
Dehydrogenation equipment	-	-	400 Nm^3-H_2/h	Hydrogen use: 400 Nm^3-H_2/h Ammonia use: N/A
Total equipment cost	JPY 63 million	JPY 14,000 million	JPY 191 million	JPY 13,500 million
Capacity factor	90%	90%	90%	90%
Equipment life span	30 years	30 years	30 years	30 years
Operation and maintenance cost ratio	4%	4%	4%	4%
Number of operators	5	5	5	5
Unit labor cost	JPY 6 million/person/year	JPY 6 million/person/year	JPY 6 million/person/year	JPY 6 million/person/year
Unit cost of water and sewerage (equivalent to hydrogen HHV)	JPY 0.36/Nm^3-H_2	JPY 0.36/Nm^3-H_2	JPY 0.36/Nm^3-H_2	JPY 0.36/Nm^3-H_2
Electricity	JPY 1.08/Nm^3-H_2	JPY 1.08/Nm^3-H_2	Estimated by dehydrogenation electricity consumption and electricity rate	Hydrogen use Trial estimation based on ammonia cracking electricity consumption and electricity rates Ammonia direct use JPY 1.08/Nm^3-H_2
Heat	-	-	Estimated with dehydrogenation heat consumption and gas price	Estimated ammonia cracking heat consumption and gas price

Source: The Institute of Applied Energy, "Research Report on Economic Evaluation of Synthetic Methane by

Methanation: Domestic Distribution."

Assumptions for natural gas pipeline utilization cost estimation

Item		Assumed value
Gas transportation volume	Monthly gas consignment volume (converted to m^3)	52,535,921 m^3-CH_4/month
	Outgoing gas volume	71,967 m^3/h
Gas consignment unit price	Basic rate	JPY 227,570 /month
	Basic flow rate	JPY 675/m^3・h
	Metered charge (winter)	JPY 1.72/m^3
	Metered charge (other)	JPY 1.36/m^3
	Additional metered rate unit price for low-pressure pipeline use	JPY 1.97/m^3

Source: Tokyo Gas, "Terms and Conditions of Retail Consigned Supply Service (Consigned Supply to be Paid at the Point of Demand)" (Type 2, Part 1)

Gas consignment charge calculation formula
Gas consignment charge = Basic charge + Basic flow rate * Maximum gas volume discharged + (Metered charge + Low pressure pipeline use) * Gas demand

CO_2 emission factor

Fuel	Emission coefficient
Renewable electricity	0
Natural gas	0.056kg-CO_2/MJ
Grid electricity in exporting country	0.236kg-CO_2/kWh
Ship fuel: Synthetic methane	0
Ship fuel: Hydrogen	0
Ship fuel: Fuel oil	0.072kg-CO_2/MJ (C heavy oil)
Ship fuel: Ammonia	0
Japan grid electricity	0.041kg-CO_2/kWh
Diesel	0.0686kg-CO_2/MJ
City gas (Japan)	0.050kg-CO_2/MJ

Source: Ministry of the Environment; IEA World Energy Outlook 2022, Announced Pledges Scenarios, 2040.

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