Comparative Economics of Hydrogen and Carbon-neutral Methane Blending into the Existing City Gas Network

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This study evaluated decarbonization impact and cost of hydrogen blending and carbon-neutral methane (CN methane) blending into the existing city gas network. These two gases are produced from renewable energy. Larger scale of variable renewables deployment allows to curb the scale of facilities like electrolyzer and methanation and can reduce CO_2 abatements cost in both cases. Decarbonization impact of hydrogen blending is limited, though the CO_2 abatement cost is smaller than CN methane blending. On the other hand, CO_2 abatement cost of CN methane is higher than hydrogen blending, though CN methane blending can bring about larger decarbonization impact on the city gas network. These results come from the fact that hydrogen blending can receive the benefit in using the existing infrastructure that is regarded as an advantage inherent to CN methane. However, it should be noted that in reality blending hydrogen or CN methane into city gas causes adjustment of calorie and combustion performance in equipment at consumers, and the adjustment cost incurred by hydrogen blending is supposed to be much higher than CN methane blending. This factor will be included in the future studies.

Keywords : Decarbonization, City gas, Blending, Hydrogen, Methanation

1. Introduction

The activities toward expanding the utilization of hydrogen for decarbonization have been accelerating throughout the world. As hydrogen can be produced from a wide range of resources, it is expected to improve energy security through the diversification of supply sources. On the other hand, demand creation is a challenge, and promotion of hydrogen utilization is under consideration for areas such as power generation, transportation, and industry. Of these, hydrogen blending into the existing city gas infrastructure is drawing attention mainly in Europe. However, it has been pointed out that hydrogen blending into existing city gas infrastructure poses various technological difficulties,[1)] and in order to circumvent these issues, the blending of carbon-neutral methane (CN methane) into the infrastructure is also being studied.[2), 3)] Prior research[4)] has shown that CN methane, which can be used as it is in existing infrastructure, offers an economic advantage over hydrogen that needs new infrastructure.

However, blending hydrogen into existing city gas infrastructure means that it would be possible to avoid building new infrastructure for the distribution of hydrogen to consumers, which would bring about similar advantages as those offered by CN methane.

This study carried out a comparative analysis on the economics and contribution to city gas decarbonization between hydrogen blending and CN methane blending.

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2. Roles and challenges of hydrogen and CN methane blending

Europe, firstly, aims to convert existing hydrogen demand derived from fossil fuels (primarily used for industrial feedstock) to hydrogen produced from renewable energy.[5)] As this demand is small-scale and distributed, and involves the procurement of hydrogen at a high cost, there is a possibility that even hydrogen produced from renewable energy, which is estimated to be expensive, can compete with the existing hydrogen. At the same time, the hydrogen market will gradually be expanded toward energy applications, such as large-scale industries. This strategy implies the intention to utilize existing infrastructure and equipment (Figure 1).

The hydrogen blending into existing city gas infrastructure has been addressed as one of the measures for creating hydrogen demand not only in Europe,[6), 7)] but also in Australia[8)] and the IEA.[9)]

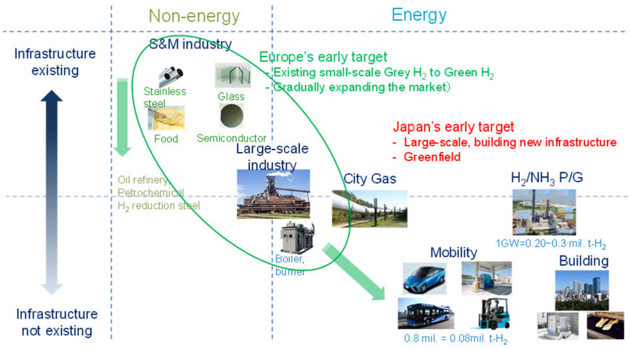


Fig 1 Difference in Hydrogen Demand Expansion Measures between Europe and Japan [10)]

However, there are many challenges in blending hydrogen into city gas infrastructure. These include changing the current measurement method based on volume to calorific value, calorific and combustion performance (combustion speed and Wobbe Index) adjustment of consumers' equipment, ensuring safety in the use of hydrogen, and specific arrangement for special industrial applications such as super high-temperature heating furnaces and carburization, which require carbon in their processes. These challenges are addressed also in Europe, and it has been pointed out that differences in the hydrogen blending rate among regions can be a barrier to the smooth transportation of city gas. Hence, the future development of infrastructure dedicated to hydrogen has also been taken into consideration.[6)]

