# Feasibility Study on Synthetic Methane Using an Electricity and City Gas Supply Model

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***Abstract***

Methane synthesis, or methanation, is attracting much attention in the context of sector integration and climate change mitigation. This study presents a techno-economic assessment on synthetic methane in Japan employing an electricity and city gas supply model. This model, formulated as a linear programming problem, explicitly considers a carbon recycling system, including carbon capture, water electrolysis and Sabatier reaction process. The electricity sector in this model is temporally disaggregated, balancing hourly consumption and supply for a year, to incorporate the intermittent output of solar and wind power (Variable Renewable Energy = VRE). Simulation results imply that to accelerate the use of synthetic methane, it would be crucial to reduce the cost of renewables combined with a high carbon price, such as 75% cost reduction of VRE (from the level in 2014) and 750 US$/t$CO_2$. The results also imply that a significant amount of VRE capacity would be necessary to decarbonize both sectors, which would pose grid operation and social (such as land-use) challenges.

***Key words:*** Synthetic methane, Carbon recycling, Variable renewables, Water electrolysis, Carbon price

## 1. Introduction

Amid the debate on which path to take for easing climate change, “carbon recycling” is being proposed as a means for decarbonization.[1)] Carbon recycling is an approach which aims to achieve the cyclical use of $CO_2$ by treating it as a natural resource, namely by separating and capturing $CO_2$ from power plants, industrial plants, the atmosphere, etc. and sequestering or recycling it as a raw material or fuel. One method of carbon recycling is methane synthesis. As methane is the main component of natural gas and city gas, methane synthesis is raising hopes for the effective use of existing energy supply infrastructure (LNG tankers, city gas pipelines, gas-fired thermal power plants, etc.), sector integration of the electricity and city gas sectors through water electrolysis, and decarbonization. Furthermore, methane synthesis using hydrogen from domestic renewable energy would help improve Japan’s energy self-sufficiency ratio, though the amount of hydrogen output may vary depending on the climate and other natural conditions. Despite such expectations, however, there have been few feasibility studies on introducing methane synthesis. This study developed an optimization model that treats the electricity and city gas sectors of Japan collectively, and conducted a quantitative assessment of the economic rationality and conditions for introducing a carbon recycling system consisting of $CO_2$ capture, water electrolysis, and methane synthesis. Specifically, the study performed a sensitivity analysis of carbon tax rates and solar and wind power costs, and considered the levels necessary for introducing large amounts of synthetic methane.

## 2. Method of study

### 2.1 Overview of the model

This study developed a multiregional, high time-resolution, and optimized electricity and city gas supply model for Japan. The model is a single-year model which calculates the cost-optimized power mix and city gas mix[1] (imported natural gas or synthetic methane) for a given electricity and city gas demand. Nine target regions were identified based on the present electricity supply areas of Japan (Hokkaido, Tohoku, Tokyo, Chubu, Hokuriku, Kansai, Chugoku, Shikoku, Kyushu, and Okinawa). The time resolution was set to one hour (8,760 one-hour slots per year), and fluctuations in solar and wind power output, operation of the water electrolysis equipment, and timing of $CO_2$ generation from power generation were explicitly considered. The details of the formula are not included here due to lack of space.

The flows in the model are outlined in **Fig. 1** (those related to $CO_2$ are indicated in red). In the model, the supply-demand balance of electricity, hydrogen, methane, $CO_2$ from electricity, and $CO_2$ from industry is secured in the 8,760 time slots of a year. Fourteen types of power generation-related technologies (solar, wind power, hydropower, nuclear, coal-fired thermal, oil-fired thermal, gas steam, combined cycle gas turbine, hydrogen turbine,

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[1] City gas can contain methane, ethane, propane, and butane, but only methane is considered in this report for simplicity.

