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Greenhouse Gas Emissions and Economic Analysis of e-methane in Japan and China

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Abstract: E-methane is considered the most important way to decarbonize the natural gas system in Japan. The advantage of e-methane is that it can use existing natural gas infrastructure and end-use facilities. There is a potential for China to produce e-methane and export it to Japan in the future. Therefore, the greenhouse gas (GHG) emissions and economic analysis of e-methane should be studied in both countries. The GHG emissions of e-methane are 0.927 kg-CO_2e per kg e-methane if all processes are powered by solar energy. The largest portion of GHG emissions from e-methane comes from hydrogen, which comprises more than 85% if solar energy is used for all processes. When solar energy is used to produce hydrogen, but grid electricity is used for other processes, the GHG emissions exceed the Europe Union's Renewable Liquid and Gaseous Transport Fuels of Non-Biological Origin (RFNBO) requirements, whether in Japan or in China. The levelized cost of e-methane produced in Japan is much higher than in China. The levelized cost of e-methane in Japan is 4489 USD/ton in the base case (2021), 2842 USD/ton in the 2030 case, and 1674 USD/ton in the 2050 case. In China, it is 2450 USD/ton, 1505 USD/ton, and 1082 USD/ton, respectively. The cost of hydrogen is the largest contributor to the levelized cost of e-methane, accounting for more than 60% in all cases. For China and Japan to cooperate in the value chain of e-methane, a carbon accounting mechanism and a carbon pricing mechanism mutually recognized by both Japan and China are necessary.

Keywords: e-methane; hydrogen; GHG emissions; economic analysis; comparison between Japan and China

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1. Introduction

Climate change is a growing threat to humanity. As early as 2015, all United Nations member states adopted the 2030 Agenda for Sustainable Development, which proposes 17 Sustainable Development Goals (SDGs), including climate action [1]. However, efforts to address climate change are far from sufficient. Zhang et al. (2025) found that "the global median action score in 2024 stands at only 25—far below the target of 65—highlighting the urgency for stronger efforts" [2]. More carbon-neutral technologies should be developed to mitigate global warming, with e-methane being one of the options.

Switching from coal and oil to natural gas is one way to reduce carbon emissions, but it is not enough to achieve carbon neutrality, because natural gas is still a type of fossil fuel, even though it emits less CO_2 than coal and oil when burned. E-methane, produced from renewable hydrogen and captured CO_2, is considered an important way to decarbonize the fossil natural gas system, especially in Japan. The main reason for this is that e-methane can use existing infrastructure and there is no need to change the end-use equipment. However,

even though the route of e-methane "does not involve any added cost or technical barrier at the gas infrastructure or end-use level, the main difficulties remain the low efficiency and the cost of the process itself due to the additional CO_2 capture and methanation steps required on top of hydrogen production" [3]. It is important for Japan to reduce the cost of e-methane domestically and import e-methane from other countries where it can be produced more cost-effectively.

Since China is the largest producer of renewable energy, there is a potential for e-methane to be produced in China and exported to Japan. Therefore, it is necessary to study the greenhouse gas (GHG) emissions of e-methane and the costs of e-methane in China and Japan. The GHG emissions of e-methane and the direct use of hydrogen are also compared in this paper. For economic analysis, the levelized cost of e-methane is studied and compared between China and Japan.

This paper consists of the following sections. Section 2 comprises the literature review, focusing on methanation and related feedstocks such as hydrogen and CO_2. Section 3 is the methodology, including the assumptions for GHG emissions and economic factors. Section 4 reports the results of GHG emissions and economics analyses of e-methane in Japan and China. Section 5 is the discussion, which includes future directions and suggestions. Section 6 is the conclusion.

2. Literature Review

Previous studies have mostly focused on techno-economic studies of methanation, especially those by scholars in Japan. Shibata (2016) analyzed the challenges for Japan to develop power-to-gas, such as the lack of surplus electricity in Japan, and suggested that the cost of electricity should be reduced for either hydrogen or synthetic natural gas (SNG) to equal the competing energy [4]. The Institute of Applied Energy (2018) in Japan studied the feasibility and economics of synthetic methane as a hydrogen carrier [5]. Otsuki and Shibata (2020) reported a techno-economic assessment of methanation in Japan [6], especially the potential amount of e-methane that can be introduced in Japan in different cases, but did not study the GHG emissions of e-methane in Japan. Morimoto et al. (2022) studied the economic feasibility and regional characteristics of methanization, focusing on the levelized cost of CO_2 [7]. Morimoto et al. (2022) [7] compared many countries and identified Indonesia as the optimal trading partner, but China was not analyzed. Kiani et al. (2021) studied the cost of liquefied e-methane from ambient CO_2 and renewable H_2, considering e-methane as a potential carrier for renewable H_2 [8], but the study did not consider the GHG emissions and was not based on Japan or China. Sternberg and Bardow (2016) studied the life cycle emissions of power-to-gas, including power-to-syngas and power-to-SNG (synthetic natural gas), i.e., e-methane [9], but the study did not consider direct air capture (DAC) as a source of CO_2. Singh et al. (2022) studied the technologies and costs of e-fuels, but did not include e-methane [10]. Other than e-methane, Tanaka and Hasanuzzaman (2022) conducted energy, economic, and environmental assessments of photocatalytic methane production in Japan and Malaysia [11].

Some scholars studied the GHG emissions and economics of hydrogen in China [12,13], but studies of the GHG emissions and the techno-economics of e-methane in China are very limited because e-methane is not considered as a way to decarbonize the energy system by the Chinese government policies and most companies have not paid enough attention to e-methane, unlike Japan. The 6th Strategic Energy Plan of Japan states that "It is aimed that in 2030, synthetic methane is injected 1% into the existing infrastructure to make 5% of gas carbon-neutralized with other means added, and in 2050, synthetic methane is injected 90% to make gas carbon-neutralized with other means added" [14]. In 2022, the natural gas

consumption of Japan was 100.5 billion cubic meters [15]. Considering that 90% of this will be replaced by e-methane in 2050, the market size for e-methane in Japan is quite large.

Regarding sources of CO_2, the International Energy Agency (IEA) has published reports on DAC [16], including for the cases of Japan and China. In short, previous studies have not discussed the potential of e-methane value chain cooperation between Japan and China, so no comparative study of e-methane in Japan and China has been conducted.

Therefore, the novelty of this paper is that it is the first comparative study between Japan and China of e-methane from the perspective of GHG emissions and economic analysis. The research question is as follows: What are the GHG emissions and economics of e-methane produced in Japan and in China, and are there opportunities for cooperation on e-methane between these two countries? For the economic analysis, the base case, the 2030 case, and the 2050 case are examined. By clearly identifying the GHG emissions and the economics of e-methane in these two neighboring countries, this study will contribute to the sustainable development of both countries and the world.