Although hydrogen blending is expected to have an impact on the decarbonization of city gas, from the viewpoint of the city gas infrastructure that will accept the hydrogen, calorific value per unit volume of hydrogen (12.8MJ/Nm^3 LHV) is extremely low at less than one-third of that for city gas in the main regions (45MJ/m^3). As such, even if 2vol% of hydrogen were blended into the city gas infrastructure, the decarbonization impact on city gas would be no more than about 0.6%. In reality, there is also a need to address the abovementioned issues. Therefore, it must be recognized that the hydrogen blending into city gas is aimed at accelerating the creation of initial demand for hydrogen, which is a hydrogen-oriented viewpoint, and in this respect, neglects the circumstances of the side receiving the hydrogen.

In view of that, the blending of CN methane is a potential candidate. Methane is one of the main feedstocks for city gas, and the blending of CN methane can significantly lower the barriers related to the adjustment of the calories and combustion performance. Furthermore, as the calorific value, at 39.8MJ/Nm^3 (LHV), is considerably close to that of city gas, it offers a higher blend tolerance (on the basis of calorific value) compared to hydrogen. Therefore, decarbonization effect is about 19 times higher than that of hydrogen blending (CO_2 emissions from LPG addition that would be necessary for the adjustment of calorific value for city gas and energy input for CO_2 capture are disregarded).[11)]

3. Structure of Analysis

This research uses a model that incorporates city gas demand module into a simple power generation mix simulator,[12)] to specify the volume that can be blended into city gas and the decarbonization impact for the cases in which hydrogen and CN methane, respectively, are produced from surplus variable renewable energy, and to analyze the economics.

3.1 Structure of the simulation model

For the sake of simplicity, the study is conducted based on the assumption that Japan is a single virtual region. Base load power generation (nuclear, hydro, biomass and geothermal) and Load Frequency Control (LFC) thermal power generation are set on "must-run" status. Scenarios are established for variable renewable energy (solar PV and wind), and the surplus electricity is identified by simulating the hourly power generation mix. The volume of hydrogen and CN methane that can be produced every hour is figured out based on the surplus electricity. The volume of CO_2 required for CN methane production takes into consideration the hourly emissions based on prior research, [4)] and include only intensive emissions from thermal power generation, biomass power generation, and large-scale industries. On the other hand, the hourly volume of hydrogen and CN methane respectively that can be blended into city gas is specified based on an assumption of city gas calorie tolerance. However, it is assumed that a volume of hydrogen and CN methane exceeding the blend tolerance is not produced. Even if the calorific value of blended city gas were the same, hydrogen blending has a greater impact on combustion performance than CN methane blending, and incurs a greater cost in relation to the adjustment of consumers' equipment. However, as there are too many uncertainties concerning the level of this cost, it is disregarded in this study.

With regard to hydrogen, this study also considers the introduction of a hydrogen tank, based on the assumption that the aim is to blend a greater volume of hydrogen into city gas. On the other hand, about CN methane, it is assumed that existing gas holders/pipelines can be used as CN methane storage facilities. Based on the results of the simulation, the volume of gas blended per year and the CO_2 reduction effect achieved through the substitution of natural gas, and the required facility scale, are analyzed.

3.2 Assumptions

(1) Electricity demand, power generation capacity, city gas demand

Based on possible long-term electrification trends and electricity saving, it is assumed that power demand will increase by 10% from the current level to 1040 TWh. Nuclear is assumed to be the same level for 2030 set out in the Long-term Energy Supply and Demand Outlook, while small and medium-scale hydro, biomass, and geothermal are assumed to be slightly higher than the level for 2030 (13GW, 8GW, 3GW respectively). No new large-scale hydro and no pumped-storage hydro will be added. Thermal power generation is assumed to be completely LNGfired from a long-term perspective. Solar PV is set at 300GW, and wind power generation is set at 100GW and 300 GW.