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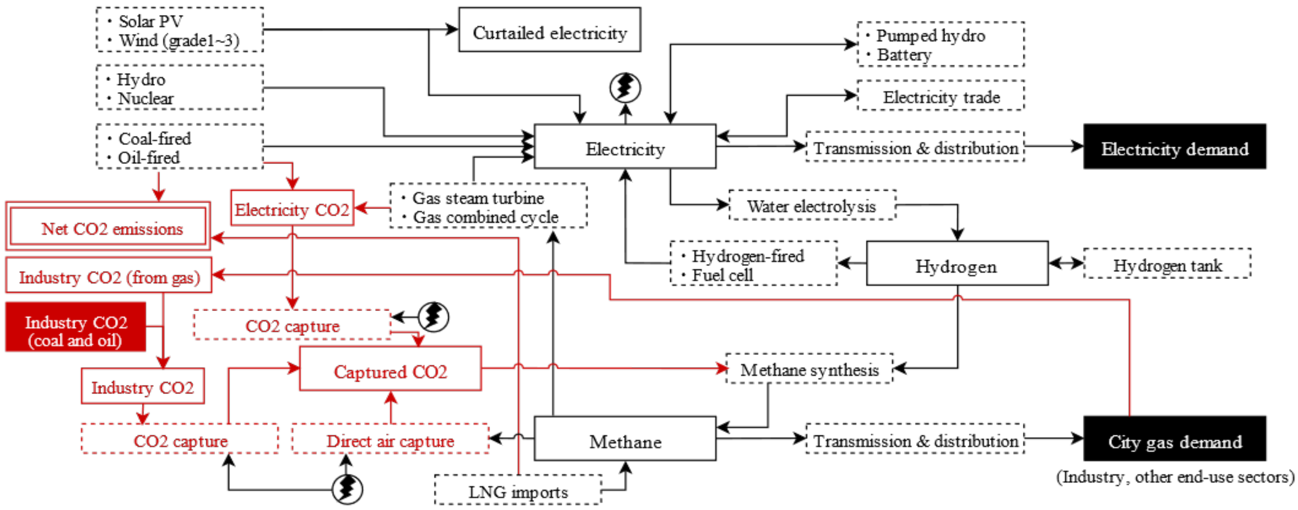



**Fig. 1** Overview of the flows of energy and $CO_2$ of the electricity and city gas supply model

**Table 1** Assumptions for the power generation and storage technologies

a. Thermal power plants

| | Coal-fired | CCGT | Gas ST | Oil-fired | Nuclear | $H_2$ turbine | Fuel cell |
|---|---|---|---|---|---|---|---|
| Construction cost [US$/kW] | 2500 | 1200 | 1200 | 2000 | 4297 | 1200 | 2500 |
| Lifetime [year] | 40 | 40 | 40 | 40 | 40 | 40 | 20 |
| Annual O&M cost rate | 0.03 | 0.02 | 0.02 | 0.03 | 0.04 | 0.02 | 0.01 |
| Fuel cost [US$/toe] | 136 | LNG import price: 396; Synthetic methane cost is determined endogenously | | 592 | 19 | $H_2$ cost is determined endogenously | |
| Efficiency | 0.41 | 0.56 | 0.42 | 0.39 | 1.00 | 0.56 | 0.50 |
| Own consumption rate | 0.06 | 0.02 | 0.02 | 0.05 | 0.04 | 0.02 | 0.02 |
| Availability | 0.90 | 0.90 | 0.90 | 0.90 | 0.90 | 0.90 | 0.90 |
| Maximum ramp-up rate | 0.26 | 0.44 | 0.44 | 0.44 | 0.00 | 0.44 | |
| Maximum ramp-down rate | 0.31 | 0.31 | 0.31 | 0.31 | 0.00 | 0.31 | |
| Minimum output rate | 0.30 | 0.20 | 0.20 | 0.30 | 0.80 | 0.20 | |

b. Renewables

| | Hydro | Solar | Wind 1~3 |
|---|---|---|---|
| Construction cost [US$/kW] | 6400 | 2940 | 2840 |
| Lifetime [year] | 60 | 20 | 20 |
| Annual O&M cost rate | 0.01 | 0.01 | 0.02 |

