Potential and Economics of Carbon-Neutral Methane; Combination of PtG and CCU

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This paper analyzed potential and economics of carbon neutral methane in Japan. 8 to 10 billion Nm^3 of carbon neutral methane can be produced from surplus electricity from 300 GW of solar photovoltaic and 100 GW of wind synthesized with CO_2 intensively emitted from biomass power plants, fossil fuel-fired power plants and large-scale industries, which is equivalent to 20% to 25% of the current city gas demand. Production cost of carbon-neutral methane is higher than hydrogen. However, supply (including production and delivery) cost of carbon-neutral methane is lower than hydrogen, as the carbon-neutral methane does not need new supply infrastructure.

Keywords : Renewable Energy, Power to Gas, Hydrogen, Methanation, Carbon Neutral, CCU

1. Introduction

In Europe and Japan in recent years, activities of Power to Gas (PtG) as a measure for grid integration of variable renewables are being accelerated. The hydrogen produced through PtG (CO_2-free hydrogen) is under consideration for use in fuel-cell vehicles, hydrogen-fired power generation, the desulfurization process in oil refinery, hydrogen-reduction steel manufacturing, heat demand in the industrial sector, and for blending into city gas pipelines. However, as the development of new equipment or infrastructure building is a challenge for many of these applications, they have not yet been realized. On the other hand, carbon-neutral methane (CN methane), being produced from CO_2-free hydrogen through PtG and CO_2 emitted from power generation and the final demand sector to be the feedstock of city gas, can use the existing city gas supply network without major barriers and contribute to decarbonization of city gas.

This study figures out the amount of surplus electricity from renewable energy and the volume of intensive CO_2 emissions by region in Japan, and estimates the potential of CN methane. In addition, economics of CN methane will be analyzed

2. What is carbon-neutral methane?

Carbon-neutral methane (CN methane) is defined as synthesized methane generated through CO_2-free hydrogen produced from renewable energy, and the CO_2 emitted from processes such as biomass power generation, thermal power generation, and large-scale industrial facilities (known as methanation process). Though CO_2 is emitted during the use of CN methane, it is offset by the CO_2 captured during methanation and CN methane can be deemed as being "carbon-neutral" (Figure 1). Furthermore, as CO_2 is effectively utilized, CN methane is also a form of carbon capture and utilization (CCU) technology. Feasibility studies and technological demonstrations are being carried out in countries such as Germany and Japan.

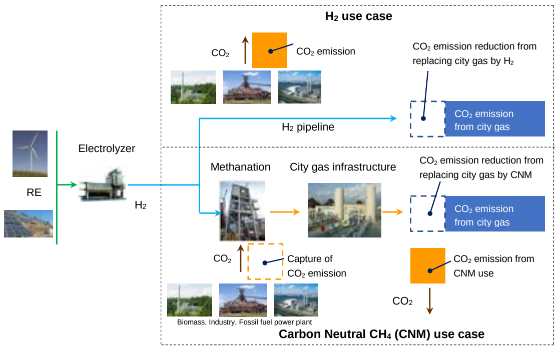

Figure 1 Comparison of hydrogen and carbon-neutral methane

3. Analysis of the potential of carbon-neutral methane

3.1 Methodology

First, the regional amount of producible hydrogen from surplus electricity from variable renewables (solar photovoltaic and wind power) is figured out by the power generation mix model (hourly-basis) based on the assumptions of deployment scale of variable renewables, battery storage capacity and capacity of interregional transmission lines. Japan is divided into nine former general electric utility regions excluding Okinawa (Figure 2). Secondly, the regional CO_2 emissions from biomass power plants and thermal power plants are estimated by the

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power generations mix model, and the regional CO_2 emissions from the industrial sector is estimated based on the existing statistics. As sizable volume of CO_2 emissions is required for efficient production of CN methane, the volume of intensively emitted CO_2 from biomass power plants and industrial sector is identified. Hourly CO_2 emissions pattern will also be addressed.

By comparing the volume of CO_2 required for CN methane production identified from the producible hydrogen and the volume of intensive CO_2 emissions, the volume of producible CN methane is specified. Additionally, the effectively usable of CN methane determined by the current city gas demand as the maximum limit is also specified.