3. Methodology

3.1. Boundary

The boundary for calculating the GHG emissions of e-methane is from cradle to the production gate. When comparing the GHG emissions of e-methane and the direct use of hydrogen, the compression process and liquefaction process are also considered. The value chain of e-methane is shown in Figure 1.

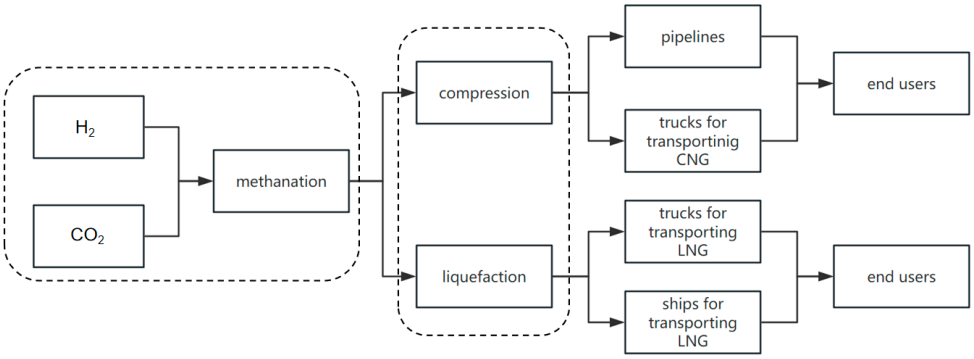

Figure 1. The value chain of e-methane.

In the economic analysis, the levelized cost of e-methane is calculated and compared. The costs of liquefied e-methane and liquefied hydrogen are also compared.

3.2. Data Assumptions

The data assumptions consist of two parts, assumptions for GHG emissions and assumptions for economic factors.

3.2.1. Data Assumptions for GHG Emissions

GHG Emissions of Producing H2 from Renewables

The hydrogen used to produce e-methane must be produced from renewables. The GHG emissions of hydrogen produced from solar power are higher than those from wind power because the emission factor of solar electricity is higher than that of wind electricity. In Japan, the emissions of electricity generated from solar power are estimated to be from 0.017 to 0.048 kg-CO_2e/kWh [17]. In Japan, the emission factors for wind power also vary. Imamura et al. (2016) calculated the emission factor for wind power and used 0.0257 kg-CO_2e/kWh as the average value for Japan [18]. Ando et al. (2009) estimated the emission factor of Japan's domestic 2 MW wind turbine to be 0.0108 kg-CO_2e/kWh [19].

In China, the emissions of electricity generated from solar power and wind power are estimated to be 0.03 kg-CO_2e/kWh and 0.01 kg-CO_2e/kWh, respectively [12]. This paper will mainly study the case of electricity generated by solar power plants. Since the emissions of electricity generated from solar power in Japan and China are generally in the same range, China's data are applied to both China and Japan. The electricity used to produce 1 kg of hydrogen reported by manufacturers ranges from 42.2 to 65.6 kWh/kg-H_2 [20], and 50 kWh/kg-H_2 is used in this paper. Therefore, the GHG emissions of hydrogen produced from solar energy are calculated as 1.5 kg-CO_2e/kg-H_2, as shown in Table 1.

Table 1. GHG emissions of hydrogen produced from solar energy.

	Emissions Factors of Electricity	**Electricity Needed to Produce 1 kg of H_2**	**GHG Emissions of Hydrogen**
Solar energy	0.03 CO_2e/kg-H_2	50 kWh/kg-H_2	1.5 kg-CO_2e/kg-H_2

GHG Emissions of Capturing CO_2

There are some debates about sources of CO_2 that can be used to produce e-methane. CO_2 from biomass and direct air capture (DAC) are qualified sources of CO_2 to produce e-fuel in Europe. According to the requirements of the Commission Delegated Regulation (EU) 2023/1185 on sources of CO_2 to produce Renewable Liquid and Gaseous Transport Fuels of Non-Biological Origin (RFNBO), CO_2 from fossil fuel power plants cannot be used after 2036, and CO_2 from fossil fuel industrial sources cannot be used after 2041 [21]. E-methane is also a form of RFNBO. Therefore, the EU regulations have set clear requirements for the CO_2 sources used to produce e-methane.

For scale-up reasons, DAC is preferred over biomass. In this paper, the source of CO_2 is assumed to be from DAC. The heat and electricity requirements for capturing 1 kg of CO_2 are 2.118–2.780 kWh and 0.440–0.494 kWh for the DAC-alkaline solution method, and are 1.400–2.777 kWh and 0.218–0.694 kWh for the DAC-adsorption method [22]. In this paper, the heat and electricity consumptions for capturing 1 kg of CO_2 are set at 2.5 kWh and 0.5 kWh, respectively, based on the range of the DAC-adsorption method, which is also consistent with data from companies such as Climeworks and ZSW [23]. The heat and electricity can be produced from low-carbon sources, e.g., Climeworks' Orca project in Iceland uses geothermal energy. In this paper, it is assumed that grid electricity is used to meet the demand for heat and electricity. Suppose the heat is provided by high-temperature industrial heat pumps that can produce heat up to about 100 °C. With a COP of 4, it takes 0.625 kWh of electricity to produce 2.5 kWh of heat. Therefore, the total energy required to capture 1 kg of CO_2 with DAC is 1.125 kWh, as shown in Table 2.

Table 2. Energy required to capture 1 kg of CO_2 with DAC.

	Amount
Heat	2.5 kWh (0.625 kWh of electricity is needed)
Electricity	0.5 kWh
Total	1.125 kWh

In this paper, these data are applied to both Japan and China because DAC projects in Japan and China are very rare and the commercial data are difficult to obtain.

GHG Emissions of the Methanation Process

The methanation process is shown in Equation (1). To produce 1 Nm^3 of methane, 1 Nm^3 of CO_2 and 4 Nm^3 of hydrogen are required.