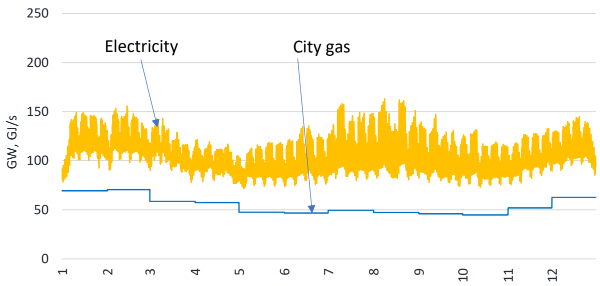


Fig 2 Hourly Load Profile of Electricity and City gas

City gas demand is assumed to be 35.1 billion m³ (45MJ/m³ equivalent) based on the demand in FY2016 of the former General Gas Utilities. Demand varies monthly, but the hourly demand within each month is assumed to be constant. Figure 2 shows the hourly electricity and city gas demand per year.

(2) Assumptions for blend tolerance of city gas (Case setting)

Although the current calorific value for city gas differs depending on the region, the calorific value of 45MJ/Nm³ for the metropolitan area is applied uniformly for the whole of Japan. As the maximum amount of calories that can be tolerated through hydrogen and CN methane blending is unknown, the range of 44-39.8MJ/Nm³ is established as the setting for various cases (Table 1). As the calorific value of methane is about three times that of hydrogen, the methane blend tolerance ratio (vol%) is about six times more of hydrogen. Note that 39.8MJ/ Nm³ is the figure for the case in which 100% methane is blended, the blend tolerance ratio for hydrogen, in this case, is 16.1%.

Table 1 Blending Cases

Acceptable calorific value (MJ/m³)	Acceptable H_2 blending ratio (vol%)	Acceptable CH_4 blending ratio (vol%)
39.8	16.1%	100.0%
41.0	12.4%	76.9%
42.0	9.3%	57.7%
43.0	6.2%	38.5%
44.0	3.1%	19.2%

(3) Assumptions for technological specifications and cost

In the case where hydrogen is blended directly into the city gas infrastructure, pressure is assumed to be 1MPa. In the case where it is blended via a hydrogen tank, pressure is assumed to be 20MPa through compression tank. Table 2 shows the technological specifications. In the case of CN methane, pressure is assumed to be 1MPa as the pressure of city gas holders is usually 0.85MPa. Table 3 shows the technological specifications, including CO_2 capture and methanation. The scale of energy storage in the city gas infrastructure is estimated using the geometric volume and pressure of gas holders and pipelines, based on the Gas Industry Handbook (Table 4). While there is room for debate on whether pipelines can be used as storage facilities, as city gas does not require instantaneous supply-demand balancing as electricity does, the pipelines are also assumed to have storage capacity. LNG price is assumed to be 50,000 yen/ton (0.92 yen/MJ) based on trends in recent years. Table 5 shows the assumptions of facility costs that are used in the economic analysis.

Table 2 Assumptions for Hydrogen Production

	Electrolyzer	Compressor	Total	Unit
Direct blending (1MPa)	4.50	0.076	**4.58**	kWh/ Nm^3-H_2
Blending through compressed tank (20MPa)	4.50	0.224	**4.72**	kWh/ Nm^3-H_2

Source: Based on 4) and 13).

Table3 Assumptions for Methanation

Electrolysis+Methanation	18.0	kWh/Nm^3-CH_4
Auxiliary	0.32	kWh/Nm^3-CH_4
Electricity for CO_2 capture	0.02	kWh/Nm^3-CH_4
Compressor (1MPa)	0.074	kWh/Nm^3-CH_4
Total	**18.42**	kWh/Nm^3-CH_4
Heat for CO_2 capture	**3,549**	kJ/Nm^3-CH_4
	(1,800)	MJ/t-CO_2
CO_2 capture ratio	90%	
Boiler efficiency	80%	

Source: Based on 4) and 13).

Table 4 Storage Capacity of City Gas Infrastructure

Gas tank	34	million Nm^3-CH_4
Pipeline	38	million Nm^3-CH_4
Total	72	million Nm^3-CH_4

Source: Estimated from "Gas Utility Handbook".