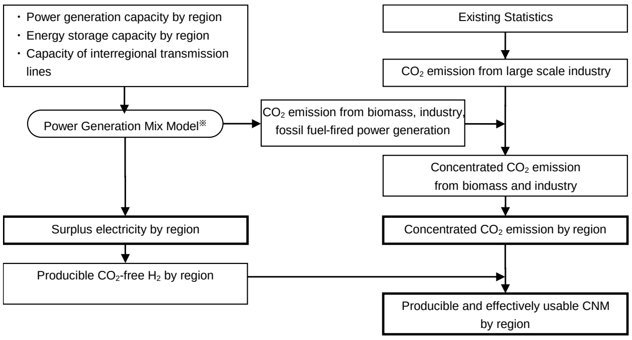

Figure 2 Flow of analysis

*This is a simulation model that specifies the surplus electricity from variable renewables in each region, based on assumptions on the operational priority of the power generation, interregional transmission lines, and energy storage (mainly pumped-storage hydro). This is not a cost minimizing optimization model.

3.2 Assumptions and scenarios

(1) Electricity demand/Base load power generation

From a long-term perspective and taking into account the trends toward electrification and energy conservation, power demand is assumed to increase by 1.13 times from the current 919 TWh to 1036 TWh (not including auto-producing). As for nuclear, the power generation is assumed to be the level in 2030 in the *Long-term Energy Supply and Demand Outlook* (amount of power generated is 193 TWh). With regard to large-scale hydro and pumped-storage hydro, no new construction is assumed. For the small and medium-scale hydro, biomass, and geothermal the capacity is assumed to be slightly above the 2030 level set out in the *Long-term Energy Supply and Demand Outlook*, taking into account of the factors such as the current development status and lead times for new development (13 GW, 8 GW, and 3GW respectively).

(2) Operation of power plants and grid

<Basic operations>

・ This research is based on a long-term perspective, and thermal power generations are assumed to be completely natural gas-fired, associating with the strengthening of climate change countermeasures.
・ Thermal power generation for frequency regulation is assumed to account approximately for 20% of hourly power demand.
・ In each region, pumped-storage hydro is first used for variable renewables as a measure for downward constraint of frequency regulation reserve. Batteries are used for variable renewables that cannot be absorbed even with pumped-storage hydro.
・ Electricity is discharged immediately when it is possible, firstly from pumped-storage hydro and then from batteries.
・ Variable renewables that cannot be absorbed even after the use of pumped-storage hydro and batteries are interchanged to other regions through interregional transmission lines. Interchange to the nearest neighboring region is prioritized, while “serial” interchange is carried out only if variable renewables cannot be absorbed by the nearest neighboring region.
・ The power output from variable renewables that cannot be absorbed by the grid even after above operations is defined as surplus electricity.
・ Hourly power demand - (Baseload power + Regulation control thermal power + Variable renewables + Power discharged from pumped-storage hydro and batteries) is met by thermal power generation (only when positive).

<Power interchange priority operations>

As the surplus electricity interchange to the areas where CO_2 emission are huge and city gas demand as an index of accommodation capacity of CN methane is also large would be a key factor for CN methane, the following cases are added to the assumption for interregional power interchange.

・ Cases where “serial” interchange to the Kanto, Kansai, and Chubu regions are prioritized

(3) Variable renewables deployment scenario

Large-scale deployment of VRE is intentionally assumed for the sake of visualization of CN methane. The following three scenarios are taken: 300GW of PV + 100 GW of wind power, 500 GW of PV + 300 GW of wind power, and 700 GW of PV + 500 GW of wind power.

(4) Scenario for batteries introduction and strengthening interregional transmission lines

As the future deployment scale of batteries is unforeseeable, it is assumed that 200 GWh of battery at 300 GW of PV + 100 GW of wind power and 1 TWh at 700GW of PV + 500 GW of wind power will be introduced. It is assumed that interregional transmission lines can be used to their maximum operating capacity for the interchange of surplus electricity from variable renewables.

The six cases for battery introduction and strengthening interregional transmission lines that are addressed in this study are shown in Table 1. In the “Base case,” batteries are not introduced, while interregional transmission lines are operated in “Basic operations”. In the “Bat case,” batteries are regionally introduced corresponding to the scale of variable renewables.

The “Bat+TMM” case is based on the assumption that batteries are introduced, and on top of that, prioritizes “serial” power interchange (for example, surplus electricity from Hokkaido passes through Tohoku directly to Kanto). The “Bat+TMM+Sn” cases expand the capacity of interregional transmission lines by *n* times from the current capacity. The simulation runs for individual VRE deployment scenario coupled with scenarios for battery introduction and strengthening interregional transmission lines.