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O\ \Delta H = -165\ kJ/mol \quad (1)$$

Using the density data of 0.717 kg/Nm^3 for methane, 1.977 kg/Nm^3 for CO_2, and 0.08988 kg/Nm^3 for hydrogen, it takes 2.757 kg of CO_2 and 0.501 kg of hydrogen to produce 1 kg of methane. In real operation, the conversion rates of CO_2 and H_2 to methane are influenced by the type of catalyst, temperature, pressure, equipment design, etc. The conversion rate of CO_2 to methane ranges from 85% to 99.8% under different conditions in the literature [24–26]. The conversion rate of H_2 is related to CO_2. In this paper, 92.5% is used for the conversion rate of CO_2 and H_2. Therefore, it takes 2.981 kg of CO_2 and 0.542 of hydrogen to produce 1kg of methane. The electricity required for the methanation process varies in the literature from 0.33 to 1.54 kWh/kg-methane [9,27,28]. In this paper, a datapoint of 0.446 kWh/kg-methane is used, which was converted from 0.32 kWh/Nm^3-methane [27]. A datapoint of 0.32 kWh/Nm^3-methane was "estimated from various materials [27]".

The main parameters of the methanation process are listed in Table 3.

Table 3. Main parameters used in CH_4 production (1 kg) by the Sabatier reaction.

Item	Unit	Amount
CO_2 input	Kg	2.981
H_2 input	Kg	0.542
Electricity input	kWh	0.446

This paper assumes that the tail gas is recycled and that there is no methane leakage to the atmosphere during this process, so only H_2 input, CO_2 input, and electricity input are considered in the calculation of the emissions from the methanation process. The GHG emissions from Japan's electricity are set at 0.421 kg-CO_2/kWh using the data of FY2023 [29]. The GHG emissions from China's electricity are set at 0.5366 kg-CO_2/kWh using the data for 2022 [30].

The equation to calculate the GHG emissions of e-methane is illustrated as follows.

$$Emission_{e\text{-}methane} = Q_{CO2} \times EF_{CO2} + Q_{H2} \times EF_{H2} + Q_{el} \times EF_{el} \quad (2)$$

where Q_{CO2} is the amount of CO_2 input, EF_{CO2} is the emission factor for CO_2 capture, Q_{H2} is the amount of H_2 input, EF_{H2} is the emission factor for H_2 production, Q_{el} is the power required for methanation, and EF_{el} is the emission factor for electricity generation.

GHG Emissions from Compression and Liquefaction of H_2 and CH_4

The energy consumption for the compression of CH_4 is related to the inlet pressure of CH_4. If the inlet pressure is low, more energy is required to compress the CH_4. Cylinder containers of methane are usually at a pressure of 20–25 MPa. In this paper, the electricity used to compress CH_4 is set at 0.25 kWh/m^3, with an inlet pressure of 1.6 MPa [31]. To compress 1 kg of methane from 1.6 MPa to 20 MPa, the electricity required is about 0.349 kWh/kg-CH_4, which is about 6.975 kWh/GJ. The energy required to liquefy methane is assumed to be 0.53 kWh/kg-CH_4 [32]. The compression and liquefaction of CH_4 are fairly mature technologies, so these parameters are applied to both Japan and China, as shown in Table 4.

Table 4. Electricity required for the compression and liquefaction of CH_4.

	Electricity Needed
Compression from 1.6 MPa to 20 MPa	0.349 kWh/kg-CH_4
Liquefaction of CH_4	0.53 kWh/kg-CH_4

Hydrogen requires significantly more energy to compress to the same pressure as methane, which is mainly due to its extremely low density [33]. The energy required to compress H_2 is also related to the inlet pressure of H_2. In this paper, the inlet pressure of H_2 is estimated to be 2 MPa because "theoretical calculations assume H_2 generated at 20 bar (290 psi) and 300 Kelvin before it is compressed and/or liquefied [34]". There are two types of target pressures for real use, 35 MPa (the corresponding refueling pressure is 44 MPa) and 70 MPa (the corresponding refueling pressure is 88 MPa). To compress 1 kg of hydrogen from 2 MPa to 44 MPa and from 2 MPa to 88 MPa, the electricity required is set at 2 kWh/kgH_2 and 2.9 kWh/kgH_2, respectively, based on data from Air Products [34]. For the liquefaction of H_2, the electricity needed is set at 12 kWh/kgH_2, based on existing medium scale plants (<50,000 kg/day) [34]. The compression and liquefaction of hydrogen are mature technologies, so these parameters are applied to both Japan and China, as shown in Table 5.

Table 5. Electricity required for the compression and liquefaction of H_2.

	Electricity Needed
Compression from 2 MPa to the refueling pressure of 44 MPa (for 35 MPa use)	2 kWh/kg-H_2
Compression from 2 MPa to the refueling pressure of 88 MPa (for 70 MPa use)	2.9 kWh/kg-H_2
Liquefaction of H_2	12 kWh/kg-H_2

3.2.2. Data Assumptions for Economic Factors

Cost of Hydrogen

There are various technological routes to produce hydrogen from renewable energy, including alkaline water electrolysis (ALK), proton exchange membrane (PEM) electrolysis, solid oxide electrolysis (SOEC), anion exchange membrane (AEM) electrolysis, etc. Since the PEM route is more adaptable to the fluctuations of renewable energy and is relatively mature, this paper will mainly study the PEM route.

This paper adopts the following assumptions for China, as carried out by a previous study [13], as shown in Table 6. The electricity is generated by solar power.

Table 6. The assumptions of the levelized cost of hydrogen produced by PEM electrolysis in China.

	Base (2021)	**2030**	**2050**
Cost (CNY)	3.56 CNY/Nm^3 [13]	1.41 CNY/Nm^3 [13]	0.72 CNY/Nm^3 [13]
Cost (USD) (USD 1 = CNY 6.45 in 2021)	0.55 USD/Nm^3	0.22 USD/Nm^3	0.11 USD/Nm^3
Annual reduction rate		9.68% (from 2021 to 2030)	3.41% (from 2030 to 2050)

According to Japan's Strategic Energy Plan released in October 2021, Japan aims to reduce the supply cost of hydrogen, which was sold at 100 JPY/Nm^3 at general hydrogen stations, to 30 JPY/Nm^3 in 2030, and to 20 JPY/Nm^3 or less in 2050 [14]. For 2030, this paper assumes that the levelized cost of hydrogen from PEM electrolysis in Japan is about 60 JPY/Nm^3, based on a previous study [35]. For 2021, this paper assumes that the levelized

cost of hydrogen from PEM electrolysis in Japan is about 100 JPY/Nm^3. For 2050, this paper assumes that the levelized cost of hydrogen from the PEM electrolysis in Japan is the same as Japan's national target, as shown in Table 7. After 2050, this paper assumes that the cost of hydrogen is the same as in 2050. Even under this assumption, the cost of hydrogen from PEM electrolysis in Japan is still higher than in China in 2030 and 2050.

Table 7. The levelized cost assumption of hydrogen produced by PEM electrolysis in Japan.