Table 5 Assumptions for CAPEX

Electrolyzer	215	1000JPY/(Nm^3-H_2/h)
Methanation	500	1000JPY/(Nm^3-CH_4/h)
CN-methane production	1360	1000JPY/(Nm^3-CH_4/h)
CCU(CO_2 capture and boiler)	134	million JPY/(t-CO_2/h)
	0.26	million JPY/(Nm^3-CH_4/h)
Hydrogen compressor	120	1000JPY/kW
Hydrogen tank	2.2	1000JPY/Nm^3

Source: Based on 12), 13) and 14).

3.3 Direct blending and blending via storage facilities

The approaches to direct blending into the city gas infrastructure and, and blending via storage facilities (new hydrogen compression tank in the case of hydrogen, and existing gas holders/pipelines in the case of CN methane), are shown below.

(1) Hydrogen blending

1) Direct blending

The capacity of the water electrolyzer is identified based on the correlation of the hourly producible hydrogen volume from surplus electricity and the blend tolerance (minimum water electrolysis facility capacity).

2) Blending via a hydrogen tank

As the blending volume is likely to be limited in case of direct blending of hydrogen, consider increasing the capacity of the water electrolyzer as larger as possible to produce a large amount of hydrogen, temporarily storing hydrogen that cannot be blended directly in a hydrogen tank, and blending this stored hydrogen at a different time. Firstly, the capacity of the water electrolyzer (maximum water electrolyzer capacity) that can produce a volume of hydrogen equivalent to the volume that can be blended yearly (Yearly city gas demand (Nm^3) × Blend tolerance ratio (%)) is specified. Next, using the water electrolyzer capacity as a variable (from minimum water electrolyzer capacity to maximum water electrolyzer capacity), the maximum capacity of the hydrogen tank that is required is identified through a simulation. However, in cases where surplus electricity is limited and a volume of hydrogen equivalent to the volume that can be blended yearly cannot be produced, all the surplus electricity is utilized for hydrogen production (in such cases, the capacity of the water electrolysis facility will be extremely large).

(2) CN methane blending

1) Direct blending of CN methane

The capacity of the CN methane production facility (water electrolyzer, methanation, CO_2 capture) is identified based on the correlation of the hourly producible CN methane volume from surplus electricity and the blend tolerance (minimum capacity).

2) Utilization of holders, etc.

It is assumed that existing gas holders and pipelines can be used for the storage of CN methane, and simulation is carried out by using CN methane production capacity as a variable.

4. Results of analysis

4.1 Blending volume

Figure 3 shows the relationship between the annual producible volume, blend tolerance, and blend volume, while Figures 4 and 5 are examples of the simulation results for a typical one-week period in summer. Both figures 4 and 5 are based on the assumption of large-scale variable renewable energy deployment, "Solar PV + Wind = 300GW + 300GW". Figure 4 shows the case in which blend tolerance at H_2 3.1vol%＝CH_4 19.2 vol%, while Figure 5 shows the case in which blend tolerance is at H_2 16.1vol%＝CH_4 100 vol%.

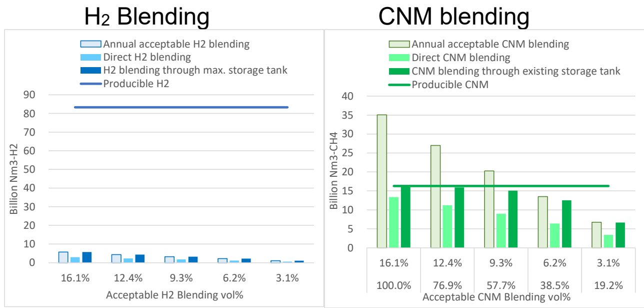


Fig 3 Producible amount, acceptable blending amount, and blending amount

Note: In case of "Solar PV + wind = 300GW + 300GW"