Table 1 Scenarios for batteries introduction and strengthening interregional transmission lines

Cases	Description
Base	No battery. Regular operation of interregional transmission lines.
Bat	Battery introduced regionally according to VRE deployment scale.
Bat+TMM	Battery introduced and serial power interchange is prioritized.
Bat+TMM+S2	In addition, interregional transmission lines capacity doubled.
Bat+TMM+S3	In addition, interregional transmission lines capacity tripled.
Bat+TMM+S4	In addition, interregional transmission lines capacity quadrupled.

3.3 Identifying intensively emitted CO_2 by region

Firstly, CO_2 emissions coefficient from natural gas-fired power generation and biomass power generation are shown in Table 2.

Table 2 CO_2 emissions coefficient from natural gas-fired power generation and biomass power generation

	LNG-fired power generation	Biomass power generation
Power generation efficiency	50%	32%*1
CO_2 emission coefficient of fuel	0.000050kg-CO_2/kJ	0.000112kg-CO_2/kJ *2
CO_2 emission per kWh generation	0.36 kg-CO_2/kWh	1.26 kg-CO_2/kWh

*1: Documents from the Procurement Price Evaluation Committee (http://www.meti.go.jp/committee/chotatsu_kakaku/pdf/026_04_00.pdf)
*2: IPCC materials

Natural gas-fired power plants are majorly located in industrial zones, and all the CO_2 emitted is assumed to be intensive. The volume of CO_2 emitted from natural gas-fired power generation is figured out from the power generation mix simulation, it differs depending on the deployment scale of variable renewables.

With regard to biomass power generation, while the total CO_2 emissions is 53 million t-CO_2 from an assumed 8 GW, not all the CO_2 is necessarily emitted intensively. Hence, biomass power plants that exist in the “industrial zones” prescribed in the *Census of Manufactures* are identified from FIT-accredited capacity data (as of the end of March 2017). Next, the targets are narrowed down by extracting only an industrial zone with the largest accredited installed capacity in each prefecture.

With regard to the industrial sector, based on the *Energy Consumption Statistics by Prefecture (FY2015)*, the CO_2 emission from the manufacturing sector was 330 million t-CO_2, however, only large-scale facilities located in the industrial zones are selected. The CO_2 emission in each industrial zone is estimated by the percentage of employees in the facilities with 300 or more employees in the total number of employees identified from the *Census of Manufactures*. The emissions only from the industrial zone with the largest emissions in each prefecture is specified.

Based on the methodologies described above, the intensive CO_2 emissions volume from biomass power generation and the industrial sector are 34 million t-CO_2 and 40 million t-CO_2 respectively. CO_2 emissions from natural gas-fired power generation changes depending on the scale of variable renewables, and ranges from 200 ~ 100 million t-CO_2 (Figure 3).

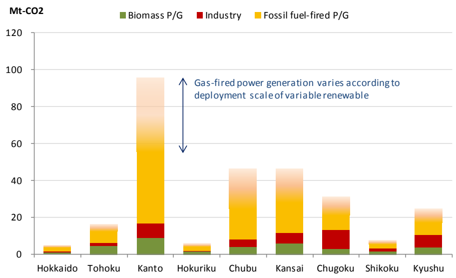

Figure 3 Intensive CO_2 emissions by region

The CO_2 emissions identified above are annual basis. As the period of CO_2 emission and the period of hydrogen production from surplus electricity presumably mismatches, it should be noted that CO_2 storage tanks are needed in order to utilize as much CO_2 as possible. Hence, the production of CN methane based on hourly CO_2 emissions is also addressed. Hourly CO_2 emissions patterns from the industrial sector are assumed to be the same as the power demand patterns. CO_2 emission pattern from biomass is assumed to be constant through the year. CO_2 emissions pattern from thermal power generation is figured out from operation pattern identified by the power generation mix simulation.

3.4 Specific energy required for the production of carbon-neutral methane

The specific electricity required for the production of hydrogen through the electrolysis of water is currently about 5kWh/Nm^3-H_2 and is assumed to be reduced to 4.5kWh/Nm^3-H_2 in the future. Taking into consideration that 4Nm^3-H_2 hydrogen is needed for the production of 1Nm^3-CH_4 (refer to the following formula), and that the auxiliary power per unit of methane generated is 0.32kWh/Nm^3-CH_4 (estimated based on various studies), the specific electricity required for the production of methane will be $4.5\times4 + 0.32 = 18.32\text{kWh/Nm}^3\text{-CH}_4$. The volume of CO_2 needed in the production of $1\text{Nm}^3\text{-CH}_4$ is $1.972\text{kg-CO}_2\text{/Nm}^3\text{-CH}_4$ (Table 3).