	Base (2021)	2030	2050
Cost (JPY)	100 JPY/Nm^3	60 JPY/Nm^3	20 JPY/Nm^3
Cost (USD) (USD 1 = JPY 109 in 2021)	0.92 USD/Nm^3	0.55 USD/Nm^3	0.18 USD/Nm^3
Annual reduction rate		5.56% (from 2021 to 2030)	5.43% (from 2030 to 2050)

Cost of CO_2 Captured from DAC

According to the International Energy Agency (IEA) DAC report, the levelized cost of CO_2 captured from solid DAC using direct heat (instead of waste heat) without a carbon price in China will be about USD 125–220 in 2030, and about 80–170 USD/tCO_2 in 2050; the cost in Japan will be about USD 170–270 in 2030, and about 130–210 USD/tCO_2 in 2050 [16]. The IEA report also predicts that the cost of CO_2 captured via DAC will decrease by 31–43% during 2020–2030. After 2050, this paper assumes that the cost of CO_2 will be the same as in 2050. The following assumptions are used in this paper, as shown in Table 8.

Table 8. The levelized cost assumption for CO_2 captured from solid DAC using direct heat without a carbon price.

	Base (2021)	2030	2050
China	254 USD/tCO_2	170 USD/tCO_2	125 USD/tCO_2
Annual reduction rate in China		4.36% (from 2021 to 2030)	1.53% (from 2030 to 2050)
Japan	328 USD/tCO_2	220 USD/tCO_2	170 USD/tCO_2
Annual reduction rate in Japan		4.34% (from 2021 to 2030)	1.28% (from 2030 to 2050)

Cost of Methanation

This paper assumes that the construction cost (including equipment) of methanation is 500,000 JPY/(Nm^3-CH_4/h) [6], which is about 4587 USD/(Nm^3-CH_4/h) using the exchange rate of USD 1 = JPY 109. For a plant with a production capacity of 400 Nm^3/h, which equals the capacity of Osaka Gas's e-methane project in Nagoya City, the CAPEX is estimated at USD 1.835 million using the factor of 4587 USD/(Nm^3-CH_4/h). The lifetime of the methanation equipment is assumed to be 20 years, as shown in Table 9. The cost of electricity is assumed to be the same for each year. The CAPEX is assumed to happen at the beginning of the first year.

For economy of scale, the scale factor is set at 0.7 in this paper. The CAPEX for a given capacity is calculated using the following formula. The production capacity targets in 2030 and in 2050 are set at 10,000 Nm^3/h and 60,000 Nm^3/h, respectively [38].

$$CAPEX_i = CAPEX_{base} \times \left(\frac{Capacity_{base}}{Capacity_i} \right)^{0.7} \quad (3)$$

where $Capacity_{base}$ is the base capacity, which in this paper is 400 Nm^3/h; $CAPEX_{base}$ is the CAPEX for the base capacity; $Capacity_i$ is the scaled capacity at a certain level; and $CAPEX_i$ is the CAPEX for $Capacity_i$.

The OPEX is calculated using the following formula.

$$OPEX = Cost_{ma} + Cost_{la} + Q_{H2} \times P_{H2} + Q_{CO2} \times P_{CO2} + Q_{el} \times P_{el} \quad (4)$$

where $Cost_{ma}$ is the maintenance cost, $Cost_{la}$ is the labor cost, Q_{H2} is the amount of H_2 required to produce e-methane, P_{H2} is the price of H_2, Q_{CO2} is the amount of CO_2 required to produce e-methane, P_{CO2} is the price of CO_2, Q_{el} is the amount of electricity required to produce e-methane, and P_{el} is the price of electricity.

The levelized cost of e-methane is calculated using the following formula.

$$Levelized\ cost = \frac{CAPEX + \sum_{t=1}^{20} \frac{(Cost_{ma} + Cost_{la})_t + Cost_{H2t} + Cost_{CO2t} + Cost_{elt}}{(1+r)^t}}{\sum_{t=1}^{20} \frac{PRD_t}{(1+r)^t}} \quad (5)$$

where $CAPEX$ is the total CAPEX, all of which is assumed to occur at the beginning of the first year in this paper, $Cost_{H2t}$ is the cost of hydrogen in year t, $Cost_{CO2t}$ is the cost of CO_2 in year t, r is the discount rate, which is set at 3% in this paper, and PRD_t is the production in year t.

Table 9. Base parameter assumptions for methanation.

	Base (2021)	Specifications
Capital expenditure (CAPEX)	USD 1.835 million	for a production capacity of 400 Nm^3/h
Annual maintenance cost	55,000 USD/year	3% of CAPEX [8]
Annual labor cost	16,500 USD/year	30% of maintenance cost [8]
Electricity price for industry in Japan	19.28 JPY/kWh [36] (0.177 USD/kWh)	using the exchange rate of USD 1 = JPY 109 in 2021
Electricity price for industry in China	0.635 CNY/kWh [37] (0.098 USD/kWh)	using the exchange rate of USD 1 = CNY 6.45 in 2021
H_2 cost in Japan	0.92 USD/Nm^3	
H_2 cost in China	0.55 USD/Nm^3	
CO_2 cost in Japan	328 USD/tCO_2	
CO_2 cost in China	254 USD/tCO_2	
Working hours	8000 h/year	
Lifetime	20 years	

4. Results

The results of the GHG emissions analysis and the economic analysis are presented in Sections 4.1 and 4.2.

4.1. Analysis of GHG Emissions

The analysis of GHG emissions consists of two parts, the GHG emissions of e-methane in different cases and the comparison of GHG emissions between hydrogen and e-methane.

4.1.1. The GHG Emissions of e-methane in Different Cases

The analysis of the GHG emissions of e-methane consists of two cases: all the electricity is produced from renewable energy, and only the hydrogen is produced from renewable energy and other inputs or processes use grid electricity.

GHG Emissions of e-methane When Using the Grid Electricity Except for Hydrogen

In this scenario, grid electricity is used to produce e-methane, except for the hydrogen production. Hydrogen is still produced from renewable energy. The emission factors of grid electricity in Japan and China are applied in this scenario. Since the emission factor of grid

electricity in Japan is lower than that in China, the GHG emissions of e-methane from cradle to production gate in Japan are also lower than those in China when grid electricity is used for all processes except hydrogen production. The GHG emissions of e-methane produced in Japan are 2.413 kg-CO_2e/kg-CH_4, which is 15% lower than e-methane produced in China, which are 2.852 kg-CO_2e/kg-CH_4. If using grid electricity except for hydrogen production, the largest part of GHG emissions of e-methane comes from CO_2, 58.5% in the case of Japan and 63.1% in the case of China. Please refer to Tables A1 and A2 in Appendix A for detailed information.