c. Storage

| | Pumped | Battery |
|---|---|---|
| Construction cost [US$/kWh] | 230 | 170 |
| Lifetime [year] | 60 | 15 |
| Annual O&M cost rate | 0.01 | 0.01 |
| Cycle efficiency | 0.70 | 0.85 |
| Self-discharge rate | 0.0001 | 0.001 |
| KWh/kW ratio | 6 | 6 |

fuel cell, pumped storage hydropower, battery, inter-regional transmission, and intra-regional distribution), two hydrogen production and storage technologies (water electrolysis and compressed hydrogen tank), three sources of methane supply (imported LNG, methanation, and intra-regional distribution), and $CO_2$ capture in the electricity and industrial sectors and direct air capture (DAC) were taken into consideration. As for the inter-regional exchange of energy, only electricity was incorporated into the model (inter-regional transport of hydrogen, methane, and $CO_2$ were not considered). Only onshore wind power was considered for wind power.

## 2.2 Major assumptions

(1) Demand for electricity and city gas

The necessary assumptions for the electricity and city gas demand for each region and hour were set in the model as follows. First, as the annual demand for electricity and city gas in the entire Japan, the 2040 values from the Sustainable Development Scenario (SDS) of the IEA's World Energy Outlook 2018[2)] were used for reference. This equals an electricity demand of 927 TWh/year and a city gas demand of 29 Mtoe/year. Then, these values were allotted to each prefecture in proportion to the size of actual demand[3)], to set the annual demand for each of the model's nine regions. Last, the electricity demand was broken down into hourly values based on the load curve for FY2017. The city gas demand was assumed to be constant year-round as an hourly demand curve data was unavailable.

(2) Power generation and storage technologies and inter-regional transmission lines

The assumptions for power generation and storage technologies are described in **Table 1**. The construction cost, lifetime, operation & maintenance (O&M) cost, generation efficiency, on-site consumption rate, and output adjustment capability were determined by referring to the Ministry of Economy, Trade and Industry[4)] and Sugiyama[5)], and the same values were applied to all regions (exchange rate: US$1 = 100 yen; generation efficiency and the amount of heat of a fuel are expressed on a low calorific value basis). The construction cost for a 2014 model plant[4)] was adopted as the unit construction cost. The construction cost for solar and wind power plants may decrease in the future, and therefore the assessments in this study factored in possible future cost reductions, as shown in Section 2.3.

**Table 2** Assumptions for water electrolysis and the compressed hydrogen tank

| | Electrolyzer | Hydrogen tank |
|---|---|---|
| Construction cost | 700 US$/kW | 700 US$/kW for compressor; 15 US$/kWh for storage tank |
| Lifetime [year] | 20 | 15 |
| Annual O&M cost rate | 0.01 | 0.01 |
| Efficiency | 0.70 | 0.9 (cycle efficiency) |

**Table 3** Assumptions for methane synthesis

| | | $CH_4$ synthesis |
|---|---|---|
| Annualized construction cost [US$/(toe/year)] | | 100 |
| Input | Hydrogen [toe] | 1.2 |
| | $CO_2$ [$tCO_2$] | 2.3 |
| | Electricity [MWh] | 0.37 |

**Table 4** Assumptions for the $CO_2$ capture equipment

| | | $CO_2$ capture | | Direct Air Capture |
|---|---|---|---|---|
| | | Power plant | Industry | |
| Annualized construction cost [US$/($tCO_2$/year)] | | 42 | 42 | 195 |
| Input | Electricity [MWh/$tCO_2$] | 0.22 | 0.22 | 0.37 |
| | Methane [toe/$tCO_2$] | -- | -- | 0.125 |

The fuel costs were set based on the 2040 values of the IEEJ[6], and the loss from intra-regional distribution was estimated at 7.6%. For the installed capacity of each power generation and storage technology, the actual 2016 value was adopted as the lower limit and was determined through optimization calculation, except for hydropower, nuclear, and pumped-storage hydropower. The installed capacities of hydropower, nuclear, and pumped-storage hydropower were set to their FY2016 capacities. Nuclear power was assumed to be operable.