$4H_2O \rightarrow 4H_2 + 2O_2$ $\Delta H = 286\text{kJ/mol}$: Water electrolysis (Endothermic reaction) (×4)
$CO_2 + 4H_2 \rightleftarrows CH_4 + 2H_2O$ $\Delta H = -165\text{kJ/mol}$: Sabatier reaction (Exothermic reaction)

Table 3 Specific electricity required for the production of hydrogen and methane

Electrolyzer	Specific electricity consumption	4.5 kWh/Nm^3-H$_2$
Electrolyzer+ methanation	Specific electricity consumption	18.32 kWh/Nm^3-CH$_4$
	Specific CO$_2$ consumption	1.972kg-CO$_2$/Nm^3-CH$_4$

3.5 Results of analysis

Firstly, the analysis results of the amount of surplus electricity are shown in Figure 4. We can see that the nationwide amount of surplus electricity decreases with the introduction of batteries and the strengthening of interregional transmission lines.

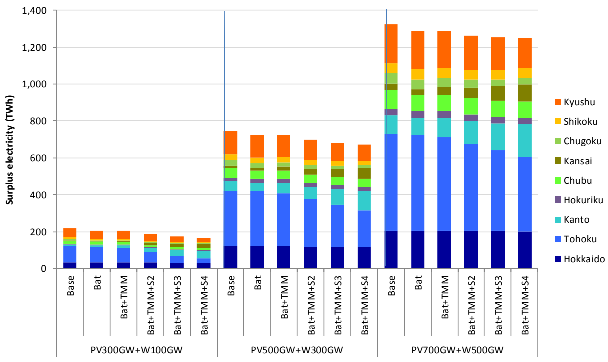

Figure 4 Amount of surplus electricity

(1) Non-hourly CO_2 emissions-basis

Figure 5 shows the amount of producible CN methane by region when hourly CO_2 emissions is ignored. In the case of "300 GW of PV + 100 GW of wind power," the amount of producible CN methane in the Kanto and Kansai regions increases due to enhancement of surplus electricity interchange as a result of strengthening of interregional transmission lines. However, the nationwide producible amount of CN methane decreases as a result of a fall in the nationwide amount of surplus electricity, due to the absorption effect of surplus electricity by the Kanto and Kansai regional grids (Figure 4). On the other hand, in the case of "500 GW of PV + 300 GW of wind power," as substantial amount of surplus electricity occurs, the utilization of interregional transmission lines allows to use more CO_2 from the regions emitting large volume of CO_2, such as Kanto and Kansai, resulting in increasing the nationwide amount of producible CN methane.

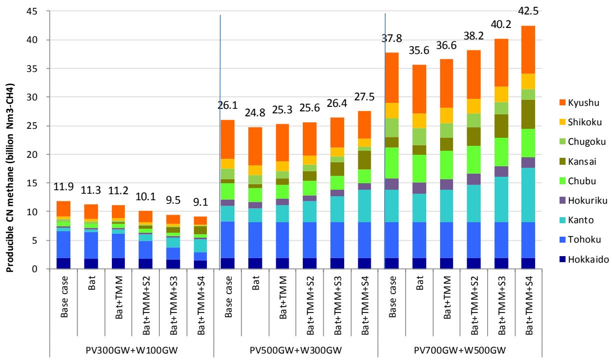

Figure 5 Amount of Producible CN methane (Non-hourly CO_2 emissions-basis)

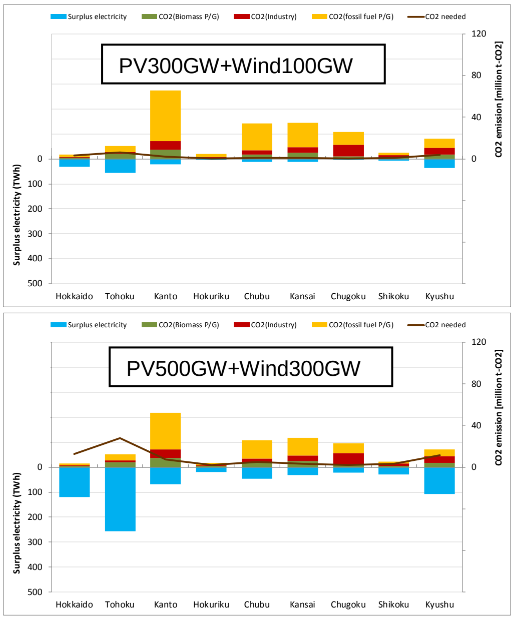

Figure 6 Regional amount of producible CN methane (Bat+TMM+S2 case)