According to the EU's RFNBO requirements, the GHG emissions from cradle to grave cannot exceed 28.2 kg-CO_2e/GJ, which is equivalent to 1.565 kg-CO_2e/kg-CH_4 for methane. Therefore, using grid electricity to produce e-methane cannot meet the EU's RFNBO requirements.

The GHG Emissions of e-methane When Using Solar Energy for All Processes

When using solar energy for all processes, the majority of the GHG emissions of e-methane come from hydrogen. Hydrogen contributes 87.7% of the total GHG emissions, as shown in Table 10. In addition, using solar energy to produce e-methane could meet the EU's RFNBO requirements. Since the emission factor of wind energy is typically lower than that solar energy, using wind energy to produce e-methane would also meet the EU's RFNBO requirements.

Table 10. GHG emissions from the methanation process (1 kg of methane) using electricity generated from solar energy.

Item	Amount	Emission Factor	GHG Emissions (kg-CO_2e)
CO_2 input	2.981 kg	0.03375 kg-CO_2e/kg-CO_2e (1.125 kWh/kg × 0.03 kg-CO_2e/kWh)	0.101 (10.9%)
H_2 input	0.542 kg	1.5 kg-CO_2 e/kg-H_2	0.813 (87.7%)
Electricity input	0.446 kWh	0.03 kg-CO_2 e/kWh	0.013 (1.4%)
Total			0.927 (100%)

4.1.2. Comparison of the GHG Emissions Between Hydrogen and e-methane

It is easy to understand that the GHG emissions of hydrogen are lower than that of e-methane from cradle to production gate because the production of hydrogen is part of the production of e-methane. In this paper, the GHG emissions of e-methane are 48.3% higher than hydrogen using solar power, as shown in Table 11.

Table 11. Comparison of the GHG emissions between hydrogen and e-methane from cradle to production gate.

	GHG Emissions (Cradle to Production Gate)
H_2 produced from solar power	1.5 kg-CO_2e/kg-H_2 (12.5 kg-CO_2e/GJ-H_2)
E-methane (all electricity is from solar power)	0.927 kg-CO_2e/kg-CH_4 (18.54 kg-CO_2e/GJ-CH_4)

Considering compression or liquefaction using solar power, the difference between the total emissions of e-methane and hydrogen is reduced. Considering compression using solar power, the emissions of e-methane are 44.2% higher than hydrogen, as shown in Table 12. Considering liquefaction using solar power, the emissions of e-methane are only 21.7% higher than hydrogen when using solar power, which is because the liquefaction process of hydrogen requires much more energy than methane, as shown in Table 13.

Table 12. Comparison of the GHG emissions between hydrogen and e-methane from cradle to production gate + compression using solar power.

	GHG Emissions (Cradle to Production Gate)	Compression (Using Solar Power)	Total
H_2 produced from solar power	1.5 kg-CO_2e/kg-H_2 (12.5 kg-CO_2e/GJ)	2 kWh/kg-H_2 (0.5 kg-CO_2e/GJ)	13 kg-CO_2e/GJ
e-methane (all electricity is from solar power from cradle to production gate)	0.927 kg-CO_2e/kg-CH_4 (18.54 kg-CO_2e/GJ)	0.349 kWh/kg-CH_4 (0.209 kg-CO_2e/GJ)	18.75 kg-CO_2e/GJ

Table 13. Comparison of the GHG emissions between hydrogen and e-methane from cradle to production gate + liquefaction using solar power.

	GHG emissions (Cradle to Production Gate)	Liquefaction (Using Solar Power)	Total
H_2 produced from solar power	1.5 kg-CO_2e/kg-H_2 (12.5 kg-CO_2e/GJ)	12 kWh/kgH_2 (3 kg-CO_2e/GJ)	15.5 kg-CO_2e/GJ
e-methane (all electricity is from solar power from cradle to production gate)	0.927 kg-CO_2e/kg-CH_4 (18.54 kg-CO_2e/GJ-CH_4)	0.53 kWh/kgCH_4 (0.318 kg-CO_2e/GJ)	18.86 kg-CO_2e/GJ

However, if the compression or liquefaction uses grid electricity, with other factors being equal, the results will be different. Using the emission factor of grid electricity in Japan, the total emissions of hydrogen and e-methane are almost the same when compression is considered, and the total emissions of hydrogen will far exceed e-methane when liquefaction is considered. Please refer to Tables A3 and A4 in Appendix A for detailed information. The results are similar when using the emission factor for grid electricity in China, which is not discussed to avoid redundancy.

The advantage of e-methane is that existing natural gas infrastructure and end-use facilities can be used. Considering the GHG emissions of building new infrastructure, the emissions of using hydrogen may exceed those of e-methane, especially in the short term. However, if hydrogen can be used on-site, the direct use of hydrogen emits fewer greenhouse gases than e-methane. Renewable electricity should also be used to compress or liquefy hydrogen to keep the emissions low.

4.2. Economic Analysis

4.2.1. The Levelized Costs of e-methane in Japan and China

The levelized costs of e-methane in Japan are 4489 USD/t (3.22 USD/Nm^3), 2842 USD/t (2.04 USD/Nm^3), and 1674 USD/t (1.20 USD/Nm^3) for the base case, the 2030 case, and the 2050 case, and 2450 USD/t (1.76 USD/Nm^3), 1505 USD/t (1.08 USD/Nm^3), and 1082 USD/t (0.78 USD/Nm^3) for China, as shown in Tables 14 and 15. Please also refer to Tables A5–A7 in Appendix B for detailed information.

Table 14. The levelized cost of e-methane in Japan.

	Base (2021)	2030	2050
Capacity (Nm^3/h)	400	10,000	60,000
Total cost (USD)	153,216,328	2,425,458,195	8,569,758,849
Present value of production (t)	34,135	853,372	5,120,232
Levelized cost of methanation (USD/t)	4489	2842	1674
Levelized cost of methanation (USD/Nm^3)	3.22	2.04	1.20

Table 15. The levelized cost of e-methane in China.