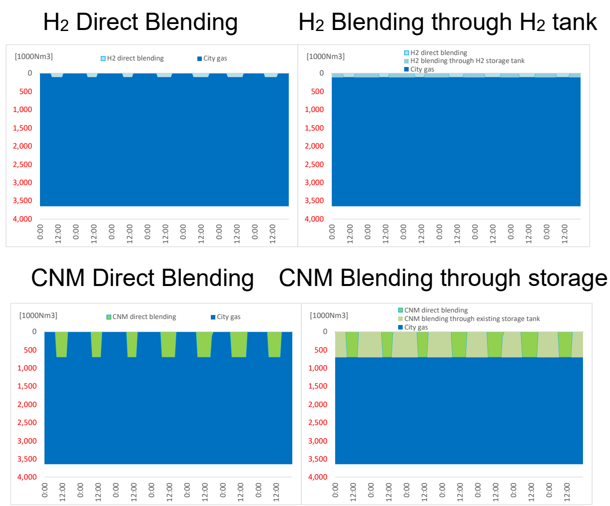


Fig 4 Blending profile (H_2 3.1vol%=CH_4 19.2 vol%)

Note: Example of a representative week in summer. "Solar PV + wind = 300GW + 300GW". Electrolyzer capacity is 0.16 million Nm^3-H_2/h for direct H_2 blending. Electrolyzer capacity is 0.24 million Nm^3-H_2/h and H_2 storage tank capacity is 64 million Nm^3-H_2 for H_2 blending through H_2 tank. Methanation capacity is 1 million Nm^3-CH_4/h for direct CH_4 blending and 1.45 million Nm^3-CH_4/h for CH_4 blending through the existing city gas storage tank.

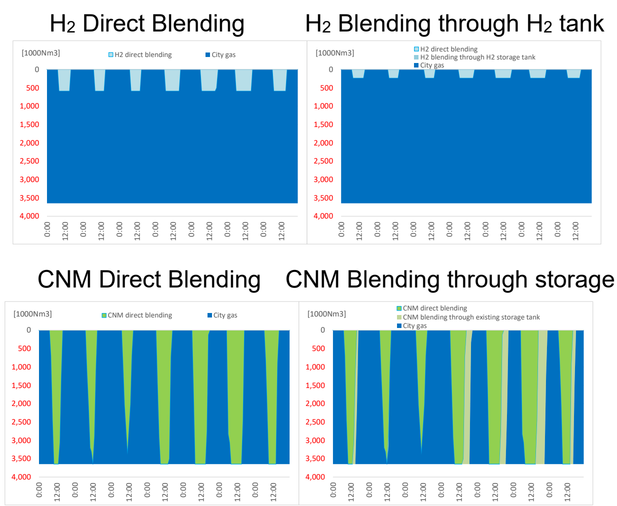


Fig 5 Blending profile (H_2 16.1vol%=CH_4 100 vol%)

Note: Example of a representative week in summer. "Solar PV + wind = 300GW + 300GW". Electrolyzer capacity is 0.84 million Nm^3-H_2/h for direct H_2 blending. Electrolyzer capacity is 1.26 million Nm^3-H_2/h and H_2 storage tank capacity is 330 million Nm^3-H_2 for H_2 blending through H_2 tank. Methanation capacity is 5.2 million Nm^3-CH_4/h for direct CH_4 blending and 7.24 million Nm^3-CH_4/h for CH_4 blending through the existing city gas storage tank.

While the hydrogen blend tolerance of city gas is considerably small in comparison with the scale of surplus renewable energy, the CN methane blend tolerance is at the almost same level as the scale of surplus renewable energy (Figure 3), which demonstrates the potential for accepting a large amount of surplus renewable energy. In the case of H_2 3.1vol%＝CH_4 19.2 vol% (Figure 4), it is possible to keep blend volume mostly flat every hour through the introduction of new storage facilities for hydrogen blending, and through the utilization of existing storage facilities for CN methane blending. However, in the case of H_2 16.1vol%＝CH_4 100 vol%, blend volume is flat for hydrogen blending, but does not remain flat in the case of CN methane blending as blend tolerance is high (Figure 5).