In the case where renewable energy deploys on a large scale, no change is observed in the amount of producible CN methane in Hokkaido and Tohoku among the scenarios for batteries introduction and strengthening interregional transmission lines, because there is an upper limit to the amount of intensive CO_2 emissions that can be used. Even if the scale of renewable energy introduced were to be expanded beyond this level, the amount of producible CN methane would not increase. This situation is described in detail in Figure 6, which illustrates the relationship between surplus electricity by region and the volume of CO_2 required for CN methane production. The amount of producible CN methane, in each of three VRE deployment cases, are 9 billion ~ 12 billion $\text{Nm}^3\text{-CH}_4$, 25 billion ~ 28 billion $\text{Nm}^3\text{-CH}_4$, and 36 billion ~ 43 billion $\text{Nm}^3\text{-CH}_4$, respectively. In comparison with the methane calorific value equivalent of current city gas demand, 38.3 billion $\text{Nm}^3\text{-CH}_4$, CN methane has huge potential. The amount of effectively usable CN methane (Figure 7) in each case is 6 ~ 8 billion

Nm^3-CH_4, 11 ~ 16 billion Nm^3-CH_4, and 17 ~ 25 billion Nm^3-CH_4 respectively. The carbon neutralization rates for city gas are 14 ~ 21%, 28 ~ 42%, and 43 – 64% respectively.

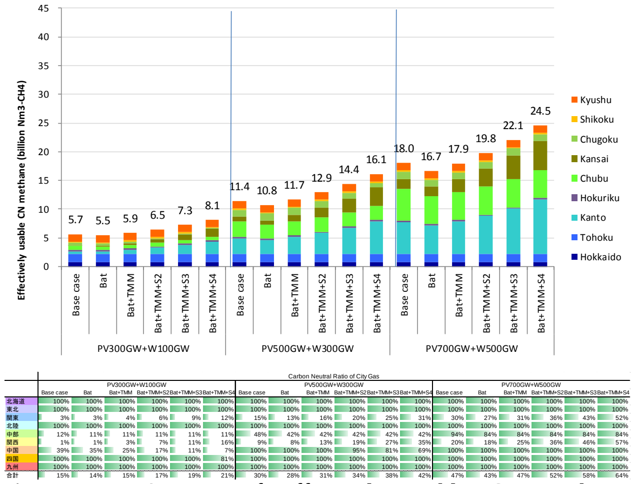

Figure 7 Amount of effectively usable CN methane (Non-hourly CO_2 emissions-basis)

(2) Hourly CO_2 emissions-basis

Figures 8 and 9 show the analysis results that take into consideration the hourly CO_2 emissions. Due to the timing mismatch between surplus electricity and CO_2 emission, the amount of producible CN methane falls by 20% ~ 40%, and the effectively usable amount falls by several % ~ 30%, in comparison with the case where hourly CO_2 emissions is not taken into consideration. As shown in Figure 10, when hourly CO_2 emissions is taken into consideration, it is observed that the volume of CO_2 that can be used decreases during the time period when surplus electricity is generated. However, in the case of "300 GW of PV + 100 GW of wind power," as the scale of surplus electricity is relatively small and there are sufficient CO_2 emissions even when the hourly CO_2 emissions is taken into account, a significant difference between the two cases is not observed.

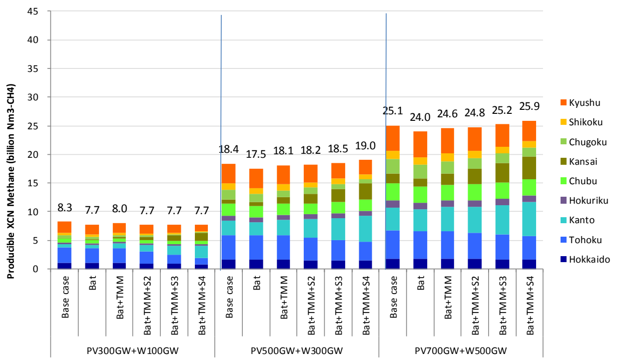

Figure 8 Amount of producible CN methane (Hourly CO_2 emissions-basis)