	Base (2021)	2030	2050
Capacity (Nm^3/h)	400	10,000	60,000
Total cost (USD)	83,629,713	1,284,519,224	5,542,181,931
Present value of production (t)	34,135	853,372	5,120,232
Levelized cost of e-methane (USD/t)	2450	1505	1082
Levelized cost of e-methane (USD/Nm^3)	1.76	1.08	0.78

The levelized costs of e-methane in Japan and China are compared as in Figure 2. The levelized cost of e-methane in Japan is higher than in China in every case. In the base case, the levelized cost of e-methane in Japan is 1.83 times the cost in China. Even in the 2050 case, the levelized cost of e-methane in Japan is still 1.55 times the cost in China. No data are available on the shipping cost of LNG from China to Japan, because it is very rare for LNG to be shipped from China to Japan. The average shipping cost of LNG from Gladstone, Australia, to Tokyo, Japan, is estimated to be 0.821 USD/MMBtu from 2022 to 2027 [39], which is equivalent to 42.7 USD/t LNG. As the distance between China and Japan is much shorter than from Australia to Japan, the shipping cost should be much lower than 42.7 USD/t. Considering the high cost of e-methane, the shipping cost is very small, less than 5% of the cost of e-methane in China in the 2050 case. Therefore, even with shipping cost, the cost of e-methane in China is still cheaper than in Japan. In other words, it is much more cost-effective to produce e-methane in China and ship it to Japan. Therefore, there are opportunities for cooperation between these two countries on e-methane.

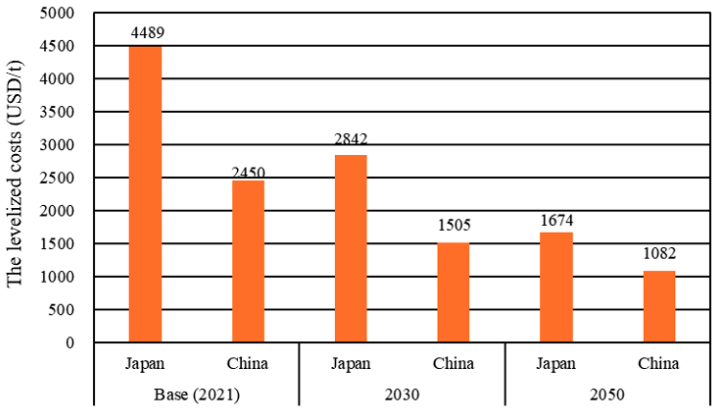

Figure 2. The levelized costs of e-methane in Japan and China.

The levelized cost of e-methane is much higher than the current price of natural gas. The natural gas price fluctuates within a fairly wide range. The Japan/Korea Marker (JKM) monthly prices ranged within 8.37–14.93 USD/MMBTU in 2024 [40], which is about 441–786 USD/t of natural gas, or 0.32–0.56 USD/Nm^3 of natural gas. The monthly JKM price reached as high as 53.95 USD/MMBTU in August 2022 due to the war between Russia and Ukraine, which is about 2837 USD/t, or 2.03 USD/Nm^3. In the base case, the levelized cost of e-methane in Japan is 5.71–10.18 times the JKM monthly prices in 2024, which is 3.12–5.56 times in China's case. Even in the 2050 case, the levelized cost of e-methane in Japan is still 2.13–3.80 times the JKM monthly prices in 2024, which is about 1.38–2.45 times in China's case. The levelized costs of e-methane in China are in all cases lower than the extremely high natural gas price in August 2022. The levelized costs of e-methane in Japan in the 2030 case and the 2050 case are lower than the natural gas price in August 2022.

Therefore, without a carbon price, e-methane is not as cost-effective as natural gas, except in extreme cases such as war.

The cost of hydrogen accounts for the largest share of the levelized cost of e-methane, followed by the share of CO_2 cost, as shown in Figure 3. The shares of the hydrogen cost are 80.1% in the base case, 76.2% in the 2030 case, and 64.9% in the 2050 case for Japan, and 71.8%, 66.9%, and 61.3% for China. The shares of the CO_2 cost are 16.3% in the base case, 20.7% in the 2030 case, and 30.3% in the 2050 case for Japan, and 22.9%, 29.6%, and 34.4% for China. The share of electricity cost is quite small but will increase when the price of electricity stays the same and the prices of hydrogen and CO_2 decrease. And the share of CAPEX is also quite small due to the 20-year lifetime and will decrease as the CAPEX per unit decreases. Therefore, the key to reducing the levelized cost of e-methane is to reduce the cost of hydrogen.

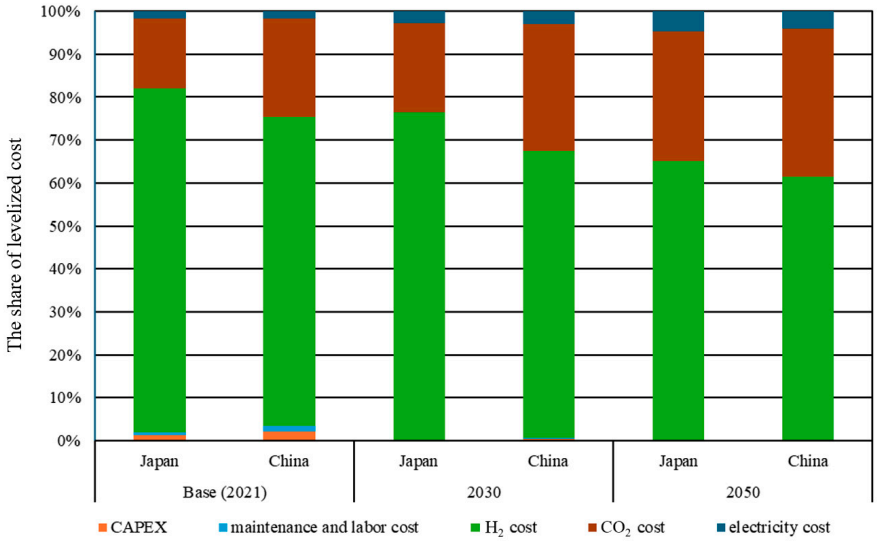

Figure 3. The internal share of levelized cost of e-methane in Japan and China.

The development of the hydrogen industry in Japan and China is slow due to the high cost of hydrogen. The hydrogen infrastructure is underdeveloped and the willingness of industrial and commercial end users to use hydrogen is low. Reducing the cost of hydrogen through scale-up will require a strong government commitment to carbon neutrality and supportive greenhouse gas reduction policies and market mechanisms that drive the demand side to accelerate the adoption of hydrogen projects and thereby influence production. In other words, if the cost of hydrogen cannot come down fast enough, both the hydrogen industry and the e-methane industry, as well as other hydrogen-based industries, cannot enter the mass production phase. The affordability of hydrogen and e-methane is also closely linked to economic development. The growth of the world's economies is facing great uncertainties, which pose challenges for the development of hydrogen and e-methane.