4.2 Facility scale

Figure 6 shows the facility scale and hydrogen blend volume in the case of hydrogen blending. In the case where only a small scale of renewable energy is introduced (Solar PV + Wind = 300GW + 100GW), direct blend volume is also low due to the smaller amount of surplus electricity. If a hydrogen tank is used in an attempt to increase blend volume, a larger scale of water electrolyzer would then be required (it would be necessary to use extremely low frequency and high output surplus power). At the same time, a large-scale hydrogen tank would also be required. Expanding the scale of renewable energy introduced (Solar PV + Wind = 300GW + 300GW) would increase the frequency for the emergence of surplus power, resulting in a greater amount of surplus power. Hence, it would be sufficient to keep the scale of the water electrolyzer and hydrogen tank small. At the respective blend tolerance ratios (hydrogen 16.1%, 12.4%, 9.3%, 6.2%, 3.1%), the introduction of the largest possible hydrogen tank would make it possible to carry out blending up to the blend tolerance almost throughout the year (5.66 billion, 4.36 billion, 3.27 billion, 2.18 billion, and 1.09 billion Nm^3-H_2 respectively).

Figure 7 shows the facility scale and blend volume in the case of CN methane blending. The direct blend volume (dots in the figure) for the respective blend tolerance ratios (CN methane 100%, 76.9%, 57.7%, 38.5%, 19.2%) does not lie in linear as it is in the case of hydrogen blending. This is because of the relative magnitude between the scale of surplus power and blend tolerance. In the case of hydrogen blending, the scale of blend tolerance is extremely small in comparison with the amount of surplus electricity (the amount of hydrogen that can be produced). For this reason, the frequency and scale of the emergence of surplus power are not significantly impacted, and the increase in water electrolyzer capacity accompanying the increase in blend tolerance has a mostly linear relationship with the increase in the volume that can be blended. On the other hand, as blend tolerance is high in the case of CN methane, even if methanation facility capacity were expanded to accompany the increase in blend tolerance, it would only have the effect of absorbing the surplus electricity that is generated at extremely low frequency, and the marginal volume of CN methane that can be blended decreases gradually.

In this study, it is assumed that renewable energy is introduced on a large scale, and the scale of surplus electricity exceeds blend tolerance. As such, methanation facility capacity in direct blending is dependent only on the blend tolerance ratio (in the figures, the position of dots of the same color in the horizontal direction is the same, regardless of the scale of renewable energy introduced). However, blend volume (vertical direction of dots) increases corresponding to the scale of renewable energy introduced.

When holders/pipelines are utilized, lines other than the 19.2% blend overlap in the scenario where the scale of renewable energy introduced is small (Solar PV + Wind = 300GW + 100GW). This is because it is dependent only on methanation facility capacity, regardless of blend tolerance ratio, since the scale of surplus power is small and the yearly producible amount of CN methane falls below the yearly blend tolerance when blend tolerance ratio is 38.5%.

If the scale of renewable energy introduced was expanded (Solar PV + Wind = 300GW + 300GW), the producible amount of CN methane also increases. In this situation, increasing the blend tolerance ratio enables a larger volume of CN methane to be blended (deviation of each line).

When blend tolerance ratio is small, the upper limit of the blend tolerance would be achieved faster even if the methanation facility capacity were increased. On the other hand, when blend tolerance ratio is large, the producible volume of CN methane would be reached before the upper limit of blend tolerance if the methanation facility capacity were increased (Blend tolerance > producible volume of CN methane).

4.3 Economics

Figure 8 shows the amount and cost of CO_2 abatement in the cases of hydrogen blending and CN methane blending. The procurement cost of electricity from renewable sources is assumed to be 5 yen/kWh.

The level of CO_2 abatement is the substitution effect of city gas through hydrogen/CN methane blending on the basis of calorific value, but in the case of CN methane, the incremental city gas consumption for supplying the necessary heat for CO_2 capture is deducted. Cost is obtained by deducting the reduction in LNG procurement from renewable energy procurement costs and facility costs. Facility costs comprise the cost of water electrolyzer, compressors, and hydrogen tank (where necessary) in the case of hydrogen blending, and water electrolyzer, methanation equipment, CO_2 capture equipment, and compressors in the case of CN methane blending.

Hydrogen blending incurs about half of the CO_2 abatement cost in comparison with CN methane blending; however, the degree of CO_2 abatement is extremely small.

Even with the expanded use of hydrogen tanks, it would still only be approximately 4 million tons. This is considerably limited when compared to the current level of CO_2 emissions from city gas, which is about 80 million tons. On the other hand, as CN methane has a high blend tolerance ratio and calorific value that is about three times that of hydrogen, it produces a significant reduction in CO_2 emissions. However, while a certain degree of cost reduction can be achieved through the utilization of existing storage facilities such as holders, CO_2 abatement cost is higher. However, for both hydrogen and CN methane, the greater the scale of renewable energy introduced, the lower the cost of CO_2 abatement.