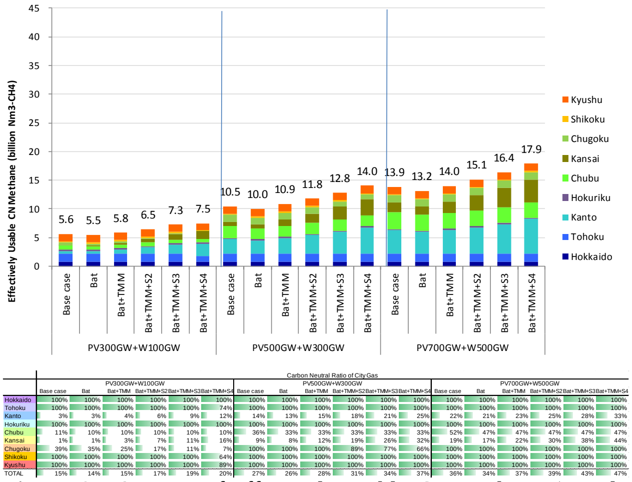

Figure 9 Amount of effectively usable CN methane (Hourly CO_2 emissions-basis)

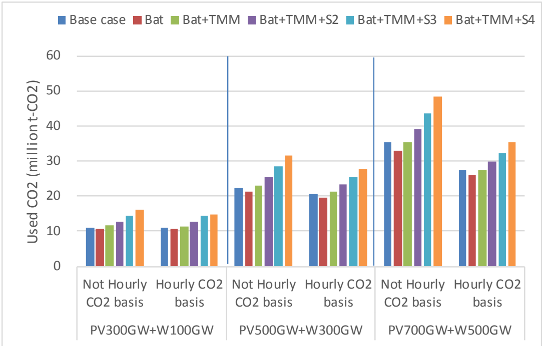

Figure 10 Comparison of amounts of CO_2 used (on the basis of the amount of effectively usable CN methane)

4. Economics of carbon-neutral methane

Here, the supply costs of hydrogen and CN methane will be compared. Though it is obvious that production cost of hydrogen is cheaper, new infrastructure is required for supplying hydrogen. On the other hand, CN methane, despite the higher production cost, can avoid investments for new infrastructure, by using the existing infrastructures.

4.1 Facility configuration

Figure 11 shows the assumed facility configuration for production and supply of hydrogen and CN methane. With regard to the production and supply of hydrogen, hydrogen produced in a water electrolysis is supplied to consumers through hydrogen pipelines along with compressors and compression tanks that are all newly invested. It is assumed that the CAPEX of hydrogen consuming equipment at the consumer is same as the CAPEX of city gas consuming equipment and no additional costs are incurred. CN methane is supplied to consumers via existing city gas production plants and pipelines. While there is a time and seasonal lag between the production of CN methane and the demand for city gas, the buffer function of existing gas holders and pipelines is assumed to be sufficient, though there is a need for new compressors. With regard to CO_2 capture, cost per ton-CO_2 is added to the CN methane production cost.

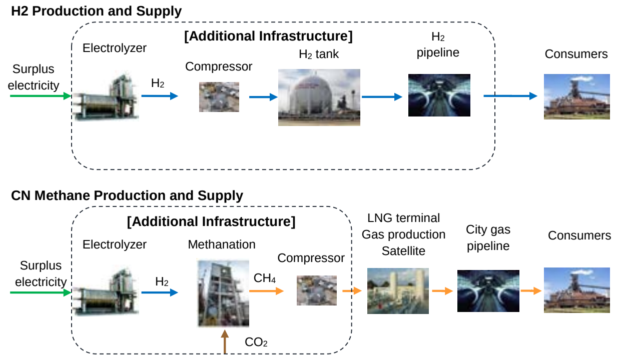

Figure 11 Facility configuration for hydrogen supply and CN methane supply

4.2 Assumptions for Costs and specifications

(1) Water electrolysis/Methanation

The assumptions for costs and equipment specifications for water electrolysis and methanation are shown in Table 4, based on references [1), 2), 3)].

Table 4 Assumptions for the costs and specifications of water electrolysis and methanation facilities

		Assumptions
Water use	Per H_2 production	0.8 kg-H_2O/Nm^3-H_2
	Per CH_4 production	3.23 kg-H_2O/Nm^3-CH_4
Water price	Industrial water *1	JPY 30 /m^3
CO_2 capture	Capture cost *2	JPY 1,000 /t-CO_2
OPEX *3		Maintenance: 1.6%/year of CAPEX Miscellaneous expenses: 0.7%/ yea of CAPEX
Operation		30 years
CAPEX of CN methane production = CAPEX of Electrolyzer×4 + CAPEX of methanation -JPY 0.25 mil./(Nm^3-H_2/h)×4 + JPY 0.5 mil./(Nm^3-CH_4/h) = JPY 1.5 mil./(Nm^3-CH_4/h) -JPY 0.1mil./(Nm^3-H_2/h)×4 + JPY 0.2 mil./(Nm^3-CH_4/h) = JPY 0.6 mil./(Nm^3-CH_4/h)		

*1: Estimated based on the Tokyo Metropolitan Government's rates for industrial water.
*2: Reference documents from the *Technology Roadmap for Next-Generation Thermal Power Generation*
*3: Assumption based on the Power Generation Cost Verification Working Group.