4.2.2. Comparison Between the Cost of e-methane and Hydrogen

The Lower Heating Value (LHV) of methane is about 3.3 times the LHV of hydrogen of the same volume. If comparing the levelized cost of hydrogen and the price of natural gas based on the same heating value, the cost of hydrogen is generally much higher than natural gas. But since the levelized cost of e-methane is much higher than the price of natural gas in general, as shown in Section 4.2.1, the cost of hydrogen is almost the same as that of e-methane in the base case of this paper. Since the levelized cost of hydrogen decreases at a higher rate than e-methane, the levelized cost of hydrogen is lower than that of e-methane in the 2030 case and the 2050 case, especially the 2050 case. In the 2050 case,

the levelized cost of hydrogen is 10.2 USD/GJ in China and 16.7 USD/GJ in Japan, and the levelized cost of e-methane is 21.7 USD/GJ in China, and 33.5 USD/GJ in Japan, as shown in Table 16.

Table 16. Comparison between hydrogen and e-methane cost in China and Japan.

Unit: USD/GJ		Base (2021)	2030	2050
China	hydrogen	50.9	20.4	10.2
	e-methane	49.1	30.1	21.7
Japan	hydrogen	85.2	50.9	16.7
	e-methane	89.9	56.9	33.5

The liquefaction cost of methane is estimated at 2.8 USD/GJ [8]. The liquefaction cost of hydrogen is estimated at 2.1 USD/kg-H_2 [8], or 17.5 USD/GJ. Considering that the liquefaction cost of hydrogen is much higher than that of methane, the cost of liquefied hydrogen is higher than that of liquefied e-methane in the 2050 case for China, and only a slightly lower than that of liquefied e-methane in the 2050 case for Japan. For example, in the 2050 case, the cost of liquefied hydrogen is 27.7 USD/GJ, and the cost of liquefied methane is 24.5 USD/GJ in China. In the 2050 case, the cost of liquefied hydrogen is 34.2 USD/GJ, and the cost of liquefied methane is 36.3 USD/GJ in Japan. Therefore, from the perspective of economics, hydrogen should be produced and used as near as possible to avoid the need for liquefaction. In addition, this result shows that it is more cost-effective to ship liquefied methane from China to Japan, rather than shipping liquefied hydrogen. China has many LNG import terminals. These terminals can be repurposed and converted to exporting terminals in the future if necessary. Therefore, infrastructure is not a big problem for China to export e-methane to Japan.

5. Discussion

As the number of methanation projects and DAC projects in Japan and China is still very limited, the number of PEM hydrogen projects is just starting to increase, and the data may not be disclosed for commercial reasons, the calculations in this paper are mostly based on assumptions from the literature. As more real data from projects are disclosed in the future, the calculation will become more informative.

It is recommended that both Japan and China should develop their standards for renewable hydrogen and e-methane. In Japan, there is only a low-carbon hydrogen standard. The low-carbon hydrogen standard of Japan is 3.4 kg-CO_2e/kg-H_2 from cradle to production gate, which is set in the Basic Energy Strategy of Japan. In China, there is no national standard in China for renewable hydrogen at present. There is only a group standard set by the China Hydrogen Alliance, which sets the renewable hydrogen standard at 4.9 kg-CO_2e/kg-H_2 from cradle to production gate. The GHG emissions threshold of these standards cannot reflect the actual emissions of renewable hydrogen. In addition, without a standard on e-methane, the credibility of the carbon reduction effect of e-methane will be compromised. The EU's RFNBO requirements are good references for the development of renewable hydrogen and e-methane standards for both Japan and China.

Cooperation between public and private sectors is also important. The key challenge for the scaling up of e-methane technology is to reduce the high cost of e-methane. In China, there is no incentive policy or even a guiding policy for e-methane. In Japan, the Ministry of Economy, Trade and Industry (METI) of Japan has established the Green Innovation Fund, which is managed by the New Energy and Industrial Technology Development Organization (NEDO). E-methane is one of the directions supported by NEDO [41]. In China, there is boom in the development of e-methanol, but e-methanol cannot be used

to decarbonize the natural gas system. In order to catch up with Japan on e-methane technologies, decarbonize the gas system in China, and seize the opportunity for cooperation with Japan on e-methane, China should also consider introducing incentive policies for e-methane.

The carbon price is not considered in this paper. There is no carbon accounting mechanism or carbon pricing mechanism that is mutually recognized between Japan and China. For China to produce e-methane on a large scale and export it to Japan and for the e-methane to be as cost-effective as natural gas in the future, a carbon accounting mechanism and a carbon pricing mechanism that are mutually recognized between the two countries are needed. To this end, government agencies, research institutions, and industry in both countries should increase dialog and explore opportunities for cooperation. Japan has published policies and targets for the development of e-methane. This provides a basis for dialog and cooperation between the two countries.

Cooperation between Japan and China on e-methane is not a zero-sum game. China has a comparative advantage in mass production, and Japan has advanced technologies in e-methane. Japan is the market for e-methane consumption in the foreseeable future, but China also has the potential to become the market for e-methane as the demands for decarbonization increase. For example, China has already started to build "zero-carbon" industrial parks and plants, which will accelerate the application of all kinds of clean energy. Finally, a stable relationship between the two countries is also crucial for energy cooperation on energy sources such as e-methane. One of the reasons that some Japanese companies are looking for e-methane cooperation opportunities in countries other than China is that they are worried about the relationship between the two countries. This issue is unavoidable and should be addressed by both countries.

6. Conclusions

This paper is the first comparative study on the greenhouse gas emissions and economics of e-methane between Japan and China. This paper is a theoretical analysis, but the findings of this paper clearly show that there are opportunities for cooperation between Japan and China and can be used to raise the awareness of policymakers, enterprises, research institutions, investors, traders, and other relevant stakeholders in Japan and China.

For GHG emissions, if solar energy is used for all processes to produce e-methane, the majority of the GHG emissions of e-methane come from hydrogen, at 87.7%. If e-methane is produced by using grid electricity except for hydrogen, which is still produced by solar energy, most of the GHG emissions of e-methane come from CO_2. If the methanation process uses grid electricity, the e-methane produced in Japan is cleaner than that in China because the emission factor of grid electricity in Japan is lower than that in China. However, using grid electricity to produce e-methane in either Japan or in China does not meet the EU's RFNBO requirements.

In most cases, the GHG emissions of hydrogen will be lower than those of e-methane. However, the GHG emissions of liquefied hydrogen may exceed those of e-methane if the liquefaction process uses grid electricity. Therefore, the direct use of hydrogen should be applied to on-site cases or cases where the locations of hydrogen production and the end use of hydrogen are within a short distance.