The output waveform for solar and wind power (hourly values) for major cities in each region was derived from the reference source[7]. Wind power was divided into three resource grades (G1–G3), each with a different capacity factor and amount of resource. The resource grades were defined as follows: G1 has a capacity factor of 20% or lower, G2 has 20–30%, and G3 has 30% or more. The amount of resource for each grade was set according to the data from the Ministry of the Environment[8].

The installed capacity of inter-regional transmission lines was set to the actual value for 2016[9] (external variables) for all lines. Various factors must be taken into account regarding the operation of inter-regional transmission lines, such as maintaining heat capacity and frequency and synchronous stability, but in this study, the upper limit of operational capacity was capped based on OCCTO[9].

(3) Hydrogen production and storage technologies

The assumptions for water electrolysis and compressed hydrogen tank were set based on FCHJU[10] and Komiyama[11] (**Table 2**). The formula for the compressed hydrogen tank in this model is set separately for the compressor and the storage tank. The ratio of installed capacity of those components is determined through optimization calculations.

(4) Methane synthesis

The Sabatier reaction process was adopted as the methane synthesis process. This is a chemical reaction which produces 1 $Nm^3$ of methane and 2 $Nm^3$ of water by combining 4 $Nm^3$ of hydrogen and 1 $Nm^3$ of $CO_2$ under high temperature and pressure using a catalyst. As 0.32 kWh of auxiliary machine power is required to produce 1 $Nm^3$ of methane[12], producing 1 toe of methane requires 1.2 toe of hydrogen, 2.3 $tCO_2$ of $CO_2$, and 0.37 MWh of auxiliary machine power (**Table 3**). A cost of 100 US$/(toe/year) was obtained through conversion into calorific units, based on an estimated construction cost of 500,000 yen/($Nm^3$-$CH_4$/hour[12]) and an annual expense ratio of 15%.

(5) $CO_2$ separation and capture technologies and $CO_2$ from the power generation and industrial sectors

For $CO_2$ capture in the power generation and industrial sectors, only post-incineration capture was considered for simplicity, and facility cost and power consumption were set based on RITE[13] (**Table 4**). We referred to Keith[14] for setting DAC and selected natural gas as the source of heat for the calcination process.

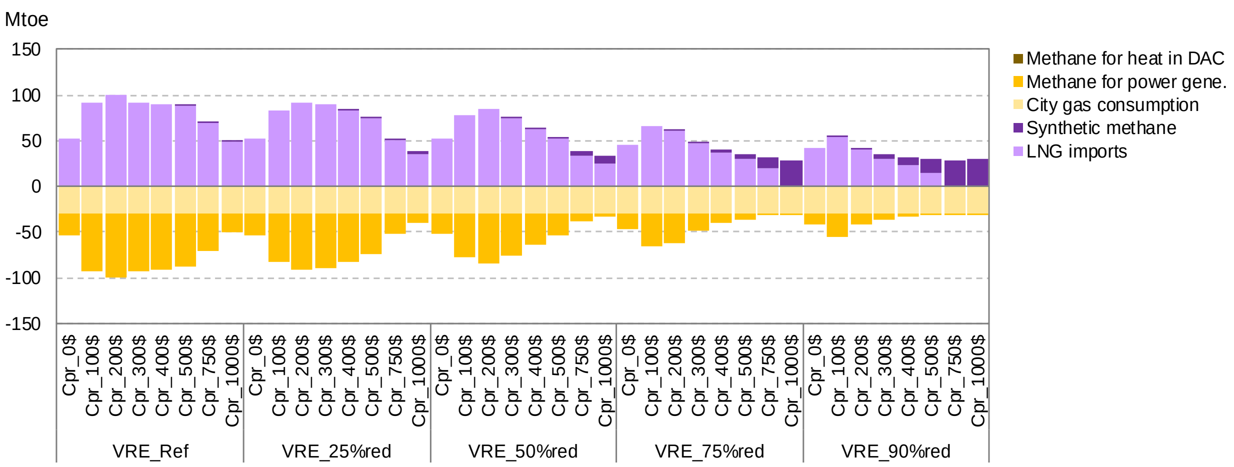



**Fig. 2** Annual nationwide supply and demand for methane in Japan

(Note) Positive figures represent methane supply and negative figures methane consumption. For reference, 101 Mtoe of LNG was imported in 2018. DAC stands for Direct Air Capture.