(2) Hydrogen supply/CN methane supply infrastructure

The calorific value per unit volume of hydrogen is about one-third that of city gas. However, as hydrogen has lower viscosity, its calorific transportation efficiency is assumed to be the same. Hence, the length of the pipelines needed per calorific value supplied is assumed to be the same for both city gas and hydrogen. The price of pipelines per unit of city gas demand by type of use estimated from references [4), 5), and 6)], is used (JPY 19,700/GJ/year for non-industrial uses, JPY 4,700/GJ/year for industrial uses, and JPY 11,400/GJ/year for all users). Hydrogen supply volume changes corresponding to the capacity factor of water electrolyzer, and the length of pipelines changes accordingly.

With regard to hydrogen compressors and compression tanks, the relationship between the hydrogen storage volume and the cost of compressors and compression tanks per unit of hydrogen storage volume, as presented in reference material [7)], is used. Compressors used for the supply of CN methane are assumed to have the same unit cost as hydrogen compressors. Setting the standard scale for the water electrolyzer and methane production facility (1,000kW = 222Nm^3-H_2/h, 1,000kW = 55Nm^3-CH_4/h respectively), the unit cost of the compressor changes corresponding to the supply volume decided by capacity factor. Figure 12 shows the costs of supply infrastructure per unit of output from the production facilities. The greater the capacity factor of the production facilities, the larger the supply volume, and the higher the cost of supply infrastructure required. The total cost for supply is the summation of the production facility cost (water electrolyzer and methane production facility) and supply infrastructure cost, and the Levelized Cost of Energy (LCOE) of hydrogen and CN methane are calculated.

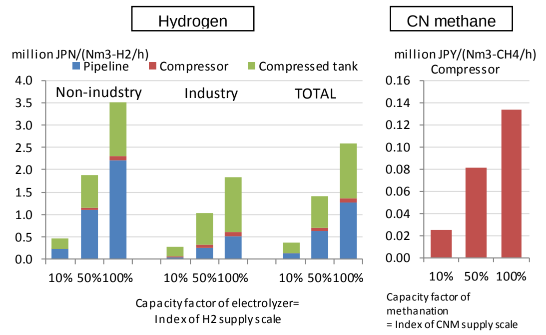

Figure 12 Unit cost of supply infrastructure for hydrogen and CN methane

4.3 Results of analysis

Firstly, the supply cost of CN methane, as compared to LNG prices and city gas retail prices, are shown in Figure 13 (the two cases; "500 GW of PV + 300 GW of wind power" and "700 GW of PV + 500 GW of wind power" are shown as examples). The vertical lines in the figure represent the capacity factor of CN methane production facilities in the major regions (identified from the power generation mix model), and their intersection with the curves indicate the supply cost of CN methane. For the purpose of comparison, range of the future LNG price and city gas retail prices including carbon price (methane calorific value equivalent) are also shown in the figure. It is revealed that CN methane supply cost can hardly compete with LNG import prices. However, if LCOE of renewable energy decreases to JPY 3 ~ 5 /kWh, it would be possible for CN methane supply cost to compete with city gas retail prices, although this is also dependent on the capacity factor.

Next, Figure 14 compares the supply cost between hydrogen and CN methane, converted to methane calorific value. Regardless of the capacity factor and LCOE of renewable energy, CN methane supply cost is significantly higher than hydrogen production cost without including infrastructure. This is obvious because although the calorific value of CN methane is about three times that of hydrogen, the production of CN methane requires water electrolysis×4 + a methanation facilities, increasing the facility cost to approximately six times that of hydrogen production. However, when hydrogen supply is included, the supply cost for CN methane is lower than hydrogen for most of capacity factor. This means that hydrogen supply can be more economical than CN methane supply only when hydrogen is distributed in the locally limited area that can minimize the pipeline investment, such as hydrogen-fired power generation and industrial complexes (where hydrogen supply costs are located between the dotted line and green line in Figure 14).