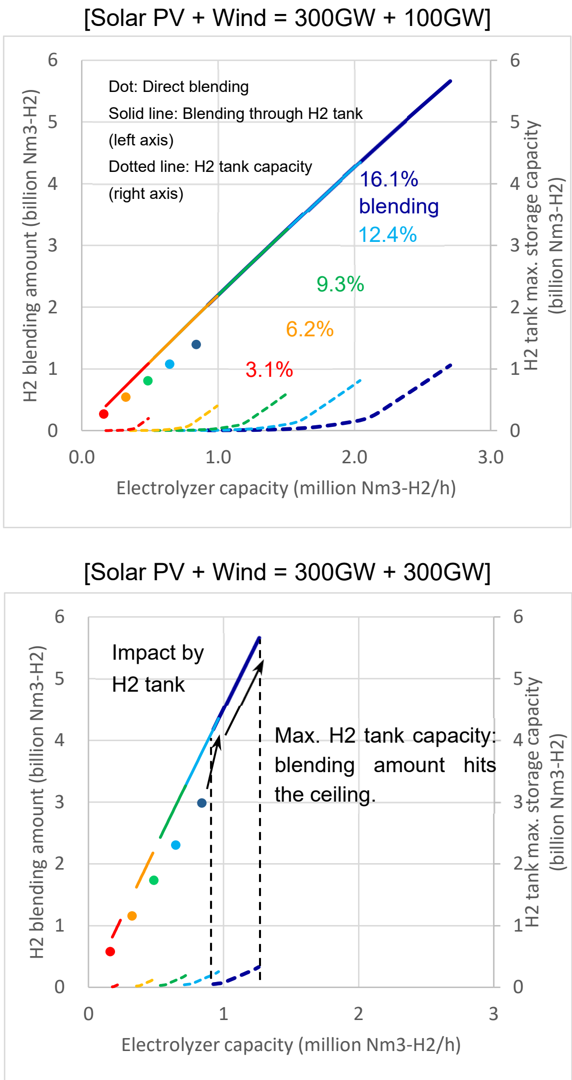


Fig 6 Electrolyzer Capacity and H_2 Blending Amount

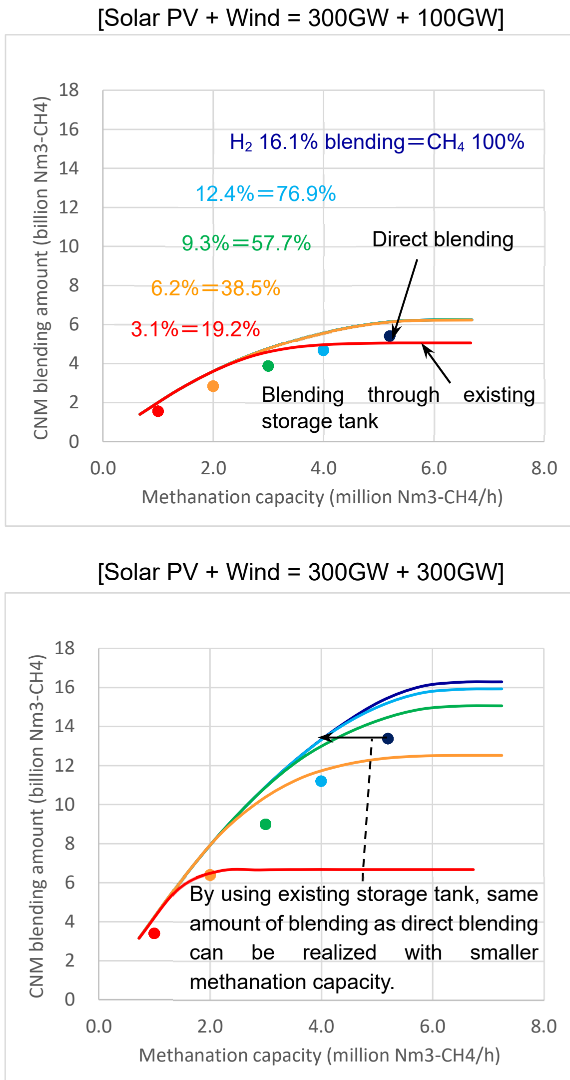
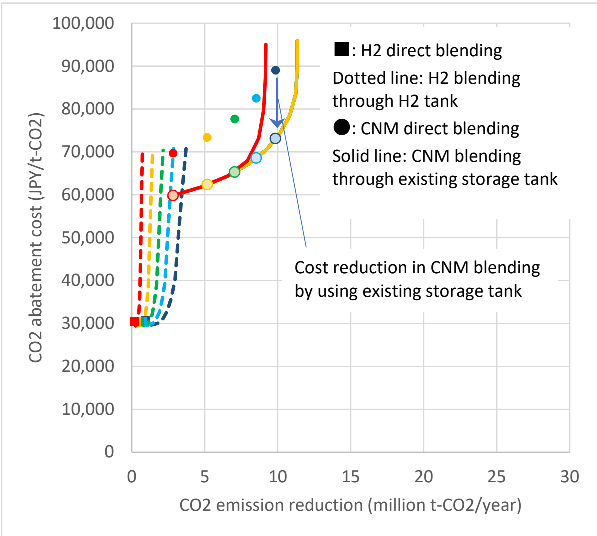