For the power generation sector, the amount and timing of $CO_2$ generation are determined endogenously based on thermal power plant operation. Meanwhile, as this model is an electricity and city gas supply model, it cannot track the $CO_2$ from coal and oil in the industrial sector. Therefore, this assessment calculated the amount of $CO_2$ emissions based on the coal and oil consumption for 2040 presented in the Sustainable Development Scenario (SDS) of the World Energy Outlook 2018[2)] and used the estimate as input (85 $MtCO_2$/year, the solid red box in **Fig. 1**). Hourly emissions were considered to be constant throughout the year. Further, steel and cement businesses of the industrial sector were handled together with all the other businesses in the sector in this assessment.

### 2.3 Case setting

This study conducted a sensitivity analysis using unit construction cost and carbon taxes of solar and wind power (variable renewable energy, or VRE) to clarify the conditions for methane synthesis to be superior in terms of cost. As the power generation cost is the dominant factor in the cost structure (**Appendix**) for methane synthesis by water electrolysis, VRE cost was selected as the target for sensitivity analysis. Specifically, five kinds of unit VRE construction cost (the cost for a 2014 (current) model plant, a reduction of 25%, 50%, 75%, and 90%) and eight carbon tax rates (0, 100, 200, 300, 400, 500, 750, and 1000 US$/$tCO_2$) were prepared, producing 40 cases in total (5×8). In setting the unit VRE construction costs, the values for solar and wind in **Table 1** were reduced by the same amount. Hereafter, the cases are named such that the case with the present unit VRE construction cost is named VRE_Ref, the one with a 25% reduction is named VRE_25%red, and so on. For the carbon tax rates, the case with no carbon tax is named Cpr_0$, the case with a tax of US$100 as Cpr_100$, and so on. Note that the carbon tax rates are imposed on the net $CO_2$ emissions from the power generation and city gas sectors (the double red-lined box in **Fig. 1** which represents the carbon in the fuel for coal- and oil-fired thermal power plants and imported LNG). The model was designed so that the tax rates would not be applied to the $CO_2$ recycled as synthetic methane.

## 3. Simulation results

### 3.1 Introduction of synthetic methane capacities

**Figure 2** shows the annual new supply of methane for all cases. It implies that a significant reduction in the unit VRE construction cost as well as a considerably high carbon tax may be required for introducing synthetic methane in large quantities. For VRE_Ref and VRE_25%red, synthetic methane capacity was limited even with Cpr_1000$. For purposes of comparison of carbon prices, under the scenario with a stable atmospheric $CO_2$-equivalent concentration of 450–480 ppm, the median tax rate is estimated at 200–300 US$/$tCO_2$ in 2050 for multiple models[15)]. 1000 US$/$tCO_2$ is considerably higher than that level, and it is assumed that the high cost of VRE becomes a cost disadvantage for water electrolysis, preventing the Sabatier reaction process, which uses the hydrogen produced with VRE, from gaining sufficient cost competitiveness.

Meanwhile, synthetic methane grew for Cpr_750$ and above for VRE_75%red and for Cpr_500$ and above for VRE_90%red. For example, for the combination of VRE_90%red with Cpr_1000$, synthetic methane output reached 29.4 Mtoe and covered the entire demand for city gas. In Fig. 3, which shows the weighted average generation cost of VRE (obtained by dividing the sum of the generation costs for solar and wind power by their combined power output), the figures decreased to as low as 41–59 US$/MWh for VRE_75%red and to 18–24 US$/MWh for VRE_90%red. A carbon tax rate of US$500 or US$750 per tCO2 is still high, but synthetic methane capacity might expand if the cost of VRE generation goes down to similar levels. Meanwhile, Fig. 3 shows that the weighted average generation cost may change suddenly depending on the carbon tax rate (as between Cpr_100$ and Cpr_200$ under VRE_Ref). This is because the composition of VRE changed significantly due to the introduction of wind power.