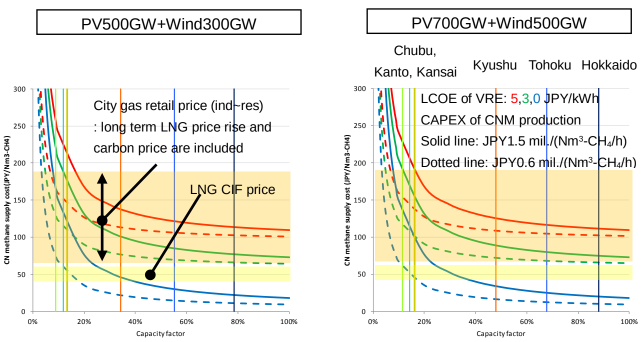

Figure 13 CN methane supply cost ("Bat+TMM+S4" case)

Note: The shapes of the curves are the same in both figures. LNG and city gas prices (shown as methane calorific value equivalent) are based on forecasts from the *Asia/World Energy Outlook 2018* (The Institute of Energy Economics, Japan). CO_2 costs are assumed to be 4,100 yen/t-CO_2, estimated based on the CCS costs in the *RITE results report for 2015* and forecast for future reduction in CO_2 capture costs in the *Technology Roadmap for Next-Generation Thermal Power Generation*.

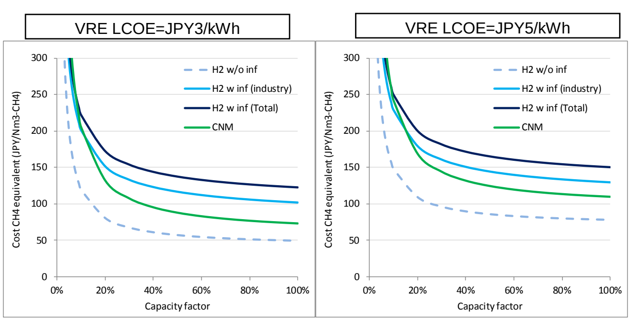

Figure 14 Comparison of supply costs for hydrogen and CN methane

Note: Water electrolyzer CAPEX is JPY 0.25 mill./(Nm^3-H_2/h), and CN methane production facility CAPEX is JPY 1.5 mill./(Nm^3-CH_4/h).

5. Conclusion

Carbon-neutral methane (CN methane) is regarded as a "low-carbon hydrocarbon energy" that is produced through the combination of PtG and CCU. This study analyzed the potential and economics of CN methane in Japan.

According to the results of the analysis, by introducing PV + wind power generation at 300 GW + 100 GW ~ 700 GW + 500 GW scale, and using intensively emitted CO_2 from the industrial sector, thermal power generation and biomass power generation, the nationwide effectively usable CN methane will amount up to 6 ~ 25 billion Nm^3-CH_4, and 14% ~ 64% of current city gas can be carbon-neutralized. If hourly CO_2 emissions are taken into account, the amount of effectively usable CN methane would fall to 6 – 15 billion Nm^3-CH_4; even then,14% ~ 47% of city gas can be carbon-neutralized.

With regard to economics, while the supply cost of CN methane can hardly reach the LNG import price, if LCOE of renewables as well as methane production CAPEX including electrolysis and methanation reduce significantly, CN methane supply cost could compete with city gas retail prices. Furthermore, in most cases, CN methane supply, which can use the existing infrastructure, has superiority in economics to hydrogen supply, which requires new infrastructure.

Unlike hydrogen, CN methane is not accompanied by significant structural changes to the energy system. As CN methane is majorly used for feedstock of city gas, not for re-electrification of surplus electricity, there is an advantage over battery in using surplus electricity effectively regardless of the various constraints in the power grid. This concept is exactly "sector coupling" that enhances decarbonization of the entire energy system by accommodating renewable energy not only by the power grid but also city gas and the transportation sector. In addition, promotion of CN methane, which utilizes CCU technology, could also be one of the exit strategies for the development of CO_2 capture technologies. In other words, even if the introduction of CCS were not realized in Japan due to challenges such as identification of CO_2 storage sites, economics, and social acceptance, the R&D investment in CO_2 capture technologies would not be a waste if CN methane is promoted.

To make the potential of CN methane in Japan realize, significant reduction in the LCOE of renewable energy and the cost of methane production facilities is a prerequisite. However, from the long-term perspective of 80% reduction in GHG emissions by 2050 and to curb the huge payment of fossil fuels import through the utilization of domestic energy resources, CN methane has an important role to play.

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