Fig 7 Methanation Capacity and CNM Blending Amount



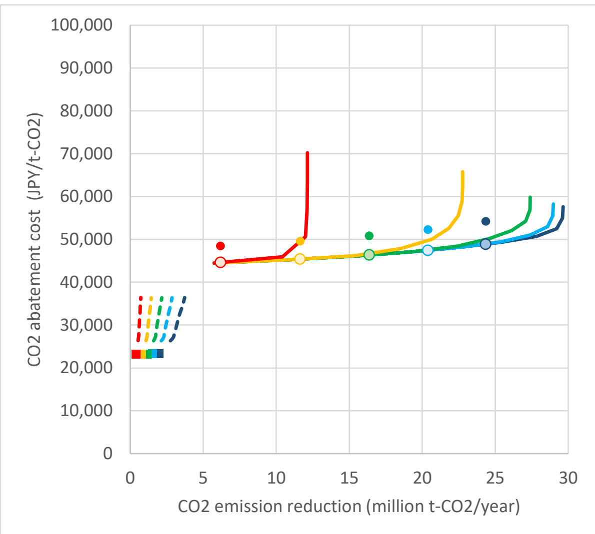


Fig 8 CO_2 Emission Reduction and CO_2 Abatement Cost

Note: Costs incurred on calorific adjustment for customers equipment by blending are ignored. Note that these costs incurred by hydrogen blending are larger than CNM blending.

5. Conclusion

This research provided a simple evaluation of the amount and costs of CO_2 abatement through the blending of hydrogen and CN methane, respectively, into city gas. For both scenarios, a larger scale of renewable energy introduced is more capable of suppressing the scale of facility per unit of blend volume, and of reducing CO_2 abatement cost. While CO_2 abatement cost is lower for hydrogen blending than for CN methane blending, its decarbonization impact on city gas is limited. On the other hand, while CN methane blending can be expected to produce a greater decarbonization impact, it poses the challenge of incurring a higher CO_2 abatement cost than hydrogen blending. This is because the economic advantage from the utilization of existing infrastructure, which is the inherent characteristic of CN methane, can also be applied to hydrogen blending.

In this study, the analysis was carried out based on the premise that standard calorific value can be changed without causing any technical issues. However, in reality, it is necessary to adjust calorific value and combustion performance of consumers' equipment by adding LPG into city gas that has been blended with hydrogen or CN methane. In the case of hydrogen blending, the costs involved in this respect are presumed to be higher than those for CN methane blending. Moreover, the production and injection of gas at a stable volume and properties are stipulated based on the current gas utility supply service provisions. This poses institutional issues for hydrogen blending and CN methane blending. An analysis that considers these factors will be a subject for the future.

Utilization of existing infrastructure is an advantage for CN methane blending, However, when the time comes to update infrastructure in the future, it will also be worth considering the establishment of infrastructure dedicated for hydrogen, depending on the region.

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