For all cases, $CO_2$ from the industrial sector was selected as the raw material for methane synthesis. $CO_2$ from the power generation sector and direct air capture were not used for any case. In the power generation sector, $CO_2$ supply apparently became harder to secure as the carbon tax rate went up and VRE increased (Section 3.2). Furthermore, the amount of $CO_2$ reused in this assessment was at most 68 $MtCO_2$ per year (in the case with VRE_90%red and Cpr_1000$), an amount that could be covered comfortably with industrial sector $CO_2$, presumably resulting in DAC not being introduced. However, it must be noted that industrial sector $CO_2$ is treated generically in this report; it may be difficult to capture $CO_2$ for some sectors or industrial plant sizes, and the industrial sector's capability to capture $CO_2$ requires detailed reviews in the future. DAC may become necessary if the supply of industrial sector $CO_2$ becomes insufficient.

### 3.2 Trends in the power generation sector

**Figure 4** shows the total power output of Japan and **Fig. 5** shows its total installed capacity. These figures indicate that solar power increases as the cost for VRE decreases and the carbon tax

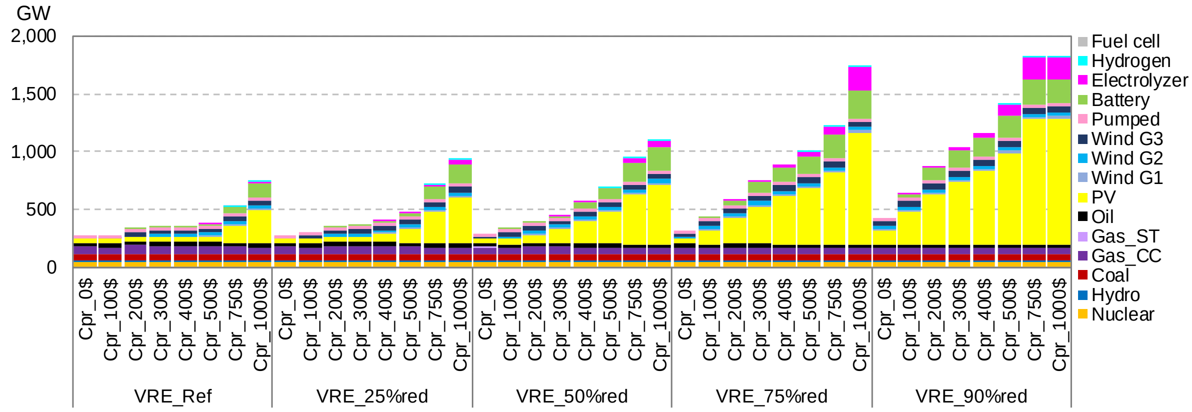
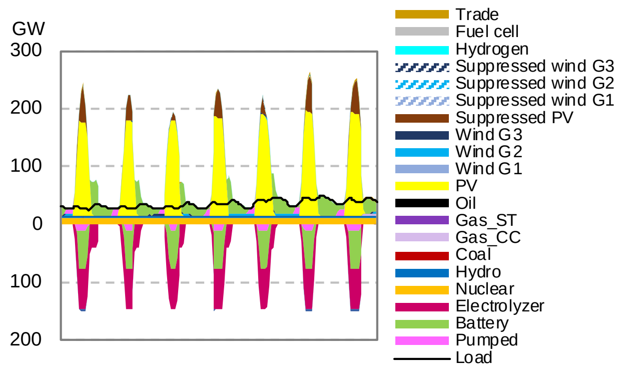



**Fig. 3** Installed power generation capacity of Japan

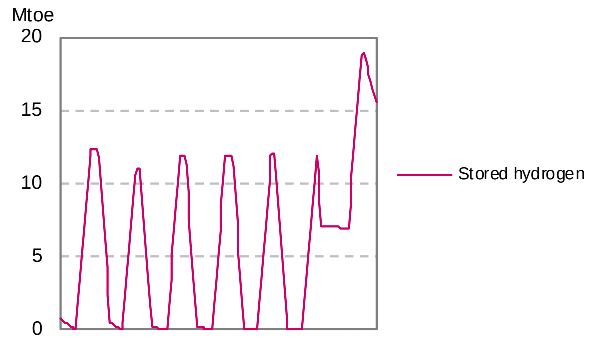
rate increases. Wind power also increased but not such that its effect on Japan as a whole was significant. This assessment does not consider any enhancement of inter-regional transmission lines, and this may have limited the introduction of new resources for wind power which are highly concentrated in certain regions.