For economic analysis, the levelized cost of e-methane is much higher than that of fossil natural gas using hydrogen produced from the PEM pathway and CO_2 from DAC. The levelized cost of e-methane in China in the 2050 case is still about 1.38–2.45 times the JKM monthly natural gas prices in 2024, and 2.13–3.80 times in Japan's case. Hydrogen is the largest contributor to the levelized cost of e-methane, above 60% in all cases, with CO_2

being the second largest contributor. Therefore, reducing the cost of hydrogen is critical for reducing the cost of e-methane.

The levelized cost of hydrogen is almost the same as that of e-methane for the same heating value in the base case, but lower than that of e-methane in the 2030 case and the 2050 case. This is because the cost of hydrogen decreases at a faster rate than the cost e-methane. When liquefaction is considered, the cost of liquefied hydrogen is higher than that of liquefied e-methane in most cases. Therefore, from an economic point of view, hydrogen should also be produced and used within a short distance, and it is more economical to ship liquefied e-methane from China to Japan than liquefied hydrogen.

It is more cost-effective to produce e-methane in China and export it to Japan. But for China to export e-methane to Japan, a carbon accounting mechanism and a carbon pricing mechanism that are mutually recognized by both Japan and China are necessary. Dialog on these issues between the two countries should begin as soon as possible.

Although there are some challenges and uncertainties, the potential for cooperation between Japan and China in the field of e-methane is huge when leveraging the comparative advantages of both countries. Opportunities for cooperation between the two countries should be explored and expanded.

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Appendix A

The GHG emissions from the methanation process in Japan and China using grid electricity except for hydrogen are listed as follows.

Table A1. GHG emissions from the methanation process (1 kg of methane) in Japan using grid electricity except for hydrogen.

Item	Amount	Emission Factor	GHG Emissions (kg-CO_2e)
CO_2 input	2.981 kg	0.4736 kg-CO_2e/kg-CO_2e (1.125kWh/kg × 0.421 kg-CO_2e/kWh)	1.412 (58.5%)
H_2 input	0.542 kg	1.5 kg-CO_2 e/kg-H_2	0.813 (33.7%)
Electricity input	0.446 kWh	0.421 kg-CO_2 e/kWh	0.188 (7.8%)
Total			2.413 (100%)

Table A2. GHG emissions from the methanation process (1 kg of methane) in China using grid electricity except for hydrogen.

Item	Amount	Emission Factor	GHG Emissions (kg-CO_2e)
CO_2 input	2.981 kg	0.6037 kg-CO_2e/kg-CO_2e (1.125kWh/kg × 0.5366 kg-CO_2e/kWh)	1.800 (63.1%)
H_2 input	0.542 kg	1.5 kg-CO_2 e/kg-H_2	0.813 (28.5%)
Electricity input	0.446 kWh	0.5366 kg-CO_2 e/kWh	0.239 (8.4%)
Total			2.852 (100%)

A comparison of the GHG emissions between hydrogen and e-methane from cradle to production gate considering compression and liquefaction using grid electricity are listed as follows.

Table A3. Comparison of the GHG emissions between hydrogen and e-methane from cradle to production gate + compression using grid electricity.

	GHG Emissions (Cradle to Production Gate)	Compression (Using Grid Electricity in Japan)	Total
H_2 produced from solar power	1.5 kg-CO_2e/kg-H_2 (12.5 kg-CO_2e/GJ)	2 kWh/kgH_2 (7.02 kg-CO_2e/GJ)	19.52 kg-CO_2e/GJ
E-methane (all electricity is from solar power from cradle to production gate)	0.927 kg-CO_2e/kg-CH_4 (18.54 kg-CO_2e/GJ)	0.349 kWh/kg-CH_4 (2.94 kg-CO_2e/GJ)	21.48 kg-CO_2e/GJ

Table A4. Comparison of the GHG emissions between hydrogen and e-methane from cradle to production gate + liquefaction using grid electricity.

	GHG Emissions (Cradle to Production Gate)	Liquefaction (Using Grid Electricity in Japan)	Total
H_2 produced from solar power	1.5 kg-CO_2e/kg-H_2 (12.5 kg-CO_2e/GJ)	12 kWh/kgH_2 (42.1 kg-CO_2e/GJ)	54.6 kg-CO_2e/GJ
E-methane (all electricity is from solar power from cradle to production gate)	0.927 kg-CO_2e/kg-CH_4 (18.54 kg-CO_2e/GJ-CH_4)	0.53 kWh/kgCH_4 (4.46 kg-CO_2e/GJ)	23.00 kg-CO_2e/GJ

Appendix B

The CAPEX and the present value of maintenance and labor cost of methanation are as follows. The base case uses parameters for 2021. The CAPEX per unit decreases as the capacity becomes much larger in the 2030 case and the 2050 case, but the total CAPEX still increases. In this paper, it is assumed that all CAPEX happens at the beginning of the first year, so the present value of CAPEX is the same as CAPEX. It should be noted that in the base case, the lifetime of the methanation project is 2021–2040; in the 2030 case, the lifetime of the methanation project is 2030–2049; in the 2050 case, the lifetime of the methanation project is 2050–2069. In this paper, the following parameters and results are applied to both Japan and China.

Table A5. The CAPEX and the present value of maintenance and labor cost of methanation.

	Base (2021)	2030	2050
Capacity (Nm^3/h)	400	10,000	60,000
CAPEX per unit (USD/(Nm^3-CH_4/h))	4587	482	137
CAPEX (USD)	1,834,862	4,819,317	8,249,562
Present value of maintenance and labor cost	1,064,627	2,796,271	4,786,573

The present values of fuels, including electricity, are as follows. It should be noted that when calculating the present values of H_2 and CO_2, the costs of H_2 and CO_2 decrease over time and the rate of decrease is not the same in the 2021–2030 period as in the 2030–2050 period, as introduced in Sections Cost of Hydrogen and Cost of CO_2 Captured from DAC.

Table A6. The present values of fuels in Japan.

	Base (2021)	2030	2050
Capacity (Nm^3/h)	400	10,000	60,000
Present value of production	34,135	853,372	5,120,232
Present value of H_2	122,719,053	1,847,658,783	5,557,741,537
Present value of CO_2	24,903,110	502,816,935	2,594,779,843
Present value of electricity	2,694,676	67,366,889	404,201,335

Table A7. The present values of fuels in China.

	Base (2021)	2030	2050
Capacity (Nm^3/h)	400	10,000	60,000
Present value of production	34,135	853,372	5,120,232
Present value of H_2	60,059,164	858,757,775	3,396,397,606
Present value of CO_2	19,172,248	380,675,555	1,907,926,355
Present value of electricity	1,498,812	37,470,306	224,821,835

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