In the cases where large amounts of methane synthesis were introduced (three cases, namely Cpr_1000$ with VRE_75%red, and Cpr_750$ and Cpr_1000$ with VRE_90%red), the total power output far exceeded the power demand (**Fig. 4**). This is because of the power required for producing hydrogen (water electrolysis), which amounted to 588–608 TWh per year. This also applies to installed capacity (**Fig. 5**), resulting in solar power capacity being required for producing hydrogen in addition to covering the final consumption. The total required installed capacity is estimated at 1729–1819 GW. This is five times the total installed capacity of 2016 (approx. 325 GW). There are high expectations that renewable hydrogen and methane synthesis would lead to sector integration and decarbonization, but the study shows that achieving decarbonization through these methods would require developing large amounts of renewable energies. Note that land-use restrictions related to solar power were not considered in this assessment; however, it will need to be considered in the process of realizing these scenarios as introducing such large capacities could affect land usage.

To illustrate the supply and demand for electricity when methane synthesis is introduced, the situation in Tokyo during the first week of April with VRE_90%red and Cpr_1000$ is shown in **Fig. 6a**. The solution with the optimal cost was to have a solar PV capacity far exceeding the final consumption and to ensure the supply-demand balance through day-time charging and discharging of batteries, while using day-time electricity for water electrolysis. **Figure 6b** shows the amount of stored hydrogen. Hydrogen is produced primarily in the daytime, but the figure shows that the hydrogen is being stored on a daily to weekly cycle to level the hourly output. Storage may play an important role in




(a) Supply and demand for electricity




(b) Stored hydrogen

**Fig. 4** Supply-demand balance in the Tokyo region (first week of April)

ensuring the supply-demand balance of hydrogen.

### 3.3 $CO_2$ emissions

**Figure 7** shows $CO_2$ emissions. The solid bars represent the net emissions from the electricity and city gas sectors (the double red-lined box in **Fig. 1**: the carbon contained in the fuel for coal- and oil-fired thermal power plants and imported LNG) while the shaded bars indicate the amount of $CO_2$ from burning synthetic methane. As the carbon from synthetic methane comes from the $CO_2$ captured in the industrial sector, synthetic methane is deemed to have effectively net-zero emission.

The net emissions from the electricity and city gas sectors tend to decrease as the carbon tax rate goes up. However, for VRE_Ref, VRE_25%red, and VRE_50%red, imported LNG is selected even

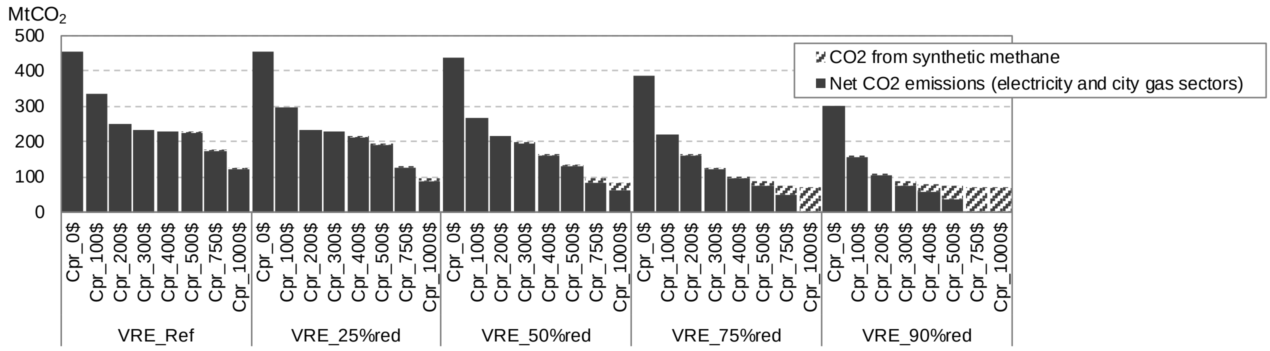


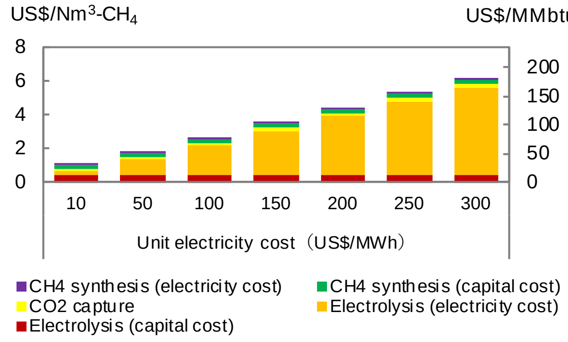

**Fig. 5** $CO_2$ emissions from the electricity and city gas sectors

under a tax rate of US$1000 per $tCO_2$, resulting in net emissions of 62–121 $MtCO_2$. Meanwhile, net emissions were suppressed significantly under high tax rates for VRE_75%red and VRE_90%red through the use of synthetic methane. For instance, in a case with VRE_90%red and Cpr_1000$, net emissions decreased to 2 $MtCO_2$. As a result of avoiding 68 $MtCO_2$ of emissions (the shaded areas in the figure) in effect through carbon recycling, electricity and city gas supplies had near-zero emissions. This is regarded as the effect of using synthetic methane. Note that we deemed synthetic methane as being carbon-neutral and attributed the $CO_2$ reduction effect to the electricity and city gas sectors in this study. However, when implementing carbon recycling in society, whether the source or the user should get credit for the recycled $CO_2$, or whether it should be allocated to both parties, may become a major subject of discussion. In-depth discussions will also be needed on the institutional aspects going forward.

## 4. Conclusion

This study presented a techno-economic assessment on synthetic methane in Japan employing a multiregional, high time-resolution, and optimized electricity and city gas supply model for Japan. Sensitivity analysis of VRE cost, which is the dominant factor for the methane production cost, and of carbon tax rates implies that cost reduction of renewables combined with a high carbon price, such as a 75% VRE cost reduction, would be crucial to accelerate synthetic methane. Developing technologies for reducing renewable energy costs and strengthening environmental policies are regarded as the key for the widespread use of synthetic methane. Another interesting result is that decarbonizing electricity and city gas with VRE, hydrogen production, and synthetic methane would considerably boost the VRE capacity as new plants become necessary for producing hydrogen as well as to meet final consumption.

Future challenges for this study include refining the assumptions, and modelling and analyzing innovative technologies. Specifically, this includes studies taking into account the feasibility of $CO_2$ capture in each business in the industrial sector, and the feasibility assessment of methane synthesis using new technologies including co-electrolysis.




**Appended fig. 1** Cost structure of synthetic methane production

## Appendix Cost structure of synthetic methane production

**Appended fig. 1** shows the cost of producing synthetic methane calculated based on the water electrolysis system, $CO_2$ capture (power generation and industrial sectors) and the cost assumption for methane synthesis described in Section 2.2. The utilization factor of the water electrolysis and methane synthesis systems were set at 30%, and the transportation cost for $CO_2$ and hydrogen were not considered (it was assumed that water electrolysis, $CO_2$ capture, and methane synthesis were all conducted in neighboring locations). A sensitivity analysis based on various unit electricity prices showed that the cost of electricity for water electrolysis becomes the dominant factor for a unit electricity price of US$50/MWh or higher. One of the main reasons is that as much as 4 $Nm^3$ of hydrogen is required to synthesize 1 $Nm^3$ of methane. Further, compared to Japan's LNG import price (US$9.4/MMBtu in FY2017, US$1 = 100 yen), the cost of synthetic methane would be 3.1 times as high even when the import price is US$10/MWh, indicating that cost is a problem.

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